STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	)	
2019 Integrated Resource Plan and	)	
Application for Certification of Capacity	)	**Docket No. 42310**
From Plant Scherer Unit 3 and Plant	)	
Goat Rock Units 9-12 and Application	)	
for Decertification of Plant Hammond	)	
Units 1-4, Plant McIntosh Unit 1, Plant	)	
Langdale Units 5-6, Plant Riverview	)	
Units 1-2, and Plant Estatoah Unit 1	)	

DIRECT TESTIMONY OF JOAN KOWAL

on behalf of

EMORY UNIVERSITY

April 25, 2019

Q. MS. KOWAL, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

I received my BS in Mechanical Engineering from Bucknell University and started my professional experience in the power generation sector that included employment in the engineering department of Philadelphia Electric. In this role, I supported the design and operation of their generating plants, including start-up of the Limerick II nuclear plant and system engineering support of the Peach Bottom nuclear plant. I relocated to Atlanta, Georgia, in 1991 and worked for an engineering consulting firm providing support to South Carolina Electric and Gas and Baltimore Gas and Electric. I moved to Connecticut to work for Northeast Utilities and supported Millstone Generating Station as a system engineer, and eventually moved to their wholesale marketing group within the New England Power Pool. In 1998, I relocated to Bethesda, MD, and held various positions within National Energy and Gas Transmission, serving as a generating asset portfolio manager and fuel trading desk manager.

In 2005, I took a position with the University of Maryland, College Park, as their Energy Manager with oversight of the 27.5MW combined heat and power plant that served the University campus. Additionally, I served as the University System of Maryland's Energy Advisor and worked with the State of Maryland to procure three large renewable energy contracts for the state and University System. In 2013, I joined Emory University as its Senior Director of Energy Strategy and Utilities and currently serve in that role.

Q. MS. KOWAL, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

No, I have not previously testified.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

My testimony is to support Emory's goal to install a distribution-connected microgrid that will enhance Emory's resiliency for critical buildings in proximity to the Georgia Power substation located contiguous to the Emory campus.

Q. WHAT AREAS OF THE IRP ARE THE FOCUS OF YOUR TESTIMONY?

My testimony focuses on sections 8.5, 10.10 and Attachment H to Georgia Power's 2019 Integrated Resource Plan ("IRP"). Those parts of the IRP regard Renewable Resources, Research Activities and Supply Side Strategy, including Distributed Energy Resources and Battery Energy Storage Systems.

Q. WHAT SPECIFIC ACTION IS SOUGHT BY EMORY?

Emory requests that the Commission permit Emory and Georgia Power in the future to propose Emory's microgrid for approval by the Commission, similar to the way that the Commission's 2016 IRP order treated similar projects.

Q. **HAS EMORY DISCUSSED ITS MICROGRID PILOT WITH GEORGIA POWER?**

Yes, Emory has been in extensive discussions with Georgia Power on the proposed Emory microgrid. As part of these discussions, there was a collaborative call with Georgia Power and Duke Energy regarding a similar project with Clemson University. *See* Exhibit 1. In addition, Georgia Power brought several members of its Southern Company Research and Development team to Emory to review the scope of the project and collaborate on possible funding paths for moving forward as a research project.

Q. WHAT BENEFITS WILL ACCRUE?

The project advances Emory's, the City of Atlanta's and neighboring communities' resilience plans through development and installation of a microgrid with distributive energy resources and distributed energy resource management. This proposed microgrid pilot project will provide benefits to the community, city, state, and ratepayers of the Company by allowing resilience of critical functions for the portion of Emory's campus proximate to Emory University Hospital, Emory's Health Sciences Research Buildings, and the CDC. Emory will partner with Georgia Power to research the ways in which such a multi-building microgrid might ensure energy delivery to critical services during a grid disruption. As a preeminent institution of healthcare and higher education, Emory is well-positioned to disseminate the findings from the pilot project and to maximize the community benefit from allowing an innovative approach to ensuring critical healthcare, health sciences and security functions during extreme weather or other grid disruption events. Emory can assist other communities, organizations, and our state with emergency response and preparedness planning as a result of the lessons learned from this project.

Q. WHAT IS RESILIENCE?

According to Georgia Power, resilience "*refers to the ability of the electric system to withstand or recover from high impact events with a low probability such as physical attacks, cyber-attacks, and extreme weather events. In addition to the ability to reliably provide customers with the quantity and quality of power demanded, resilience addresses the ability of the system and utilities to reduce magnitude, duration and damage from high impact disruptive events. A lack of resilience can impede a utility's ability to reliably serve customers under these conditions." See* Direct Testimony of Jeffrey Grubb, Narin Smith, Michael Bush and Jeffrey Weathers, p. 55. This definition aligns with Emory's request for a proposed microgrid pilot project that includes the functioning of critical infrastructure to sustain essential services for communities during and following high impact events. Communities and customers understand the critical need for health, safety, and the preservation of critical health sciences research that the proposed microgrid pilot project would provide.

Q. IS EMORY PROPOSING ANY SPECIFIC RESILIENCE ENHANCEMENTS?

Yes, the proposed Emory pilot microgrid is a specific resilience enhancement that will serve critical buildings located on the Georgia Power electric distribution system during a high impact event. Recent events such as the sustained outage at the Atlanta Airport, the sniper attack at Pacific Gas and Electric's transmission substation, outages from Hurricane Sandy, as well as others throughout the country, highlight that the unexpected can happen. Georgia Power indicates that it will continue to address resilience in ways that will cost effectively provide consistent levels of sustained reliability, and that resilience need is particularly needed once the reliability measures are compromised from high impact events—particularly at facilities that meet critical needs like health services and nationally significant health sciences research. Life safety generators do not sufficiently address these needs. The number of failed emergency generators and stand-by generators following Hurricane Sandy demonstrates their potential inadequacies during extreme weather events.

While Georgia Power did not specifically ask for any resilience enhancements in this IRP related to high impact events, it did recognize the growing threat of these risks and indicated that Georgia Power would, where appropriate, propose applicable projects for the Commission's consideration. *See* IRP, pp. 13-82 and 13-83. The proposed Emory microgrid pilot project would enhance resilience where there are a number of critical and high risk facilities including the Emory University Hospital, critical health science research buildings, the Emory Police Department, the Centers for Disease Control and Prevention, and local community support facilities such as a high school, pharmacy, and local food providers.

Q. WHAT BENEFITS ACCRUE FOR INCLUSION OF COMBINED HEAT AND POWER ("CHP") IN A MICROGRID?

Having a microgrid, such as Emory proposes, that includes CHP facilities located near critical loads, improves resiliency when severe weather or other extreme events occur. In a 2016 report, the American Council for an Energy-Efficient Economy appropriately noted several reasons why CHP improves resiliency, especially over traditional backup power such as emergency diesel generators:

- CHP, being located at the point of use for the electricity and steam, can operate in "island mode" as a microgrid to continue powering the local site during outages or instability of the grid.
- Since CHP is operated and in service year-round, it avoids the maintenance and reliability issues which frequently occur with emergency generators that operate only during infrequent outages.
- For natural gas CHP, fuel is delivered via reliable underground distribution networks. In contrast, diesel relies on ground transportation which is often disrupted during severe weather or regional disasters.

Q. WHAT REAL-LIFE EXAMPLES DEMONSTRATE THE BENEFITS OF CHP FACILITIES IN MICROGRIDS?

There are many examples where CHP facilities have demonstrated increased resiliency, bringing value to the university or industrial hosts and to surrounding communities. Examples include:

- Louisiana State University was one of the few facilities that never lost power when Hurricane Katrina struck the Gulf Coast. With its CHP, the school continued to operate and even allowed the administrative offices of the University of New Orleans and the LSU Medical School to relocate to the LSU campus in Katrina's aftermath.
- When Hurricane Sandy struck the Northeastern U.S., the Princeton University campus was powered for two full days on its microgrid powered by CHP and solar panels alone without the external grid. During that period, the University served as a staging area for emergency service workers and as a place for local residents to get warm, recharge electronic devices, and gain access to the Internet.

Q. WHAT ALTERNATIVES DOES EMORY HAVE IF THIS PILOT IS NOT INCLUDED IN THE GEORGIA POWER IRP?

First, Emory hopes that its pilot microgrid will be included in Georgia Power's IRP. However, if for whatever reason it is excluded, then Emory would pursue alternatives. Emory has discussed options with Georgia Power and third party microgrid developers. If Georgia Power is not approved to allow Emory's proposed pilot microgrid on Georgia Power's electric distribution system, Emory may pursue a less desirable non-utility solution. While such a possible solution would be viable for Emory, it would eliminate any future expansion of the microgrid to the community and would substantially reduce revenue from Emory to Georgia Power. This lost revenue contributes to Georgia Power's fixed costs which, if Emory installs its own CHP, would likely be spread to all other customers. There have been a number of evaluations and developments by Duke Energy, DTE Energy, AEP and Florida Public Utilities that showed having Utility owned CHP generation was more beneficial to rate payers than having a large load leaving the utility's system by developing CHP behind their meter. Duke Energy presently has a 15

MW CHP under construction at Clemson University which is owned by Duke Energy, with Clemson paying for all steam produced from the waste heat which Duke then credits back to fuel for all customers. This makes the utility owned CHP a least-cost resource with lower levelized cost than a combined cycle plant. If Georgia Power owns a similar CHP at Emory, the steam normally produced by Emory in its boilers by burning natural gas would be supplied by waste heat from the Georgia Power CHP, reducing emissions with the steam payment from Emory being credited back to fuel for all Georgia Power customers. The Duke Energy CHP at Clemson University is being designed to provide microgrid capability where it will automatically 'island' if there is a grid disturbance providing the enhanced resiliency.

Q. HOW WOULD THE EMORY MICROGRID ADD VALUE TO GEORGIA POWER RATEPAYERS?

By combining a CHP generating asset with solar generation and battery storage, ratepayers would potentially benefit from a low cost generating asset that has an effective heat rate lower than a standalone, natural gas combined cycle plant or standalone large scale solar project because there are no losses due to transmission and distribution. It would also provide fuel clause revenue from the sale of the steam produced by the CHP. Microgrids also provide local grid control and demand response peak shaving during times of high system loads.

Direct testimony of DTE Electric Company on a similar proposed pilot that was approved in their service territory contained some of the following examples of its value to ratepayers:

> **Q. Why did DTE Electric enter into these arrangements?**
> A. DTE Electric was interested in this pilot project for the following reasons:
> 1) Retains Ford (DTE Electric's largest customer) as a bundled customer which provides benefits to all ratepayers.
>
> 2) Provides an estimated 62 million kWh of annual load growth over the next 10 years and associated margin value over the 30-year contract life with a present value of $15.4 million.

3) Provides an opportunity for DTE Electric to learn and gain experience from the CHP plant as a demonstration pilot and it collects information for use of this generation technology in future applications.

4) Provides information that could potentially be applied to other large campuses or industrial projects that require a sustainable, environmentally friendly energy solution.

5) Allows DTE Electric to add a new and efficient generation resource to its generation fleet.

6) Assists in fulfilling Michigan's anticipated electric generation needs.

7) Allows DTE Electric to access the site, water and wastewater from Ford at no cost to serve the Central Energy Plant.

8) Improves the air quality of the area, once Ford retires the existing boilers used to service the current facilities.

9) Allows CHP to synchronize to the electric grid, as black-start generation is already located on-site.

Q. What is the net impact on other DTE customers?
A. In the event Ford were to contract with a third party for its campus wide integrated solution with the CHP unit located behind the DTE meter and directly serving Ford's electrical requirements for this site, DTE Electric estimates that remaining bundled customers would have had to pay $102.1 million more on a present value basis over the 30-year contract life to make up for Ford's lost margin.

See Exhibit 2, p. RDF-8.

While Emory's proposed microgrid pilot is not as large as Ford's, the relationship of the lost revenue to ratepayers if Emory pursues self-generation behind the meter is still valid. Duke Energy was also able to show the benefit to ratepayers in its CHP project for Clemson University. If there is a reluctance to pursue this path with Emory because of a perceived lack of capacity need, Georgia Power could consider reducing the amount of capacity reallocated from Plant Scherer Unit 3 or consider the proposed Emory microgrid capacity to fill some of the Distributed Generation Procurement outlined on page 8-53 of the IRP as well as some as some of the 50MW of energy storage as proposed on IRP page 10-74.

Q. ARE THERE OTHER ENTITIES THAT SHOW SUPPORT OF MICROGRIDS TO END USE CUSTOMERS?

Yes, the Department of Energy has created the Distributive Energy Resources Program with the specific mission of "leading a national effort to develop the next generation of clean, efficient, reliable, and affordable distributed energy technologies and to support the transmission and distribution system." *See* Exhibit 3. There have also been a number of presentations at the National Association of Regulatory Utility Commissioners (NARUC) that focus on the integration of Distributed Energy Resources via microgrids, as well as published papers highlighting the value of utility owned CHP. *See* Exhibits 4, 5, and 6.

DIRECT TESTIMONY OF JOAN KOWAL

on behalf of

EMORY UNIVERSITY

Docket No. 42310

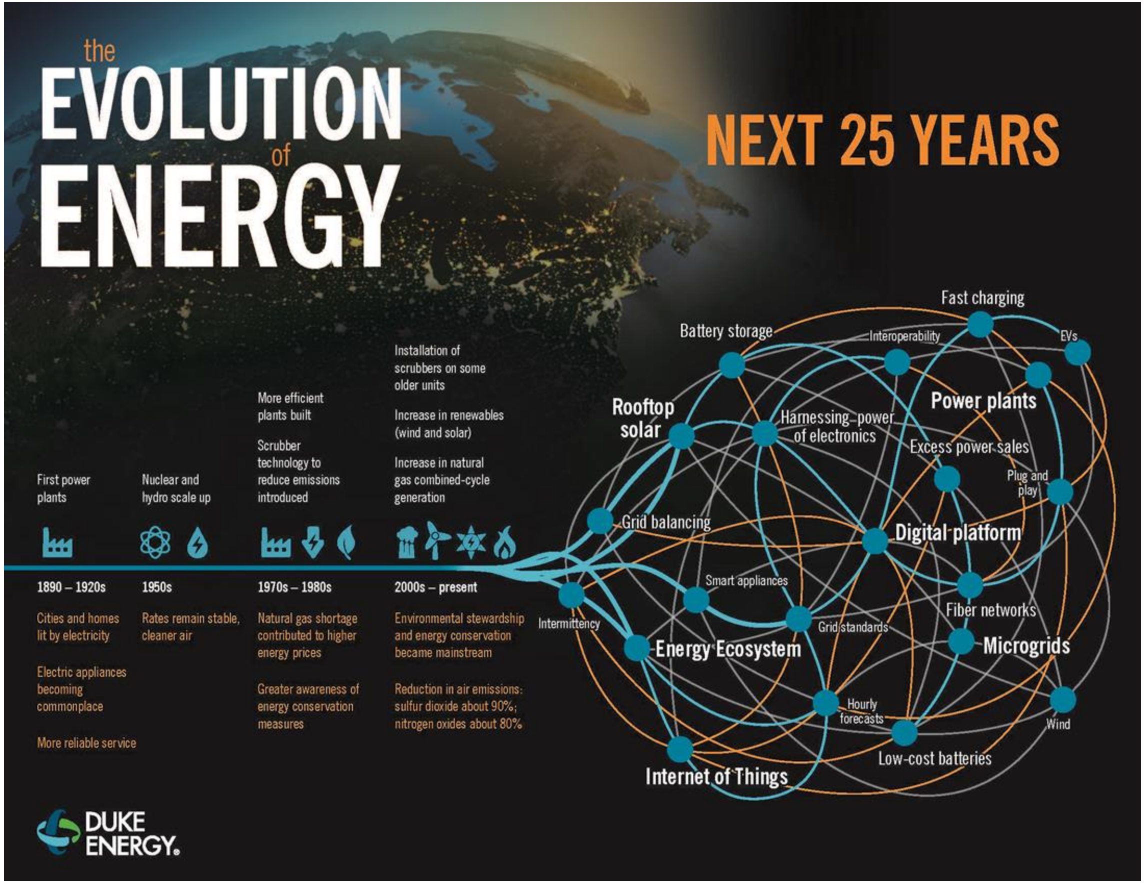
Exhibit 1

Combined Heat and Power – Brief Program Overview for Georgia Power and Emory University

08/23/17

DUKE ENERGY®

A more distributed generation future…



Brief Overview of Duke Energy CHP Program

- After thorough evaluation, Duke Energy incorporated building of CHP at host customer sites as a **base load supply resource** for Carolinas and Indiana 2015/2016 IRPs
- Key Customer segments for hosts include Universities, Military, and many Industries with continuous thermal loads
- Duke Energy customer response has been <u>excellent</u> and Commission support positive
  - SC Commission approved first project, 15 MW CHP at Clemson University recently which will start construction in 1Q 18
  - A number of other CHP projects at University, Military and Industrial customer sites are in various stages of development
- Following Slides provide a high level overview of program

Fast Facts About Combined Heating & Power

Properly Applied CHP is the **Most Efficient Method of Generating Power** – yet traditionally not viewed as a Resource to Utilities – **Duke Energy has incorporated distributed natural gas CHP into IRPs**

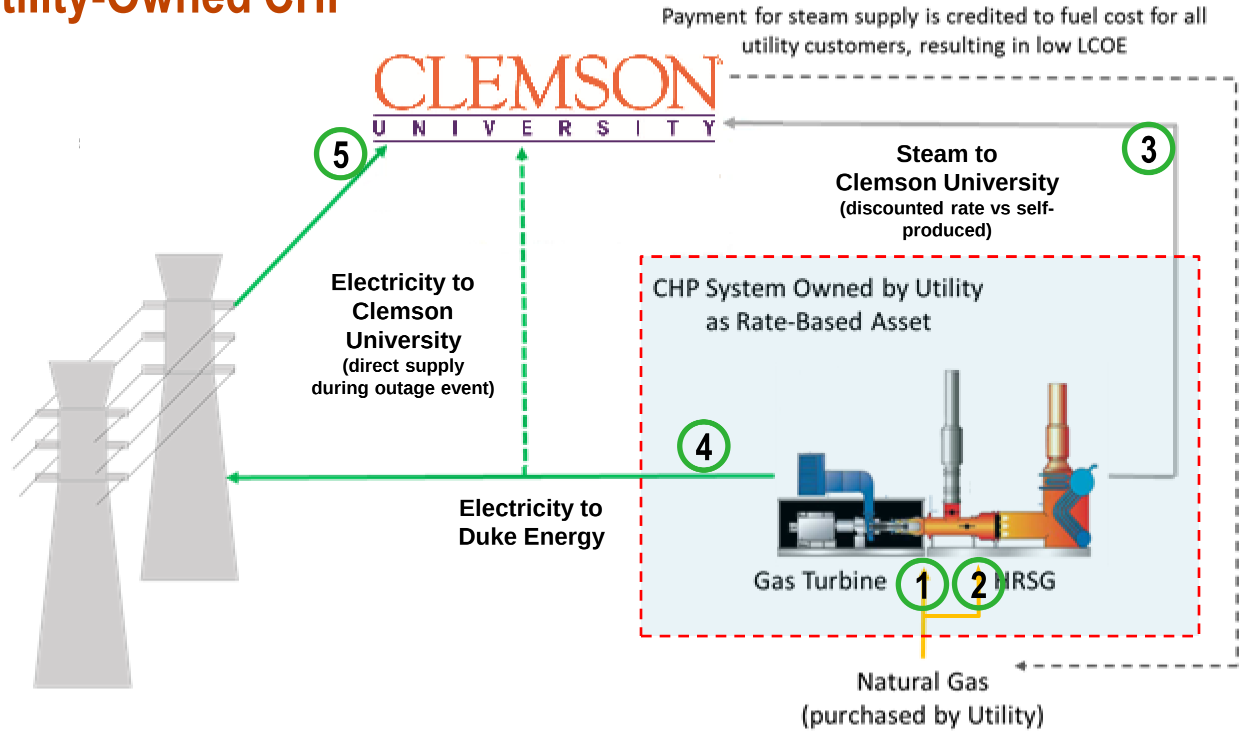
- CHP is **50% more efficient than next best grid resource** & results in lowest levelized cost of energy (LCOE) among any resource (CHP 75-80% HHV efficiency, best CC 50-55% HHV efficiency)
- Provides a Duke Energy owned distributed generation resource to the grid and efficient thermal resource to customer with shorter lead times and smaller sizes to **more closely match generation needs**
- CHP is based upon long proven GT/HRSG equipment (same as CC) – no technology curves to get up
- In addition to superior efficiency, CHP provides **many additional valuable benefits**
  - Unloads Grid, Reduces Congestion and **reduces T&D losses** – supports higher penetrations of RE
  - **Increases Resiliency** from grid disturbances for customers in today's digital economy
  - Significantly **reduces emissions and water** use per MWh
  - Lowers Investment Risk / much Faster Planning, Permitting & Implementation
- **And, CHP provides valuable benefits on both sides of the meter**
  - Lowers costs, Increased competitiveness for host /Customer – helps retain high load factor customers
  - **Increased local tax base, economic development & growth in jobs**

What does Utility-Owned CHP look like – Structurally

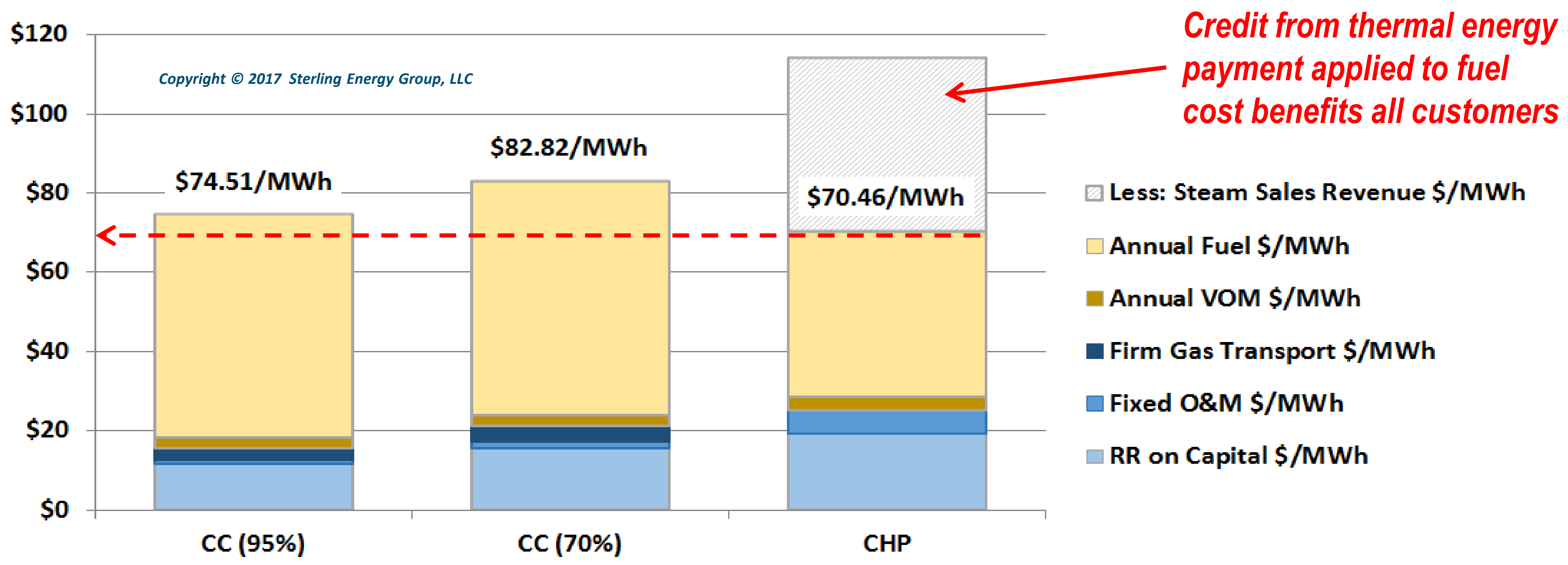
Simplified Structure for Utility-Owned CHP

Meter Points for Utility-owned CHP

1. Fuel to Gas Turbine
2. Fuel to Duct Burner
3. Steam/Thermal to Host
4. Electricity Produced by CHP
5. Electricity to Customer
   Utility continues to serve
   Customer Electric Load



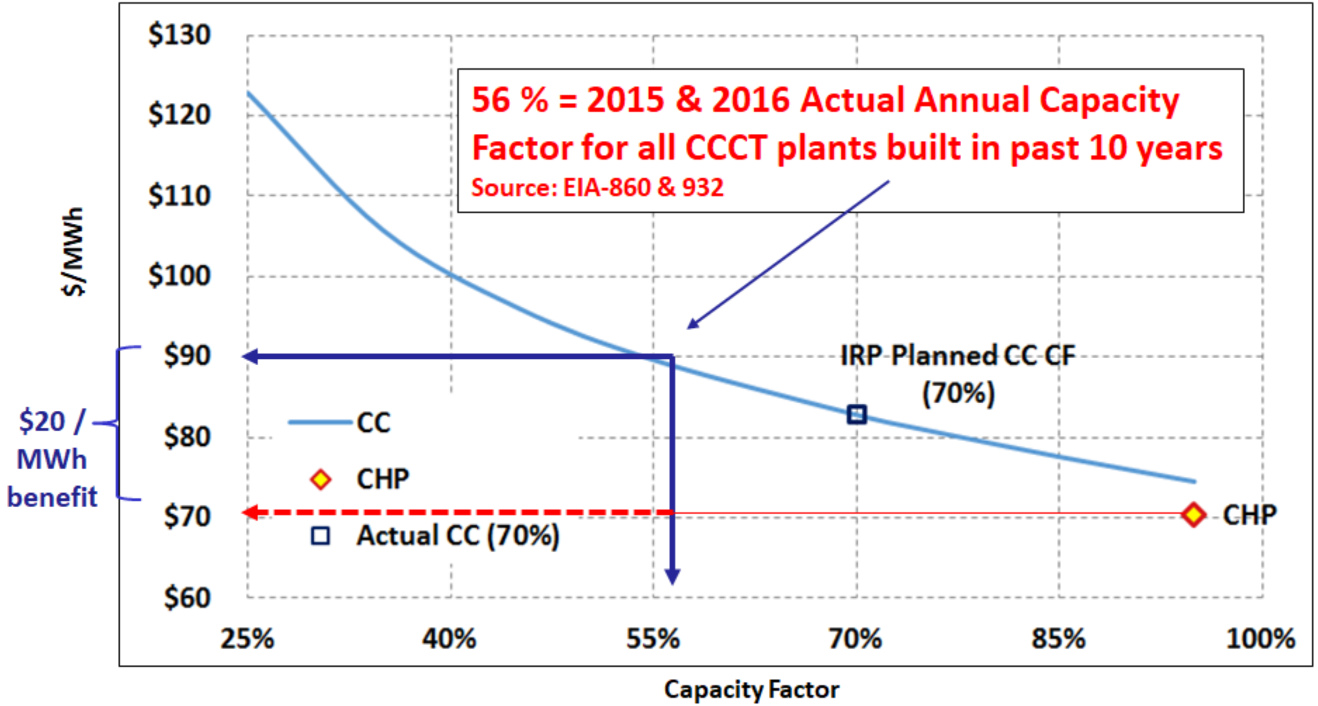
Levelized Cost of Energy Comparison (life cycle)
800 MW Advanced CCCT vs 21 MW CHP - with thermal credit to fuel



Notes: LCOE calculations are based upon standard IRP life cycle methodology, for cost of capital, depreciation F & V O&M taken from several published Utility IRP data and cost to construct CCCT and actual CHP plants costs. Capacity factors for CC are 95% and 70% with CHP 95%

A Closer Look - Levelized Cost of Energy Comparison

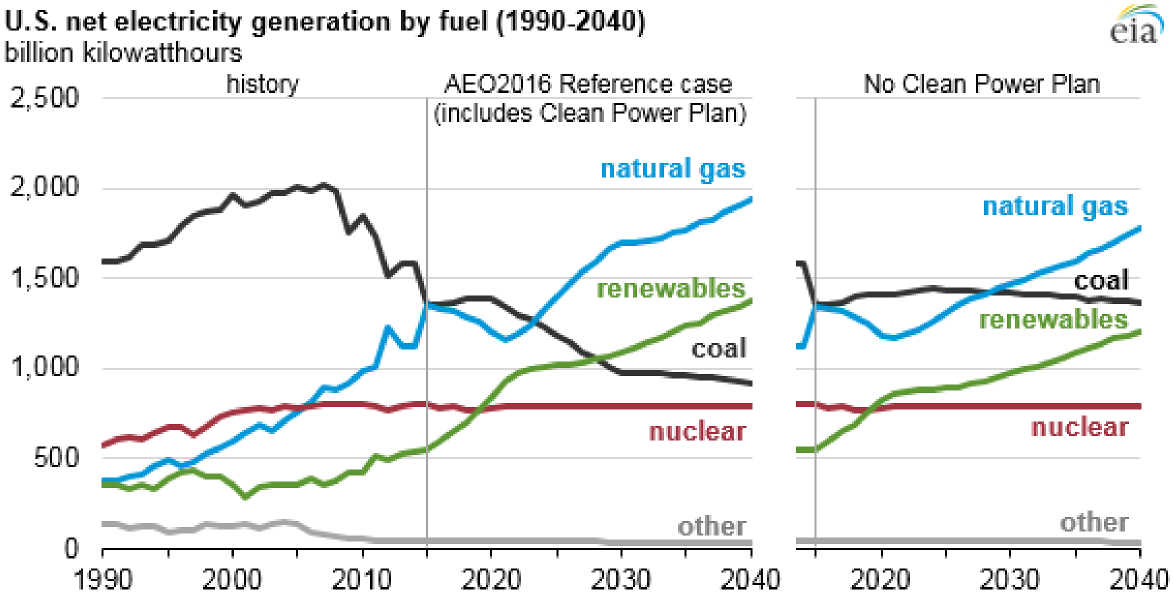
800 MW Advanced CCCT vs 21 MW CHP - with thermal credit to fuel



Notes: LCOE calculations are based upon standard IRP life cycle methodology, for cost of capital, depreciation F & V O&M taken from actual Utility IRP data and cost to construct CCCT and CHP plants. Capacity factors for CC are 95% and 70% with CHP 95% Actual CCCT capacity factor of 56.3% from EIA-860 for 2015

U.S. Electricity Production - US EIA 2017 – Fossil fuels will supply 50% of US MWh in 2040

Natural Gas will be a major part of our electricity production in the U.S. for decades … Why not make it as efficient as possible



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2017*

Highlights of Duke Energy 15 MW CHP at Clemson University

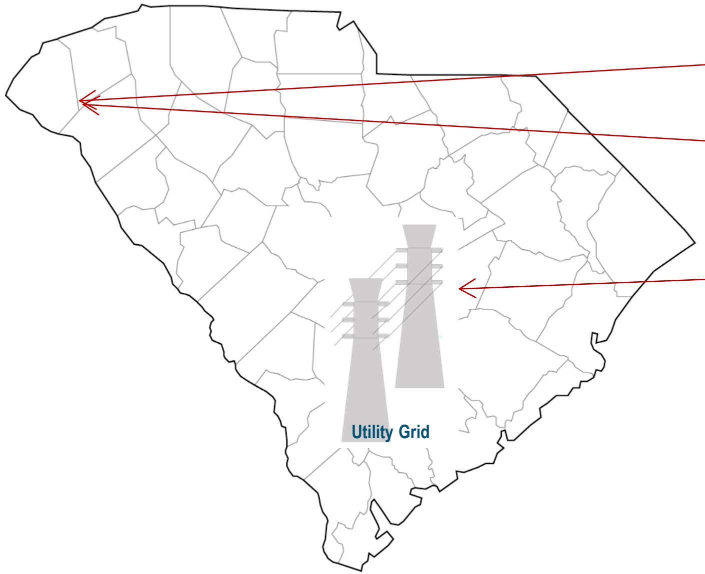
For Duke Energy Carolinas

- 16 MW to Duke Energy grid and ~ 60 kpph steam to campus @ 94-95% CF
- Clemson University steam payment applied back to fuel for all Duke Energy customers making CHP least cost resource
- May help avoid future grid upgrade in Clemson / Anderson SC region

For Clemson University

- Increased energy security & resiliency of campus power supply with 16 MW CHP on campus designed for seamless islanding with Grid
- Eliminates need and significant cost of building second utility service point for growth and resiliency
- Permits aging steam plant facility to be closed in future with premier site overlooking Stadium repurposed for University needs

Clemson University - Emission Reduction Summary for State of S.C.



CU Steam Plant: – 26,458 MT CO_2e

CU CHP Plant: + 74,842 MT CO_2e

Electric Grid: – 111,027 MT CO_2e

Net SC Air Shed: – 62,643 MT CO_2e

Table 1: Annual Energy Savings - Vs Avg Fossil Electric Plants

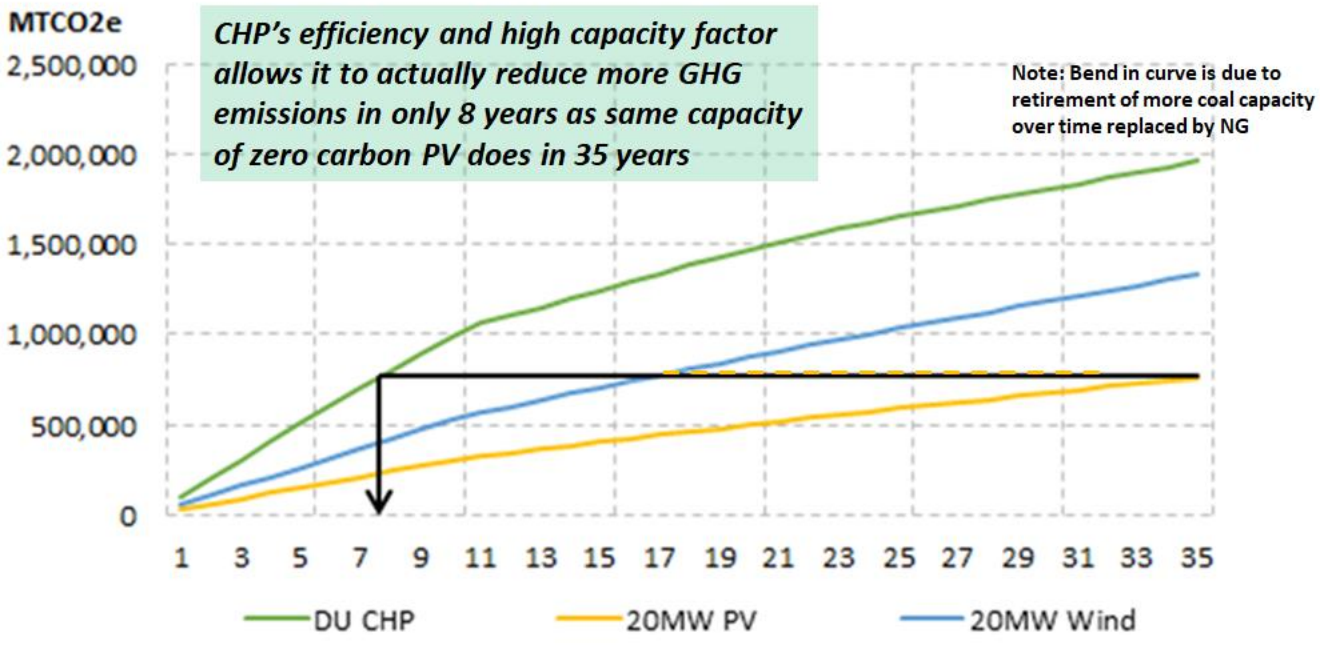
	CHP System	Displaced Electricity Production	Displaced Thermal Production	Fuel Savings	Percent Savings
Fuel Consumption (MMBtu/year)	1,410,302	3,169,696	498,562	2,257,956	62%
Equal to the annual energy consumption of this many passenger vehicles:				35,701	
Equal to the annual energy consumption from the generation of electricity for this many hc				8,180	

Table 2: Annual Emissions Savings - Vs Avg Fossil Electric Plants

	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions Savings	Percent Savings
NOx (tons/year)	38.98	53.03	9.10	23.14	37%
SO2 (tons/year)	0.41	89.89	0.15	89.62	100%
CO2 (tons/year)	82,432	121,541.50	29,141	68,250.29	45%
CH4 (tons/year)	1.55	13.04	0.55	12.04	89%
N2O (tons/year)	0.16	1.91	0.05	1.81	92%
Total GHGs (CO2e tons/year)	**82,513**	**122,407**	**29,170**	**69,063**	**46%**
Total GHGs (CO2e MT/year)	**74,842**	**111,027**	**26,458**	**62,643**	**46%**
Equal to the annual GHG emissions from this many passenger vehicles:				3,568	
Equal to the annual GHG emissions from the generation of electricity for this many homes:				2,492	

Based on latest EPA CHP emissions calculator
Using EPA eGRID database for average fossil fuel plants
Using average losses associated with Eastern Interconnect

Life Cycle Emission Benefits of CHP Capacity Greater than Equivalent RE Capacity



Calculated using actual dispatch model results beginning 2020 for DEC North Carolina, demonstrating specific unit emissions displaced by year
Capacity Factors: 95% for CHP, 22% for PV, and 34% for Wind

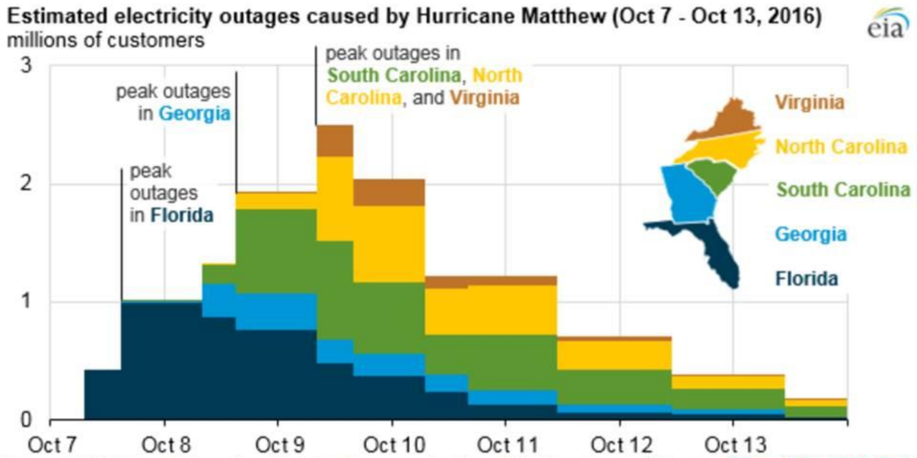
Key Benefits of a Duke Energy Owned CHP on Clemson Campus

- **Significant Capital and Operating Cost Avoidance**
  - On campus CHP will **eliminate need for second transmission line and substation and avoids significant extra facilities charge and impact of building transmission into campus**
  - On campus CHP will **eliminate a portion of the capital investment planned by Clemson for upgrade of electric distribution system** to tie to new substation and other electric distribution costs
  - CHP will be designed to serve **full campus steam load permitting Clemson to permanently close existing campus boiler operations and repurpose valuable steam plant site overlooking Stadium**
- **Annual Clemson Operating Cost Savings = hundreds of thousands $ / year for Thermal "Heat" Energy and even greater savings from avoiding extra facilities charge for second service**
- **Reliability and Growth Enhancements**
  - CHP will be designed to seamlessly 'island' and serve campus load (up to CTG MW capability) if Duke grid out, and feeder serves campus load if CHP out – increased redundancy
  - When Islanded, 15 MW will meet full campus critical power supply (with load shed on non-critical loads)

Duke Energy CHP Increases Resiliency For Clemson University Campus

OCTOBER 17, 2016

Hurricane Matthew caused millions of customers to go without power



Source: U.S. Energy Information Administration, compiled from U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability Situation Reports

Hurricane Matthew resulted in temporary electricity outages for millions of customers along the southern Atlantic Coast. Matthew was a Category 3 hurricane when it hit the east coast of Florida, just north of the St. Lucie Nuclear Plant, on Thursday, October 6. The hurricane traveled north along the Florida coastline, and by Saturday, October 8, it had reached South Carolina and continued its track along the coastlines of North Carolina and southeastern Virginia before heading out to sea.

Utility Industry – Newer (Changing) View of CHP

- In summary:
  - Lowest cost generating asset for all customers and no lost revenue that has to be recovered from all customers (as with customer-owned CHP)
  - 30-50% Higher efficiency results in lower net heat rate and lower Levelized Cost of Energy (life cycle)
  - Substantially reduced T&D losses (particularly peak hours when I^2R losses are highest from heat, equipment loading & congestion)
  - Greater system resiliency for host customer provided by CHP (both steam and electric)
  - Substantially reduced emissions and low / no water use
  - Avoided future T&D capital investments due to CHP 'unloading' T&D system
  - Much faster planning and development cycle – will help Duke Energy fine tune expansion plans and avoid over/under building capacity
  - Lower energy costs, increased competitiveness and energy resiliency for key customers serving as CHP host
  - Supports industrial development, growth in jobs and expanded local tax base

Questions

Dr. Zak Kuznar

Director, CHP & Storage, Duke Energy

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DIRECT TESTIMONY OF JOAN KOWAL

on behalf of

EMORY UNIVERSITY

Docket No. 42310

Exhibit 2

DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279

DTE Energy

Andrea Hayden
(313) 235-3813
andrea.hayden@dteenergy.com

July 6, 2018

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
<u>MPSC Case No. U-20162</u>

Dear Ms. Kale:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Application, Prehearing Notice, Protective Order, Nondisclosure Certificates, Testimony and Exhibits**.** Also attached is the Proof of Service.

Very truly yours,

Andrea Hayden

AH/rsf
Enc.
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-20162

APPLICATION

DTE Electric Company ("Applicant," the "Company" or "DTE Electric"), a corporation organized and existing under and by virtue of the laws of the State of Michigan, with its principal office at One Energy Plaza, Detroit, Michigan 48226, files this Application pursuant to MCL 460.6 et seq., and various Michigan Public Service Commission ("Commission") orders, requesting authority to increase rates, and amend its rate schedules and rules governing the distribution and supply of electric energy. In support of the relief requested in this Application, the Company respectfully represents to the Commission as follows:

1. Applicant is a wholly-owned subsidiary of DTE Energy, supplying retail electric service to customers located in Michigan, and is a public utility subject to the jurisdiction of the Commission.

2. Applicant is presently serving its electric customers under schedules of rates and charges approved by this Commission in its Orders dated April 18, 2018 and June 28, 2018, in Case No. U-18255 ("U-18255 Orders"), and pursuant to various special contracts approved by the Commission.

3. This Application is being filed in accordance with filing requirements contained in the Commission's Order in Case No. U-18238, dated October 11, 2017.

4. The Company has determined the need for additional annual revenues in the amount of approximately $328 million effective as early as June 6, 2019, in order to recover, among other things, capital costs associated with the addition of plant involving generation and the electric distribution system; capital structure cost changes; increased operation and maintenance expense due to inflation and accounting standard changes.

5. This filing reflects DTE Electric's continuing efforts to minimize, to the extent possible, the amount of rate relief required. In order to moderate the required rate increases to our customers, DTE Electric has, and continues to aggressively pursue opportunities to reduce costs. DTE Electric has proactively engaged in a number of efforts to improve processes and to reduce costs as much as possible while still providing safe and reliable service to its customers.

6. The proposed revenue increase described in this Application is necessary in order to allow the Company to continue to provide safe and reliable electric service, to meet customers' service quality expectations, and to allow the Company a reasonable opportunity to recover its costs of operation, including a reasonable rate of return.

7. The historical test year being used by DTE Electric is the calendar year ended December 31, 2017. This 12-month period was then normalized and adjusted for known and measurable changes, as supported by the Company's witnesses in this case, to arrive at the Company's May 1, 2019 through April 30, 2020 projected test year.

8. DTE Electric's projected rate base of approximately $17.2 billion includes actual net plant and working capital as of December 31, 2017 with projected changes through April 30, 2020 and includes the impact of base capital expenditures and further adjustments for specific major

projects. Major capital projects during the projected period ending April 30, 2020 are described in the testimony and exhibits of the Applicant's witnesses.

9. Thus, the Applicant's testimony and exhibits filed contemporaneously with this Application evidence a need for additional annual revenue beginning May 2019 of approximately $328 million.

10. Attachment 1 to this Application summarizes the Company's request. DTE Electric proposes to allocate the required electric revenue increase among rate classes as set forth on Attachment 2 to this Application. A comparison of typical bills and proposed rates for Residential Service Rate D1 is shown on Attachment 3 to this Application. In addition, the Proposed Draft Notice is included as Attachment 4 to this Application.

11. DTE Electric is proposing, among other things, certain changes to the Company's tariffs, including a change in the Residential D1 rate design to a time of use based charge, in compliance with the Commission's direction in Case No. U-18255; a new Weekend Flex pilot program and a Fixed Bill pilot program for the Residential D1 rate design; a new Distributed Generation Rider (Rider 18); inclusion of billing demand voltage level adjustments for Rate Schedule D6.2; proposed voltage level adjustments for demand charges which account for differences in losses and cost allocation at each voltage; changes to determining power supply cost allocation to Standby Service Rider 3 and associated rate design changes to better align cost allocation with cost causation principles, and development of surcharges for years 2020, 2021, and 2022, associated with the Company's proposed Infrastructure Recovery Mechanism (IRM).

12. With respect to DTE Electric's proposed time of use rate, the Company is requesting that the Commission reverse its decision in Case No. U-18255 and allow customers to retain the ability to opt-in voluntarily to the various time of use rate products currently available. In the alternative, DTE Electric is requesting that the Commission allow the Company to transition

its Rate Schedule D1 non-capacity rate to a time of use rate over a reasonable period of time in light of the information technology, customer service, and customer communications issues that will need to be addressed for such a transition.

13. The Company is requesting the waiver of the Commission's Residential Billing Rules R 460.125 and R 460.121 in order to implement the proposed Weekend Flex and Fixed Bill pilot programs. Rule 460.125 states that a utility shall bill each customer for the amount of electricity consumed. Customers enrolled on the Weekend Flex pilot will pay a fixed monthly charge for their weekend electricity usage, while customers enrolled on the Fixed Bill pilot will pay a fixed price for their monthly electricity usage, therefore, waiver of R 460.125 is needed. R 460.121 which states that a utility shall bill a customer with satisfactory payment history on an equal monthly billing program if requested. Customers enrolled on the Weekend Flex or Fixed Bill pilots will not be eligible to be enrolled on an equal monthly billing program.

14. DTE Electric is proposing an Infrastructure Recovery Mechanism which is designed to recover the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures incurred beginning May 1, 2020 through December 31, 2022. The Company is proposing an interim reconciliation process be conducted, and that any over or under recovery of IRM surcharges be deferred as a regulatory liability or regulatory asset until the following IRM reconciliation.

15. The Company is proposing an electric vehicle program (Charging Forward) which is designed to address customer education and outreach; residential smart charger support and charging infrastructure enablement. The Company is requesting that rebates provided through the program be deferred as a regulatory asset.

16. The Company is also seeking to increase its tree trimming expenditures so as to achieve a steady-state five-year cycle of tree trimming. The Company is requesting that this tree

trimming "surge" expense be deferred as a regulatory asset which will be securitized when the asset reaches an appropriate balance.

17. As required by Commission orders in Case Nos. U-16991 and U-16117, DTE Electric filed a depreciation case on November 1, 2016 in Case No. U-18150. On November 10, 2016, the Company also filed a joint depreciation case with Consumers Energy Company in Case No. U-18195 for the Ludington Pumped Storage Plant. The Commission issued a final order approving a settlement in Case No. U-18195, and those new Commission approved depreciation rates are reflected in this case. However, the Commission has not issued a final order in Case No. U-18150, therefore, DTE Electric has reflected in this case the new depreciation rates as proposed in the Company's application in Case No. U-18150. Should new deprecation rates be established in a Commission order in Case No. U-18150 before the conclusion of this rate case, the Company proposes that those new depreciation rates be reflected in the retail rates established in this proceeding.

18. DTE Electric is seeking cost recovery of its variable compensation programs that are used to attract and retain employees with the requisite skills and experience to ensure quality customer service; ensure that DTE Electric's employees' total compensation is externally competitive; and that differentiate total rewards based on organizational and individual contributions. The Company is not seeking to recover the variable compensation for the top five DTE Energy executives.

19. DTE Electric is requesting a return on equity of 10.5% with an overall rate of return of 5.76% after tax, 7.19% pre-tax. The Company is requesting a permanent capital structure of approximately 51% equity and 49% long-term debt. The projected average rate base for the test year is approximately $17.2 billion, which includes an equity base of approximately $6.7 billion.

20. Applicant is requesting that the Commission adopt the PSCR base established in

the Commission's Order in Case No. U-15244 on January 13, 2009.

21. In 2016, the Michigan legislature passed and the Governor signed into law 2016 PA 341 which, in the part pertinent to this proceeding, amended MCL 460.1 *et seq.* by adding Section 6w (MCL 460.6w). Act 341 became effective on April 20, 2017 and directed the creation of a state reliability mechanism ("SRM") and capacity charge. DTE Electric is proposing the same methodology for the SRM and capacity charge as proposed in Case No. U-18255.

22. The Commission issued Orders on January 11, 2010 in Case No. U-15768, October 20, 2011 in Case No. U-16472, December 11, 2015 in Case No. U-17767, and on January 31, 2017 in Case No. U-18014 approving the Company's Advanced Metering Infrastructure program ("AMI") and reaffirmed the earlier Orders on remand from the Michigan Court of Appeals on October 17, 2013 and November 6, 2014. The Commission's April 18, 2018 Order in Case No. U-18255 instructed the Company that a full cost-benefit analysis was no longer required. Based on the Commission's directives, the Company is no longer providing this analysis, however, a description of the program's success and shortcomings as well as the direct benefits customers receive from the program is included with this filing.

23. DTE Electric is also requesting specific Commission authority to implement certain accounting requests. Specifically, 1) Regulatory Asset treatment of 2017 Customer 360 post-implementation O&M expenses; 2) Regulatory Asset treatment for certain Advanced Distribution Management System (ADMS) costs; 3) Regulatory Asset treatment for rebates in the Charging Forward program (electric vehicle charging stations); 4) Regulatory Asset treatment for Tree Trim Surge costs; 5) Regulatory Asset treatment for time-of-use rate implementation expenses and 6) Regulatory Liability or Regulatory Asset treatment for over or under recovery of the IRM.

24. Applicant is filing the direct testimony and exhibits of 27 witnesses concurrently with

this Application. The contents, recommendations, revenue and expense items and proposed ratemaking items set forth in those documents are incorporated into this Application by reference.

25. The fact that Applicant may not address an item or position addressed by Applicant in previous cases, or which is presently on appeal before the courts, does not constitute a waiver of such item or position by the Company, or of any rights or positions that the Company may wish to take on these matters in this or any other proceedings before the Commission (now or in the future), or in any other appropriate court or venue (now or in the future).

WHEREFORE, Applicant requests that the Commission:

A. Accept this Application for filing;

B. Give such Notice to interested parties as may be required by statute or the Commission's rules;

C. Establish a date, place and time for a prehearing conference;

D. Conduct a hearing on this Application in order to determine the just and reasonable rates, effective as early as May 2019, which will provide Applicant a reasonable opportunity to recover its costs of operation, including a reasonable rate of return, in the projected test year and beyond;

E. Enter its Order approving an additional annual revenue increase effective as soon as possible in the projected test year as described herein;

F. Enter its Order approving Applicant's proposed capital structure and return on Equity;

G. Grant Applicant's request to implement an infrastructure recovery mechanism and the associated reconciliation process proposed by the Company;

H. Grant Applicant's request for increased tree trimming expenditures and the associated request for regulatory asset treatment and securitization;

I. Grant Applicant's request to reverse the previous ruling in Case No. U-18255 related to time of use rates, or alternatively allow the Company to implement the transition over a reasonable period of time and approve recovery of all costs associated with the transition.

J. Approve the implementation of the Company's proposed Weekend Flex and Flex Bill pilot programs and grant a waiver of the Commission's Residential Billing Rules R 460.125 and R 460.121;

K. Approve the Company's proposed electric vehicle program;

L. Enter its Order approving new rates effective as early as June 6, 2019 in the manner described in this Application, the accompanying Attachments and the Company's Direct Testimony and Exhibits;

M. Grant Applicant's request to approve the PSCR base;

N. Enter its Order approving the Company's proposals to implement certain customer rate schedules and tariffs;

O. Enter its Order approving recovery of the Company's generation investments;

P. Enter its Order approving recovery of the Company's investments related to the strengthening of the Company's distribution system and reliability improvements;

Q. Enter its Order approving a capacity charge based on the methodology established in Case No. U-18248 and the capacity-related costs approved in this proceeding;

R. Grant any accounting authority associated with this Application not already the subject of any other application filed by the Company;

S. Grant any other relief described in this Application as requested by the Company;

T. Grant Applicant such further additional relief, as the Commission may deem suitable and appropriate.

Respectfully Submitted,

DTE ELECTRIC COMPANY
Legal Department

By: ______________________________

Andrea E. Hayden (P71976)
Jon P. Christinidis (P47352)
David S. Maquera (P66228)
Megan Irving (P75232)
One Energy Plaza, 688 WCB
Detroit, Michigan 48226
(313) 235-3813

DTE ELECTRIC COMPANY

By: ______________________________

Don M. Stanczak
Vice President - Regulatory Affairs

Dated: July 6, 2018

Attachment 1

DTE Electric Company

Electric Revenue Deficiency by Major Component

($ Millions)

	(a)	(b)
Line	Description	Projected Revenue Deficiency (1)
1	Rate Base (Plant Investment - Return On & Of plus Property Taxes)	$ 215
2	Working Capital	10
3	New Depreciation Rates	182
4	Capital Structure	55
5	O&M	45
6	Sales Margin	29
7	Other	(19)
8	Tree Trim	7
9	Tax Reform	(196)
10	Total Requested Rate Relief	$ 328

(1) Revenue Deficiency calculated from last approved rate case U-18255

Attachment 2

DTE Electric Company
Summary of Present and Proposed Revenue by Rate Schedule

	(a)	(b)	(c)	(d)	(e)
Line No.	Rate Schedule	Total Present Revenue ($000's)	Total Proposed Revenue ($000's)	Total Net Increase/ (Decrease) ($000's)	Total Net Increase/ (Decrease) (%)
1	D1/D1.6 Residential	$2,202,636	$2,405,575	$202,939	9.2%
2	D1.1 Int. Air	$44,397	$47,785	$3,389	7.6%
3	D1.2 TOD	$23,803	$24,786	$982	4.1%
4	D1.7 TOD	$11,151	$12,702	$1,551	13.9%
5	D1.8 Dynamic	$17,939	$19,547	$1,608	9.0%
6	D1.9 Elec. Vehicle	$504	$543	$39	7.8%
7	D2 Elec. Space Heat	$41,148	$44,575	$3,427	8.3%
8	D5 Res. Water Ht.	$14,698	$15,740	$1,042	7.1%
9	Total Residential	$2,356,276	$2,571,253	$214,977	9.1%
10					
11	**Secondary**				
12	D1.1 Int. Air	$702	$722	$20	2.8%
13	D1.7 TOD	$679	$719	$40	5.9%
14	D1.8 Dynamic	$32	$33	$1	3.0%
15	D 1.9 Elec Vehicle	$0	$0	$0	-
16	D3 Gen. Serv.	$931,380	$966,958	$35,578	3.8%
17	D3.1 Unmetered	$8,469	$8,771	$302	3.6%
18	D3.2 Sec. Educ.	$27,980	$30,850	$2,870	10.3%
19	D3.3 Interruptible	$10,327	$10,631	$304	2.9%
20	D4 Lg. Gen. Serv.	$244,392	$258,132	$13,740	5.6%
21	D5 Com. Wat. Ht.	$402	$425	$23	5.8%
22	E1.1 Eng. St. Ltg.	$932	$996	$64	6.8%
23	R7 Greenhs. Ltg.	$208	$222	$14	6.6%
24	R8 Space Cond.	$8,610	$8,933	$323	3.7%
25	Total Secondary	$1,234,113	$1,287,391	$53,277	4.3%
26					
27	**Primary**				
28	D11 Prim. Supply	$969,915	$1,011,035	$41,120	4.2%
29	D6.2 Pri. Educ.	$54,129	$61,307	$7,178	13.3%
30	D8 Int. Primary	$51,781	$51,466	($315)	(0.6%)
31	D10 El.Schools	$3,224	$3,145	($79)	(2.4%)
32	R1.1 Alt. Mtl. Melt.	$3,616	$3,696	$80	2.2%
33	R1.2 El. Pr. Htg.	$32,933	$33,859	$926	2.8%
34	R3 Standby	$9,029	$11,080	$2,051	22.7%
35	R10 Int. Supply	$93,155	$97,357	$4,201	4.5%
36	Total Primary	$1,217,783	$1,272,945	$55,163	4.5%
37					
38	**Other**				
39	D9 Protective Ltg.	$7,388	$7,856	$467	6.3%
40	E1 Muni Street Ltg	$47,913	$52,070	$4,157	8.7%
41	E2 Traffic Lights	$4,383	$4,780	$397	9.1%
42	Total Other	$59,685	$64,706	$5,021	8.4%
43					
44	**Total All Classes**	$4,867,857	$5,196,295	$328,438	6.7%

Attachment 3

DTE Electric Company
Comparison of Typical Bills Under Present and Proposed Rates
Residential Service Rate D1

	(a)	(b)	(c)	(d)	(e)
				Increase	
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent
1	100	$22.69	$25.38	$2.68	11.83%
2	200	$36.95	$40.82	$3.87	10.47%
3	300	$51.22	$56.27	$5.05	9.86%
4	400	$65.48	$71.71	$6.24	9.52%
5	500	$79.74	$87.16	$7.42	9.31%
6	600	$95.41	$104.16	$8.75	9.17%
7	700	$111.24	$121.33	$10.09	9.07%
8	800	$127.07	$138.50	$11.43	9.00%
9	900	$142.90	$155.67	$12.77	8.94%
10	1,000	$158.73	$172.84	$14.11	8.89%
11	1,500	$237.88	$258.70	$20.82	8.75%
12	2,000	$317.03	$344.56	$27.53	8.69%
13	4,000	$633.62	$688.00	$54.37	8.58%

ATTACHMENT 4

PROPOSED

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
NOTICE OF HEARING

FOR THE ELECTRIC DELIVERY AND SUPPLY CUSTOMERS OF
DTE ELECTRIC COMPANY
CASE NO. U-20162

- DTE Electric Company may increase its annual base electric revenues by approximately $328 million above existing base electric rate levels along with other requested relief if the Michigan Public Service Commission (Commission) approves its request.

- A TYPICAL RESIDENTIAL CUSTOMER'S AVERAGE ELECTRIC BILL MAY BE INCREASED BY UP TO $9.42 PER MONTH, IF THE MICHIGAN PUBLIC SERVICE COMMISSION APPROVES THE REQUEST.

- The information below describes how a person may participate in this case.

- You may call or write DTE Electric Company, One Energy Plaza, Detroit, Michigan 48226, 1-800-477-4747, for a free copy of its application and testimony and exhibits. Any person may review the application and testimony and exhibits at the offices of DTE Electric Company.

- The first public hearing in this matter will be held:

DATE/TIME:	__________________, 2018, at 9:00 a.m. This hearing will be a prehearing conference to set future hearing dates and decide other procedural matters.
BEFORE:	Administrative Law Judge _________________
LOCATION:	Michigan Public Service Commission 7109 W. Saginaw Highway P.O. Box 30221 Lansing, MI 48917
PARTICIPATION:	Any interested person may attend and participate. The hearing site is accessible, including handicapped parking. Persons needing any accommodation to participate should contact the Commission's Executive Secretary at (517) 241-6160 in advance to request mobility, visual, hearing or other assistance.

The Commission will hold a public hearing to consider DTE Electric Company's July 6, 2018 request for authority to increase its annual base electric revenues by approximately $328 million along with other requested relief.

DTE Electric Company's Application states that the requested increase is required to recover costs associated with the capital costs associated with the addition of plant involving generation and the electric distribution system; capital structure cost changes; increased operation and maintenance expense due to inflation and accounting standard changes.

The chart below summarizes DTE Electric Company's proposed base revenue increases.

SUMMARY OF PROPOSED BASE REVENUE INCREASES

DTE Electric Company
Summary of Proposed
Base Electric Revenue Increase /(Decrease)

Rate Schedule	Total Present Revenue ($000's)	Total Proposed Revenue ($000's)	Total Net Increase/ (Decrease) ($000's)	Total Net Increase/ (Decrease) (%)
D1/D1.6 Residential	$2,202,636	$2,405,575	$202,939	9.2%
D1.1 Int. Air	$44,397	$47,785	$3,389	7.6%
D1.2 TOD	$23,803	$24,786	$982	4.1%
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D3 Gen. Serv.	$931,380	$966,958	$35,578	3.8%
D3.1 Unmetered	$8,469	$8,771	$302	3.6%
D3.2 Sec. Educ.	$27,980	$30,850	$2,870	10.3%
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D4 Lg. Gen. Serv.	$244,392	$258,132	$13,740	5.6%
D5 Com. Wat. Ht.	$402	$425	$23	5.8%
E1.1 Eng. St. Ltg.	$932	$996	$64	6.8%
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Rate Schedule	Total Present Revenue ($000's)	Total Proposed Revenue ($000's)	Total Net Increase/ (Decrease) ($000's)	Total Net Increase/ (Decrease) (%)
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D8 Int. Primary	$51,781	$51,466	($315)	(0.6%)
D10 El.Schools	$3,224	$3,145	($79)	(2.4%)
R1.1 Alt. Mtl. Melt.	$3,616	$3,696	$80	2.2%
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R10 Int. Supply	$93,155	$97,357	$4,201	4.5%
Total Primary	$1,217,783	$1,272,945	$55,163	4.5%
Other				
D9 Protective Ltg.	$7,388	$7,856	$467	6.3%
E1 Muni Street Ltg	$47,913	$52,070	$4,157	8.7%
E2 Traffic Lights	$4,383	$4,780	$397	9.1%
Total Other	$59,685	$64,706	$5,021	8.4%
Total All Classes	$4,867,857	$5,196,295	$328,438	6.7%

All documents filed in this case shall be submitted electronically through the Commission’s E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to: mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 241-6180 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by _____________, 2018. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon DTE Electric Company’s attorney, Andrea E. Hayden, One Energy Plaza, 688 WCB, Detroit, MI 48226.

Any person wishing to make a statement of position without becoming a party to the case, may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of his or her wish to make a statement of position. All information submitted to the Commission in this matter will become public information: available on the Michigan Public Service Commission's website, and subject to disclosure.

Requests for adjournment must be made pursuant to the Commission's Rules of Practice and Procedure R 792.10415 and R 792.10432. Requests for further information on adjournment should be directed to (517) 241-6060.

A copy of DTE Electric Company's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets, and at the office of DTE Electric Company, One Energy Plaza, Detroit, MI. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 241-6180.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, as amended, 1999 AC, R 460.17101 et seq.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	)))))))	Case No. U-20162

PROPOSED PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that DTE Electric Company ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's Exhibits, discovery or audit responses, any witness' related exhibit and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

   a. Examples of such trade secrets, confidential, proprietary, or commercially sensitive information include, but are not limited to, information regarding compensation, generation, transmission and distribution facilities and related equipment, infrastructure, energy market projections or assumptions, forecasts, gas conversion analyses, sensitivity analyses, revenue requirement analyses, or financial arrangements including but not limited to those set forth in contracts.

   b. Exclusions include Critical Energy Infrastructure Information ("CEII"), technical data subject to U.S. export control laws and regulations, including but not limited to 10 C.F.R. Part 810 *et. seq*., and information regarding Cyber Security which shall not be disclosed pursuant to this Protective Order or under any other circumstance. No individual DTE Energy employee's compensation benefits or other personal information is relevant in this proceeding. No individual DTE Energy employee's compensation, benefits or other personal information shall be required to be disclosed in this proceeding in the course of a hearing, through discovery, under this Protective Order, or otherwise.

2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third- party licensor to disclose consistent with the terms and conditions of this Protective Order.

3. Where protection from all means of disclosure is demanded in writing by a vendor of commercially-available market analyses and/or studies concerning employee compensation levels and such written demand is submitted to the Commission by DTE Electric, no Party shall obtain access to such commercially-available market analyses and/or studies concerning employee compensation levels until the Commission promises confidentiality for such market analyses and/or studies concerning employee compensation levels in writing, the Chairman of the Commission authorizes that promise of confidentiality in writing and the Commission thereafter through issuance of an

order grants Protected Materials involving such market analyses and/or studies concerning employee compensation levels exemption from disclosure under the Michigan Freedom of Information Act ("FOIA") as *"Trade secrets or commercial or financial information"* pursuant to MCL 15.243(1)(f) and the material marked "CONFIDENTIAL-SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-20162 – <u>EXEMPT FROM PUBLIC DISCLOSURE UNDER THE MICHIGAN FREEDOM OF INFORMATION ACT MCL 15.243(1)(f)</u>". If the AG or any other Party to this proceeding is itself subject to disclosure requirements under FOIA and wishes to obtain Protected Materials involving market analyses and/or studies concerning employee compensation levels that have been exempted by the Commission from disclosure under FOIA, the AG or other Party, in addition to executing a Non-Disclosure Certificate, must also exempt such Protected Materials from disclosure under FOIA prior to obtaining such Protected Materials.

4. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (*i.e.,* before the Disclosing Party has entered into a power purchase agreement or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Party" refers to the Applicant, MPSC Staff ("Staff"), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in Case No. U-20162 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

D. “Receiving Party” means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. “Reviewing Representative” means a person who has signed a Nondisclosure Certificate and who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;

2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.E.1;

3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. An employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. “Nondisclosure Certificate” means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to, and use of, Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding hearing officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

H. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-20162." Software executable files containing protected material may not be capable of being marked with the foregoing required protective language. The inability to mark software executable files containing protected material with such protective language shall not diminish the requirements of this Protective Order. It shall be sufficient if the medium used to deliver software executable files containing protected information is marked with the required protective language. However, any output from the software executable files containing protected material that is generated only as a reproducible document, whether electronic or non-electronic, that is capable of being marked with the required protective language, shall be marked by the party who generated the output with such protective language and subject to the requirements of this Protective Order. If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL – SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-20162." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party. If any person files a request under the Freedom of Information Act with the MPSC or the Michigan Attorney General seeking access to documents subject to this Protective Order, the MPSC's Executive Secretary, Staff, or the Attorney General shall immediately notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the MPSC, Staff, and/or the Michigan Attorney General grant the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

Protected Material remains the property of the Disclosing Party and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in Case No. U-20162 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives-including all copies and notes of Protected Material-or certify in writing to the Disclosing Party that the Protected Material has been destroyed.

VI. Limitations and Disclosures

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.5. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the

Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes immediately notifying the MPSC, the presiding hearing officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

____

Administrative Law Judge

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority ______________________________________	)))))))	Case No. U-20162

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-18424, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date: ____________

____
Title:
Representing:

____
Printed Name

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	)))))))	Case No. U-20162

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA BRANSON, being duly sworn, deposes and says that on the 6th day of July, 2018, she served a copy each of DTE Electric Company's Application, Prehearing Notice, Protective Order, Nondisclosure Certificates, Testimony and Exhibits, and Proof of Service via electronic mail upon the persons listed on the attached service list.

____
ESTELLA BRANSON

Subscribed and sworn to before
me this 6th day of July, 2018

____
Lorri A. Hanner, Notary Public
Wayne County, Michigan
My Commission Expires: 04-20-2020

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DON M. STANCZAK

DTE ELECTRIC COMPANY
QUALIFICATIONS OF DON M. STANCZAK

Line
No.

Q. Please state your name, business address and by whom you are employed.

A. My name is Don M. Stanczak. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC a subsidiary of DTE Energy as Vice President, Regulatory Affairs.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your education background?

A. I received a Bachelor of Science Degree in Business Administration, with a major in Finance, from Central Michigan University. In addition, I received a Master of Business Administration Degree, with a major in Accounting, from Wayne State University.

Q. What work experience do you have?

A. I joined Michigan Consolidated Gas Company (MichCon) in 1983 and through 1994 had several assignments of increasing responsibility in a number of areas within MichCon, including Financial Services, Regulatory Affairs, Corporate Planning, Gas Supply and Supply Chain. In 1994, I was promoted to Director, Market Planning. In 1999, I transferred to Gas Transmission and Resource Planning as Director. In 2000 I moved back to Regulatory Affairs as Director, responsible for all of MichCon's regulatory activities. In 2001, MichCon's parent, MCN Energy, was acquired by DTE Energy, DTE Electric's (formerly Detroit Edison) parent. In 2005, I transitioned my responsibility to Director for DTE Electric's regulatory activities. In 2013, I assumed my present position having responsibility for the development and implementation of regulatory strategy and administration for both DTE Electric and DTE Gas (formerly MichCon).

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony in the following DTE Electric, Detroit Edison, DTE Gas, and MichCon cases:

U-10544	MichCon Facility Application
U-10547	MichCon Facility Application
U-10744	MichCon Conservation Plan
U-10640	MichCon GCR Plan
U-10915	MichCon GCR Plan
U-11145	MichCon GCR Plan
U-12762	MichCon GCR Suspension Termination
U-13060	MichCon GCR Plan
U-13060-R	MichCon GCR Reconciliation
U-13549-R	MichCon GCR Reconciliation
U-13808	Detroit Edison Rate Case
U-13898	MichCon Rate Case
U-13933	Detroit Edison Low-Income Credit
U-14399	Detroit Edison Rate Unbundling
U-14428	Detroit Edison Other Post Employment Benefit Equalization Mechanism
U-15768	Detroit Edison Rate Case
U-16472	Detroit Edison Rate Case

U-16489	Detroit Edison deferred pension and post-employment benefits expense for future amortization and recovery
U-16780	Detroit Edison Revenue Decoupling Mechanism Reconciliation
U-16952	Detroit Edison 2011 Choice Incentive Mechanism Reconciliation
U-17437	DTE Electric PLD Transitional Cost Recovery Plan
U-17689	DTE Electric Public Act 169 of 2014 Filing
U-17767	DTE Electric Rate Case
U-17999	DTE Gas Rate Case
U-18014	DTE Electric Rate Case
U-18248	DTE Electric Capacity Charge Case
U-18255	DTE Electric Rate Case
U-18419	DTE Electric Certificate of Necessity

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Provide an overview of the Company's entire rate case;
- Review the overall methodology used to develop the Company's projected test year amounts in this case;
- Review the Company's proposed Capacity Charge modification;
- Address the status of the Company's pending depreciation case and the impact on this case and future DTE Electric rate cases;
- Provide an overview of DTE Electric's proposal for an Infrastructure Recovery Mechanism (IRM) which is designed to recover the revenue requirement associated with certain capital expenditures through 2022;
- Describe the proposed rate making treatment and planned securitization of costs associated with the Company's tree trimming surge;
- Discuss the status and consequences of the Commission's directive that the Company establish time based rates for all residential customers; and
- Introduce the Company's other witnesses.

Q. Are you sponsoring any exhibits in this proceeding?

A. No, I am not.

Case Overview

Q. What is DTE Electric's overall business objective?

A. DTE Electric's overall business objective is to provide safe, reliable and cost effective electric service to its customers and deliver reasonable and appropriate compensatory returns to DTE Energy shareholders while maintaining its financial

Line No.

health.

Providing safe, reliable and cost effective service to its customers means that DTE Electric: 1) provides quality customer service, 2) operates its system safely, and 3) delivers electric service reliably at a reasonable cost. The Company believes that providing our customers with quality customer service entails accurately billing our customers, ensuring our customers have ready access to a qualified customer service representative, and responding to customer inquiries and service orders in an efficient and effective manner.

Maintaining DTE Electric's financial health requires that the Company has a reasonable opportunity to earn its cost of capital, that the Company has a well-balanced capitalization (no less than 51% equity to total permanent capitalization), and that the Company is able to maintain its A/Aa3/A credit ratings for senior secured debt from the three major rating agencies. These preconditions are necessary to ensure DTE Electric's full access to capital markets at reasonable rates, terms and conditions regardless of business cycle timing or industry conditions. As discussed by Company Witness Mr. Solomon, without full access to capital markets at reasonable terms and conditions, the cost of providing utility services can increase significantly.

Thus, it is essential to DTE Electric's financial health that the ultimate cost that customers are asked to pay for Company services generates sufficient cash flow from operations to fund capital expenditures and pay a reasonable dividend.

Line
No.

Q. What rate relief was provided by the Commission's Order in the Company's last rate case, Case No. U-18255?

A. The Company's last general rate case, Case No. U-18255, was filed in April 2017 requesting $231 million in rate relief. On November 1, 2017, DTE Electric self-implemented a rate increase of $125 million. On April 18, 2017, DTE Electric received rate relief in the amount of $65.2 million in Case No. U-18255.

Q. Why has DTE Electric filed this general rate case?

A. The Company has carefully considered the need for filing this case. While I am aware of the impact that utility rate changes have on our customers, I am similarly aware that our customers expect and deserve safe and reliable service. DTE Electric's current authorized rates are not expected to provide DTE Electric with a reasonable opportunity to earn a fair return on equity beginning in May 2019. The Company continues to make improvements to its distribution and generation fleet in order to improve reliability and our customers' experience using our product. The only way that DTE Electric can adequately provide the required service levels that our customers desire and deserve is by being financially healthy. In order to attract the capital necessary for the prudent operation of our facilities, the Company must be able to demonstrate its ongoing financial health. Inadequate rates will ultimately result in higher financing costs, and will have a significant negative impact on our ability to adequately serve our customers and maintain the integrity of our electric distribution and generation assets. This negative impact will occur because more dollars are required to support our financing costs, and therefore are not available for system maintenance or customer service. Similarly, inadequate funding for capital and maintenance programs, over time, will result in the deterioration of DTE

Electric's generation and distribution infrastructure, ultimately resulting in reduced system reliability.

Q. Does the financial stability of DTE Electric provide additional benefits to customers and the region?

A. Yes. DTE Electric has an important positive economic impact on the communities it serves. DTE Electric is one of the largest employers in Southeast Michigan with over 4,800 employees; and through the Pure Michigan Business Connect campaign, the Company utilizes the services of numerous local contractors and vendors. DTE Energy spent over $1.65 billion with Michigan based companies in 2017. In addition, through property taxes, DTE Electric contributes to the financial health of the communities in which it serves; in the historical test year, DTE Electric paid about $250 million annually in property taxes to Southeast Michigan communities. Further, to maintain facilities and comply with various regulations, and related to the implementation of our Renewable Energy Plan, DTE Electric continues to make major capital investments in the communities in which it serves and operates. Thus, DTE Electric supports additional job growth opportunities and provides incremental tax revenue for the communities it serves.

Q. Has DTE Electric taken steps to minimize the impact on the need for rate relief in this proceeding?

A. Yes. DTE Electric has taken a number of actions to minimize, to the extent possible, the amount of rate relief required. In order to moderate the required rate increases to our customers, DTE Electric has in the past, and continues to aggressively pursue opportunities to reduce costs. DTE Electric has proactively

Line No.

engaged in a number of efforts to improve processes and to reduce costs as much as possible while still providing safe and reliable service to its customers. As noted by Company Witness Mr. Cooper, the Company's collective bargaining agreements and general market-driven wage increases result in expected annual escalations in wages of about 3%. Further, wages and contractor costs represent about two thirds of the Company's O&M expense. Therefore, the Company's ability to manage O&M in the past has been exceptional, particularly in light of the annual wage escalation I just noted. Unfortunately, the Company cannot continually reduce non-labor O&M in order to offset wage growth. Moreover, as addressed by a number of other Company witnesses, DTE Electric is experiencing inflation pressure relative to non-labor costs.

Q. What rate relief is DTE Electric requesting in this case?

A. As Company Witness Mr. Slater summarizes, DTE Electric expects a revenue shortfall of $328 million for the May 1, 2019 through April 30, 2020 projected test year. The key factor contributing to this shortfall is the revenue requirement associated with increased investments made in plant, working capital and associated depreciation and property tax increases, plus an increase in O&M.

Rate Case Methodology

Q. What approach is the Company using to support its projected test year positions and its recommendations in this case?

A. Although 2008 Public Act 286 allows for fully projected future test periods in setting utility rates, DTE Electric has used actual historical data as the point of departure for most estimated cost levels for the projected test year. These historical costs were then adjusted for the impact of inflation. As has been the Commission's practice in prior cases, certain other costs reflect specific estimates or projections where general impacts of inflation alone would not be appropriate. For example, some of these include, but are not limited to, capital expenditures, uncollectible expense, injuries and damages, pension and other post-employment benefits. All these cost components are supported by other Company witnesses.

Q. What historical and projected test year periods are being used by DTE Electric for purposes of calculating its projected revenue deficiency?

A. The historical test year used by DTE Electric is the calendar year ended December 31, 2017. This 12-month period was then normalized and adjusted for known and measurable changes, as supported by the Company's witnesses in this case, to arrive at the Company's May 1, 2019 through April 30, 2020 projected test year.

Capacity Charge

Q. Is the Company proposing to apply the same capacity charge to all of its customers regardless of whether they are on Choice or are bundled service customers?

A. Yes. As required by 2016 Public Act 341 (PA 341), and as more fully addressed by Company Witness Mr. Lacey, all customer classes will be allocated the same amount of generation capacity costs and all similarly situated customers, both Choice and bundled service will pay the same rate for generation capacity. That is, all Choice and bundled service customers paying for capacity will pay the same rate.

Line
No.

Q. Is it reasonable for Choice customers to pay the same full embedded cost of DTE Electric's generation fleet as bundled customers even though the Choice customers are buying their energy from a third party?

A. Yes, it is reasonable for Choice customers to pay the same full embedded cost of DTE's electric generation fleet as bundled customers even though Choice customers are buying their energy from a third party. Not only is it reasonable for Choice customers to pay the same rate for capacity as bundled customers I believe it is expressly required by Section 6w(3) of PA 341. The service reliability provided by DTE Electric's generation capacity is the same for the Choice customers as it is for bundled customers. With the exception of its interruptible services, the Company serves all customers, bundled and Choice, with the same level of service relative to generation capacity.

Q. Specifically, what generation costs are reflected in the Company's proposed capacity charge?

A. I have directed Witness Lacey to include all Production related costs except fuel, variable O&M and certain purchase power costs in the capacity charge. This is the same methodology the Company proposed in its last rate case, Case No. U-18255.

Q. What types of capacity related costs are included in purchase power?

A. The Company pays capacity costs related to its PURPA/PA2 contracts and renewable energy resources; both company owned and related to purchase power agreements. Company Witness Mr. Arnold determines these costs.

Q. Are the generation capacity costs you just described consistent with the requirement of PA 341?

A. Yes. Witness Lacey has included all capacity related generation costs included in DTE Electric's base rates, surcharges and power supply cost recovery cases consistent with PA 341, section 6w (3) (a). These costs do not include fuel, variable O&M, nor non-capacity purchased power expenses. The proceeds of energy market sales, net of fuel, are subtracted from those costs.

Q. Is the Company assuming that any Choice customers are paying the capacity charge?

A. For purposes of determining the capacity charge in this proceeding, the Company is assuming that zero Choice load will take capacity service from DTE Electric during the projected test year since earlier this year Choice providers demonstrated that they had the required capacity necessary to serve their customers through 2021.

Q. How frequently do you expect that the capacity charge will be modified by the Commission?

A. Generally, any base rate or PSCR factor change will change the capacity charge rates. Additionally, each year the Commission must conclude a proceeding by December 1 to review the capacity charge.

Q. In light of the December 1 required review you just addressed, when would you propose new capacity charge rates, pursuant to such a review, be implemented?

A. I propose that the capacity charge rates established by the Commission pursuant to the required December 1 review become effective on January 1^{st} of the next year. There are costs and revenues in the capacity charge and the PSCR that are directly related. The PSCR operates on a calendar year basis, as such, administrative efficiency will be achieved by reflecting PSCR changes in the capacity charge on a calendar year basis and then reconciling them contemporaneously for that same calendar year.

<u>Depreciation</u>

Q. When did the Company file its most recent depreciation case?

A. As required by a prior Commission order, the Company filed a depreciation case on November 1, 2016, in Case No. U-18150. In addition, on November 10, 2016 the Company filed a joint depreciation case with Consumers Energy Company in Case No. U-18195 for the Ludington Pumped Storage Plant.

Q. Has the Company reflected the new depreciation rates that are the subject of Case Nos. U-18150 and U-18195 in this rate case?

A. Yes. The Commission has issued a final order approving a settlement in the Ludington Pumped Storage Plant deprecation case, Case No. U-18195; those new Commission approved depreciation rates are reflected in this case. However, the Commission has not issued a final order in Case No. U-18150, therefore, the Company has not reflected the impact of any potential change from the Company filed depreciation rates that could result from a final order in that case in this proceeding. Rather, the Company has reflected in this case the new depreciation rates as proposed in its application in Case No. U-18150.

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Q. Is it likely that a final Commission order will be issued in Case No. U-18150 prior to the conclusion of this rate case?

A. Exceptions to the Proposal for Decision (PFD) were filed in Case No. U-18150 on May 22, 2018, therefore, it seems likely that a final order in Case No. U-18150 will be issued before the conclusion of this rate case. Further, should new deprecation rates be established in a Commission order in Case No. U-18150 before the conclusion of this rate case, the Company proposes that those new depreciation rates be reflected in the retail rates established in this proceeding. This timing of the effective date of the new depreciation rates is consistent with the treatment requested by the Company in Case No. U-18150 and past Commission policy. That is, the new depreciation rates are implemented concurrent with the issuance of the first rate case order subsequent to the completion of the depreciation case.

Infrastructure Recovery Mechanism

Q. Is the Company proposing an Infrastructure Recovery Mechanism (IRM) in this case?

A. Yes. As supported through the testimony of Company Witnesses, Mr. Bruzzano, Mr. Davis, and Mr. Paul, the Company is proposing recovery of the incremental revenue requirement associated with certain distribution, fossil generation and nuclear generation capital expenditures through 2022 in this proceeding. Company Witness Ms. Uzenski summarizes the capital proposed to be covered by the IRM, and Witness Mr. Slater addresses the revenue requirement associated with the proposed IRM capital expenditures through 2022. Finally, Company Witness Mr. Bloch addresses the rate design and proposed rates associated with the IRM.

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Q. Why is the Company proposing an IRM in this proceeding?

A. This current rate case is the fourth rate case in the last five years for DTE Electric. The Company's need for rate increases has been and is expected to be largely driven by its need to replace critical infrastructure required to safely and reliably serve our customers. The Company believes, with the proper IRM in place for the intervening years, it may be able to defer filing for a rate increase until sometime in 2022 for new base rates in 2023. Deferring the need to file rate cases should reduce the workload at the Commission and should result in a reduction in costs for all the parties that typically participate in Company rate cases. In addition, the systematic implementation of IRM surcharges should allow for more orderly and potentially smaller rate increases than what would occur if the Company continued to file rate cases, which should be beneficial for our customers. Finally, as more fully covered by Company Witnesses Bruzzano, Davis, and Paul, the IRM will support critical infrastructure improvements that will benefit our customers for years to come. In addition, some level of certainty relative to cost recovery should allow for the more efficient deployment of capital.

Q. If an IRM is approved by the Commission in this proceeding, is the Company guaranteeing that it will be able to defer filing a rate case until 2022?

A. No. The Company faces many cost pressures, beyond the capital expenditures that would be covered by the proposed IRM, that may require the Company to file a rate case before 2022 even if the proposed IRM is adopted by the Commission in this proceeding.

Q. What other cost pressures could impact the Company's ability to defer filing a

rate case until 2022 even if the proposed IRM in this proceeding is approved by the Commission?

A. There are several cost and revenue areas, beyond the capital expenditures covered by the proposed IRM, that could make it difficult for the Company to defer filing a rate case until 2022. These include incremental capital expenditures that are not included in the IRM, O&M general inflation or other O&M cost increases, reductions in sales and finally any other unforeseen external events.

Q. Specifically how will capital expenditures that are not included in the IRM impact the Company's ability to defer filing a rate case?

A. Generally the capital expenditures that are proposed to be recovered in the IRM are capital expenditures that are above and beyond replacement capital. I define replacement capital as capital expenditures that approximate annual depreciation expense. Thus, the Company is not seeking IRM treatment for normal capital expenditures that effectively are replacing capital that is being depreciated. Rather, the Company is seeking IRM treatment for capital expenditures that are above and beyond replacement capital. In the context of revenue requirement, replacement capital essentially backfills the decline in rate base due to the normal depreciation of gross plant. Therefore, theoretically, replacement capital has no impact on net rate base and thus no incremental return on rate base is associated with replacement capital. However, since depreciation and property tax expense are effectively based on gross plant, the Company experiences an increase in revenue requirement associated with these cost components even relative to replacement capital expenditures. Finally, any capital expenditures beyond replacement capital, that is not included in the IRM, will increase required return, deprecation and property tax.

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Q. Specifically how could O&M costs impact the Company's ability to defer filing a rate case?

A. Since O&M is not included in the IRM, the Company will be required to absorb any inflation or other cost increases that occur during the pendency of the IRM in order to defer filing a rate case. As summarized by Witness Ms. Uzenski, the Company's proposed O&M for the projected test year is $1.3 billion. Therefore, even if the Company experiences general inflation of two percent for example, it will have to absorb about $26 million annually. Similarly, any other potential O&M increase beyond inflation, such as increases in uncollectibles or employee benefits, will need to be absorbed by the Company in order to defer filing a rate case until 2022.

Q. Beyond the incremental capital and O&M increases you just described, what other issues could force the Company to seek rate relief prior to 2023 even if the IRM, as proposed in this case, is approved by the Commission?

A. Either a material decline in sales or some other external event, such as a change in relevant legislation, could necessitate filing for a rate increase prior to 2023.

Q. Specifically when and how will the IRM be implemented?

A. As noted earlier in my testimony, the projected test year in this proceeding is May 1, 2019 through April 30, 2020, therefore, the IRM is proposed to cover certain capital expenditures incurred beginning May 1, 2020 through December 31, 2022. To that end, the Company proposes that the initial IRM surcharge be implemented January 1, 2020 which would cover capital expenditures from May 1, 2020 through December 31, 2020. As more fully addressed by Witness Mr. Slater, the initial IRM will also include the second half of capital expenditures for the projected test year. Similarly, incremental IRM surcharges will be implemented January 1, 2021 and 2022, for the IRM capital expenditures for those calendar years. See Witness Bloch's testimony for a description of the surcharge design.

Q. Is the Company proposing that the IRM surcharges be reconciled?

A. Yes. The Company is proposing that the IRM surcharge be reconciled. More specifically, the Company is proposing that if the Company does not spend all the capital that is reflected in the IRM surcharge, the Company will refund the IRM surcharge revenue associated with that under spending. However, any incremental spending, beyond the level approved by the Commission, would not result in any incremental surcharge.

Q. Is the Company also proposing to reconcile the IRM dollars collected?

A. Yes. The Company is also proposing the revenue collected through the surcharge be reconciled. That is, if the Company over or under recovers the revenue that should have been recovered in the IRM surcharge, the Company will refund or surcharge that difference at the conclusion of the IRM. However, in no event will the Company be allowed to recover more than the maximum amount of revenue defined by the operation of the IRM. That is, if the Company under spends capital, the total amount of revenue recoverable will be reduced based on that under spend. In summary, the Company is effectively proposing an asymmetrical reconciliation relative to capital spend and a symmetrical reconciliation for revenue recovery up to the maximum allowed revenue based on the operation of the IRM.

Q. How does the Company propose to address any over or under recovery of

surcharges?

A. The Company proposes that any over or under recovery of the IRM be deferred as a regulatory liability or regulatory asset until the next IRM reconciliation. Once the IRM is terminated, the Company proposes there be one final reconciliation, which would result in a refund or surcharge. This is essentially the same over or under recovery reconciliation methodology already in use for the Company's Transition Reconciliation Mechanism (TRM) relative to the transition of Detroit Public Lighting Department (PLD) customers to DTE Electric service. Short term interest should be accrued on any over or under recovery.

Q. When does the Company propose that the interim reconciliations occur?

A. The Company proposes that the initial reconciliation be filed by April 30, 2021 for the capital expenditures from May 1, 2020 through December 21, 2020. Similar reconciliations will be filed by April 30 of the subsequent years for 2021 and 2022.

Q. When does the Company propose that the IRM surcharge(s) be terminated?

A. The Company is proposing that the IRM operate until a final order is issued in its next rate case. Accordingly, the Company proposes that any surcharges implemented pursuant to the IRM remain in effect until a final order is issued in the Company's next rate case and new base rates are implemented.

Q. Generally, what type of cost of service and rate design is being proposed relative to the IRM surcharges?

A. The cost of service methodology relative to IRM rate base will follow the same cost of service methodology as other similar capital that is reflected in base rates. Witness

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Lacey addresses the cost of service allocation for the proposed IRM. For residential and small commercial customers, the Company is proposing a per kWh charge. For large commercial and industrial customers on rate schedules with a demand component, the Company is proposing an IRM demand charge. Company Witness Bloch address the rate design in detail and rates for the IRM.

Q. Is the Company proposing to report on the projects or units of work completed relative to the IRM?

A. Yes. The Company believes that it is essential that not only the capital dollars approved in the IRM be spent, but also that the capital is spent efficiently and effectively. As I will address later in my testimony, the Company is proposing that each fall the Company and Staff meet to review expected IRM expenditures and the scope of IRM work to be accomplished for the upcoming IRM year. The Company is proposing that actual work completed will be summarized and provided to Staff in the reconciliation. These are described in Company Witnesses Bruzzano, Davis and Paul's testimony as Program Metrics.

Q. Are there any other metrics the Company will report to allow the MPSC to assess the benefits of the programs in the IRM?

A. Yes, as described by Company Witnesses, Bruzzano, Davis and Paul, the Company is proposing to include specific results of program metrics in the annual reconciliation. Additionally, Company Witnesses, Bruzzano, Davis and Paul, describe specific performance indicators that the Company is proposing to be reported annually to the MPSC Staff.

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Q. What type of additional review, if any, is the Company proposing regarding the IRM?

A. The Company proposes that every fall prior to the IRM year, the Company meets with the Commission Staff to review specific spending and projects as well as measures. In addition, the Company proposes to meet with Commission Staff throughout the year to review progress relative to the plan.

Q. Is the Company proposing that there be any flexibility in the amount spent on any particular capital expenditure category?

A. Yes. The Company proposes that within distribution, generation and the proposed combined cycle natural gas plant, the Company be allowed some flexibility. However, the Company is not seeking to move any capital between those three broad business units. Within those business units, the Company is proposing to be able to move up to 20 percent of the capital dollars to or from any discrete category of work as defined on Exhibit A-30 T2, T3 and T4.

<u>Tree Trimming Surge</u>

Q. What is the Company proposing with respect to tree trim expenditures in this case?

A. DTE Electric is proposing to increase its tree trim expenditures significantly above its average spend over the last three years to eliminate the backlog of necessary work. As discussed in detail by Company Witness Ms. Rivard, this "surge" in tree trimming spending will occur over a seven-year period, and at its termination the Company expects to maintain a steady-state five-year cycle of tree trimming.

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Q. Is the Company seeking recovery of the tree trimming surge expense in the O&M levels in its projected period revenue requirement?

A. No. DTE is seeking approval in this case to defer the surge related expenses as a regulatory asset, which will be securitized when that asset reaches an appropriate balance. The securitization of the deferred expense is discussed by Company Witness Solomon.

Q. Why is it appropriate to defer and then securitize the surge related tree trimming expenses?

A. The surge related tree trimming expenses will vary, so allowing the deferral of the expenditures above the level that is included in the rates approved in this case will ensure that customers only pay for the work that is accomplished. Additionally, the benefits provided by the surge will continue for years after the work is completed. Allowing these costs to be deferred and then securitized with a 14 year amortization period will better match those benefits to the recovery of the cost. Finally, the securitization of these deferred expenses will lower the cost to our customers due to lower-cost of debt only financing.

<u>Rate Schedule D1 Time of Use</u>

Q. Are you familiar with the Commission's Order in Case No. U-18255 issued on April 18, 2018, and in particular the required change in the residential rate structure for Rate Schedule D1?

A. Yes I am. In the April 18, 2018 order in Case No. U-18255, the Commission ordered the Company, in its next general rate case, to include proposed tariffs for non-capacity charges based on summer on and off peak rates. In other words, approximately 1.9 million residential customers will be defaulted to time based rates for non-capacity charges. Note, the capacity charge component of customers' rates will be unchanged.

Q. Did the Company file for rehearing of this issue in Case No. U-18255?

A. Yes. In its rehearing, the Company stated that the directive to move approximately 1.9 million customers to a time-based rate will have unintended consequences, and therefore requested that the Commission reconsider this requirement. The Company already offers several optional rates to its residential customers which incorporate time of day and seasonal pricing; however, the Commission's directive to convert Rate Schedule D1 to a time of use rate structure would force all residential customers to be subject to time of use pricing. This will have a significant impact on the Company's rate structure and on the individual bills of the approximately 1.9 million Rate Schedule D1 residential customers.

Q. Specifically what relief did DTE Electric seek in its rehearing request?

A. The Company requested that the Commission eliminate the requirement to move all residential customers to time of use rates. In the alternative, the Company proposed that the Commission require the Company to file a proposed plan or process to transition its Rate Schedule D1 non-capacity rate to a time of use rate structure over a reasonable period of time. This would allow the Company to have more time to analyze and determine the best way to develop and implement such a fundamental change. Such a transition plan would also provide for appropriate customer communication as well as the evaluation of potential changes in customer behavior due to the expanded use of time of day rates.

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Q On June 28, 2018, the Commission issued an order on rehearing in U-18255. What was their response to the Company's rehearing request on this issue?

A. The Commission denied DTE Electric's petition for rehearing on this issue and affirmed that new non-capacity rates for Rate Schedule D1 should be based on summer on-peak rates. However, the Commission properly recognized that moving approximately 1.9 million residential customers to a time-based rate is a significant change to our business and our customers, by stating it "should be thoughtfully implemented, and does not view the decision in this case as foreclosing consideration of implementation issues related to timing or costs in future rate case" (June 28, 2018 Order, page 7).

Q What impact will moving to default time based rates for essentially all residential customers have on residential customers and the Company?

A. First, relative to customers, they should be allowed to choose to opt-in voluntarily to any new and significantly different rate program the Company offers. By offering several different residential rates as we do today, customers have a wide range of options, including whole home time of use rates, interruptible air conditioning, dynamic peak pricing, and geothermal rates. If customers believe they can take advantage of savings related to a time of use rate structure, or any other rate program, customers will opt-in, however customers should not be forced on to time of use rates. For the Company, this change in residential rate structure will impact a number of areas including Information Technology, Customer Service, and Marketing and Communications. These impacts, both operational and financial are discussed further by Company Witnesses Mr. Griffin, Ms. Johnson, and Mr. Clinton, respectively.

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Q What is the Company's recommendation in this case related to changing Rate Schedule D1 to having a time-based charging component?

A. In addition to the significant costs and extended timing issues as discussed by Witnesses Clinton, Johnson, and Griffin related to implementing this new rate structure, as stated above, the Company believes it currently has sufficient time-based rate products available to customers who desire to opt-in. Therefore, the Company continues to support its position taken in Case No. U-18255, and requests that the Commission in the final order in the present case, reverse its previous ruling from Case No. U-18255 and allow the Company to retain its existing Rate Schedule D1 pricing structure (with no time-based element). If the Commission does not grant this request, the Company must be allowed to proceed with implementation over a reasonable time period given the scope of work involved, and be allowed to recover all costs associated with this implementation consistent with Witness Uzenski's testimony.

Q What has the Company proposed from a rate design perspective in this case related to its Rate Schedule D1?

A. As Company Witness Mr. Dennis states in his testimony, DTE Electric has complied with the Commission's directive to develop a time-based rate for Rate Schedule D1. He also proposes rates based on the Rate Schedule D1 as it traditionally has been designed. He does this for two reasons. First, in anticipation that the Commission will reverse its prior decision and allow the Company to retain its existing Rate Schedule D1 pricing structure (with no time-based element) in the final order in the present case. Second, even if the Commission chooses to not reverse its prior decision, the existing rate structure needs to stay in place until such a time as all customers can be transitioned to the new rate structure given the long lead time needed to facilitate this change company wide.

Introduction of Other Witnesses

Q. How will the Company present evidence in support of its positions in this case?

A. The Company proposes to present its case through 27 witnesses, including myself, as described below (in alphabetical order).

1) Mr. Derek M. Arnold, Supervisor – Strategic Merchant Analytics, establishes the capacity-related generation costs included in the Company's Power Supply Cost Recovery Factor and the benefit of energy and ancillary services sales from the Company's capacity resources.

2) Mr. Timothy A. Bloch, Principal Financial Analyst – Pricing, supports the Company's proposed primary customer rate design and other proposed tariff changes as well as the IRM rate design and proposed rates.

3) Mr. Marco A. Bruzzano, Vice President – Distribution Operations supports the historical capital expenditures and Operations and Maintenance expenses related to electric distribution efforts for 2017 and the projected capital expenditures and O&M expenses for 2018 through April 2020. He will describe the major segments and driving forces behind this spending and discuss the organizations that incur these costs. Additionally, he will support the capital expenditures in the period beginning on May 1, 2020 and ending on December 31, 2022 that the Company is proposing to be included in its IRM.

4) Mr. Eric W. Clinton, Manager Electric Sales and Marketing – will provide details on the Company's Electric Vehicle (EV) education and development

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programs; provide details around two new pricing pilot programs for residential customers and; provide details and support for the Regulated Marketing O&M Expense.

5) Mr. Michael S. Cooper, Director - Compensation, Benefits & Wellness, presents an overview of benefit expense for DTE Electric for the 2017 historical test period and the May 1, 2019 through April 30, 2020 projected test period. He will provide support for the Company's pension costs, other post-employment benefits ("OPEB"), active employee health care costs and other employee benefits; provide an overview of the Company's compensation philosophy for non-represented employees and the role that the Company's incentive plans play in the overall reasonableness of its total compensation policies; describe the components of the Company's short and long-term incentive plans and support the inclusion of such costs in the Company's revenue requirement, exclusive of the costs related to DTE Energy's top five executives: and demonstrate the quantifiable customer benefits of the Company's incentive plans exceed the expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

6) Mr. Jeffery C. Davis, Manager – Nuclear Strategy and Business Support, will support the Company's actual O&M and capital nuclear expenditures for the 12-month historical test year ended December 2017. He will also discuss and support the projected nuclear O&M and capital expenditures for the interim forecast period and a twelve-month projected test period ending April 30, 2020. Additionally, he will support the capital expenditures in the period beginning on May 1, 2020 and ending on December 31, 2022 that the Company is

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proposing to be included in its IRM.

7) Mr. Philip W. Dennis, Manager, Regulatory Economics will support the proposed rate design for the residential customer rate schedules and the development of capacity charges for each residential rate schedule, pursuant to the requirements of 2016 PA 341 as well as the development of power supply non-capacity charges based on summer on-peak rates (i.e. Time of Use (TOU)) as required by the Commission's Order in Case No. U-18255.

8) Ms. Irene Dimitry, Vice President – Business Planning & Development, will support and justify the expenditures related to both DTE Electric's existing and future demand side management programs; and discuss the River Rouge Unit 3 economic analysis.

9) Mr. Keegan O. Farrell, Principal Financial Analyst - Load Research, will support and justify the development of the May 2019/April 2020 forecast allocation schedules; and the methodology DTE Electric used to include the demand associated with the Electric Choice loads in the forecast distribution allocation schedules; support and justify the hours used for the summer 6 on-peak non-capacity charge; and support and justify the anticipated load shift by residential customers in the Weekend Flex Pilot Program.

10) Mr. Robert D. Feldmann, Executive Director, Electric Sales and Marketing, will provide details on DTE Electric's investment in a pilot, Combined Heat and Power (CHP) plant that will be located on Ford Motor Company's (Ford) Research and Engineering (R&E) campus in Dearborn, Michigan, and the inclusion of that asset in the Company's rate base.

11) Mr. Daniel J. Griffin, IT Director of Operations & Infrastructure – supports the reasonableness of DTE Electric's IT capital expenditures for the historic test

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year of 2017 as well as the projected capital spend from January 2018 through the end of the projected test period ending April 30, 2020; discuss DTE Electric's IT's planning process; and provide details on the impacts to the Company from emerging technology trends.

12) Ms. Kelly A. Holmes, Principal Financial Analyst – Regulatory Economics, will support the development of the proposed rate design for the secondary customer (mostly commercial) tariff offerings. She is also supporting the calculation of power supply costs for the Company's projected test period in this case. She will support power supply rates designed to include a capacity charge, pursuant to the requirements on 2016 PA 341 and consistent with the methodology used in Case No. U-18248 as instructed by the Commission in its Order in U-18255; and distribution rates designed to approach a uniform rate for all commercial secondary tariff offerings.

13) Ms. Tamara Johnson, Director – Revenue Management & Protection, will explain the details of the Company's Customer Service Operation and Maintenance (O&M) expenses for the 12-months ended December 31, 2017, and provide explanation and support of the projected O&M expenses for the 12-month projected test period ending April 30, 2020 inclusive of uncollectible expense. She will provide details for the historical costs, discuss the inflationary impact on forecasted costs, provide an update on our level of uncollectible expense, support proposed changes to merchant fees, discuss Customer Service performance and areas of improvement, discuss the Company's Low Income initiative, Customer 360 (C360) Project costs and proposed changes the Company's tariff.

14) Mr. Kenneth D. Johnston, Manager – Community Lighting, will support the

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energy forecast for outdoor lighting; the development of the proposed rate design for the outdoor lighting rate schedules (municipal lighting and other); support the reasonableness of the historic and projected Community Lighting O&M; discuss the Community Lighting capital expenditures; and the establishment of a post/pole charge.

15) Mr. Thomas W. Lacey, Principal Financial Analyst – Revenue Requirements Department, will present Unbundled Cost of Service (UCOS) Studies for DTE Electric's projected test year ending April 30, 2020. He also supports revenue requirement calculations for: (1) customer related costs, (2) capacity charge by rate class, and (3) Infrastructure Recovery Mechanism (IRM) by rate class.

16) Mr. Markus B. Leuker, Manager – Corporate Energy Forecasting, will provide the Company's current electric sales, maximum demand and system output forecast for the period 2018-2028, including the projected period for the 12 months ending April 30, 2020. He will discuss the outlook for the national and local economy which is the basis of the forecast. He will also describe how the forecast of electric sales, maximum demand and system output is developed and support the reasonableness of the electric sales forecast used by DTE Electric in this proceeding.

17) Mr. David C. Milo, Fuel Resource Specialist – Fuel Supply, will support DTE Electric Fuel Supply's and Midwest Energy Resources Company's operations and maintenance expense and capital expenditures for the twelve months ended December 2017 historical actual, and as projected for January 2018 through April 30, 2020.

18) Mr. Brian V. Moccia, Manager – Advanced Metering Infrastructure - Technical, will support the reasonableness of DTE Electric's AMI project

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from a benefit perspective. He will provide a brief background on the progress made with AMI and current status of completion; and will also provide testimony to discuss and support AMI 3G to 4G communication upgrade, AMI Industrial 4G communication upgrade, and AMI leveraged tools (PI, Analytics).

19) Mr. Matthew T. Paul, Vice President – Plant Operations, Fossil Generation, will explain DTE Electric's Fossil Generation planned changes in power plant capacity ratings; provide a review of the Fossil Generation base coal unit availability performance for five years prior and five years following the test year in this case; support the historical 2017 level of capital expenditures on a plant level basis and provide forecasts of capital expenditures planned for 2018 through April 30, 2020; support the known and measurable changes in Fossil Generation Operating and Maintenance expenses that will span the timeframe from the 2017 historic test year in this case to the projected test year, ending April 30, 2020; describe the new CHP unit;. finally, he will support the capital expenditures in the period beginning on May 1, 2020 and ending on December 31, 2022 that the Company is proposing to be included in its IRM.

20) Ms. Heather D. Rivard, Senior Vice President of Electric Distribution – will discuss the Company's tree trimming program including the 2017 historic period expense, and the expense for the projected test year; and support funding for a program structure that will enable the Company to deliver the reliability goals established in its Five-Year Plan.

21) Mr. Camilo Serna, Vice President of Corporate Strategy – will detail electrification of transportation in Michigan; describe and support the

Company's proposed EV program; and support the cost estimates of that program along with the associated approach for cost recovery.

22) Mr. Kenneth Slater, Manager - Revenue Requirement, will support DTE Electric's twelve months ended December 31, 2017 historical revenue deficiency. In addition, he is sponsoring Net Operating Income ("NOI") adjustments for interest synchronization and income tax savings, as well as, the revenue conversion factor. Mr. Slater is sponsoring DTE Electric's twelve months ending April 30, 2020 projected revenue deficiency. Furthermore, he is sponsoring the NOI adjustments for interest synchronization and income tax savings as well as the projected revenue conversion factor. He is also calculating the incremental revenue requirement for DTE Electric's Tree Trim Surge Amortization request and the projected value of the Tree Trim Surge Program. In addition, he supports the calculation of the incremental revenue requirements for DTE Electric's Infrastructure Recovery Mechanism (IRM) and provides an example of the revenue requirement impact of an under spend in the IRM reconciliation.

23) Mr. Edward J. Solomon, Assistant Treasurer and Director – Corporate Finance, will support DTE Electric's projected capital structure; the cost of its long and short-term debt to be used in the determination of DTE Electric's overall rate of return; and the securitization of the Company's deferred surge-related tree trimming expenses.

24) Ms. Theresa Uzenski, Manager – Regulatory Accounting, will support DTE Electric's financial statements for the historical test year ended December 31, 2017, the interim forecast period and a twelve-month projected test period ending April 30, 2020, with certain adjustments necessary for presenting the

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financial information in the appropriate format for ratemaking purposes. She will support the development of the projected test year adjusted electric operating income based on forecasted changes from the normalized historical electric operating income. Ms. Uzenski will also support the Corporate Staff Group expenses for the historical and forecasted periods and explain the function of this group and the method for allocating costs to DTE Electric and the other DTE subsidiaries. She will support that costs recovered from other mechanisms are excluded from the financial statements in this case (including the Transitional Recovery Mechanism for the transition of Detroit Public Lighting Department customers, Renewable Energy Program, Energy Optimization, etc.). She will also request regulatory asset treatment for certain costs.

25) Dr. Michael Vilbert– A Principal at The Brattle Group, will estimate the cost of capital for the Company. Specifically, Dr. Vilbert provides return on equity (ROE) estimates derived from a sample of comparable risk, regulated electric utility companies. Dr. Vilbert also considers the relative risk of the Company's proposed capital structure ratio to arrive at his recommendation for the allowed ROE of 10.5%.

26) Ms. Sherri Wisniewski, Director – Tax Operations, will support the DTE Electric Federal Income Tax, Michigan Corporate Income Tax, Municipal Income Tax, property tax and other general taxes for the 2017 calendar year historical period and the twelve months projected test period ending April 30, 2020. She also proposes how re-measurement of deferred taxes resulting from Tax Cut Jobs Act 2017 will be returned to customers through amortization of the tax regulatory liability starting on May 1, 2019.

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Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate Schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DEREK M. ARNOLD

DTE ELECTRIC COMPANY
QUALIFICATIONS OF DEREK M. ARNOLD

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Q. What is your name, business address and by whom are you employed?

A. My name is Derek M. Arnold. My business address is 414 S. Main Street, Suite 300, Ann Arbor, Michigan 48104. I am employed by DTE Electric Company (DTE Electric or Company).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric.

Q. What is your current position with the Company?

A. I am currently the Supervisor of the Strategic Merchant Analytics Team within the Generation Optimization Department.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Mechanical Engineering from Wayne State University in 2008 and a Master of Business Administration Degree from Wayne State University in 2016.

Q. What is your work experience?

A. From 2006-2008, I worked at DTE Electric's Monroe Power Plant as an engineering co-op responsible for equipment inspections and special projects. After obtaining my Bachelor of Science degree from Wayne State University in 2008, I was employed by DTE Electric as an associate engineer in the Generation Optimization Organization. In the Generation Optimization group, I was responsible for forecasting and optimization of the Fossil Generation Power Plant fleet, including leading the fuel blending initiative.

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In 2009, I joined the Fossil Generation Strategic Planning group as a principal market engineer. In this role, I was responsible for the modeling of the DTE Electric generation fleet to support corporate forecasting, fuel contracts, and regulatory filings.

In 2012 and 2013, I cross-trained as a capital and O&M financial controller at Monroe Power Plant. In this role, I was responsible for budgeting, tracking, and accounting activities at the power plant.

In 2014, I returned to the Fossil Generation Strategic Planning group to continue as a principal market engineer where I was responsible for modeling and analyzing strategies and scenarios.

In 2016, I was promoted to my current Supervisor position within the Generation Optimization Department.

Q. What are your duties and responsibilities in your current position?

A. My current responsibilities include supervising a group of engineers responsible for resource adequacy processes, modeling the DTE Electric generation fleet, optimizing financial transmission rights, procuring emission allowances, executing special studies, and advocating Company recommendations in MISO stakeholder forums.

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Q. What has been your involvement in cases before the Michigan Public Service Commission (MPSC or Commission)?

A. I was the Generation Optimization witness for the 2018 Power Supply Cost Recovery (PSCR) Plan Case No. U-18403. I also provided support for the 2014 PSCR Plan Case No. U-17319, 2015 PSCR Plan Case No. U-17680, 2016 PSCR Plan Case No. U-17920, and 2017 PSCR Plan Case No. U-18143.

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Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to establish the capacity-related generation costs, the benefit of energy and ancillary services sales from the Company's capacity resources, and the energy sales revenue net of fuel cost included in the Company's Power Supply Cost Recovery (PSCR) Factor. This information is used by Company Witness Mr. Lacey in his cost of service.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-29	S1	Projected 2018 PURPA Capacity-Related Generation Cost
A-29	S2	Projected 2018 PA295 Capacity-Related Generation Cost
A-29	S3	Projected 2018 Capacity-Related Generation Cost & Energy Sales Revenue Net of Fuel Cost

Q. Section 6w(3)(A) of Act 341 requires that the capacity charge include capacity-related generation costs in the Company's PSCR Factor, as well as other rates and surcharges. What are the capacity-related generation costs included in the Company's PSCR Factor?

A. The Company's PSCR Factor includes capacity-related generation costs associated with PURPA power purchase agreements, PA295 Company-owned renewable energy systems, PA295 renewable energy contracts, and capacity purchases.

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Q. How did the Company project the 2018 capacity-related generation costs for PURPA power purchase agreements as included in its PSCR plan filing on September 28, 2017 in Case No. U-18403?

A. The Company's PURPA contracts have three rate components; fixed, operation and maintenance (O&M), and variable. The projections for both the fixed and O&M components were included in the capacity-related generation costs. The total projected 2018 PURPA capacity-related generation cost is approximately $24.1 million as shown on Exhibit A-29, Schedule S1.

Q. What costs associated with PA295 company-owned renewable energy systems and power purchase agreements are included in the PSCR?

A. The portion of the cost of PA295 company-owned renewable energy systems that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the renewable energy systems and the levelized cost of energy calculated for the renewable energy system. The portion of the cost of PA295 power purchase agreements (i.e. non-Company owned) that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the power purchase agreement and the contract price of the agreement.

The Transfer Price is a proxy for the incremental non-renewable capacity and energy expense that would be passed on to the customer if the renewable energy resource was not developed. The relevant statute explains that when setting the Transfer Price, the Commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs, information filed under Section

6j of 1939 PA 3 (MCL 460.6j), and wholesale market data including, but not limited to, locational marginal pricing.

Q. How did the Company project the 2018 capacity-related generation costs for PA295 company-owned renewable energy systems and power purchase agreements?

A. The capacity-related generation cost for PA295 company-owned and non-company owned renewable energy systems and power purchase agreements is the approved Transfer Price fixed component for each specific renewable energy system. The total projected 2018 PA295 capacity-related generation cost is approximately $66.6 million as shown on Exhibit A-26, Schedule S2.

Q. How did the Company project the 2018 cost of capacity purchases?

A. The Company included the net capacity purchase costs based on forecasted expense for the calendar year 2018.

Q. How did the Company calculate the projected 2018 energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341?

A. Section 6w(3)(B) of Act 341 requires that the revenue, net of projected fuel costs, from energy market sales, off-system energy sales, ancillary services sales, and energy sales under unit specific bilateral contracts be subtracted from the capacity charge. To calculate the energy sales revenue net of projected fuel costs, first the revenue associated with energy sales from the Company's generation resources was determined, which is any excess generation sold into the MISO energy market after serving the Company's bundled load. I used this methodology at the direction of

Company Witness Stanczak. Next, the revenue associated with ancillary services provided by the Company's generation resources was determined. The portion of those ancillary services associated with the energy sales was then determined by multiplying by the ratio of energy sales volume to total generation volume.

Q. What is the projected revenue associated with energy sales from the Company's generation resources in 2018?

A. In the Company's 2018 PSCR Plan (U-18403), there are 2,389 GWh of projected energy market sales in 2018 with associated revenue of $88.8 million as shown on Exhibit A-29, Schedule S3, lines 11 and 12, respectively.

Q. Is the Company projecting any off-system energy sales or sales under unit specific bilateral contracts in 2018?

A. No. These values are shown as zero on Exhibit A-29, Schedule S3, lines 13 and 14.

Q. What is the projected ancillary services revenue associated with energy sales from the Company's generation resources in 2018?

A. The Company's generation resources receive revenue for providing the following ancillary services: regulation reserves, spinning reserves, and supplemental reserves (all settled via MISO's energy and ancillary services market) and reactive reserves (settled per Schedule 2 of the MISO tariff). The Company's 2018 PSCR Plan projected that Company's generation resources would generate $1.8 million of revenue associate with regulation, spinning, and supplemental reserves and $13.1 million of revenue associated with Schedule 2 reactive reserves. The portion of these ancillary services revenues associated with the energy sales from the Company's generation resources in 2018 is determined by multiplying the total ancillary services revenue by the ratio of the energy sales volume to the total projected generation volume (2,389 GWh / 41,697 GWh), which amounts to $0.1 million for regulation, spinning, and supplemental reserves revenue as shown on Exhibit A-29, Schedule S3, line 15 and $0.8 million for reactive reserves revenue as shown on Exhibit A-29, Schedule S3, line 16.

Q. What is the total projected energy sales revenue including ancillary services in 2018?

A. The total projected energy sales revenue including ancillary services in 2018 is $89.7 million as shown on Exhibit A-29, Schedule S3, line 17.

Q. What is the projected fuel and fuel related cost required to generate the projected energy and ancillary services sales from the Company's generation resources in 2018?

A. The projected fuel and fuel related cost required to make the energy and ancillary services market sales is projected by calculating a fleet average generation fuel price and multiplying it by the energy sales volume. The fleet average generation fuel price is calculated by summing the total projected fuel, emission allowance, and chemical costs for the Company's generation fleet ($857.9 million as shown on Exhibit A-29, Schedule S3, line 24) then dividing by the total projected generation volume (41,697 GWh as shown on Exhibit A-29, Schedule S3, line 25) which results in a generation fuel price of $20.58/MWh as shown on Exhibit A-29, Schedule S3, line 26. The generation fuel price is multiplied by the projected energy market sales volume to get a projected 2018 energy sales fuel cost of $49.2 million as shown on Exhibit A-29, Schedule S3, line 28.

Q. What other costs are associated with the projected energy sales described above that should be netted against the revenue?

A. MISO incurs costs when providing the following services including, but not limited to: 1) market modeling and scheduling functions; 2) market bidding support; 3) locational marginal pricing support; 4) market settlements and billing; 5) market monitoring functions; and, 6) simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the MISO Balancing Authority Areas while also establishing a spot energy market. MISO recovers these Energy and Operating Reserve Markets Support Administrative Service Cost through a recovery adder filed as Schedule 17 in the MISO tariff. The projected Schedule 17 rate for 2018 is $0.0732/MWh, so the Schedule 17 admin fees associated with the 2,389 GWh of projected energy market sales in 2018 is $0.2 million as shown on Exhibit A-29, Schedule S3, line 30.

Q. What is the Company's projected energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341 for 2017?

A. The total projected 2018 energy sales revenue of $89.7 million, net of $49.2 million in fuel related costs and $0.2 million in Schedule 17 admin fees equates to $40.3 million energy sales revenue net of fuel related costs as shown on Exhibit A-29, Schedule S3, line 32. This amount was provided to Company Witness Mr. Lacey to develop his capacity related cost of service.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TIMOTHY A. BLOCH

DTE ELECTRIC COMPANY
QUALIFICATIONS OF TIMOTHY A. BLOCH

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Q. Will you please state your name, business address and by whom are you employed?

A. My name is Timothy A. Bloch. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC within Regulatory Affairs as Principal Financial Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company) formerly, the Detroit Edison Company (Detroit Edison).

Q. What is your educational background?

A. I graduated from Michigan Technological University in 1980 with a Bachelor of Science degree in Mechanical Engineering.

Q. Have you completed any other courses of study?

A. Yes, I have completed several professional level training courses including Power Systems Engineering, P.U.R. Guide course, Fundamentals of Economic Analysis, Public Utility Accounting, AEIC Fundamentals of Load Research, AIC Negotiating Power Supply Contracts, Sampling Methods & Statistical Analysis in Power Systems Load Research, EEI Rate Fundamentals course, EEI Advanced Rate course and others.

Q. What work experience do you have?

A. I joined Detroit Edison in 1981 as an Assistant Engineer in the Central Heating Plants of the Production Organization. I was responsible for equipment

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performance and efficiency testing, system troubleshooting, outage management and capital improvement projects.

In 1984, I accepted a position as an Associate Engineer with the District Heating Management Organization. My responsibilities in this position included financial reporting, preparing testimony for the steam cost recovery cases and providing technical assistance to the sales and service staff. In addition, I provided technical recommendations and managed several engineering and economic projects related to the design, expansion, operation and maintenance of the steam distribution system and customer service installations. During this period, I was promoted from Associate Engineer to Engineer and in 1988 from Engineer to Senior Engineer.

In 1989, I cross-trained in the Customer Options Group of Marketing. In this position, I assisted in the administration of Detroit Edison's power purchase contracts with FERC-qualified facilities. In 1990, I accepted a permanent position in this group.

From 1990-1994, my primary responsibility was to assist in the development and negotiation of waste-to-energy contracts resulting from Public Act 2 (PA2). I was directly involved in developing the terms and conditions for these contracts, meeting with and providing information to customers and developers interested in developing PA2 projects, and representing the Company in the negotiation process. I was also the Company's witness in the filing of PA2 contracts.

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In 1994, after the Company went through a restructuring process, Customer Options became part of the Pricing group and my job title changed to Analyst/Pricing.

From 1994 to 1998, my primary responsibilities in Pricing included contract administration of PA2 contracts, rate analysis and design, and support in the development of special contracts, such as the Special Manufacturing Contracts (SMC) and the Large Customer Contracts (LCC). During this period, I also cross-trained for approximately one year with our Load Research group to learn statistical sampling techniques, methods of accessing customer data and how the Total System Analysis (TSA) is performed. In June 1998, I was promoted to Principal Financial Analyst. My current responsibilities include the development of residential, commercial, industrial, and governmental rates. I am also responsible for developing and recommending pricing policy and development, application and administration of rate tariffs and special contracts, as well as the rules and regulations governing service.

Q. Have you testified previously before the Michigan Public Service Commission?

A. I have sponsored testimony in the following cases:

U-18419	Certificate of Necessity
U-18255	DTE Electric General Rate Case
U-18248	DTE Electric Section 6w of 2016 PA 341 Filing
U-18091	DTE Electric Avoided Cost Calculation
U-18014	DTE Electric General Rate Case
U-17767	DTE Electric General Rate Case
U-17734	In the matter of the Formal Complaint of AK Steel

	Corporation (successor to Severstal Dearborn, LLC) against DTE Electric Company for standby service.
U-17689	DTE Electric Public Act 169 of 2014 Filing
U-17251	DTE Electric Amendment to Rider No. 3
U-16472	DTE Electric General Rate Case
U-16384	U-15768 Self Implementation Refund
U-15768	Detroit Edison General Rate Case
U-15244	Detroit Edison General Rate Case
U-11452	Detroit Edison Direct Access Tariff
U-10066 – U10070	1989 PA2 Power Purchase Agreements
U-10232	1989 PA2 Power Purchase Agreement

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to develop and support the Company's proposed primary rate design and other proposed tariff changes. In addition, I am supporting the Company's proposed annual surcharge schedules related to the Infrastructure Recovery Mechanism (IRM) proposed by Company Witness Mr. Stanczak for years 2020 through 2022 and the calculation of the annual IRM reconciliation over and under recovery by class. More specifically, my testimony and exhibits address:

1) The Company's proposed changes to the determination of voltage level energy discounts and voltage level demand adjustments.
2) The Company's proposal to add voltage level demand adjustments to the D6.2 Billing Demand charge.
3) The Company's proposed changes to determining power supply cost allocation to Standby Service Rider 3 and associated rate design changes.
4) The Company's proposed changes to the Retail Access Service Rider – EC2 with respect to the conditions for (Retail Access or Choice) customers to return to full service.
5) Calculation of the nuclear surcharge.
6) The Company's proposed IRM surcharge schedules and calculation of IRM reconciliation over and under recovery by class.

Q. Mr. Bloch, are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-16	F2	Summary of Present and Proposed Revenue by Rate Schedule – 12 months ending April 30, 2020

A-16	F3	Present and Proposed Revenues by Rate Schedule – 12 months ending April 30, 2020
A-16	F4	Comparison of Present and Proposed Monthly Bills– 12 months ending April 30, 2020
A-16	F5	Calculation of Voltage Level Distribution Charges – Primary Sub-transmission and Transmission Voltage Levels
A-16	F12	Calculation of Proposed Voltage Level Energy Discounts and Voltage Level Demand Adjustments for Rates D6.2, D8 and D11
A-16	F6	Calculation of Nuclear Surcharge
A-16	F10	Proposed Tariff Sheets
A-30	T10	Schedule of Proposed Infrastructure Recovery Mechanism (IRM) Surcharges _2020 through 2022

With respect to Exhibit A-16, Schedule F3, I am sponsoring the Commercial and Industrial (C&I) primary rate classes, which includes pages 26 through 40 of this exhibit. On Exhibit A-16, Schedule F4, I am sponsoring the typical monthly bills comparison for the C&I primary rate classes shown on pages 31 through 50. Company Witnesses Ms. Holmes, Mr. Johnston, and Mr. Dennis are sponsoring the remaining customer classes in Schedules F3 and F4. On Exhibit A-16, Schedule F10, I am sponsoring the proposed tariff changes related to the C&I primary tariffs, the standard allowance table in Section C6.2 (4), and the Retail Access Service Rider EC2. Witnesses Holmes, Johnston, and Dennis are sponsoring the remaining sheets contained in this exhibit.

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Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Will you please summarize your conclusions and recommendations?

A. My conclusions and recommendations are:

- The Company's proposed power supply rates are cost based, utilizing the power supply base revenue deficiency/sufficiency levels by major rate class as shown in Exhibit A-16, Schedule F1.1 and sponsored by Company Witness Mr. Lacey.
- The Company's proposed delivery rates are cost based by voltage level, utilizing the distribution base revenue deficiency/sufficiency levels by voltage class as shown in Exhibit A-16, Schedule F1.2 and sponsored by Witness Lacey.
- The proposed power supply rates include capacity and non-capacity related power supply charges pursuant to the requirements of Section 6w 2016 PA 341.
- The Company's proposed voltage level energy discounts and voltage level demand adjustments are cost based by properly accounting for differences in losses and cost allocation at each voltage level.
- The Company proposed rate design includes the addition of cost based voltage level demand adjustments for Rates D6.2.
- The Company's evidence supporting R3s abnormal demand variability clearly demonstrates that 4CP does not represent the true demands the R3 class imposes on the system during high load periods and therefore the current method of allocating capacity costs to R3 based on 4CP is inappropriate and significantly understates R3 cost responsibility resulting in rate D11 subsidizing R3. The Company's proposed method of allocating capacity costs to R3 accounts for

R3s abnormal demand variability and results in proper cost allocation to R3.

- The Company's proposed nuclear surcharge is designed to collect the Proposed Nuclear Surcharge Revenue.
- The Company's proposed IRM Surcharges are designed to collect the proposed power supply and distribution revenue requirements by class as supported by Company Witness Lacey.

Q. Can you please provide a brief description for each of the Company's major primary customer rate schedules?

A. Rate Schedule D11 is the Company's main primary rate schedule and is available to customers served at primary, sub-transmission or transmission voltage. Rate Schedule D6.2 is available to educational institution customer locations (school, college or universities) desiring service at primary, sub-transmission, or transmission voltage. Rate Schedule D8 is the Company's primary voltage interruptible rate which is limited to 300 megawatts. Rate Schedule D10 is our all electric school building rate (including electric space and water heating). Rider 1.1 and 1.2 are specific interruptible rates for customers operating electric furnaces for metal melting (Rider 1.1), or using electric heat as an integral part of manufacturing (Rider 1.2). The Company's Rider 3 rate provides standby service for various customers with generation facilities operating in parallel with the Company's system. Finally, Rider 10 is an interruptible supply rate available to customers with larger interruptible loads

Q. Will you please describe Exhibit A-16, Schedule F2?

A. This exhibit summarizes present and proposed revenues by rate schedule for the 12-

month period ending April 30, 2020. Present revenues are based on rates approved on April 27, 2018 in the Company's last general rate case, U-18255. The exhibit provides a comparison of total present and proposed revenues on page 2, present and proposed power supply revenues on page 3, and present and proposed distribution revenues on page 4. The proposed power supply revenues on page 3 provides a separate breakout of capacity and non-capacity related power supply revenues.

Q. Will you please describe Exhibit A-16, Schedule F3?

A. This exhibit compares the present and proposed rate design and corresponding revenue by rate schedule based on the 12-month period ending April 30, 2020 billing determinants. The exhibit details the billing determinants, and corresponding present and proposed rates and revenue. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The billing determinants were developed based on historical data and relationships, as well as known and measurable changes, and are consistent with Company Witness Mr. Leuker's sales forecast. The existing rates, as approved in Case No. U-18255, are in column (c), and are used to calculate the present revenues in column (d). The proposed rates, which now include separate capacity and non-capacity related power supply charges, are in column (e), with the resulting revenues in column (f).

Q. What is the basis for your proposed rate levels in this proceeding?

A. Consistent with the requirements of 2008 PA 286, Sec. 11, DTE Electric's rates are designed to be cost based. Therefore, the basis for my proposed rates are the

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functionalized cost based power supply and distribution revenue deficiency/sufficiency levels shown on Exhibit A-16, Schedules F1.1 and F1.2 respectively, sponsored by Witness Lacey. My proposed primary rate designs result in power supply and distribution charges which are set equal to cost-to-serve.

Q. How were the capacity and non-capacity charges determined for the primary rate schedules?

A. Witness Lacey determined the capacity and non-capacity revenue requirement for each cost of service class, which are shown on lines 9 and 10 in his Exhibit A-16, Schedule F1.5. For primary rates with billing demand components, capacity rates were designed to collect the total capacity revenue requirement through the billing demand charges. For primary rates that do not have billing demand components, capacity rates were designed to collect capacity revenue requirement through energy charges. Generally, non-capacity rates were designed to recover non-capacity revenue requirement through energy charges. For rate D11, a non-capacity demand charge was designed to recover transmission expenses on a demand basis as approved in Case No. U-18255. For rate D8, a non-capacity demand rate was designed to collect transmission and other non-capacity costs.

Q. Will you please explain how the Company's proposed voltage level energy discounts and billing demand voltage level demand adjustments for Rates D6.2, D8 and D11 were determined?

A. Yes. The calculation of the voltage level energy discounts and voltage level demand adjustments are shown in my Exhibit A-16, Schedule F12. The energy voltage level discounts for Rates D11 and D8 were treated as one class for determining energy voltage level discounts since both rates share the same energy rates. Voltage level loss adjustments were applied to the D11 and D8 voltage level sales to determine loss adjusted sales. Loss adjusted sales were used to allocate energy revenue to each voltage level and then voltage level energy rates were calculated to determine the voltage level energy discounts. Voltage level energy discounts for rate D6.2 were calculated in a similar manner. The Billing Demand voltage level adjustments were determined separately for D6.2, D8 and D11 to account for differences in each rates voltage level contribution to the 4CP. This is appropriate since the power supply expenses collected through the billing demand charges are allocated to the D6.2, D8 and D11 classes on their respective 4CP. Demand revenue was allocated based on the voltage level 4CP and then divided by the voltage level billing demands to determine voltage level demand rates and voltage level adjustments which account for both loss factors and cost allocation differences at each voltage. For D8, the 4CP contributions were adjusted to remove product protection demands. Product protection demands were removed since product protection receives the D11 billing demand charge and associated demand charge voltage adjustments.

Q. Will you please explain how the Company's proposed transmission related voltage level demand adjustments for Rates D11 and D8 were determined?

A. Yes. The calculation of the transmission related voltage level demand adjustments are shown in my Exhibit A-16, Schedule F12. Transmission related voltage level demand adjustments were determined separately for D8 and D11 to account for differences in each rate's voltage level contribution to the 12CP. Transmission

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costs were allocated to each voltage level following the same cost of service principles used to determine billing demand voltage level adjustments which considers both loss factors and cost allocation differences. For transmission expenses, the appropriate cost allocator is each voltage levels' 12CP as this is the same allocation basis used to allocate transmission expenses in COS. Transmission demand revenue requirement was allocated based on the voltage level 12CP and then divided by the voltage level billing demands to determine voltage level demand rates and voltage level adjustments which account for both loss factors and cost allocation differences at each voltage.

Q. Is the methodology used for determining billing demand voltage level adjustments the same as was approved in U-18255?

A. No. The method used to determine demand based voltage level adjustments in Case U-18255 results in unintended consequences by creating intra class subsidies between voltage levels. The approved method only considers loss differences between voltage levels but fails to consider the voltage level cost responsibility to which the losses are applied. The Commission's direction to determine voltage differentiated power supply demand charges must be interpreted to mean voltage level demand charges that are consistent with cost based principles. To do otherwise, implies the Commission is directing rate subsidies to be created. The Company's proposed voltage level demand rates are cost based using in the same voltage level cost responsibilities that would result by performing separate power supply voltage level COSS for each rate.

Q. Does the current method approved in U-18255 move cost responsibility at each

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voltage level closer to the cost to serve at each voltage level?

A. No, considering voltage level loss differences and ignoring the 4CP voltage level cost responsibility can result in shifting costs further away from each voltage level cost to serve. The most obvious demonstration of this can be found in rate D6.2 where the impact of 4CP cost allocation is much larger than the voltage level loss adjustment resulting in a sub-transmission voltage level adjustment that is a charge as opposed to a discount when determined under the current method. This same issue impacts all voltage level demand charges calculated under the current method, even when the resulting voltage level rate is a discount.

Q. Will you please describe Exhibit A-16, Schedule F4?

A. This exhibit shows a comparison of typical monthly bills by rate schedule based on present and proposed rates. For each rate schedule, comparisons were made across a broad range of energy consumption levels and load factors, as appropriate, to indicate the impact of my proposed rate changes.

Q. Will you please describe Exhibit A-16, Schedule F5?

A. This exhibit shows the development of the voltage level Distribution Demand Charges for the primary tariffs.

Q. Will you please describe the development of the voltage level distribution charges shown in Exhibit A-16, Schedule F5?

A. The present (U-18255 Base Rates) base delivery revenue by voltage level for each rate schedule is shown in column (a). The base delivery revenue includes all revenues from service charges, distribution energy and demand charges, and

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substation credits. The cost based deficiency/(sufficiency) for each service voltage level, from Exhibit A-16, Schedule F1.2, sponsored by Witness Lacey, are shown in column (b). Column (c) shows the total proposed base delivery revenue to be collected from each voltage level, which is the sum of columns (a) and (b). Columns (d) and (e) show the proposed service charge revenue and substation credits. Columns (d) and (e) are subtracted from column (c) to determine the amount of base delivery revenue to be collected in distribution demand charges, shown in column (f). The distribution demand revenue in column (f) was divided by the distribution demands in column (g) to determine the distribution demand charges by voltage level shown in column (h).

Q. Will all primary customers pay the same $/kW distribution charges or an equivalent amount as shown in column (h)?

A. Yes, all primary rates will have the same $/kW charges shown in column (h) with the exception of rates D10 and R1.1 and R1.2 which have energy based delivery charges. For these rates, I have calculated energy charges equivalent to the proposed voltage level distribution charges.

Q. Will you please describe Exhibit A-16, Schedule F6?

A. This exhibit shows the calculation of the Nuclear Surcharge which recovers costs associated with nuclear site security & radiation protection, and the funding for nuclear decommissioning and low level radioactive waste disposal. The proposed nuclear surcharge increase is due to increases in site security & radiation protection costs and Low Level Radioactive Waste Disposal Funding as supported by Company Witness Mr. Davis, and lower forecasted jurisdictional sales.

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Q. Will you please describe Exhibit A-16, Schedule F10?

A. This exhibit contains the proposed rule and tariff sheet changes which result from the Company's proposals in this case.

Q. Please describe the Return to Full Service provisions in the Retail Access Service Rider (RASR).

A. The Return to Full Service provisions require non-residential Retail Access Service customers to provide the Company with written notice no later than December 1st if they intend to take Full Service from the Company during the following summer, defined as the billing months of June through September. Customers who notify the Company are obligated to take Full Service for twelve consecutive months after their specified return date.

Q. What are the implications of not providing appropriate written notice of intent to return to Full Service as described in the RASR?

A. Non-residential customers who return to Full service with the Company for the following summer without providing the requisite written notice are subject to the higher of the applicable tariff energy price plus 10% or the Market Priced Power (MPP) charge plus 10%.

Q. Do other conditions exist in which non-residential customers may be subject to the higher of MPP or the applicable tariff energy price?

A. Yes. Non-residential customers who have not fulfilled their minimum two-year commitment on Retail Access Service will be charged the higher of the applicable tariff energy price or MPP until their minimum two-year term is satisfied.

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Q. Do these tariff provision apply to residential customers as well?

A. No. Residential customers are not subject to MPP charges, nor are they required to fulfill a minimum two-year commitment on Retail Access Service. However, residential customers are required to remain on Retail Access Service for a minimum of one full billing cycle, and once they return to Full Service they must remain on Full Service for a minimum of one year from the date of their return to Full Service.

Q. What changes to the Return to Full Service provisions is the Company proposing?

A. The Company is proposing that the less restrictive existing Return to Full Service provisions applicable to residential customers be implemented for all customers. Non-residential customers that participate on Retail Access Service would no longer be required to satisfy a two-year minimum stay on Retail Access Service nor would they be subject to MPP charges when they return to Full Service.

Q. Why is the Company proposing to standardize the Return to Full Service provisions for all customers?

A. The original basis for establishing the Return to Service provisions in the November 23, 2004, Order in MPSC Case No. U-13808 was to ensure that the returning customers didn't cause undue power supply costs to be borne by other Full Service customers. The Company needed an adequate timeframe to plan for serving the summer peak demand power supply needs of its customers and the requirement for customers to provide notification of their return by December 1st of the prior year provided for that planning. At the time of the MPSC's Order there were no limits

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in place to either limit the amount of DTE load which could avail itself of Retail Access Service or the amount of switching between Full Service and Retail Access Service. Customers were only required to provide a 30 or 60-day notice of their intended return to Full Service, an insufficient time frame for the Company to plan for their power supply service.

Q. Have the basis for the establishment of the Return to Service provisions changed since 2004?

A. Yes. On October 6, 2008, the Customer Choice and Electricity Reliability Act, part of Public Act 286, was enacted, followed by the Commission order on September 29, 2009 in Case Nos. U-15801 et al which established procedures to implement, among others things, a cap of 10 percent of an electric utility's average weather-adjusted retail sales for the preceding calendar year for customers taking Retail Access Service. By December 2009, participation in the Company's Retail Access Service program reached 10 percent. With one brief exception, participation has been at or above 10 percent ever since, with an overwhelming majority of Retail Access Service customers participating in the program continuously for over eight years and only a small number of customers returning to Full Service. Implementation of the 10 percent cap created stability in the Company's ability to plan for the needs of its customers.

Q. Have there been other changes which the minimize the need for the Return to Service provisions established in 2004?

A. Yes. Subsequent legislation, Public Act 341 passed on December 21, 2016, not only maintained the 10 percent cap on participation but also introduced a State

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Reliability Mechanism (SRM) to ensure reliable electric service and sufficient capacity resources for Michigan's customers. The SRM requires all electric providers to demonstrate that they have sufficient capacity resources to serve their customers. A Retail Access Service customer whose Alternative Electric Supplier (AES) does not demonstrate sufficient capacity will be assessed an SRM capacity charge by the utility. On March 14, 2018 in a report issued by the Commission in Case No. U-18441, all AESs with customers participating in the Company's Retail Access Service program demonstrated they have sufficient capacity to serve all of their customers for the next four resource adequacy planning years, June 1, 2018 through May 31, 2022 and therefore the Company will not be required to secure capacity to serve these customers during this period. After May 31, 2022, if AESs are unable to secure adequate capacity for their customers, the SRM capacity charge is the appropriate mechanism to ensure the Company's Full Service customers are not subsidizing the capacity requirements of Retail Access Service customers.

Q. Will the change in return to Full Service provisions for non-residential Retail Access Service customers adversely impact those customers currently on Full Service?

A. No. Given the current state of Retail Access Service including the establishment of the 10% cap and the AES demonstration of capacity to serve these customers for the foreseeable future, I don't believe existing Full Service customers will be impacted in any way.

Q. Could you please discuss your proposed changes to standby service rate

schedule Rider 3 (R3)?

A. Yes, I am proposing to change the method of allocating the power supply capacity costs to R3 to account for R3 abnormal demand variability and eliminate the associated subsidy to R3 by the D11 customers. I am also proposing to change the basis for setting the generation reservation fee approved in Case U-18255.

Q. Why are you proposing changes to the method of allocating power supply costs to R3?

A. In U-18255 the Company filed a separate cost of service class for Rider 3 as directed by the Commission in paragraph N of its January 31, 2017 order in Case No. U-18014. The Company presented several concerns with respect to treating R3 as a separate cost of service class, or attempting to allocate power supply costs to Rider 3 on a 4CP basis in case U-18255. "Fundamentally, assigning power supply costs based on 4CP to a standby COS class where loads can be very irregular and can vary significantly at any point in time compared to normal loads, does not follow proper cost allocation principles. This is especially true in a small class, where generation size varies greatly and when one customer can influence the outcome of the entire class." (T9 1974) Although the Commission's order decided against using a separate cost of service class for R3, thereby keeping R3 in the D11/Other COS Class (as recommended by the Company), it did approve ABATE's recommended power supply costs for R3 which are based on 4CP data averaged over 10-years (U-18255 Order at 72 and 76). The Commission's order in Case U-18255 approved the ALJs recommendations in the PFD to determine power supply revenue requirement for Rider 3 based on a cost of service that utilized 4CP data averaged over 10-years as recommended by ABATE Witness Dauphinais' (U-

18255 PFD page 276). While the PFD acknowledged the Company's concerns with respect to determining costs for R3 based on 4CP, it accepted ABATE's argument that the variability may be normalized by using an average of 4CPs over a longer term. "DTE Electric's concern that R3 demand variability is not amenable to traditional cost allocation principles is legitimate. However, as ABATE argues, that variability may be normalized by using an average over a longer term." (U-18255 PFD page 276).

The Company has determined that R3's 4CP does not accurately represent standby service loads placed on the system during peak load periods, due to its demand variability, and does not provide an appropriate basis to determine power supply cost allocation to the R3 Class. Therefore, the method of averaging R3 4CPs over several years, as recommended by ABATE, does not correctly address this variability, it only masks it, resulting in D11 customers subsidizing R3 customers.

Q. Please explain how you determined that 4CP does not accurately represent standby service loads during peak load periods due to demand variability?

A. Capacity costs are allocated to each cost of service class based on the average of each class' demand coincident with the Company's highest monthly peak demand during the peak load months of June, July, August and September (4CP). This method serves as a relative proxy of the demands each class places on the system during high demand periods in the summer. Properly allocating capacity costs on a 4CP basis is dependent on how well 4CP demands represent the demands a class places on the system during high demand periods, not just at the 4CP hours. To determine how well 4CP represents the actual R3 class demands during peak demand periods, I prepared the following Tables 1, 2 and 3 below, which are based on historic test year data provided by Company Witness Mr. Farrell.

Table 1

Frequency of Hourly Class Loads Exceeding 4CP During Summer Peak Hours[1] (2017)			
Class	**Total Hours**	**Hours Above 4 CP**	**Percent**
D1 & Other	340	4	1%
D3 & Other	340	69	20%
D4	340	66	19%
D11 & Other	340	61	18%
R3	340	185	54%

Table 2

Variance of Hourly Class Load Above 4CP During Summer Peak Hours[1] (2017)				
Class	**Avg of Monthly Max Hrs.**	**4 CP**	**Variance[2] (kW)**	**Percent**
D1 & Other	4,309,617	4,277,567	32,050	1%
D3 & Other	1,571,462	1,438,553	132,909	9%
D4	379,558	357,194	22,364	6%
D11 & Other	1,938,302	1,853,080	85,221	5%
R3	18,287	8,789	9,498	108%

Table 3

Variance of Hourly Class Load Above 4CP During Summer Peak Hours[1] (2017)				
Class	**Max Hr**	**4 CP**	**Variance[2] (kW)**	**Percent**
D1 & Other	4,553,937	4,277,567	276,370	6%
D3 & Other	1,595,497	1,438,553	156,944	11%
D4	390,423	357,194	33,229	9%
D11 & Other	1,952,545	1,853,080	99,464	5%
R3	24,583	8,789	15,794	180%

1 Summer Peak Hours defined as non-holiday weekdays between the hours of 15-18 during June – September

2 Variance defined as avg Monthly Max Hrs. or Max Hr above 4 CP

Table 1 provides a comparison of how often a class is operating above their 4CP during high demand on-peak hours 15, 16, 17 and 18 for the months of June through September. These are the summer hours when the Company's 4CPs

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normally occur. This table indicates the R3 class is operating at demand levels above their 4CP 54% of the time during these high load hours compared to normal load classes which operate below 20%. This is 2.7 times more operating hours above their 4CP than the next highest class. This is an indication that the R3 Class 4CP demands understate the average R3 demands placed on the system during high demand periods compared to other classes. The most compelling evidence that R3 4CP does not reasonably represent the actual R3 class demands placed on the DTE system during high demand hours is demonstrated in the demand variance comparisons shown in Tables 2 and 3. Table 2 compares the class 4CP to the average of their 4 monthly class peaks during high demand hours (4NCP). This comparison indicates that normal load classes have variances below 10% compared to the R3 class which has a variance that is 108% higher than their 4CP. This means the average of the 4 monthly R3 class demands is more than twice their 4CP demand which is over 1,000% higher than normal load classes. Table 3 compares the class 4CP to the class highest hourly demand during high demand hours. This comparison also indicates that normal load classes again have variances around 10% compared to the R3 class which has a variance that is 180% higher than their 4CP. This means that during high demand hours the R3 class has placed a demand on the system that is almost 3 times higher than their 4CP demand.

Q. Based on these comparisons what are your conclusions?

A. The Class 4CP to actual Class load comparisons presented in Tables 1-3 and discussed above, clearly demonstrate that due to the demand variability of the R3 class, 4CP is not representative of the demands R3 places on the system during high demand periods and should not be used to allocate costs to R3. Further, averaging

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4CPs over several years does not address this variability, it only masks it, resulting in D11 customers subsidizing R3 customers

Q. What are your recommendations with respect to allocating capacity costs to the R3 class?

A. I recommend calculating an equivalent 4CP demand for the R3 class by taking their actual 4NCP demand shown in Table 2 and reducing it by a variance adjustment in line with normal system load classes, which all operate with variances below 10%. Using 10% results in an equivalent 4CP demand of approximately 16MW. Allocating capacity costs on this basis results in a capacity revenue requirement for R3 of $3.895 million[1].

Q. Do your proposed changes to R3 power supply cost allocation affect how costs are allocated in the COSS?

A. No. R3 is included in the D11/Other cost of service class which includes rate schedules D10, D11 and R3. The allocation of power supply costs to the D11/Other COS class in the COSS is correct. The concern is after cost of service, where these costs are assigned to each rate schedule within the class (D10, D11 and R3).

Q. Can you explain how the capacity cost assignment within the D11/Other class is performed?

A. The power supply capacity revenue requirement allocated to the D11/Other class from the COSS are assigned to each rate (D10, D11 and R3) in the following order.

[1] R3 Capacity Rev. Req. = 16MW R3 equivalent 4CP ÷ 1,853MW D11&R3 4CP x $449,849 D11&R3 capacity revenue requirement = $3.895 million

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First, I allocate revenue requirement to D10 based on present revenues (this is consistent with the final order in U-18255). Next, I assign revenue requirement to R3 based on the calculation I described above. Last, I calculate the D11 revenue requirement by subtracting the D10 and R3 revenue requirement from the total D11/Other revenue requirement. Since D10 revenue requirement is assigned before R3, it is not affected by my proposed changes to R3 cost allocation. My proposed R3 cost allocation change only affects the revenue requirements of R3 and D11. To the extent the revenue requirement assigned to R3 understates the cost to serve R3, it shifts revenue requirement/cost responsibility to D11 causing D11 customers to subsidize R3 customers. The Company's proposed capacity revenue requirement for R3 eliminates the current D11 subsidy to R3 that resulted from allocating capacity costs to R3 based on a 10-year average of their 4CP.

Q. Please explain why you are proposing to change the basis for setting the generation reservation fee adopted in Case U-18255?

A. I have both cost of service and rate design concerns with the method adopted for setting generation reservation fee. The Commission adopted ABATE's proposal to set generation reservation based on the best performing generators of R3 customers. "The Commission finds that it is reasonable to approve an R3 standby tariff that sets a monthly power supply reservation charge based on the forced outage rates of the best performing generators." (p77 April 19, 2018 Order in U-18255). The ordered rate design in U-18255 set the R3 generation reservation based of an availability of 96.4%. The order in U-18255 did not specifically address the concerns presented by the Company that availability is not the appropriate basis to set generation reservation fee since availability does not reflect generator performance and the Company's need to reserve capacity. The notion that availability is an appropriate indicator of how well a customer's generator serves its' load is not supportable. Many proponents of using availability as an indicator incorrectly conclude that if a generator has a forced outage rate of 3.5% this means that the generator will serve all of its' load requirements the remaining 96.5% of the time. This conclusion is simply not true due to operating costs and other operational limitations. To determine this, using 2017 data, I compared three of the largest R3 standby customers which all have annual availabilities of 98% or higher to determine if their use of standby service was in the 2% range, as the above premise would suggest. The results indicate an average annual standby requirement of 30%, which ranged from 17% to over 50%. To lend additional perspective as to whether these results are representative of the class, these customers represent over 75% of the R3 class sales. These results support that availability is not an indicator of how well a customer's generator serves its' load and therefore is not an indicator of the standby requirements a standby customer places on the system.

Further, the best performing generator in this group has an availability of 100%. The Company reserves a substantial amount of capacity to serve this customer's standby needs yet based on this customer's availability of 100% the generation reservation should be set to zero based on the method adopted in U-18255. Now consider what would happen if this customer was the Company's only R3 customer. The Company still needs to reserve capacity to serve this customer, yet the generation reservation fee is set to zero, leaving daily demand and maintenance demand as the only recovery mechanism to recovery these costs. These are fixed costs that should be recovered through a charge that is not dependent on the performance of a customers' generation.

In addition to these concerns, from a rate design perspective, the Commission's order in U-18255, approving ABATE's proposed R3 changes, has over constrained the R3 rate design by having all R3 demand charges based the D11 billing demand (maintenance demand is 50% of daily demand, daily demand is 10% of the D11 billing demand, and generation reservation fee is set based on forced outage rate applied to the D11 Billing Demand). This constraint limits the ability to design R3 capacity rates equal to R3 costs, which are not determined based on the D11 billing demand. Prior to the R3 changes adopted in U-18255, any changes in R3 power supply revenue requirement were designed into R3 by changing each demand rate on an equal percentage basis to maintain existing recovery relationships.

Q. Can you summarize your recommendation with respect to determining the R3 Generation Reservation Fee?

A. From a cost of service basis I fundamentally disagree with the concept of setting generation reservation fee based on the best generator availability as this has no supportable linkage to cost causation. To eliminate the R3 design over constraint mentioned above, I recommend the Commission remove the requirement to set the generation reservation fee based on availability and allow changes in R3 capacity revenue requirement to be collected through the generation reservation fee.

Q. Can you describe your role with respect to the Company's proposal to implement an Infrastructure Recovery Mechanism (IRM)?

A. I will address the calculation of the proposed IRM surcharges for the years 2020, 2021 and 2022. With respect to the annual IRM reconciliations, I will describe how the over and under collections of capacity and delivery revenue requirements approved through the annual IRM reconciliation will be determined for each class.

Q. Can you describe Exhibit A-30, Schedule T-10, pages 1 through 4?

A. Page 1 summarizes the proposed total IRM revenue requirements by rate schedule for each year 2020, 2021, and 2022. Page 2 shows the power supply IRM revenue requirements and corresponding proposed IRM power supply surcharges by rate schedule for each year 2020, 2021 and 2022. Page 3 shows the delivery IRM revenue requirements and corresponding proposed IRM delivery surcharges for rates with energy based delivery charges. Proposed IRM delivery surcharges for rates with demand based delivery charges are calculated and shown page 4.

Q. What is the basis for your proposed IRM Surcharges in this proceeding?

A. The Power Supply and Delivery IRM surcharges are based on Witnesses Lacey's Production and Distribution IRM Revenue Requirement COSSs, the results of which are shown in Exhibit A-30, Schedules T8 and T9 respectively.

Q. How were the proposed IRM revenue requirements by rate schedule determined?

A. The Power Supply IRM revenue requirement for each cost of service class for years 2020, 2021 and 2022 are shown on lines 2, 3 and 4 of Exhibit A-30, Schedule T8. For those cost of service classes that have more than one rate schedule, I allocated the revenue requirement to each rate schedule based on present revenues consistent with the development of our base tariff rates. The Distribution IRM Revenue

Requirement for each cost of service class for years 2020, 2021 and 2022 are shown on lines 2, 3 and 4 of Exhibit A-30, Schedule T9.

Q. How were the IRM Power Supply Surcharges calculated for each year as shown on Exhibit A-30, Schedule T10, page 2?

A. IRM Power Supply Surcharges for each rate schedule were determined by dividing the IRM Revenue Requirement for each year, columns (d), (f) and (h), by the power supply sales in column (b). The sales in column (b) are based on the forecasted sales for the projected test year supported by Witness Lueker. These are the same billing determinants used in development of our base tariff rates as shown in Exhibit A-16.

Q. How were the IRM Delivery Surcharges calculated for each year as shown on Exhibit A-30, Schedule T10, pages 3 and 4?

A. I am proposing energy based IRM Delivery Surcharges (cents per kWh) for those rate schedules that have energy based delivery charges and demand based IRM Delivery Surcharges (dollars per kW) for those rate schedules that have demand based delivery charges (e.g. D4, D11, etc). For rate D4, I calculated a demand surcharge equivalent to the Commercial Secondary energy surcharge and for primary rates D10, R1.1 and R1.2 I calculated energy surcharges equivalent to their voltage level demand surcharges.

Q. With respect to IRM reconciliations, can you please describe how over and under collection of the approved revenue recovery will be determined for each rate class?

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A. As discussed by Witness Stanczak, the IRM reconciliation will consist of two parts. The first is related to spending the capital dollars reflected in the approved IRM surcharge, and the second is reconciling the IRM dollars collected. The IRM reconciliation related to the spending of capital dollars will determine an approved revenue recovery for power supply, and an approved revenue recovery for delivery based on actual spend as describe in further detail by Witnesses Mr. Slater and Mr. Lacey. If the approved revenue recovery is less than the revenue requirement used to set the IRM surcharges, then a new lower revenue requirement will be calculated for each class using the same COS and rate design processes used to calculate the original IRM surcharges. If the actual spend is equal to or exceeds the revenue requirement used to set the IRM surcharges, then the approved revenue recovery will be set equal to the revenue requirement used to set the IRM surcharges. The actual IRM power supply and delivery surcharge revenues collected from each class will be compared to the approved power supply and delivery revenue requirements for each class to determine any over and under recovery of the approved revenue requirement for each class, and those differences will be carried forward to future IRM reconciliation periods as discussed by Witness Stanczak.

Q. How does the Company propose implementing any over or under recovery of IRM spend or revenue?

A. At the conclusion of the IRM, the Company proposes that in the final reconciliation it would include all net amounts over the period (plus any applicable interest), and refund or surcharge customers consistent with the calculation performed in our self-implementation surcharge filings.

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Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

EXHIBITS

OF

TIMOTHY A. BLOCH

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

WORKPAPERS

OF

TIMOTHY A. BLOCH

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BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
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its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARCO A. BRUZZANO

DTE ELECTRIC COMPANY
QUALIFICATIONS OF MARCO A. BRUZZANO

Q. What is your name, business address and by whom are you employed?

A. My name is Marco Bruzzano. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. Please state your educational background.

A. I earned a bachelor of science degree, with honors, and a master's degree in Mechanical Engineering from the Georgia Institute of Technology. During my master's program, I received a full fellowship, working as a research assistant on a project sponsored by the Electric Power Research Institute (EPRI). I also earned an MBA, with distinction, from Duke University.

Q. Please describe your work experience.

A. Immediately prior to joining the Company, I was a principal with Booz Allen Hamilton's Energy & Utilities practice. I also worked as an engagement manager with McKinsey & Company, primarily in the Electric Power & Natural Gas and Petroleum practices. During my consulting career, I led projects for utilities, major international oil companies, and independent power producers on a broad range of strategic, operational, and organizational engagements. I was directly involved in or led the development of multiple capital investment strategies. During my tenure at McKinsey, I was also a leader of firm's Capital Productivity initiative.

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Prior to consulting, I worked for Chevron USA's refining division, where I was a design engineer in the Richmond, CA refinery. In that role, I managed multiple capital upgrade and maintenance projects. I also worked as a planning analyst, with responsibility for evaluating major capital investments and coordinating the refinery's capital budget.

I joined DTE Electric in 2008 as a director in the Corporate Strategy group. In this role, I led the Company's operational benchmarking program, managed the development of long-term commodity price forecasts, and led a number of strategic projects. In 2013, I was appointed vice president, Corporate Strategy, and assumed overall responsibility for supporting DTE Energy's business units on priority strategic initiatives, including the development of an updated investment strategy for electric distribution. In 2016, I was appointed to my current position, vice president, Distribution Operations, where I built on the work I had led in Corporate Strategy to develop the Distribution Operations Five-Year Investment and Maintenance Plan.

Q. Please describe your current position and duties.

A. My current responsibilities include two primary focus areas: 1) Electrical Engineering & Planning; and 2) Scheduling & Coordination. These organizations are briefly described below:

Electrical Engineering & Planning (EE&P): This organization is responsible for determining the health of the Company's electric distribution assets and developing programs to maintain and improve their safe, reliable, and cost-effective operation. EE&P is also responsible for defining technical standards for the equipment to be

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utilized on the distribution network and for developing projects needed for customer connections, relocations, increasing loads, infrastructure improvements, and technology improvements.

Scheduling & Coordination (S&C): This organization schedules and dispatches planned work, facilitates and oversees contractor field resources, manages capital projects and programs, and performs contract management.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support, as reasonable and necessary, the historical capital expenditures and Operations and Maintenance (O&M) expenses related to electric distribution activities for 2017 and the projected capital expenditures and O&M expenses for 2018 to 2020, leading to the capital and O&M forecasts for the projected test period of May 1, 2019 to April 30, 2020. In addition, my testimony will support the Infrastructure Recovery Mechanism, which is being proposed to recover investments made on behalf of the Company's customers in the period beginning on May 1, 2020 and ending on December 31, 2022.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures – Distribution Plant
A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-23	M1	Distribution Plant Capital Project Detail – Base Capital
A-23	M2	Distribution Plant Capital Project Detail – Infrastructure Resilience & Hardening
A-23	M3	Distribution Plant Capital Project Detail – Infrastructure Redesign
A-23	M4	Distribution Plant Capital Project Detail - Technology & Automation

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A-23	M5	Distribution Operations Five-Year (2018-2022) Investment and Maintenance Plan Final Report
A-30	T2	Infrastructure Recovery Mechanism Capital - Distribution Plant
A-30	T2.1	Distribution Plant Capital Project Detail - Infrastructure Recovery Mechanism Capital

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How is your testimony organized?

A. My testimony consists of the following nine (9) parts:

Part I	Distribution Operations Organization, Electrical System Overview, and System Performance
Part II	Five-Year Investment and Maintenance Plan
Part III	Strategic Capital Investment Programs
Part IV	Forecasting Methodology
Part V	Capital Exhibits Description
Part VI	O&M Exhibits Description
Part VII	Risks
Part VIII	Infrastructure Recovery Mechanism
Part IX	Summary

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Part I: Distribution Operations Organization, Electrical system overview, and System Performance

Distribution Operations Organization

Q. Can you please describe the organization that manages the costs that you are sponsoring?

A. Distribution Operations (DO) is the organization that manages the costs included in the exhibits I am sponsoring. It is focused on the design, construction, maintenance, and operation of DTE Electric's distribution system.

In addition to the organizations that I lead (Electrical Engineering & Planning and Scheduling & Coordination), DO is comprised of six other business units:

(i) Service Operations, which is responsible for the physical construction and operation and maintenance of the Company's overhead and underground systems;

(ii) Substation Operations, which is responsible for the operation and maintenance of the Company's substations;

(iii) System Operations, which includes the Company's System Operations Center (SOC), where the electrical system is monitored and controlled to maintain a reliable and secure flow of electric power;

(iv) Emergency Preparedness & Response, which plans efforts to reduce the time customers spend without power and develops, maintains, and manages DO's incident response procedures;

(v) Tree Trimming, which plans, communicates, and implements the Company's tree trimming program;

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(vi) Operational Technology, which is responsible for meter engineering, equipment calibration, and for working with business units within Distribution Operations to define and implement technology and analytical solutions.

Electrical System Overview

Q. Can you briefly describe the electrical system that DTE Electric owns and operates?

A. The Company owns and operates approximately 31,000 miles of overhead subtransmission and distribution lines and 16,000 miles of underground distribution lines. DTE Electric's service territory encompasses approximately 7,600 square miles and includes approximately 2.2 million residential, commercial, and industrial customers. Additional key statistics are listed in Tables 1-4.

Table 1: Substations

Substation Type	Total Number of Substations	Number of Substations by Low Side kV							
		4.8	8.3	13.2	4.8 13.2	24	40	24 40	Other
General Purpose	550	254	4	238	35	3	10	1	5
Single Customer	138	49	0	79	1	0	0	0	9
Customer Owned	95	NA	NA	NA	NA	NA	NA	NA	NA
Total	783	303	4	317	36	3	10	1	14

NA: Not Applicable

Table 2: Transformers

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	174	12,350,000
Substation – Distribution	1,449	23,176,200
Distribution - Overhead and Padmount	437,845	31,392,104
Total	439,468	66,918,304

Table 3: Subtransmission Circuits

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	67	60	8	68
40 kV	318	2,297	376	2,673
24 kV	255	182	689	871
Total	640	2,539	1,073	3,612

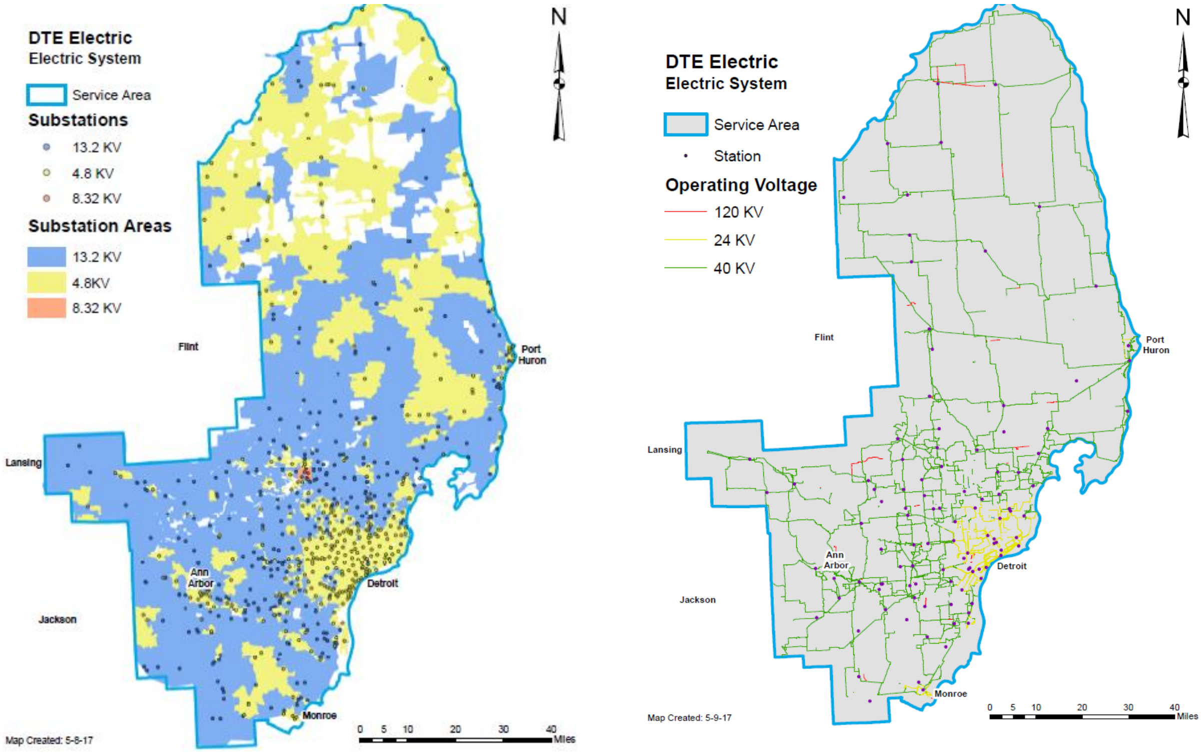
Table 4: Distribution Circuits

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
13.2 kV	1,222	11,623	11,613	23,236
8.3 kV	13	52	14	66
4.8 kV	2,082	16,784	3,332	20,116
Total	3,317	28,459	14,959	43,418

Q. How are the Company's distribution and subtransmission voltages distributed throughout the service territory?

A. Figure 1 illustrates the location of the Company's equipment voltages.

Figure 1: Location of Distribution and Subtransmission Voltages



Q. What is the age of DTE Electric distribution system assets?

A. Table 5 provides the average age and age range of the Company's key distribution assets along with the life expectancy.

Table 5: Asset Age Summary

Asset	DTE Electric Average Age (Years)	DTE Electric Age Range (Years)	Industry Life Expectancy (Years)
Substation Power Transformers	41	0 – 93	40 – 45
Network Banks	62 (structures) 46 (transformers)	0 – 85+	40 – 45 (transformers)
Circuit Breakers	48	0 – 87	30 – 40
Subtransmission Disconnect Switches	51	0 – 75+	NA
Relays	46	0 – 60+	15 – 50
Switchgear	34	0 – 64	35 – 45
Poles and Pole Top Hardware	44	0 – 90+	40 – 50
Small Wire (i.e., #6 Copper, #4 ACSR, and #4 Copper)	70+	Not available	Varies based on field conditions
Fuse Cutouts	19	0 – 50+	30
Three-Phase Reclosers	11	0 – 25	20
SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	15	0 – 25	15
40 kV Automatic Pole Top Switches	32	0 – 50+	30
Overhead Capacitors	Not available	Oldest: 25+	20
Overhead Regulators	Not available	Oldest: 25+	20
System Cable	40	0 – 100+	25 – 40
Underground Residential Distribution (URD) Cable	23	0 – 50+	25 – 35
Manholes	75	0 – 90+	Varies based on construction and field conditions
Vaults	Not available	Not available	Varies based on construction and field conditions
Advanced Metering Infrastructure (AMI meters)	4.5	0 – 11	20

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System Performance

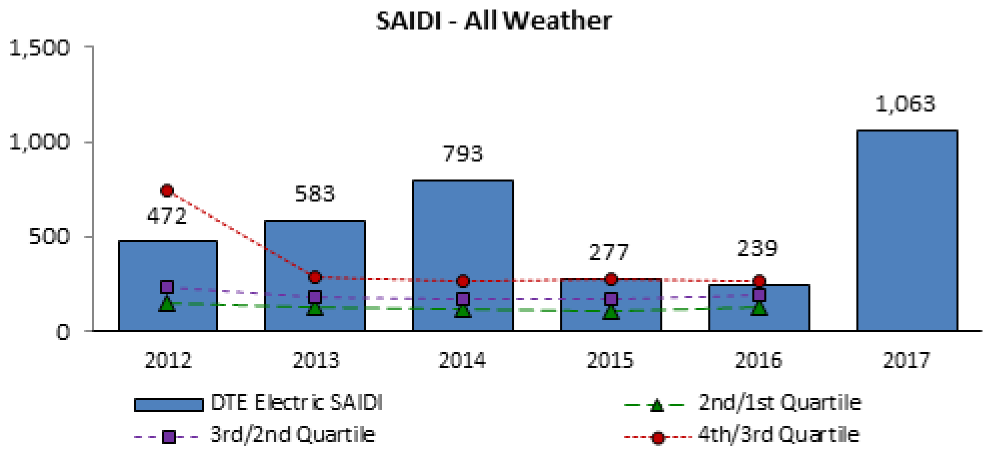
Q. How does the Company measure system reliability?

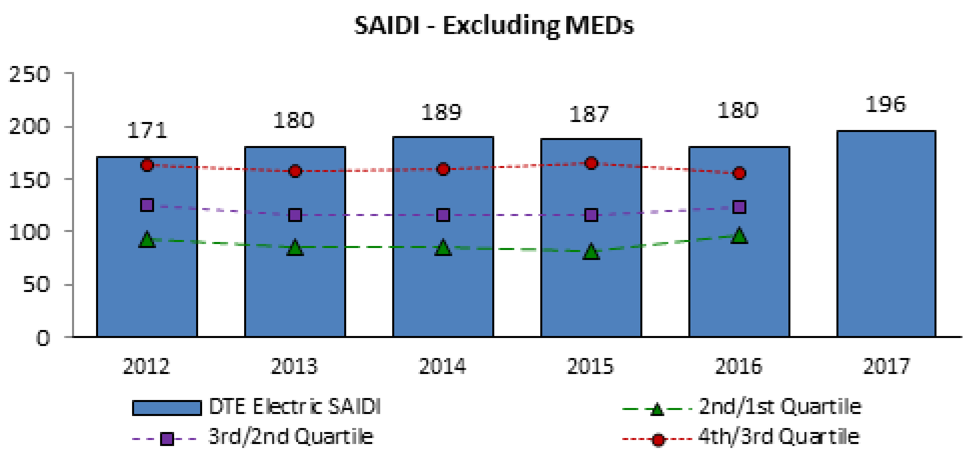
A. The Company's primary focus is on System Average Interruption Duration Index (SAIDI). SAIDI is defined by the Institute of Electrical and Electronics Engineers (IEEE) as the total time (in minutes) of all customer interruptions divided by the total number of customers served. SAIDI measures the average time that customers are without power in a year because it measures both the frequency and the duration of interruptions. IEEE measures SAIDI in two ways: (1) All-Weather SAIDI, which includes all outages, and (2) SAIDI-Excluding Major Event Days (MEDs), which excludes days with outages that exceed a size threshold to isolate the impact of the most severe weather events. The latter metric provides a more benchmarkable measure of the performance of the electrical system and is broadly used in the industry.

Q. What is the trend in SAIDI for DTE Electric's electrical system?

A. Figure 2 shows performance from 2012 to 2017 for both SAIDI-All Weather and SAIDI-Excluding MEDs. The latter measure, which offers a more meaningful comparison to other utilities, has been in the fourth (worst) quartile of the industry for the past several years.

Figure 2: SAIDI Performance*





* The impact of the March 8, 2017 storm on 2017 SAIDI–All Weather was 828 minutes; the impact on 2017 SAIDI-Excluding MEDs was 7 minutes; quartile information for 2017 is not yet available.

Part II: Five-Year Investment and Maintenance Plan

Q. What is the Distribution Five-Year Investment and Maintenance Plan?

A. The Distribution Five-Year Investment and Maintenance Plan (Five-Year Plan) is a

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comprehensive document that focuses primarily on describing the Company's planned Strategic Capital Investments from 2018 to 2022, along with the drivers for these investments and the benefits customers will receive. It also describes the importance of tree trimming as a strategic program, along with the expenses that are needed for preventive maintenance. It was developed following the MPSC's Order in Case No. U-18014, and is included as Exhibit A-23, Schedule M5.

Q. What did the MPSC Order from MPSC Case No. U-18014 require?

A. The Company was directed to develop and submit a five-year distribution investment and maintenance plan. The Order further directed the Company to submit a draft plan by July 1, 2017 and meet with the Staff to complete a final five-year distribution investment and maintenance plan, which was to be submitted by December 31, 2017. In October 2017, the Commission issued a supplemental order providing further clarification, including the need for the plan to include a timeline and strategy to meet the Governor's 2013 reliability goals. The supplemental order extended the date for the final report to January 31, 2018.

The Company and the Staff participated in a number of working meetings to review and discuss the various elements of the Company's Five-Year Plan. The Company also participated in a meeting with external stakeholders in August, 2017. These meetings provided opportunities for the Company, Staff, and external stakeholders to ask questions, discuss priorities, and get a better understanding of each other's perspective relative to the different elements of the Five-Year Plan.

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Q. What are the objectives and contents of the Five-Year Plan?

A. The Five-Year Plan illustrates how capital and maintenance investments should best be directed on behalf of customers to support three key objectives:

1. Reducing Risk
2. Improving Reliability
3. Managing Costs

The plan contains a significant level of detail around the scope and rationale for the Strategic Capital investments the Company plans on making between 2018 and 2022. The supporting rationale and projected customer benefits for these investments are described in detail in my testimony and accompanying exhibits. The Five-Year plan also provides an outlook for Base Capital, tree trimming, and preventive maintenance spending.

Q. What is included in Base Capital?

A. Base Capital programs include work the Company is required to perform to address customer requests (e.g., new connections, relocations) or to recover from interruptions in electric service (e.g., emergent replacements during storms or for equipment failures).

The Five-Year Plan did not focus on Base Capital in detail, as the level of investment in this category is primarily driven by factors outside of the Company's control. The projection of Base Capital spending has been refined in my testimony based on more recent information (e.g., 2017 actuals, 2018 data for new customer connection requests). Additional details on Base Capital programs are included in Exhibit A-12, Schedule B5.4, pages 3 to 6 and Exhibit A-23, Schedule M1.

Q. What is included in Strategic Capital programs?

A. Strategic Capital programs include investments that are necessary to ensure the long-term health of the electric distribution network and the continued ability to serve customers with a high level of reliability, particularly as economic activity continues to rebound in southeast Michigan. Tree trimming is also included in the Five-Year Plan as a strategic program, but the costs are O&M as opposed to capital. The three categories included in Strategic Capital are:

<u>Infrastructure Resilience & Hardening</u>: These projects and programs are focused on replacing aging infrastructure, hardening the system, and addressing areas with known poor reliability.

<u>Infrastructure Redesign</u>: These projects and programs include more fundamental changes to the electrical system, such as converting entire substations and circuits to a higher voltage level to serve increased load.

<u>Technology & Automation</u>: These programs are designed to leverage proven technology solutions that provide significant customer benefits and bring the Company on par with current industry standards.

Q. Why is the level of Strategic Capital investment proposed in this case higher than it has been in the past?

A. There has been a significant shift in the need to invest proactively in the electric distribution system over the past few years. While DO has been spending capital above the rate of depreciation for the past decade to maintain its assets and to connect customers to the grid, three key factors are driving the need to increase Strategic Capital investments from current levels.

The first factor has been the increasing number of failures for assets such as substation equipment, poles, and cable that have been observed in recent years, as described in detail later in my testimony, in the supporting exhibits, and in the Five-Year Plan. The Company believes that the increasing rate of equipment failures indicates that the condition of the system and the age of equipment have reached a point at which increasing proactive equipment replacements is both prudent and urgent. These investments are described in detail in the Infrastructure Resilience & Hardening section of my testimony and in the supporting exhibits.

The resurgence of economic activity and development in southeast Michigan has been a second key driver of the projected increase in Strategic Capital Spending, particularly in high growth areas such as Ann Arbor and downtown Detroit. As can be seen in Exhibit A-12, Schedule B5.4, page 8, a significant amount of Strategic Capital is being directed toward improvements to the Ann Arbor electric distribution system with a goal of both serving new load and improving reliability. Similarly, several City of Detroit Infrastructure (CODI) Upgrade projects and 4.8kV conversions to 13.2kV are needed to support increasing customer load in the center of Detroit and other nearby areas where growth and new construction activities are particularly strong. These investments are described in detail in the Infrastructure Redesign section of my testimony and in the supporting exhibits.

The third major driver of the increase in Strategic Capital is the need to upgrade the technology the Company utilizes to monitor and manage the electric distribution system. These technology upgrades will drive greater levels of customer satisfaction by improving the ability to respond quickly to adverse events, such as catastrophic storms, and will prepare the Company for the growth in Distributed Energy Resources. These investments are described in detail in the Technology & Automation section of my testimony and in the supporting exhibits.

Q. How does the Company assess the customer benefits of Strategic Capital programs and projects?

A. DTE Electric assesses the impacts of strategic investment programs and projects on each of the three objectives it is pursuing on behalf of its customers: risk reduction, reliability improvement and cost management. The expected benefits of each program and project are used to develop a ranking so that capital investments can be evaluated against each other.

Q. Please describe the process to evaluate programs and projects in more detail?

A. Strategic investment programs are evaluated against seven impact dimensions, as described in Table 6, in the Company's Global Prioritization Model (GPM). Quantitative assessments are developed for all the impact dimensions to score and rank programs.

Table 6: Program Impact Dimensions

Index	Impact Dimension	Major Drivers
1	Safety	• Reduction in wire down events • Reduction in secondary network cable manhole events • Reduction in major substation events
2	Load Relief	• System capability to meet area load growth and system operability needs • Elimination of system overload or over firm rating
3	Regulatory Compliance	• MPSC Staff's recommendation (March 30, 2010 report) on utilities' pole inspection program • Docket U-12270 – Service restoration under normal conditions within 8 hours • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours • Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of less than 5 within a 12-month period
4	Substation Outage Risk	• Reduction in substation outage events that could lead to a large amount of stranded load for more than 24 hours
5	Reliability	• Reduction in number of outage events experienced by customers • Reduction in restoration duration for outage events
6	O&M Cost	• Trouble event reduction and truck roll reduction • Preventive maintenance spend reduction
7	Reactive Capital Spend	• Trouble event reduction and truck roll reduction • Reduction in capital replacement during equipment failures

Q. How are projects evaluated across these seven dimensions?

A. Strategic programs are assessed, scored, and ranked against each impact dimension. Detailed analyses based on historical data, engineering assessments, and field feedback are utilized to estimate each program's impact. The quantified benefits are then compared to the programs' costs to derive their benefit-cost ratios. Table 7 shows the benefit mapping of programs against each of the impact dimensions.

Table 7: Selected Programs and Projects' Benefit Mapping

Program	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Cost	Reactive Capital
Tree Trimming to the Enhanced Specification	X		X		X	X	X
4.8/8.3 kV Conversion and Consolidation	X	X		X	X	X	X
4.8 kV Hardening	X		X		X	X	X
Substation Outage Risk Reduction	X	X		X	X		X
Load Relief		X		X			
System Cable Replacement	X			X	X		X
Breaker Replacement	X			X	X	X	X
Ground Detection (4.8 kV Relay Improvement)	X						
Line Sensors					X	X	
ADMS	X	X		X	X	X	X
System Automation	X			X	X	X	X
Subtransmission Hardening	X	X			X	X	X
System Resiliency					X		
Frequent Outage (CEMI)	X		X		X	X	X
URD Cable Replacement					X	X	X
Pole Replacement	X		X		X		X
Pole Top Hardware Replacement	X				X	X	X

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Q. How are the programs and projects compared to each other and ranked?

A. Safety, load relief, regulatory compliance, and major substation outage benefits are rated as indexed scores. Reliability benefits are captured in customer minutes of interruption reduction. Cost benefits are captured in dollar savings.

To aggregate a program's benefit-cost ratios across all the impact dimensions, benefit-cost ratios are indexed to benefit-cost scores of 0-100. Then, a program's overall benefit-cost score is calculated as the weighted summation of the program's benefit-cost scores across all the impact dimensions. Table 8 lists the weights given to different impact dimensions.

Table 8: Impact Dimension Weights

Impact Dimension	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Cost	Reactive Capital
Weight	10	4	4	4	3	3	3

Q. Are all projects and programs ranked using this methodology?

A. No. Some strategic projects are excluded from the prioritization model due to unique circumstances that are being addressed by that program or project. For instance, AMI 3G to 4G upgrades are necessary to address the phase-out of 3G technology by telecommunication companies.

Q. What are the results of the Global Prioritization Model?

A. Strategic Capital investments, prioritized from highest to lowest, are shown in Table 9. Tree Trimming is mainly an O&M expenditure and is therefore not shown in the table. However, Tree Trimming is the highest priority strategic program, and as such separate

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testimony is being filed for this program by Company Witness Rivard. When compared to the projects and programs in Table 9, Tree Trimming is the top ranked program by a wide margin.

Table 9: Top 50 Strategic Capital Programs and Projects Based on Benefit-Cost Prioritization Ranking

Rank	Capital Program / Project
1	CODI (City of Detroit Infrastructure) – Charlotte Network
2	4.8 kV Hardening
3	Frequent Outage (CEMI) Program
4	Pole Top Hardware Replacement
5	Ground Detection Program
6	Line Sensors
7	CODI – Madison Upgrades
8	CODI – Garfield Network
9	CODI – Targeted Secondary
10	ADMS
11	I-94 Substation and Circuit Conversion
12	HK Substation and Circuit Conversion
13	Malta Substation Risk
14	CODI – Howard Upgrades
15	Argo/Buckler Load Transfer
16	CODI – Amsterdam Upgrades
17	CODI – CATO/Orchard Upgrades
18	Pole Replacement
19	Apache Substation Risk Reduction
20	8.3 kV Conv/Cons – 3rd Phase Catalina
21	System Cable Replacement
22	Pontiac 8.3 kV Overhead Conversion
23	Calla Circuit Conversion
24	Almont Relief and Circuit Conversion
25	Bloomfield Substation Risk Reduction
26	White Lake Decommission and Circuit Conversion
27	Belle Isle Substation and Circuit Conversion
28	Spruce (SCIO) Substation Risk Reduction
29	System Resiliency
30	Subtransmission Hardening
31	Savage Substation Risk Reduction
32	Chestnut Substation Risk Reduction
33	Wixom Load Relief
34	Grayling Load Relief
35	Sheldon/Gilbert/Zachary Load Relief
36	Circuit Breaker Replacement
37	Reno Decommission and Circuit Conversion
38	Birmingham Decommission and Circuit Conversion
39	Lapeer-Elba Expansion and Circuit Conversion
40	CODI – Kent/Gibson Network Upgrades
41	Hancock/Quaker Load Relief
42	URD Cable Replacement
43	Jupiter Substation Risk Reduction
44	System Automation
45	Diamond Load Relief
46	Berlin Load Relief
47	Trinity Load Relief
48	Oasis Load Relief
49	South Lyon Decommission and Circuit Conversion
50	Cypress/Mohican Load Relief

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Q. Are there considerations other than the Global Prioritization Model (GPM) for when specific projects move forward?

A. Yes. The benefit-cost scores of programs and projects provide a solid foundation for DTE Electric's strategic investment decisions. However, there are other key considerations that impact capital funding decisions:

- Schedules for new projects are subject to uncertainty, especially during the conceptual and early development stages because of unknown factors related to land availability and property purchases, municipal approvals for construction permits, rights-of-way and easements, and major equipment lead times. While DTE Electric takes proactive measures to mitigate these execution risks, many of these activities are not within the Company's control and can introduce schedule delays or cost variances.
- Funding decisions must also consider the implication for resource needs. Resource gaps need to be understood and addressed before final decisions in project timing can be made, and the Company must also consider the ability to engage the right partners at the right time to support execution.
- The Company must also ensure that investments are not just directed to the projects and programs that receive the highest score in the GPM, as other programs, such as proactive replacements of Underground Residential Distribution cable, must be funded to avoid a rapid acceleration of failures in asset classes that are nearing end of life because of the very negative consequences of such an occurrence.

Projected System Impact

Q. What does the Company expect to achieve due to the implementation of the Five-Year Plan?

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A. The Company expects to substantially reduce risk, improve reliability, and manage costs for its customers. The projected benefit for each of these dimensions is described below. Furthermore, by improving reliability the implementation of the Five-Year Plan will drive $6-9 billion in economic benefit to the region, as also described below.

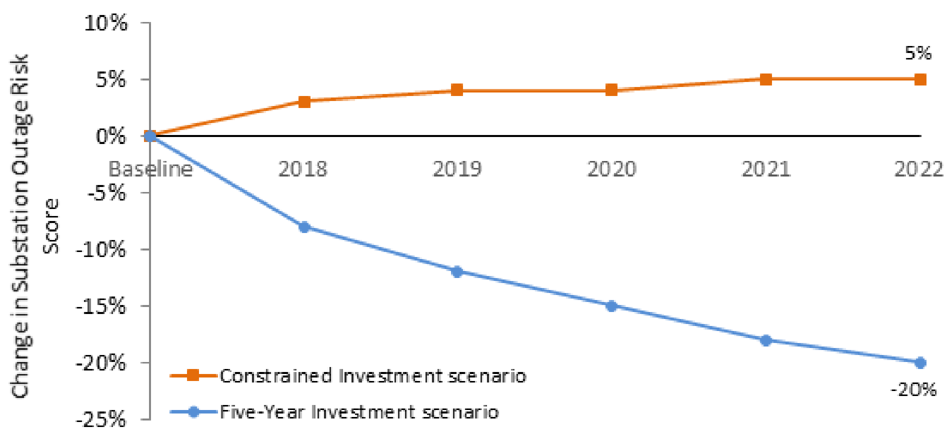
Reduced Risk

Q. How will the Five-Year Plan reduce risk?

A. The Strategic Capital investments will reduce safety risks by addressing the areas that are most susceptible to downed wires and secondary network cable manhole events. As discussed previously, improving safety is the highest priority for the investments included in the Five-Year Plan.

Eliminating the risk associated with a major substation failure is also a critical part of reducing risk. As illustrated in Figure 3, the investments in the Five-Year Plan are projected to reduce the risk of significant substation outages with large stranded loads by 20% from current levels over the next five years. The risk and impact of a major substation outage was modeled by calculating a risk score that is the product of condition-based asset failure risk multiplied by the amount of stranded load remaining after all load transfers are made. This scenario is compared to one in which capital is constrained to Base Capital funding with no Strategic Capital available (Constrained Investment scenario). Reducing risk is critical to DTE Electric's customers because large substation outage events can result in thousands of customers being without power for extended durations and lead to high cost restoration events. Without the Strategic Capital investments in the Five-Year Plan, the risk of significant substation outages is conservatively projected to increase by at least 5%.

Figure 3: Substation Outage Risk Forecast

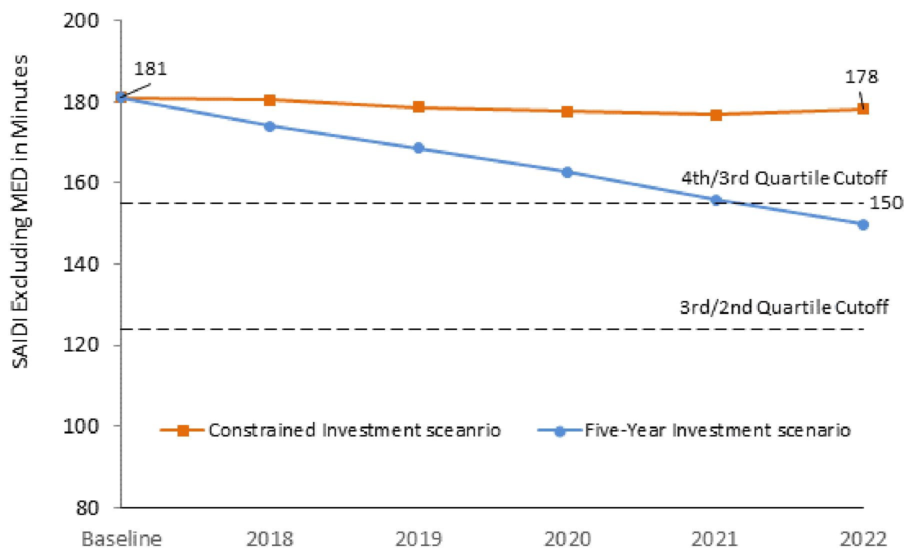


Improve Reliability

Q. What reliability improvements does the Company forecast in this case as a result of the Five-Year Plan?

A. The electrical system in southeast Michigan is currently in the fourth quartile with respect to SAIDI-Excluding MEDs, and has been deep into the fourth quartile for All-Weather SAIDI in several of the past few years. Improving reliability is a key focus of the Five-Year Plan and puts the Company on a path to achieving the Governor's goal for Michigan utilities to be operating in the top half of peer utilities for SAIDI-Excluding MEDs. Figure 4 shows the expected improvements that will result from the Five-Year Plan's implementation for both SAIDI metrics. It is important to note that these projections do not include the benefit of increased tree trimming discussed by Company Witness Rivard.

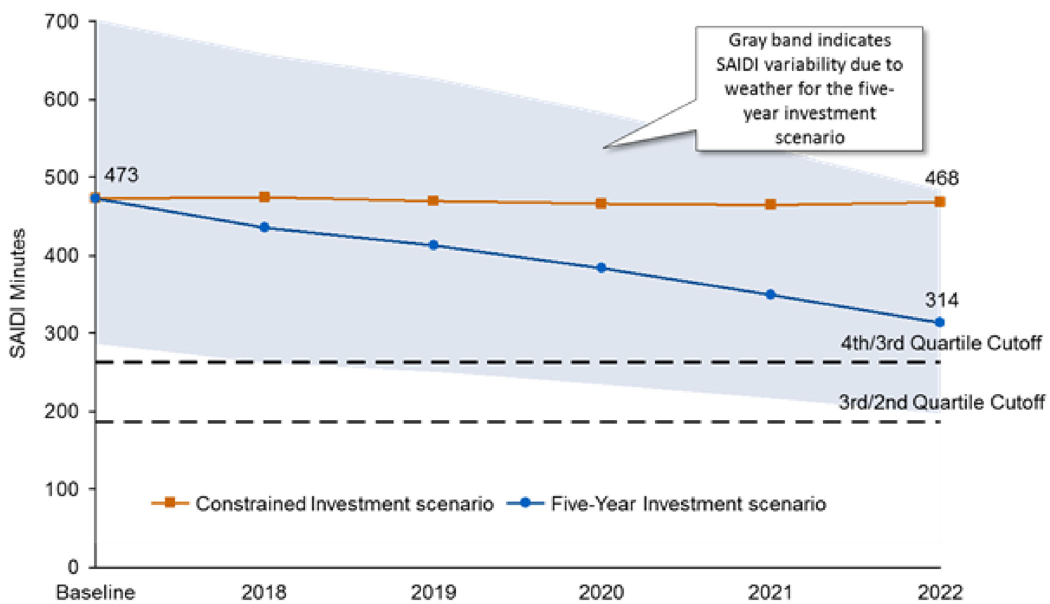
Figure 4:
SAIDI-Excluding MEDs Forecast



SAIDI-All Weather

Manage Cost

Q. How will the Five-Year plan help the Company manage costs?



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A. If the Five-Year Plan is funded and implemented as described, then the Company forecasts that capital required for emergent replacements will be reduced compared to what it otherwise would have been. The savings were calculated during the development of the Five-Year Plan by modeling the reduction in emergent events due to Strategic Capital investments and a base level of tree trimming (i.e., it does not include the proposed tree trimming surge and its related benefits described by Company Witness Rivard) and other maintenance. These reductions were then applied to the forecasted emergent capital spend projected in the current case. The reductions in emergent capital can be seen in Exhibit A-12, Schedule B5.4, page 1, line 6.

Q. Are there other significant benefits that customers will receive from the implementation of the Five-Year Plan?

A. Yes. Beyond the cost reduction benefits described above, improved reliability will reduce down-time for customers' manufacturing processes, allow commercial businesses to remain open, and reduce the inconveniences that residential customers experience. The Company's Five-Year Plan is expected to bring a present value of $6-9 billion of economic benefit to DTE Electric's customers because of the improvements in reliability.

Q. How was this economic benefit calculated?

A. The economic benefit was calculated based on the Interruption Cost Estimation Calculator developed by Nexant and the Lawrence Berkeley National Lab (Lawrence Berkeley Study).

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Q. Can you describe the Lawrence Berkeley Study?

A. The Lawrence Berkeley Study provides a comprehensive analysis to be utilized as a long-term reliability planning and prioritization tool for customer benefits. The study quantified the customer cost of power outages by using 34 cost-of-outage surveys conducted by 10 major utilities across the United States. Commercial and industrial customers were asked for direct costs due to outages, and residential customers were asked for their willingness to pay to avoid outages, a reflection of the value they would ascribe to improved reliability. Statistical analyses were then completed on the combined survey responses to estimate customer cost of outages, which were used to create the Department of Energy's Interruption Cost Estimate Calculator (ICECalculator).

Q. Have other entities used the Lawrence Berkeley Study?

A. Yes. The following is a list of the utilities the Company is aware of that have used this study.

- Southern Company
- National Grid
- Pacific Gas & Electric
- San Diego Gas & Electric
- We Energies
- Commonwealth Edison Company
- Central Maine Power
- Electric Power Board of Chattanooga

Furthermore, the White House has referenced the study in their 2013 report on the Economic Benefits of Increasing Electric Grid Resilience to Weather Outages[1].

[1] Prepared by the President's Council of Economic Advisors and the U.S. Department of Energy

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Q. What value did the Lawrence Berkeley Study assign to outages?

A. The results vary by the type of outage and customer. The ICECalculator also considers time-of-day and seasonal variation. Table 10 summarizes the results.

Table 10: Customer Savings due to Avoided Outages

Customer Type	Length of Outage Momentary (2013$)	30 Minutes (2013$)	1 Hour (2013$)	4 Hours (2013$)	8 Hours (2013$)	16 Hours (2013$)
Residential Non-Summer	3.9	4.5	5.1	9.5	17.2	32.4
Small Commercial and Industrial Non-Summer	412	520	647	1,880	4,690	9,055
Medium and Large Commercial and Industrial Non-Summer	12,952	15,241	17,804	39,458	84,083	165,482

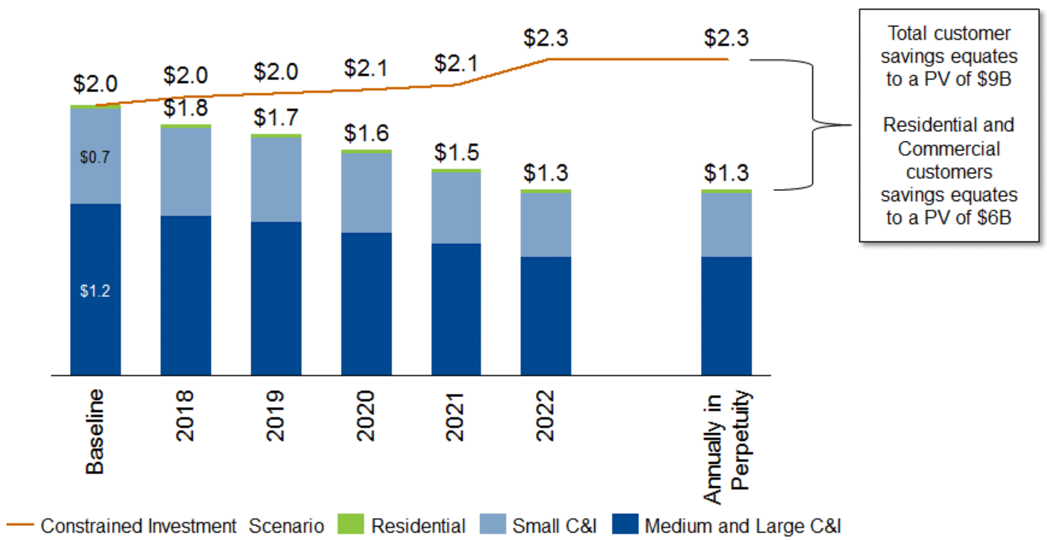
Q. How did the Company use the avoided outage savings to determine the benefits customers will receive as a result of the Five-Year Plan implementation?

A. The Company modeled outage scenarios with the ICECalculator to determine the annual savings for 2018 and beyond, adjusting projected benefits for inflation. The present value was determined for both the Constrained Investment scenario and the Five-Year Plan scenario. The difference is the economic benefit customers can expect due to the Strategic Capital programs and other work described in the Five-Year Plan.

Q. What are the results of the Five-Year Plan when the ICECalculator is used?

A. Customer benefits are expected to be between $6 billion and $9 billion, which is illustrated in Figure 5. The high end of the range of customer savings includes all customers and the low end conservatively considers only residential and commercial customers. This value does not include the benefit of improved reliability from the tree trimming surge described by Company Witness Rivard.

Figure 5: Customer Outage Costs ($ billion)



Q. What would be the consequences of not executing the Strategic Capital investments?

A. The consequences would be negative on many fronts.

- The system would continue to degrade and the volume of equipment failures would grow, with negative impacts on safety, reliability, and costs. An acceleration of equipment failures would cause a negative, costly spiraling effect.
- It would become extremely challenging to support economic development and customer growth, as overloaded circuits would not be addressed (further damaging equipment) and needed capacity would not be added, making it

uneconomical and unacceptably slow for new customers to connect to the grid.

- The system would be less resilient to intense weather events, putting the service territory at greater risk of prolonged outages.

Q. How will the Company ensure that the increased level of distribution spending is managed in a cost-effective way?

A. The Company will continue to utilize the techniques it has put in place to ensure that projects and programs are managed in a way that ensures efficient use of funds. Projected costs for the projects and programs contained in this testimony takes into account the robust sourcing and project management practices DTE Electric has established.

DTE Electric's policy is to initiate Request for Proposals for any work with an expected cost greater than $100,000 unless there are strategic reasons not to do so. These reasons could include short-term onboarding of a new supplier to increase the Company's marketplace competitiveness and ability to bid work to more companies in the future, or the need to address an emergent situation.

Overhead and underground construction work is competitively bid on fixed unit pricing typically, but not always, on a three-year cycle. These units of work contain all labor and equipment needed to perform a given task. The Union Collective Bargaining Agreements, which govern the contract workforce that performs a significant portion of the planned capital work for DO, calls for annual labor rate increases for craft labor. As a way of driving productivity in its contract workforce, unit prices negotiated by DTE Electric with its contractors do not increase during the 3-year timeframe of the contract. To ensure a competitive environment, the opportunity to bid on the work is opened to many (20+) local and national firms. Changes to the 2016 overhead construction contracts resulted in significant savings by embedding costs of items, such as rocks to set poles, into unit costs. In addition, the management of items such as traffic control and pull-out yards was shifted to the contractors, ensuring they are effectively managing the associated processes resulting in improved crew efficiency and reduced costs. Additionally, more rigorous processes were set in place to confirm upfront costs per job, giving DO the ability to hold contractors accountable to cost estimates and require documentation for any associated change orders.

For substation projects, construction is competitively bid on a fixed price basis except on rare occasions in which the Company enters into a strategic agreement with a third party to increase the overall supply base in anticipation of needing to bid out additional work, or when seeking unique technical expertise.

Tree trimming work has been competitively bid on a fixed price per circuit for the next two years. The fixed price includes all labor and equipment to complete the circuit. This bid opportunity was opened to many (10+) local and national Tree Trimming firms. Additionally, a more rigorous auditing processes was put in place to insure quality of workmanship and hold contractors accountable of quality work execution.

When possible, the Company utilizes benchmarking to validate whether the cost at which it executes major projects is competitive. Benchmarking that allows true cost comparability is challenging because suppliers are unwilling to share data they deem competitive in nature or because utilities may not be able to allocate the resources that are required for accurate benchmarking. However, some benchmarking is possible, particularly when facilitated by a third party with deep expertise in the field. To that end, the Company engaged Independent Project Analysis (IPA), a global advisory firm for capital project improvement based in Ashburn, Virginia. IPA has a database of over 20,000 capital projects, and has been benchmarking projects in the energy and utility industry for 30 years. Because substations are the most expensive projects for Distribution Operations and because the Company expects to make significant investments in substations in the coming years, the benchmarking focused on comparing the costs of substation investments to the utility industry. After analyzing the costs of the five substations constructed by DTE Electric from 2012 to 2017, IPA concluded that the Company constructed its substations at an average cost that was 8% below the utility industry's average for similar substations.

Q. Does the Company expect the Five-Year Plan to be adjusted over time?

A. Yes. The electric grid is dynamic in nature in terms of the demands that are placed on it and the impact of external factors, such as technology changes and evolving customer needs. The Company's plan will be updated formally every two years, consistent with the MPSC's Order.

Part III – Strategic Capital Investment Programs

Q. What programs will you describe in this section of your testimony?

A. Part III of my testimony will provide an overview of each of the three capital investment pillars described in the Company's Five-Year Plan. These investments represent the Strategic Capital portion of the plan. Tree trimming is also a strategic priority as discussed in the Five-Year plan, but is not included in this section of my testimony because it is an O&M expenditure. The investment pillars included in this section are:

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- Infrastructure Resilience & Hardening
- Infrastructure Redesign
- Technology & Automation

<u>Infrastructure Resilience & Hardening</u>

Q. Can you elaborate on Infrastructure Resilience & Hardening programs?

A. Table 11 provides an overview of what is contained in this category and includes the program title, a brief description of the scope of the program, and how the Company's customers will benefit from the program. Details of these projects and programs are included in A-12, Schedule B5.4, page 7 and Exhibit A-23, Schedule M2.

Table 11: Infrastructure Resilience & Hardening Summary

Programs	Scope of Work	Benefits
Mobile Fleet Program	• Equipment required to serve stranded load in the event of equipment failure	• Reduce outage duration by restoring customers through mobile generation
Substation Risk	• Replace aging/at risk equipment (primarily switchgear)	• Reduce substation outage risk and improve reliability • Reduce reactive costs
4.8 kV Hardening	• Test all utility poles that have DTE Electric equipment attached and replace or reinforce poles as necessary • Replace wooden crossarms with fiberglass crossarms • Coordinate with the Detroit Public Lighting Department (DPLD) to remove abandoned DPLD arc wire and distribution wire • Remove overhead service wires from abandoned houses • Perform targeted secondary removal • Trim trees as required to support construction activities	• Enhance safety and reliability • Extend the life of 4.8 kV circuits
Pole and Pole Top Hardware (Pole Top Maintenance)	• Based on testing and inspection results, (inspection cycle is 10-12 years) replace or reinforce poles and pole top hardware that has failed or is likely to fail	• Enhance safety, reliability, and costs
Cable Replacement Program	• Replace at-risk cable	• Improve reliability and reduce reactive maintenance costs
Frequent Outage Program (CEMI) including Circuit Renewal	Scope includes, but is not limited to: • Rebuild/reconductor/relocate overhead lines • Add or strengthen ties to other circuits • Provide circuit load relief • Install sectionalizing and switching devices	• Address circuits that experience poor reliability performance by focusing on removing root causes to prevent reliability and power quality events
Breaker Replacement Program	• Remove or replace at-risk breakers	• Enhance safety and reduce the risk of large outages • Remove aging equipment and improve system reliability • Reduce reactive maintenance costs
Pontiac Vaults	• Replace aging infrastructure on the 8.3 kV system and upgrade to 13.2 kV	• Enhance safety associated with end-of-life equipment housed in confined spaces • Remove at risk equipment, reducing reactive costs and improving reliability
Underground Residential Distribution (URD) Replacement Program	• Replace at-risk URD cable	• Remove at-risk equipment, reducing reactive costs and improving reliability
System Resiliency – Efficient Frontier	• Install sectionalizing and switching devices to reduce the size and frequency of outage events and enable "restore before repair" process changes	• Improve reliability by localizing outage events and reducing outage duration

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Programs	Scope of Work	Benefits
Porcelain Cutout Replacement Program	• Replace defective cutouts	• Remove at-risk equipment to reduce reactive costs and improve reliability
4.8 kV Relay Improvements (Delta Ground Detection Program)	• Install and/or upgrade telecommunication and RTUs for substation remote monitoring • Install substation ground/wire down alarms	• Enhance safety by allowing System Operations Center to automatically detect and receive alerts of wire down events
Relay Replacement	• Replace aging relay panels at Warren and Northeast subtransmission stations	• Remove aging equipment, improving grid visibility and system reliability
Disconnect and Switcher Replacement	• Replace disconnect switches	• Reduce operational safety risk • Remove aging equipment, improving system operability

Q. Are there specific Infrastructure Resilience & Hardening programs that you would like to discuss in more detail?

A. Yes. I would like to highlight the following programs because I believe that discussion beyond what is contained in the exhibits will be helpful to establish a deeper understanding of their scope, the rationale for making the investments, and the benefits customers will receive:

- 4.8kV Hardening
- Pole / Pole Top Hardware (Pole Top Maintenance)
- Substation Outage Risk

<u>4.8kV Hardening</u>

Q. What is the scope of the 4.8kV Hardening program?

A. The 4.8kV Hardening program was developed to address the aging 4.8 kV system. The program's scope is described below:

1) Test all utility poles that have DTE Electric equipment attached and replace or reinforce those poles as needed.
2) Replace wooden crossarms with fiberglass crossarms.

3) Remove Detroit Public Lighting Department (DPLD) arc wire from DTE Electric-owned equipment and ensure the remaining DTE Electric wires are left in a safe configuration.
4) Remove DPLD distribution wire from DTE Electric-owned equipment when it can be confirmed that the wire is not serving customers.
5) Remove service lines to abandoned properties.
6) Perform targeted secondary removal.
7) Trim the trees as required to support construction activities.
8) Perform any additional necessary work as dictated by field conditions.

Q. What caused the 4.8kV system, specifically in the City of Detroit, to require this program?

A. The aging of the infrastructure is the key driver, as DTE Electric's distribution system in the City of Detroit and the immediately adjacent suburbs was the earliest part of DTE Electric's distribution network to be built. Not surprisingly, the volume of trouble events on this part of the electric grid is disproportionately higher when compared to the rest of the service territory. This is driven primarily by the age of the infrastructure, but is also exacerbated by the abandoned and overgrown alleys in the City of Detroit. DTE Electric has worked to maintain the electric grid across the entire service territory in a cost-effective manner for decades; in many areas, general maintenance practices are simply no longer sufficient and it is time to invest in more aggressively hardening and upgrading the infrastructure. This is especially true for the oldest part of the system.

It should also be noted that in response to the MPSC's Order in Case No. U-18484, which among other things ordered the Company to work with relevant entities to accomplish a

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long-term comprehensive plan to address out-of-service DPLD owned arc wire, the Company closely examined the options to best address this issue. In the course of its investigation, DTE Electric concluded that addressing DPLD arc wire as a standalone program was not the option that best served the interests of its customers because of the overall aging of DTE Electric's infrastructure in the city. To that end, the Company has developed the 4.8kV Hardening program. This program will also allow for the removal of DPLD arc wire where it is co-located with DTE Electric's assets, though the removal of arc wire is not the primary driver nor the primary benefit of this program.

Q. Is the 4.8kV Hardening program the most cost-effective way of addressing the concerns with the 4.8kV system?

A. Yes. The Company evaluated four alternatives. Given the costs per overhead mile addressed and the level and timing of the benefits customers will receive, the Company believes the 4.8kV Hardening program is the best option, as illustrated in Table 12. It should be noted that the costs per overhead mile are estimated based on current experience with this program. Estimates could change as more experienced is gained.

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Table 12: 4.8kV System Alternatives

	Full Conversion	Pre-Conversion of Overhead Only	Secondary Program	4.8kV Hardening Program
Total Cost - Detroit System (Direct $)	$4,200 M	$2,250 M	$1,800 M	$660 M
Cost Per OH Mile	$1.85 M	$1.0 M	$0.80 M	$0.30 M
Minimum Years Required to Stabilize Detroit 4.8kV System	30+	30	25	10
Includes UG Cable	Yes	No	No	No
Includes Substation Replacement	Yes	No	No	No
Includes PLD and Arc Wire Removal	Yes	Yes	No	Yes
Wire down reduction	90%	90%	70%	65%
Customer interruptions reduction	85%	85%	70%	60%
Customer minute reduction	85%	85%	75%	70%
Trouble events reduction	85%	85%	70%	60%
Non-tree reactive capital reduction	90%	90%	60%	40%
Tree related reactive capital reduction	80%	80%	80%	80%
O&M trouble cost reduction	85%	85%	70%	60%

Alternative Selected

Q. How is the 4.8kV Hardening work being prioritized to best support the Company's customers?

A. DTE Electric is prioritizing the order in which it addresses the different sections of the 4.8kV system based on numerous criteria, including safety and reliability performance, with safety being the primary driver in the prioritization efforts. Work is prioritized at the substation level, as it is cost efficient to perform all the work for circuits tied to the same substation as part of the same project. Each 4.8kV substation within the City of Detroit was scored based on the following factors:

1) Recorded DTE Electric wire down incidents
2) Recorded DPLD arc wire down incidents
3) Estimated foot traffic within the substation service area
4) Total customer count within the substation service area
5) Outages caused by tree interference

6) Total outage and non-outage events requiring the dispatch of a line crew

Greater weight was given to factors that impact safety (wire down events, population density) as compared to factors that are targeted to improving reliability. This prioritization was then overlaid with the current schedule for 4.8kV conversions to eliminate overlapping scope (because 4.8kV conversions are primarily driven by load growth and circuits that are part of the conversions are upgraded, there is no need to harden them). Once the initial prioritized substations for the 4.8kV Hardening program were identified, an operational rollout plan was developed, including how the work would be sequenced to maximize resource efficiency. It is important to note that prioritization factors and weightings may be adjusted over time based on input from the MPSC and the ongoing assessment of program effectiveness and cost.

Q. Which substations will be addressed by the 4.8kV Hardening program from 2018-2020?

A. While adjustments to the exact sequence of the circuits may occur, and because with experience the cost estimates may be adjusted, Table 13 represents the current plan for the 4.8kV Hardening program between 2018 and 2020. The program is projected to last 10 years and will address approximately 50% of the 4.8kV infrastructure in the City of Detroit. The remaining infrastructure will be addressed primarily through conversions to 13.2kV, as supported by load growth or by favorable customer economics.

Table 13: 4.8kV Hardening 2018 to 2020 Scope and Estimates

4.8kV Hardening 2018 to 2020 Scope and Estimates ($000)			
Substation	2018	2019	2020
BALFR	$ 19,925		
PURTN	$ 12,727		
CRTIS	$ 140	$ 10,821	
SIXMI	$ 12,741	$ 1,264	
APPOL	$ 4,429	$ 7,704	
TIRMN	$ 2,766	$ 11,984	
CONAT		$ 12,989	
WAYBN		$ 9,177	$ 7,718
TURNR		$ 5,322	$ 12,331
FLANE			$ 7,154
HAWTH			$ 18,454
GRANT			$ 9,328
GARY			$ 8,650
Total	**$ 52,728**	**$ 59,261**	**$ 63,635**

Q. How will the 4.8kV Hardening program benefit customers?

A. The program will enhance safety and significantly improve reliability and power quality for the aging 4.8kV system. By reducing outages and other maintenance needs, the program will also help mitigate upward pressure on operating costs.

In addition, the program will extend the life of the 4.8kV system, allowing the deferral of more expensive conversions to 13.2kV. It is DTE Electric's long-term goal to convert most of the 4.8kV system to a 13.2kV system to allow for new load to be added and to improve power quality and reliability. However, given the complexity and cost of these conversions, the Company only converts systems when required to serve new load or when poor reliability drives very high maintenance costs, making conversions economically advantageous for customers. The 4.8kV Hardening Program supports the deferral of conversion projects by improving the condition of the system and reducing costs.

Pole and Pole Top Hardware (Pole Top Maintenance)

Q. What is included in the Pole and Pole Top Hardware program?

A. Poles and pole top hardware are exposed to harsh conditions (e.g., ice, extreme heat, wind), causing them to degrade and weaken over time. High cost and long duration customer outages can result when this equipment fails unexpectedly. This program proactively identifies and replaces damaged equipment before unexpected failures occur.

Q. How does the Company determine what poles and pole top hardware need to be replaced?

A. Annually, patrols are performed on a portion of the system to test and inspect poles and pole top hardware. The Company inspects poles on a 10-12 year cycle. Results from these patrols have typically shown that approximately five to seven percent of the total poles inspected have reduced strength and need to be remediated. These poles are either replaced or reinforced based on specific criteria. During the patrols, pole top hardware that has failed is also identified. Examples include cracked or broken insulators, which can lead to pole fires; broken guy wires, which can lead to excessive leaning and potentially to broken poles; and obsolete equipment that is prone to failures (such as cutouts and arrestors with known defects).

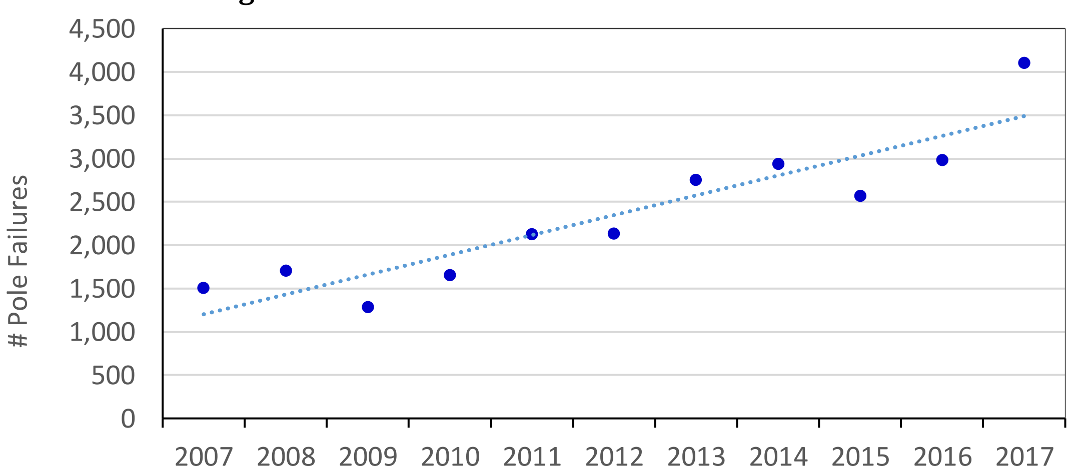
Q. Does the Company replace failed equipment with identical equipment for the pole and pole top hardware program?

A. No. When the Company replaces these items, it uses equipment that complies with current standards. For example, the minimum pole class for poles with primary voltage wire (4.8kV and 13.2kV) is stronger than previous standards. Also, DTE Electric replaces wood crossarms with fiberglass crossarms, porcelain cutouts with polymer cutouts, and porcelain insulators with polymer clamp-top insulators. Fiberglass crossarms have five times the mechanical strength of their wood counterparts, and polymer equipment has six times the mechanical strength of its porcelain counterparts.

Q. What trends is the Company experiencing with poles and pole top hardware?

A. In recent years, the number of poles that are failing in service has increased, which is consistent with the increasing age of the system and the ongoing damage from tree interference. The increasing trend in pole failures is shown in Figure 6.

Figure 6: In Service Pole Failures from 2007 to 2017



Q. What is the Company doing to address the trend in pole failures?

A. The Company is increasing the annual Pole and Pole Top Hardware program by approximately $20 million to respond to this trend and prevent costly and unexpected outages for its customers.

Q. Can the Company breakdown the increase in funding and the benefits customers can expect?

A. Yes. Table 14 describes the increased scope, funding, and benefits of the program compared to the 2017 level.

Table 14: Pole and Pole Top Hardware Increased Scope

Scope Increase Category	Additional Funding Required (2017 to Test Year)	Driving Force	Benefits
Inspections	$4.7 million	Increase the inspection scope and rate of pole inspections to prevent emergent failures: 2017: 63,000 through PTM and 39,000 through Joint Use visual inspection process Test Year: 110,000 through an enhanced PTM inspection program (per industry best practices) and a similar amount as in the past through Joint Use visual inspection process	Increased inspections will reduce the risk of pole and equipment failures, improving reliability and reducing reactive maintenance costs by allowing work to be performed on a planned basis.
Pole Top Hardware	$2.2 million	Increase the components of pole top hardware inspected and repaired to prevent emergent failures: 2017: 16 components Test Year: 48 components	It is more efficient and safer to perform work on a planned basis and outages can be avoided with proactive work.
Reinforce and Replace Poles Identified through Inspections	$13.3 million	Enhanced and increased inspections per industry best practices will identify additional volume of work: 2017: Poles addressed 2,700 Test Year: Poles addressed 10,600	Addressing poles in a proactive and planned way will reduce the time customers spend without power, reduce reactive costs, and enhance safety.
Total	$20.2 million 2017: $19.2 million + $20.2 million Test Year: $39.4 million		

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Substation Outage Risk

Q. What is the scope of the substation outage risk program?

A. The Company has two approaches for addressing the risk posed by major substation outages:

Substation Outage Risk Reduction Program (Substation Risk): Replace aging and at risk equipment to reduce the probability of a failure and change substation design to withstand contingency operations. This approach permanently reduces substation outage risk. However, execution of these projects is complex, so pace must be measured and projects must be prioritized. The priority is to implement the program for substations that meet two criteria:

1) High probability of failure and high level of stranded load, as indicated by the substation outage risk model score.
2) Limited opportunity for deployment of mobile fleet assets or cannot restore the entire substation load (in other words, load will be stranded for more than 24 hours).

The Company uses this as the starting point for further evaluation before finalizing capital investment decisions and determining project timing.

Mobile Fleet Program: Expand mobile generation, portable substations, and mobile switchgear to decrease restoration time for stranded substation load to within 24-48 hours of a substation failure. As proven in the Apache substation outage, the mobile fleet provides relatively quick restoration as compared to the time needed to repair the substation. While it is not a long-term solution to reducing substation outage risk, the mobile fleet program is an extremely important program to help restore customers as quickly as possible while major substation upgrade projects are completed over time.

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Q. What is the driving force for the Substation Outage Risk program?

A. The Company has experienced an increasing number of major substation outage events in the past few years. Figure 7 and Table 15 show a summary of the major substation events where DTE Electric experienced a temporary loss of an entire substation. Most of these major substation events were caused by end-of-life equipment.

Figure 7: Number of Major Substation Outage Events (Complete Loss of Substation)

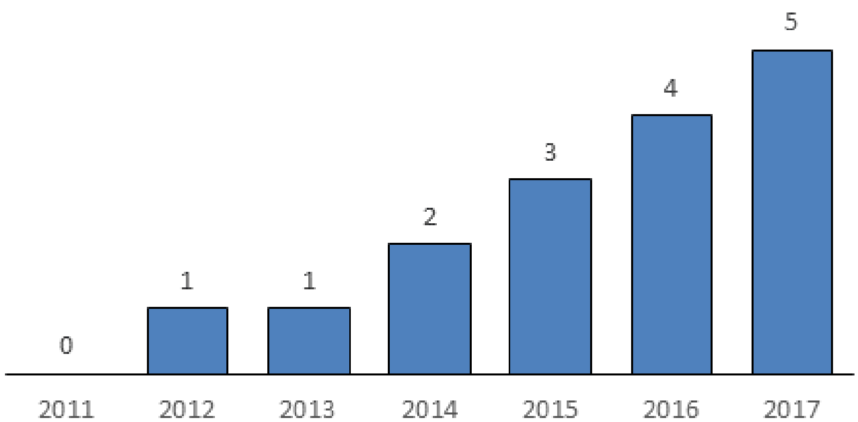

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Table 15: Major Substation Outage Events Details

Substation	Date	Cause	Customers Interrupted	Hours to Full Restoration (Temporary Repairs)	Contribution to System SAIDI
Webster	07/17/12	Breaker	9,519	48	7.3
Stephens	10/23/13	Transformer	5,943	8	0.8
McGraw	08/14/14	Flooding	4,424	11	0.3
Daly	09/07/14	Loading	3,832	7	0.5
Apache	07/23/15	Switchgear	9,486	34	3.8
Arnold	09/15/15	Cable	2,617	31	2.2
Warren	11/23/15	Switchgear	3,063	24	2.0
Benson	04/18/16	Switchgear	12,139	3	0.6
Liberty	01/04/16	Breaker	3,712	13	1.3
Drexel	07/18/16	Cable	3,213	13	0.7
Alpha	10/23/16	Circuit Switcher	6,678	7	0.6
Chandler	01/27/17	Transformer	6,135	9	1.1
Indian	05/26/17	Cable	5,422	13	1.9
Macon	08/08/17	Transformer	1,444	24	0.8
Plymouth	08/16/17	Transformer	3,910	32	2.6
Brazil	09/20/17	Cable	3,288	5	0.5

Q. How do these events impact the Company's customers?

A. The loss of an entire substation can negatively impact customers for an extended duration, as illustrated by the Apache substation event. In July 2015, Apache substation experienced a switchgear failure, which caused the entire substation to be de-energized, interrupting approximately 10,000 customers. A portion of the customers were restored by transferring the load to adjacent substations. The remaining customers were restored by installing a portable substation and six portable generators on the site. It took a total of 34 hours to achieve full restoration for all customers. The substation was in abnormal configuration for approximately two months following the event to repair, replace and test all the switchgear wiring, and replace several breakers. Any additional failures during this time would have severely impaired the Company's ability to serve these customers.

Q. How does the Company determine what substations are at risk?

A. To help the Company identify the need for risk mitigation actions and to prioritize them, the substation outage risk model was developed. The model quantifies relative substation outage risk scores based on two factors:

1) Stranded load at peak (load which cannot be transferred to adjacent circuits due to voltage differences, load restrictions, or other physical limitations).
2) Asset condition and likelihood of failure.

Figure 8 illustrates the result of this model in terms of the overall risk level by substation, indexed to 100 for the substation with the greatest level of risk, and Table 16 shows the substations with the highest risk. These substations are being addressed in the 2018-2022 time period.

Figure 8: Substation Risk Model Results

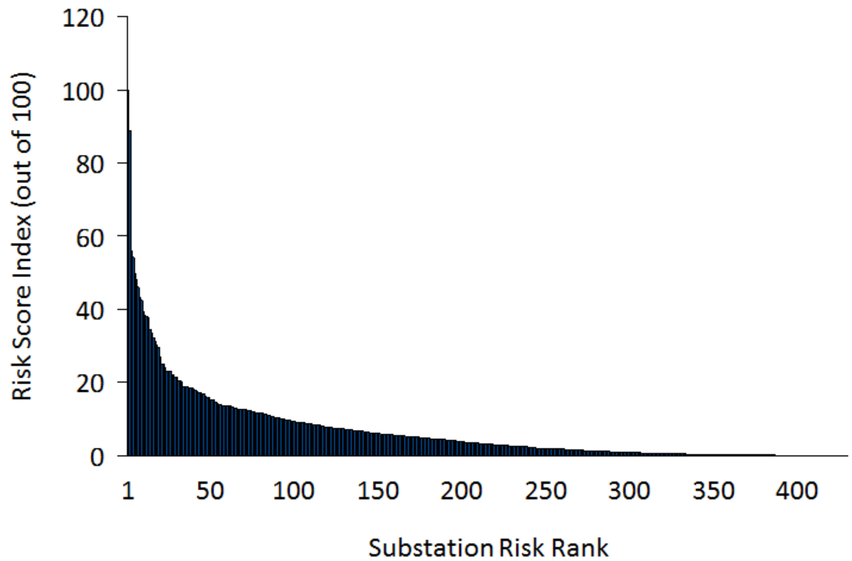

Table 16: Substation Risk Model Results

Substation	Substation Outage Risk Score	Substation Outage Rate*	Stranded Load after Load Transfer (MVA)	Stranded Load after DG (MVA)
Malta	100	2.4%	63	29
Crestwood	60	2.9%	32	32
Bloomfield	45	3.0%	23	23
Savage	45	2.2%	32	32
Apache	42	2.0%	33	32
Chestnut	42	2.0%	32	20
Birmingham	33	2.3%	21	19
Jupiter	31	1.2%	41	10
Spruce	28	1.3%	34	20

**Annual Probability of Complete Loss of the Substation*

Q. What benefits will the customer receive from the Substation Outage Risk program?

A. The investments to address the substations with the greatest risk of failure or for which the possibility of stranded load is largest will significantly reduce the likelihood that a large number of customers will be without power for several days. In addition, by addressing the highest probability failures before they occur, reactive maintenance and

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capital costs will be reduced.

Infrastructure Redesign

Q. What is included in Infrastructure Redesign?

A. Table 17 provides an overview of the programs in this category. Significant additional details are included in Exhibit A-12, Schedule B5.4, page 8 and Exhibit A-23, Schedule M3.

Table 17: Infrastructure Redesign Summary

Programs	Scope of Work	Benefits
Ann Arbor System Improvement	• Build two new 120kV to 40kV substations • Modify existing substations, overhead and underground circuits to reduce interruption risk	• Add capacity to serve new load • Address subtransmission integrity and power quality concerns in Ann Arbor
Subtransmission Hardening	• Reconductor critical subtransmission lines • Build new substations as necessary • Rebuild and replace underbuilt distribution assets as necessary	• Improve reliability and safety of the subtransmission system by addressing circuits that have experienced significant loss of wire strength
City of Detroit Infrastructure (CODI) Upgrades	Project scope includes but is not limited to: • Replace netbank transformers • Replace system cable • Modify existing substations • Build new substations	• Add capacity to serve new load • Address aging infrastructure in the City of Detroit to provide long-term reliable service and prevent significant asset failures
4.8 kV Conversion and Consolidation	• Convert and consolidate 4.8 kV substations and corresponding circuits into one 13.2 kV substation and circuits • Consolidate 4.8 kV substations into one 4.8 kV substation in lightly loaded areas where supported by customer economics	• Add capacity to serve new load • Upgrade wiring, poles and pole top hardware to enhance safety, reliability and power quality • Reduce O&M and reactive maintenance costs by decreasing the number of assets and replacing aging infrastructure • Enhance grid technology and automaton
8.3 kV Pontiac Overhead Conversion	• Convert the overhead portion of the 8.3 kV system to 13.2 kV	• Replace aging infrastructure • Reduce risk of stranded load and improve contingency options • Improve reliability and power quality • Reduce O&M costs by decreasing the number of assets in the field and the number of trouble events • Enhance grid technology and automaton

Programs	Scope of Work	Benefits
System Loading	Scope includes but is not limited to: • Building new substations/stations • Installing additional transformers • Installing additional switchgear • Upgrading existing equipment • Reconductoring wire/cable	• Provide load relief to the electrical system, extending asset life • Add capacity to serve new customers • Improve system operability • Reduce system operation risks • Reduce excessive wear (loading stress) on equipment
Pilot: Non-Wire Alternatives	Integrate Distributed Energy Resources (DERs) into electric distribution system. DERs considered include: • Energy storage • Energy Efficiency (EE) • Demand Response (DR) • Distributed Generation (DG)	• Assess impacts of DER integration on distribution electrical system • Provide data and knowledge for Standards development related to DER integration • Evaluate benefits and costs of non-wire alternatives compared to traditional electric distribution investments

Q. Are there specific Infrastructure Redesign programs you would like to discuss in more detail?

A. Yes. I would like to highlight the following programs because I believe that discussion beyond what is contained in the exhibits will be helpful to establish a deeper understanding of their scope, the rationale for making the investments, and the benefits customers will receive:

- City of Detroit Infrastructure (CODI) Upgrades
- 4.8kV Conversion and Consolidation
- System Loading
- Non-Wire Alternatives

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City of Detroit Infrastructure (CODI) Upgrades

Q. What is the scope of the CODI Upgrades program?

A. The CODI program is driven primarily by the need to reliably serve existing and new load. The work is occurring in the heart of the City of Detroit and has significant amount of underground equipment in scope. One important distinction for this program as it relates to what has been previously discussed regarding the relationship between the 4.8kV Hardening program and the 4.8kV Conversion and Consolidation program, is that there is not an effective hardening solution that can support delaying the investments that are needed for the CODI Upgrades. The CODI upgrades planned for 2018-2022 consists of several projects. The projects and their scopes are summarized in Table 18 and their location is illustrated in Figure 9.

Table 18: City of Detroit Infrastructure Projects

Project	Key Scope of Work	Estimated Timeline
CODI – Midtown Substation Expansion	Expand 13.2 kV Midtown substation by installing 3rd transformer and a 12-position switchgear	2018-2019
CODI – Alfred Substation Expansion	Expand 13.2 kV Alfred substation by installing 3rd transformer and a 12-position switchgear	2019-2020
CODI – New Corktown Substation	Build a new general purpose substation named Corktown	2018-2020
CODI – Charlotte Network Upgrades	• Replace 30 miles of network feeder cable • Replace seven miles of radial powerline system cable • Replace or remove 68 netbank transformers • Convert eight primary customers from 4.8kV to 13.2kV • Convert the circuits to 13.2 kV fed by Temple substation • Decommission Charlotte substation	2018-2021

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Project	Key Scope of Work	Estimated Timeline
CODI – Garfield Network Upgrades	• Replace 36 miles of network feeder cable • Replace 32 miles of radial powerline system cable • Replace or remove 78 netbank transformers • Convert 26 primary customers from 4.8kV to 13.2kV • Convert 24 miles of overhead from 4.8kV to 13.2kV • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation • Decommission Garfield substation	2018-2024
CODI – Kent Network Upgrades	• Rebuild six miles of radial powerline system cable • Convert one primary customer from 4.8kV to 13.2kV • Convert seven miles of overhead from 4.8kV to 13.2kV • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission Kent substation	2020-2024
CODI – Gibson Network Upgrades	• Rebuild 10 miles of radial powerline system cable • Convert 22 miles of overhead from 4.8kV to 13.2kV • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission Gibson substation	2020-2024
CODI – Howard Upgrades	• Rebuild 15 miles of network feeder cable • Rebuild 30 miles of radial powerline system cable • Replace or remove 89 netbank transformers • Convert 26 primary customers from 4.8kV to 13.2kV • Convert three miles of overhead from 4.8kV to 13.2kV • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission Howard substation	2021-2024
CODI – Amsterdam Upgrades	• Rebuild 22 miles of network feeder cable • Rebuild 50 miles of radial powerline system cable • Replace or remove 60 netbank transformers • Convert 28 primary customers from 4.8kV to 13.2kV • Convert seven miles of overhead from 4.8kV to 13.2kV • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation • Decommission Amsterdam substation	2022-2026

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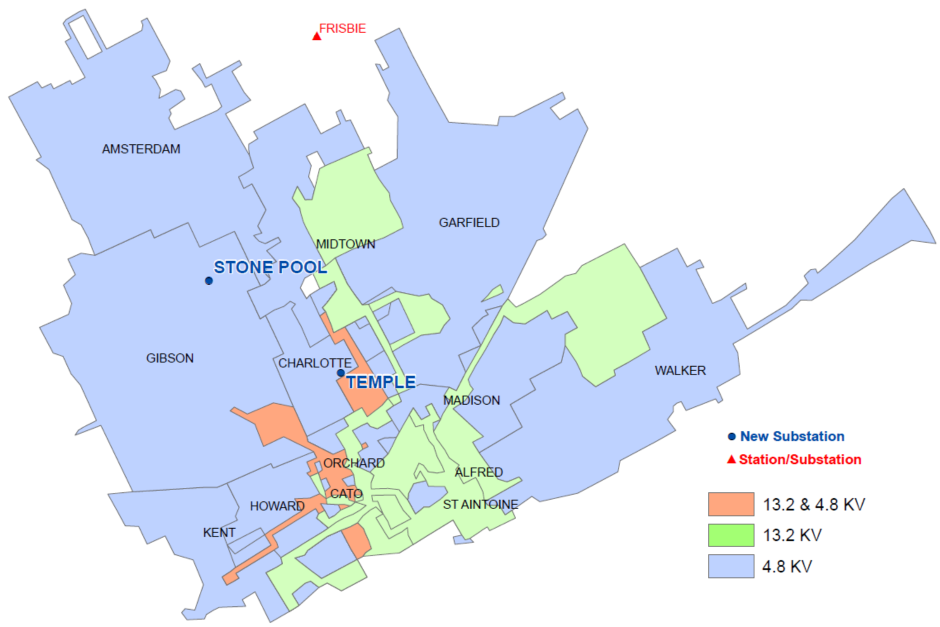
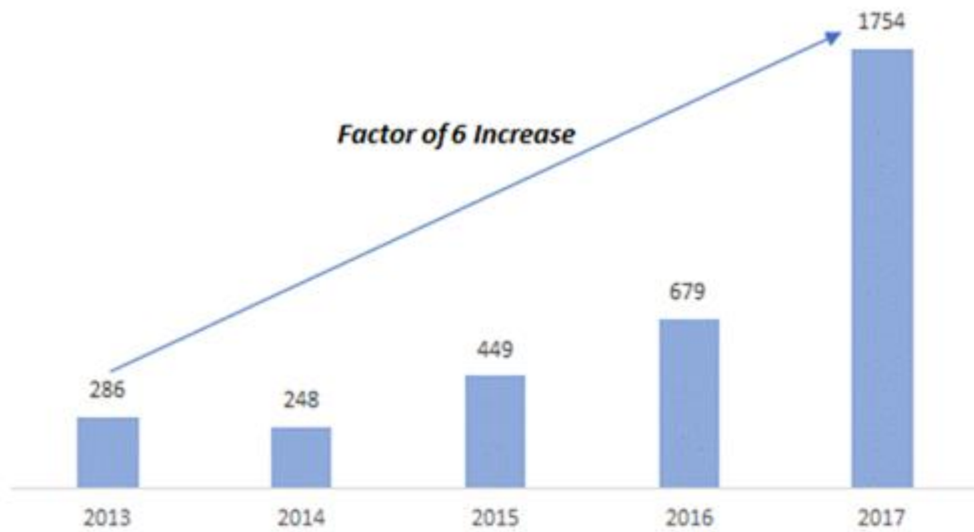
Figure 9: City of Detroit Infrastructure Substation Map



Q. Why is the CODI program needed?

A. Significant portions of the electrical infrastructure in the City of Detroit were placed in service in the early part of the 20th century. Redevelopment in the City of Detroit is stressing this aging infrastructure, and new customer load cannot be served with existing capacity. Between 2013 and 2017, the annual number of construction permits requested in the City of Detroit has increased by a factor of six, as illustrated in Figure 10. The CODI area specifically has experienced over 13% load growth between 2011 and 2017, and 19% load growth is expected between 2018 and 2022. This situation must be addressed if the existing and growing load is to be served reliably and to support economic development in the area. The Company has developed the CODI program for that purpose.

Figure 10: City of Detroit Construction Permits
(source: Buildings, Safety Engineering and Environmental Department)



In addition, the substations, underground cables and manholes, network equipment, and other assets which have served the area well over many decades, are experiencing higher failure rates, increasing the risk of long-duration outages that can lead to high reactive maintenance costs.

4.8kV Conversion and Consolidation

Q. What is the scope of the 4.8kV Conversion and Consolidation program?

A. The program is similar in nature to the CODI Upgrade projects, and is aimed at upgrading the 4.8kV system to 13.2kV by building new substations and upgrading circuits to add capacity to serve growing load. The main difference from the CODI Upgrade work is that CODI projects contain a significant amount of underground work. These investments will also allow customers to be served more reliably and from a smaller asset footprint, as the load from multiple 4.8kV substations can be transferred to a single

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13.2kV substation.

Q. Why does the Company plan on converting and consolidating its 4.8kV system?

A. The 4.8kV system is aging and much of its equipment is obsolete. Like most other utilities have done, DTE Electric plans to convert most of its 4.8kV system to a higher voltage level over the long term to better serve customers. Very few, if any, utilities still operate large parts of their networks at this lower voltage level. They have converted their networks over time, as population and load growth have driven the need for higher voltage levels and modern equipment. Conversely, population and economic trends in southeast Michigan did not support the need for conversion until recently. This has left DTE Electric with comparatively more small and outdated substations than comparable utilities.

Q. Besides the ability to support economic development and serve greater load, are there other benefits from the 4.8 kV Conversion and Consolidation program?

A. Yes. The program will allow the decommissioning of aging equipment, which will lead to improved reliability and lower reactive maintenance costs, as there will be fewer equipment failures. Furthermore, restoration times will be improved and costs will be reduced, as substation equipment will be remotely operated from the Systems Operation Center, eliminating the need to dispatch operators to perform switching activities.

Q. Over what time horizon does the Company expect the conversion of its network to 13.2kV to occur?

A. The Company has no defined timeline, as conversion and consolidation will primarily be driven by load growth when it occurs. Other factors, such as unacceptable levels of reliability at some substations or the ability to reduce operating costs in a way that can fund the investments to benefit customers will also be considered. The Company expects conversions and consolidations of the 4.8kV system to occur over several decades.

Q. What impact will the 4.8kV Hardening program have on the pace of conversion and consolidation of the 4.8kV system?

A. The 4.8kV Hardening program will delay the need to convert and consolidate circuits because of poor reliability or high costs, as the investments will improve the reliability and reduce maintenance costs for some of the oldest circuits in the DTE Electric system. Improving the condition of the circuits often provides benefits to the substations that serve them because of fewer faults occurring. These faults have negative impacts on substation breakers, transformers, and other equipment. Circuits that have been hardened will only be converted when needed to support load growth, when cost savings justify it based on positive customer economics or when reliability performance at the substation level requires it.

System Loading

Q. What is the scope of the System Loading projects?

A. System Loading projects are implemented to relieve situations in which the capacity of overhead, underground, and/or substation equipment cannot serve customer load reliably. If overloading conditions are not identified and addressed, equipment can be damaged and customer outages can result.

Q. How do overloads occur?

A. Load increases may be the result of general load growth, new customers attaching to the system, customers relocating from one area to another, or commercial and industrial facilities increasing capacity.

Q. How does the Company assess loading?

A. Capacity needs are considered for two conditions: normal state and contingency state. The normal state exists when all equipment and components are in service and operating as designed. The contingency state exists when there is either a temporary planned equipment shutdown, the failure of a component on the electrical system (e.g., subtransmission line), or the failure of a specific piece of equipment (e.g., transformer or breaker). Under contingency conditions, equipment on the rest of the system may see an increase in loading to compensate for the out-of-service equipment, and hence, requires additional capacity above normal state.

To meet these capacity requirements, most components and equipment have two ratings: day-to-day and emergency. These ratings are calculated to maintain the viability of an asset throughout its expected useful life. Operating equipment above its designated rating can cause immediate failure or accelerate end-of-life. The day-to-day rating is the load level that the equipment should be operated at per-design specifications. The emergency rating is higher than the day-to-day rating and is the load level that the equipment should be operated at for only short periods of time. Operating at the emergency rating adds stress to the equipment and shortens its useful life. If a piece of equipment exceeds its emergency rating, then the Company's System Operations Center takes immediate steps to transfer load or shed load if necessary. For substations, there is also a firm rating. The substation firm rating is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating

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of all the substation equipment that is required to serve the load.

Q. How does DTE Electric identify overloads?

A. To ensure that expected load growth can be served within the equipment ratings, the Company's planning engineers conduct annual Area Load Analyses (ALA). These analyses include verification of equipment ratings and substation firm ratings, historical loading data, system conditions and configurations changes, known new loads, and input from large customers and municipal officials about potential development.

For areas and cities that have experienced steady and/or strong load growth, capital investments are required to add or upgrade overhead or underground lines and/or to expand or build new substation capacity. Often, a strategic load relief project is the result of a combination of general load growth, specific customer connection requests, aging infrastructure replacement, and reliability improvement needs.

<u>Non-Wire Alternatives</u>

Q. Why is DTE Electric evaluating Non-Wire Alternatives?

A. The electric generation and distribution industry is evolving, as technologies such as energy storage, demand response and solar generation have been decreasing in cost and are becoming more widely adopted. DTE Electric seeks to identify opportunities where these "non-wire alternatives" provide value to the electrical system which exceeds more conventional solutions. Specifically, DO is pursuing pilot projects in energy storage to gain operational experience and to measure the value that battery storage can bring to the distribution system in various use cases. It should be noted that these pilots funded as "Pilot: Non-Wire Alternatives" are separate from the storage pilots discussed by Company

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Witness Dimitry that will be sited at customer-owned facilities or properties. While information and lessons learned will be shared and the two teams will collaborate, the funding requests are separate.

Q. What criteria did the Company use to initially screen energy storage pilot projects?

A. DTE Electric uses three screening criteria to evaluate an energy storage pilot project:

(1) Cost-benefit analysis

(2) System value

(3) Feasibility

The cost-benefit analysis uses an economic analysis to compare an energy storage solution with a conventional solution. Either the energy storage solution replaces the conventional solution, in which case the costs of the two can be directly compared, or the energy storage solution defers the conventional solution, in which case the potential deferral length and time value of money help determine the relative value of the two solutions. System value is a factor meant to estimate the likelihood that opportunities to deploy similar projects on the electrical system will present themselves in the next five years, based on either system conditions or trends in the industry. Finally, the feasibility criteria help screen out potential projects that could not be executed in the appropriate timeframe due to factors such as available space to site a storage solution.

Q. What energy storage pilot projects have resulted from the initial screening process using the selection criteria?

A. The leading candidates for energy storage pilot projects involve combining storage with solar generation on the distribution system. As distributed energy resources become increasingly common, introducing power flow variability that is difficult to predict and

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control, the Company expects a pilot combining solar and storage to offer the opportunity to demonstrate how a battery can help manage this variability. The battery solution could also be an alternative to a more conventional system upgrade required specifically for distributed resource integration, though this will need to be evaluated on a case-by-case basis and may only support a certain level of distributed resources.

A battery solution can offer three distinct value streams when paired with solar generation. First, it can help smooth out variable generation and mitigate any potential power quality or load flow issues. Second, it can be used to time-shift generation to better coincide with system peak, reducing overall demands on the system. Third, in some cases the battery can capture excess solar generation if the solar array is overbuilt with respect to the inverter, which is an increasingly common configuration as solar panel prices decrease. Gaining operational experience on how to optimize the battery system design and operation to capture and quantify multiple benefits will provide value that could be expanded to other solar generation sites. As always, customer affordability is a key input in the decisions DTE Electric makes, and the Company does seek pilot projects with more favorable economics, even though the primary objective of the pilots is operational learning because the economics of storage are expected to improve over time and the Company wishes to be prepared for larger scale deployment when it benefits customers.

Q. Has the Company identified opportunities to use energy storage as an alternative to traditional distribution infrastructure upgrades?

A. DTE Electric completed a study to identify locations where energy storage could be used for load relief as an alternative to substation upgrades. The study did not identify any

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locations for which a battery solution provided more favorable customer economics than a substation upgrade. The main drivers for this conclusion were:

1) Most of DTE Electric's load relief projects address substations that are 3 MVA or more over firm rating, which would require a battery size that would be expensive and challenging to deploy.
2) Many of the projects which address smaller substation overloads also bring benefits which a battery solution would not, such as increased operational flexibility, improved reliability, and reduced risk associated with aging infrastructure.

DTE Electric will continue to evaluate energy storage as an alternative to more traditional infrastructure upgrades.

Q. What specific battery storage pilot projects does the Company plan on pursuing?

A. DTE Electric has identified and is conducting more detailed studies for a battery storage pilot that couples battery storage with existing solar generation. Initial engineering analysis has determined that a battery storage facility could help with renewable integration by improving the voltage flicker seen during ramp-up, ramp-down or intermittent generation, and high voltage seen during high solar generation periods. Pursuing these projects will offer the following benefits to the electrical system:

1) Ability to compare modeled power quality improvements with actual results, increasing confidence that a battery solution could be more broadly deployed to defer conventional circuit upgrades in areas with high renewable penetration.
2) Defining and testing standards for battery interconnections.
3) Developing expertise in managing the design and construction of a battery storage project.

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4) Managing battery storage operations by defining and testing processes for daily operational decisions for using the battery.

Q. Is DTE Electric pursuing other uses of energy storage?

A. Yes. DTE Electric plans to acquire a trailer-mounted battery or generator-battery combination sized between 750kW-2MW. While traditional portable generators have been effective in supporting large-scale planned or unplanned outages, in certain situations a battery would be preferable. The battery trailers would primarily be used to supplement the fleet of portable generators to support either planned work that requires a shutdown or as part of an emergency restoration.

Technology & Automation

Q. What technology investments does the Company plan to support the Five-Year Plan's objectives?

A. Table 19 provides an overview of what is included in this category. Additional details are included in Exhibit A-12, Schedule B5.4, page 9. In addition, Exhibit A-23, Schedule M4 shows more detailed information for the projects, including the rationale for their execution and benefits customers will receive.

Table 19: Technology & Automation Summary

Programs		Scope of Work	Benefits
ADMS	Energy Management System (EMS) / Generation Management System (GMS)	• Replace existing EMS/GMS systems	• Replace end-of-life equipment • Provide more robust platform for NERC-CIP compliance • Provide platform for the OMS and DMS portions of the ADMS
	Outage Management System (OMS) / Distribution	• Install the OMS and DMS components of the ADMS system to integrate different	• Enhance safety and restoration times by providing real-time situational awareness to all resources

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Programs	Scope of Work	Benefits
Management System (DMS)	operational technology and analytical tools	• Enhance safety, reliability, and efficiency by eliminating paper maps and switching orders • Provide platform for Fault Location, Isolation and Restoration • Enable remote switching operations • Enable integration of Distributed Energy Resources
Network Management System (NMS)	• Install Network Management System	• Support achievement of the full benefit of ADMS by ensuring high quality system data • Shorten the duration of distribution studies
Advanced Metering Infrastructure (AMI) 3G to 4G Upgrades – Supported by Company Witness Moccia	• Replace existing 3G technology with 4G capable equipment • Firmware upgrade on 2.5 million meters	• Sustain AMI benefits after telecommunication providers phase out 3G in Michigan by 2020
System Operations Center (SOC) Modernization	• Construct Systems Operations Center and Back-up Center for the operation of the electrical system	• Replace end-of-life facility which has limited mechanical and electrical redundancy • Improve ability to respond to major operational disruptions • Allow co-location of dispatchers and system supervisors to improve operational efficiency and reduce outage duration • Mitigate NERC-CIP risks and create modern high availability control center
Line Sensors	• Install line sensors on cable poles and strategic locations along the circuit	• Enhance grid-wide situational awareness
13.2 kV Telecommunications	• Install and/or upgrade telecommunication and RTUs	• Provide the telecommunication package at substations to allow for SCADA upgrades
40 kV Automatic Pole Top Switch	• Develop and install a solution to sectionalize sub transmission circuits when faults occur	• Improve the reliability of the subtransmission system
Pilot: Technology Programs	• 4.8 kV automated pole top devices • Trip Savers • SCADA-controlled regulators and capacitor banks	• Test application of circuit automation devices for 4.8 kV system • Test application of SCADA regulators and capacitors for advanced Volt/VAR control
Substation Automation	• Install SCADA control at substations to allow for fully remote monitoring and control starting in 2021	• Improve situational awareness and flexible real-time operations • Improve operational efficiency

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Programs	Scope of Work	Benefits
Circuit Automation	• Retrofit existing circuits with SCADA reclosers and/or switches to allow for remote control starting in 2021	• Enable FLISR, reducing sustained outage events and improving reliability • Replace legacy switches

Q. Are there specific Technology & Automation programs you would like to discuss in more detail?

A. Yes. I would like to highlight the following programs because I believe that discussion beyond what is contained in the exhibits will be helpful to establish a deeper understanding of their scope, of the rationale for making the investments and of the benefits customers will receive:

- ADMS
- SOC Modernization

<u>Advanced Distribution Management System (ADMS)</u>

Q. Can you describe the scope of the ADMS project?

A. ADMS is the umbrella name for three projects that are tightly connected to each other but are being executed in different phases and have different but complementary objectives. In its totality, ADMS is the technology architecture and software that will substantially improve DTE Electric's ability to manage the flow of electricity from the point of generation to the point of delivery, to monitor the condition of the grid, to safely operate it, and to respond to emergency conditions and outages.

DTE Electric uses several systems to perform these activities today, but they are built on platforms which are at end of life. Furthermore, these systems are not integrated with one another and activities that will become automated with the full deployment of the ADMS are currently manual. Operations and calculations that currently take hours will be done in minutes with ADMS, significantly improving restoration times and reliability. The "Advanced" portion of the ADMS refers not just to improved functionality, but also to the significant level of integration that is now available across systems that in the past were separate from one another. These systems perform different functions but benefit significantly from being able to share data in a seamless way. The ADMS is comprised of the following functional components:

- Generation Management System (GMS): allows the Company to manage the Generation fleet and includes Automatic Generation Control to balance system load and support frequency control; utilized to interface with MISO.
- Energy Management System (EMS): allows the Company to manage the subtransmission system and the connections to the transmission system; provides tools to analyze real-time system conditions; allows the Company to operate devices on the subtransmission system.
- Outage Management System (OMS): aggregates outage information provided by customers or AMI to prioritize response and allows dispatchers to properly assign crews for repairs.
- Distribution Management System (DMS): provides a complete model of the electrical system for operators to view system conditions in real time; allows the Company to operate devices on the distribution system.
- Network Management System (NMS): allows the Company to maintain high quality system data.

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Q. Does the Company currently have the GMS, EMS, OMS, DMS, and NMS functionality available?

A. The Company has versions of these systems with outdated, non-integrated and limited functionality, with the exception of the NMS, which the Company does not currently have or operate.

Q. Why does the Company need to replace the existing systems with the ADMS project?

A. The Company is replacing the existing systems because the current GMS, EMS, and DMS systems and hardware have reached end of life, meaning that they are no longer properly supported by the vendors that supplied them. These systems would need to be replaced regardless of the ADMS project. In addition, modern systems, such as the new OMS software that is part of ADMS, have a significantly greater level of functionality and integration that will benefit the Company's customers by improving restoration times, which is the main driver of the ADMS project.

Q. Can you expand on why the current systems have reached the end of their useful life?

A. Yes. The hardware and software for the GMS/EMS and DMS are currently at end of life. While the systems are currently stable, the existing infrastructure, which supports the current software, is no longer commercially available. This increases the risk of recoverability from system failure and puts the operation of the electric system at risk. In addition, the age of the infrastructure means the Company cannot upgrade further without replacing the hardware and performing a significant upgrade of the application software. The hardware and software support is currently being phased out by vendors,

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which increases risks due to the lack of replacement hardware, software patches, and support. Existing hardware is approximately 15 years old. Typically, a hardware refresh is completed every five to seven years.

The ADMS project provides an opportunity to upgrade the GMS/EMS and DMS to a new, more advanced software suite, and to seamlessly integrate it on a common platform with an OMS that has a much greater level of functionality. In the absence of the ADMS project, the Company would have to take on a separate upgrade project that would leave it with a much lower level of functionality and system integration.

Q. Can you elaborate on the enhanced functionality of the new systems?

A. The new GMS/EMS platform provides improved visibility and data sharing, which allows for quicker analysis and responses to real-time electric grid events.

The new OMS/DMS will integrate operational data from across the electrical system grid (SCADA) and Advanced Metering Infrastructure (AMI) and seamlessly interface with the EMS to provide real-time visibility of current conditions and provide operational control of the distribution circuits. For example, the new OMS will use SCADA to confirm that operating devices have sectionalized a circuit and produce more accurate assessments of the location and the number of customers impacted by outages to allow improved prioritization of crew dispatching. The new OMS will allow crew rosters to be uploaded and will track the location of available crews to optimize dispatch in a way that addresses the most critical outages first and reduces overall outage duration.

The ADMS will allow damage assessment results to be more effectively integrated in the development of restoration plans by making it possible for field personnel to upload information about damage they encounter directly into the system for everyone to see in real time. The OMS will also expand the use of AMI data, improving the ability to confirm restoration status by crews in the field, reducing the chance that they could be reassigned to a different outage before all customers in an area are restored, which can occur with current technology. The ADMS system will also be able to analyze outage cases to quickly locate the likely source of the trouble, reducing patrol times and leading to a significant reduction in outage restoration time.

The new DMS will include an unbalanced power flow calculation, fault locating, sectionalizing device coordination, and switching plan management. Automatic Fault Location Isolation and Restoration (FLISR) will also available with DMS to automate the sectionalizing of circuits to isolate faults based on the fault locating function.

The tool will allow visualization of the system parameters in “study mode”. System operators and dispatchers will be able to model operations on the system (such as jumpering to a different circuit) and test the results based on actual field conditions before operations are executed. System operators will be able to study multiple restoration options with consideration of equipment availability, and then track the condition of the system through restoration repairs and follow-up.

In addition, the planning of switching operations for maintenance and system upgrades will be managed through the new DMS/OMS, increasing safety and the ability to maintain project schedules.

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In summary, with a focus on complete integration of critical systems, the ADMS will provide the Company's operations team more information and better tools to be used to more effectively operate the electrical grid.

Q. What prevents the Company from utilizing the existing systems to achieve this same level of functionality?

A. Aside from most systems being at end of life, they do not provide the level of integration or functionality available in newer ADMS applications because they were developed by separate companies using now outdated technology. The OMS is not connected to the EMS or DMS, so system operators need to utilize three separate systems to evaluate whether opportunities exist to use field devices to isolate a fault and restore customers by jumpering circuits. This slow, manual process of moving between different systems, examining circuit drawings, and using paper switching orders slows the restoration process significantly when compared to other utilities. The ADMS the Company is implementing will identify likely fault locations and recommend optimal restoration sequencing in minutes. The level of integration of the new platform, combined with new features, makes it far superior to the existing tools.

Q. Can you describe the importance of having high quality data about the electric grid for the ADMS?

A. The Company learned from benchmarking that ADMS systems require high quality operating data to ensure that all the benefits of an ADMS are realized. Therefore, DTE Electric conducted a data gap analysis in 2017 with the support of a third party that specializes in the field. The study concluded that overall the Company's data availability and quality are far from best practice levels. Specific areas of DTE Electric's data gaps

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include spatial integrity, multiple operating models, and the lack of a consistent source for load, voltage, and connectivity information.

Q How will DTE Electric correct these data gaps and ensure they stay corrected in the future?

A. As part of the ADMS project, the Company will implement a Network Management System (NMS). The NMS will incorporate network data from GIS and harmonize the network data with other systems to directly serve the new ADMS functionality. The Company's AMI infrastructure and SCADA will enable the NMS to establish phase and transformer-to-meter connectivity through machine learning algorithms. The NMS will leverage these algorithms to correct and maintain network data through continuous meter to network validation. The NMS will also consolidate multiple network models to one common network model, reflecting the consistent view of the electrical system in real time to be used by all functions of the ADMS.

In addition to implementing the NMS software, new data governance will be established with clear data ownership accountabilities and support processes that will be implemented as part of the project.

Q. Could the Company pilot ADMS prior to full implementation?

A. In the Company's view, piloting ADMS is not a viable option due to the significant complexity and risk of operating two systems simultaneously. In addition, there are costs associated with the implementation of ADMS that would be incurred regardless of the scale of the implementation, including software licenses, software implementation, personnel training, etc. A phased implementation approach, as DTE Electric has

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described, with different portions of the ADMS being added in sequence, is the more common and recommended approach.

Q. Can you describe the progress that has been made on the ADMS project?

A. The project is well underway. The Company completed all planning and scoping work, definition of system requirements, and selected the software vendor after a very thorough RFP process. A contract with the chosen software vendor was signed in December of 2017 and an agreement on a statement of work has been reached. Software and hardware purchases are on target to be completed in 2018 for all phases of the project. The project is scoped in five phases and the first two phases (GMS/EMS) started as planned in January of 2018. The Company also completed the data gap analysis, as described previously, and identified a sustainable solution for achieving and maintaining very high data quality standards resulting in the scoping of the NMS phase of the project, which will launch once the vendor is selected for this system.

Q. Why did the Company start the project with the implementation of the GMS/EMS?

A. The upgrade to the GMS/EMS was necessary because the existing system was no longer supported and would have proceeded regardless of the decision to pursue the ADMS project. During the software vendor selection process for the OMS/DMS component of the ADMS, it became clear that the software provider had outstanding capabilities in GMS and EMS implementations, and is in fact an industry leader. These capabilities include robust real-time visualization tools, increased ability to share data between applications, and advanced alarming functionality. The replacement of the Company's GMS/EMS had started during the software vendor selection process because the existing platform was at end of life. The Company was able to redirect its resources to pursuing the GMS/EMS project on an improved platform. By completing the GMS/EMS first, the Company is laying a robust foundation for the implementation of the OMS/DMS portion of the ADMS.

Q. Can you describe the funding required to support the ADMS project?

A. The capital investment associated with the new hardware and software is described in detail in Exhibit A-12, Schedule B5.4, page 9. The Company is also seeking regulatory asset treatment for certain specific aspects of process development, training, and software maintenance fees. Company Witness Uzenski supports the regulatory asset accounting treatment.

Q. How will customers benefit from ADMS?

A. Customers will benefit from reduced outage durations and from better communication on the status of their electric service and expected restoration times. ADMS will reduce the time it takes to identify an outage and dispatch the proper crew to the correct location to repair the cause of the outage. Switching studies to isolate faults and restore customers will become much faster. Table 20 identifies the operational improvements that will come from ADMS implementation and the related improvement in All-Weather SAIDI.

The improvements in data quality and availability that will results from the NMS will also provide several benefits to go beyond the optimal use of ADMS, including:

- Ability to expedite distribution studies for planned maintenance work or when needed for other purposes.
- Ability to preload "as-built" maps into the system so that circuit diagrams can be updated as soon as work is completed and also to update them from the field in the

mapping software, enhancing both safety and operational capabilities.

- Identification of any mis-mapped AMI meters to ensure accurate customer information to aid restoration activities.
- Identification of potentially incorrect equipment shown on system drawings.
- Identification of any conflation issues (i.e., exact mapping of poles, circuits and other equipment to GPS data) to aid troubleshooting, damage assessment and restoration activities.

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1 **Table 20: Estimated SAIDI Benefits of ADMS**

Benefit Driver	Description of Benefits	Estimated All-Weather SAIDI Benefit
As-operated electrical Model Analysis	Utilize to view and analyze the as-operated electrical model to make informed decisions about how to restore customers	4-8 minutes
Trouble Call Analysis	Utilize remote monitoring capabilities to confirm trouble locations when devices in the field have opened and transmitted their status	4-8 minutes
Assign the Appropriate Crew	Utilize the as-operated model to determine the appropriate resources (e.g., OH vs. UG) to respond to an outage	1 minute
Nested Outage Notification	Utilize the as-operated model to identify incidents of nested outages (trouble behind trouble) to better direct restoration crew efforts	1 minute
Closest Crew Assignment	Utilize the as-operated model integrated with vehicle GPS to locate the closest available crew to an outage	2-3 minutes
Fault Location Identification	Provide a visual indication of the possible fault locations, allowing SOC to better develop a restoration strategy and the field crew to more quickly locate the troubled section of the circuit	5-10 minutes
Momentary Interruption Analytics	Utilize Momentary Interruption Analytics to produce daily reports of the number and location of momentary faults; patrol and resolve before momentary outages become sustained outages	0-1 minute
Switch Order Management System	Utilize the Switch Order Management System to quickly determine switching solutions for restore-before-repair	1-3 minutes
Restoration Switching Analysis	Utilize Restoration Switching Analysis to develop multi-step plans for optimal switching to restore customers based on current system conditions	4-14 minutes
Simulation Tools for Outage Restoration	Utilize Simulation tools to conduct contingency studies to simulate the impact of a restoration plan on the broader electrical system	2-3 minutes
Storm Damage Assessment	Utilize ADMS to assess initial storm damage to better direct resources for restoration efforts	3-4 minutes
Improve SCADA Availability	Monitor the health and availability of SCADA devices to minimize down time and maximize control and monitoring capability	2-4 minutes
Total		***29 - 60 minutes***

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Q. Is this benefit analysis specific to DTE Electric?

A. Yes. The Company calculated these benefits based on the performance of DTE Electric's electric distribution system and on an analysis of how the benefits of the ADMS would apply to its own operations. The Company believes these estimates are conservative based on feedback received in discussions with other utilities.

Q. Are there other benefits of ADMS?

A. Yes. ADMS will be a critical enabler to the integration of Distributed Energy Resources (DERs), such as rooftop solar, energy storage, and demand response. In fact, the Distributed Energy Resource Management System (DERMS) is an application that can be added to the ADMS platform the Company is implementing as the penetration of DERs increases on DTE Electric's system. Because of the potential for DERs to swing power flows and voltage levels on the electric distribution system substantially, system operators must be able to monitor the condition of the grid in real time to ensure safe and reliable operations. In addition, an ADMS, with its underlying high quality data, historical information about system performance, and built-in modeling capabilities, can accelerate and simplify analysis about the impact of adding additional DERs to specific parts of the electric distribution network. None of this functionality is available today.

System Operations Center (SOC) Modernization

Q. What is the SOC Modernization project?

A. The SOC Modernization project is aimed at replacing the Company's outdated primary SOC and the smaller, outdated backup SOC by constructing two facilities designed using current industry security, resiliency, and operability standards. The existing SOC was built in the early 1980's and poses significant limitations as I will describe later in my

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Q. What functions does the SOC perform?

A. The SOC is the most critical facility in Distribution Operations. Personnel in the SOC support generation operations and operate the subtransmission and distribution system in southeast Michigan, monitor alarms and system conditions, and direct field personnel to operate electrical equipment for routine switching needed for maintenance and other planned activities and for outage restoration. The SOC also interfaces with Central Dispatch personnel to ensure appropriate crews are assigned to address system issues.

Q. Why is the SOC Modernization Project needed?

A. The current SOC poses several limitations which the utilities DTE Electric has benchmarked have already addressed.

- Outdated facility. The facility lacks the redundancy in mechanical and electrical systems that is necessary to ensure continued operations in the event of a crisis.
- Outdated technology. The System Operation Center utilizes a magnetic tile representation of the electric network, as opposed to an electronic display board of the transmission, subtransmission, and distribution network as is now very common in the industry. This severely limits situational awareness, which is critical at all times, but particularly during periods of crisis (for example, during large storms). The current tile map board is running out of space to accommodate growth of the system. The lack of modern technology also limits training opportunities.
- Space limitations. DTE Electric's SOC and dispatch personnel are currently physically separated, and their primary method of interaction is through repeated phone calls to share information and collaborate on dispatching field resources.

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The current SOC does not have sufficient space to achieve the co-location of these resources that manage the system and dispatch field personnel to resolve operational issues. The co-location of SOC and dispatch personnel is a well-established industry best practice, as it provides significant customer benefits in terms of the speed at which issues can be addressed and electric service can be restored.

- Limited visibility of telecommunication infrastructure performance. The reliability of telecommunication paths from field devices to the SOC is critical for the effective monitoring of the grid and for remote operations. Developing the ability to separately monitor the condition of the telecommunication network through the construction of a Network Operation Center is part of the SOC Modernization project.

Q. Can you elaborate on the Company's benchmarking efforts for SOC Modernization?

A. Benchmarking and/or site visits were conducted with Public Service Electric & Gas (New Jersey), Southern Company (Alabama, Georgia, Florida, and Mississippi), FirstEnergy (Ohio and Pennsylvania), Pacific Gas & Electric (California), PPL Electric Utilities (Pennsylvania), CenterPoint Energy (Texas), Eversource (Massachusetts and Connecticut), We Energies (Michigan and Wisconsin), and Consolidated Edison (New York). This work demonstrated to the Company that its SOC facilities significantly lag the industry.

Q. Is a backup facility needed for the SOC?

A. Yes. Given the critical nature of the SOC in operating the electric infrastructure, a back-

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up facility is required in the event the primary facility is inoperable. The existing backup facility is inadequate for sustained operations and for disaster recovery efforts. Though it does meet the minimal regulatory requirements for NERC regulated Balancing Authority and Generator Operator tasks, managing the distribution system and recovering from a storm or other disaster from the existing backup SOC would be extraordinarily challenging and lead to very slow restoration of the distribution system. The new backup (or alternate) SOC will have the appropriate mechanical and electrical system redundancy and be outfitted with the technology needed to monitor and operate the electric grid. The new alternate SOC will be built close to the existing backup facility to maximize the use of available land and infrastructure. The alternate SOC will be located approximately 25 miles away from the primary facility and will allow the Company to safely operate the grid in the case of a major adverse event at the primary SOC. Having both a primary and an alternate location from which to operate the grid is a NERC requirement to be able to operate the electrical system and to safely and quickly recover from a catastrophic event.

Q. How will customers benefit from this project?

A. Customers will benefit from reduced risk in the event of a catastrophe and from faster restoration times, particularly during storms. The ability to understand system conditions and dispatch resources to address issues will be greatly enhanced by the technology available in the new facilities and the co-location of system operators and dispatchers. The new SOC and backup SOC will also be far more resilient and hardened to adverse natural and man-made disasters, allowing electric grid operations to recover much more quickly in the case of a major catastrophe, like the ones that have been observed in other states in recent years.

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Q. What progress has been made on the SOC Modernization project?

A. The site selection for both the primary and backup SOC has been completed. A contract for the detailed design of the primary SOC was issued in March 2018. Design of the primary SOC is targeted for completion in August 2018 when the design for the alternate SOC is scheduled to begin. The design team will issue construction work packages with a target construction start in the early fall of 2018. A contractor was selected to perform pre-construction services to support constructability review, estimating, and work package coordination. The primary SOC is scheduled for construction to be completed and occupancy to begin in December 2019. The alternate SOC facility is scheduled to be completed in December 2020.

Part IV: Forecasting Methodology

Capital

Q. How did the Company forecast capital expenditures for this case?

A. The Company used the following approach:

For Base Capital:

- Emergent Reactive: Used the five-year average through the end of 2017 and reduced projected costs based on the benefits of the Strategic programs.
- Customer Connections, Relocations, and Other: Used 2017 actuals or known 2018 expenditures.

For Strategic Capital:

- Utilized the Five-Year Plan, with adjustments to a small number of projects based on known project schedule and cost changes that have occurred since the submission of the plan on January 31, 2018.

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Q. Did the Company normalize emergent reactive capital in this case?

A. Yes. The Company normalized emergent reactive capital based on the five-year average, using a methodology that is consistent with what is used for storm and non-storm O&M restoration costs. This is presented in Exhibit A-12, Schedule B5.4, page 3.

Q. Did the Company forecast reactive capital savings?

A. Yes. The Company developed a model that estimates the number of failures per year in several asset classes (e.g. system cable, breakers) as well as the number of trouble / storm events driven by trees and other factors. This model was used to estimate the reactive capital saved per year based on the Five-Year Plan. Savings from the model were applied to Emergent Replacements in Exhibit A-12, Schedule B5.4, Page 1, line 6.

Q. Is the reduction in reactive capital from the five-year average dependent on the strategic spending?

A. Yes. If the Strategic Capital programs and other work described in the Five-Year Plan are implemented, then the Company expects that reactive capital will be lower than the five-year average. These reductions are expected from lower equipment failure rates that will result from the Strategic Capital spending included in the Five-Year Plan and this case. The Company has included a reduction in capital in the test period of approximately $10 million for the projected test year.

Q. What was the Company's basis for forecasting Customer Connections, Relocations, and Other?

A. Customer Connections and Relocations are completed at the request of customers or by other external parties, such as the Michigan Department of Transportation. The

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Company used 2017 actual spending for small projects (less than $350,000) and Customer Connections (services and line extensions). Volumes, project mix, and costs are projected at the same spend levels experienced in 2017 with adjustments for inflation. These are conservative estimates considering that the trend in this spending has been higher than inflation, as shown in Figures 11 and 12.

Figure 11: Volume of New Services and Line Extensions

(Quantity)

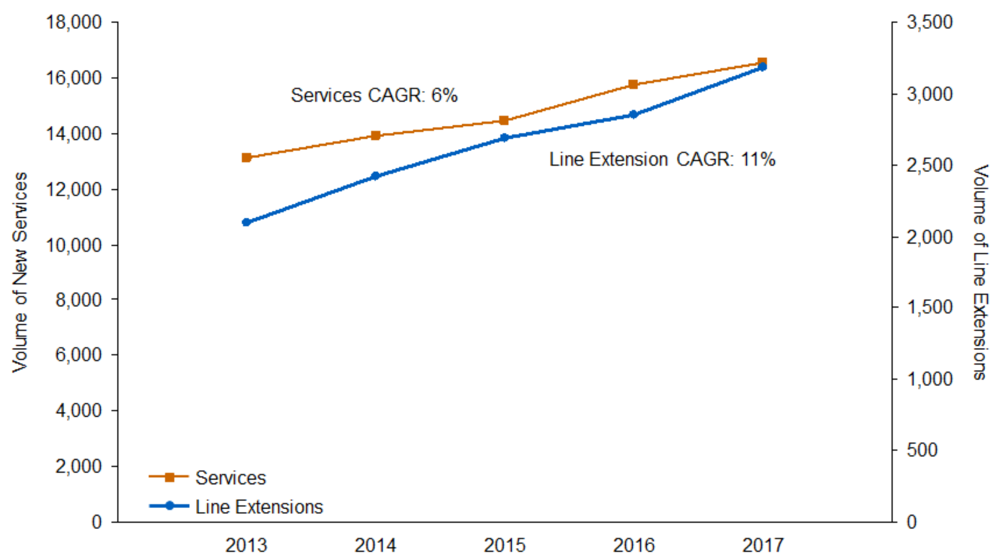
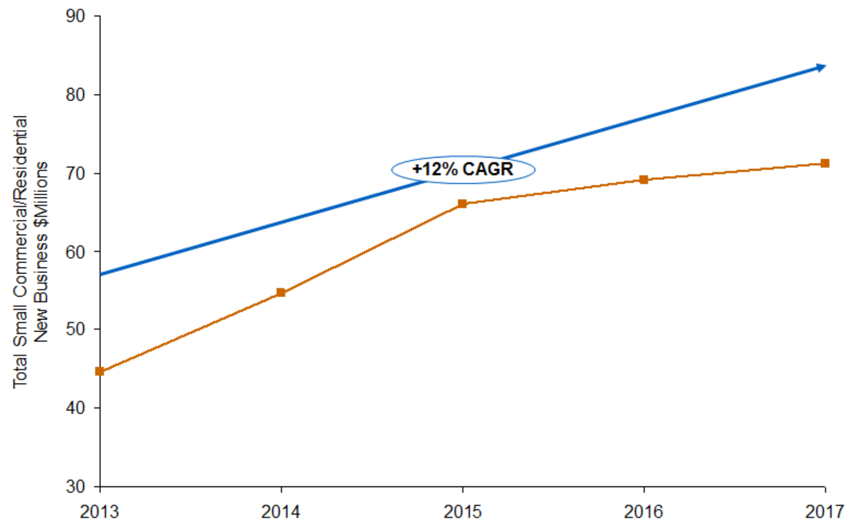
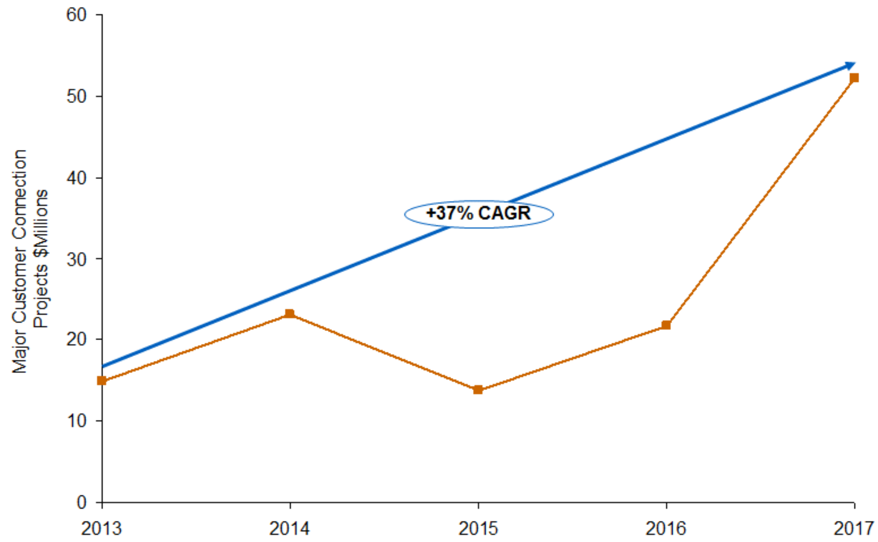


Figure 12: Total Small Commercial/Residential New Business ($ Millions)



New Business projects (projects greater than $350,000) are projected based on currently known projects for 2018 with adjustments for inflation in 2019 and beyond. The trend in this category of spending has been much higher than the rate of inflation, as shown in Figure 13. Because of the nature of these large New Business projects, visibility into specific project names is limited until a few months before a new major customer needs electric service. There is an extremely high likelihood that these expenditures will occur given the conservative projection of future New Business projects which was developed utilizing inflation to arrive at the calculation of Expected New Business shown on line 43 of Exhibit A-12, Schedule B5.4, page 4.

Figure 13: New Business Projects



For Small Relocation projects, inflation was applied to actual expenditures through 2017, as shown on Exhibit A-12, Schedule B5.4, page 5, line 52.

Larger Relocation Projects (excluding the Gordie Howe International Bridge project) were also forecasted conservatively, applying inflation to 2018 Relocation Projects to determine Expected Relocation Projects, which is shown on line 67 of Exhibit A-12, Schedule B5.4, page 5. This forecasting methodology is appropriate given the significant redevelopment activity that is occurring in the Company's service territory.

Electric System Equipment, Normal Retirement Unit Changeouts (NRUC) and General Plant, Tools and Equipment are projected utilizing 2017 actuals adjusted for inflation.

Q. How did the Company forecast Strategic Capital?

A. The Company's forecast for Strategic Capital was based on the analysis contained in the

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Five-Year plan, with some adjustments to a small number of projects based on more recent information. For example, significant work has occurred on the ADMS project in the months since the Five-Year Plan was submitted. This testimony reflects the updated projections for that project. The overall level of Strategic Capital is based on the investments that are needed to maintain and upgrade the system to meet the highest priorities, balanced with the ability to effectively manage the project portfolio as strategic investments are ramped up over time.

O&M

Q. How did the Company forecast O&M expenses?

A. The Company used 2017 actual spending by FERC account and adjusted each account to remove expenses associated with the Company's support for former PLD customers, which are addressed in separate rate proceedings, and normalized the spending for restoration variation due to weather fluctuations and a one-time expense associated with the ADMS project. With those adjusted amounts, the Company applied inflation and adjusted the expenses for additional streetlighting work, which is supported by Company Witness Johnston, and tree trimming work, which is supported by Company Witness Rivard.

Q. How did the Company normalize O&M expenses in this case?

A. The restoration expenses for 2017 were less than the five-year average, so the Company adjusted these expenses to the five-year average, consistent with the method that has been used in past rate filings.

Q. What is the significance of the 2017 O&M restoration costs being lower than the

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five-year average?

A. DTE Electric and the MPSC have agreed in numerous rate cases to forecast restoration costs based on the five-year average, adjusted for projected inflation. In the following cases, adjustments were made based on the five-year restoration cost average:

U-18255 (order April 18, 2018):	$27 million increase in O&M
U-18014 (order January 31, 2017):	$16 million reduction in O&M
U-17767 (order December 11, 2015):	$12 million reduction in O&M
U-16472 (order October 20, 2011):	$14 million increase in O&M
U-15768 (order January 11, 2010):	$16 million reduction in O&M
U-15244 (order December 23, 2008):	$24 million increase in O&M forecast - final order established annual reconciliation method

In this case, forecasting to the five-year average results in increasing the restoration costs in the projected test year by approximately $7.4 million, as shown in Exhibit A-13, Schedule C5.6, page 2, line 24.

Q. Will the implementation of the Strategic programs described in the Five-Year Plan have a positive impact on O&M costs?

A. Yes. Investments in tree trimming and in the Strategic Capital programs will reduce the number of outage and non-outage events from what they otherwise would have been, leading to a positive impact on O&M costs. However, this improvement is not expected to lead to a reduction in the absolute level of O&M. Normal inflation will place upward pressure on O&M costs; also, the level and pace of strategic investments will help to slow the negative impacts of system degradation, but will not reverse it in the 2018-2022 timeframe. Only a sustained period of higher investment (10+ years), and a greater level

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of tree trimming, as noted by Company Witness Rivard, will reverse the impact of continued system degradation.

<u>Part V: Capital Exhibits Description</u>

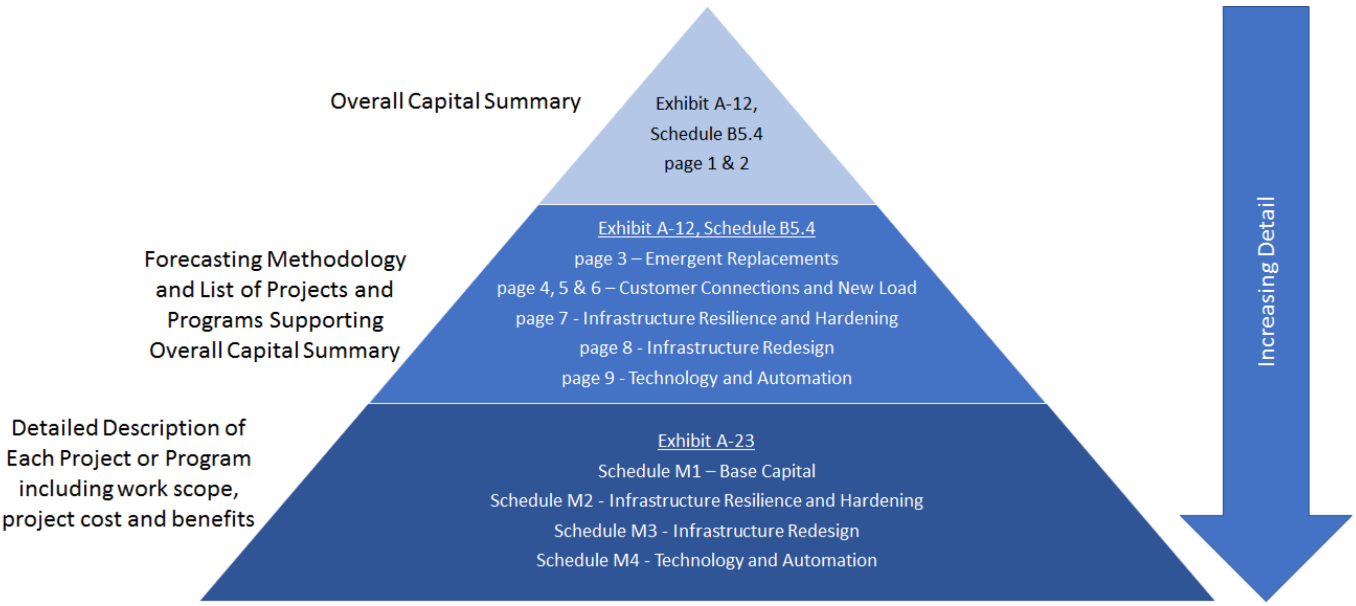
Q. What does Exhibit A-12, Schedule B5.4, "Projected Capital Expenditures – Distribution Plant" show?

A. Exhibit A-12, Schedule B5.4 depicts the actual capital expenditures for the 12-month period ending December 2017 and the forecasted capital expenditures for January 2018 through December 31, 2020. The capital expenditures are broken out into various categories, which are each explained below.

Q. Can you briefly describe how the Company is supporting its needed capital?

A. Yes. The Company provides a high-level overview of overall needed capital on pages 1 and 2 of Exhibit A-12, Schedule B5.4. Pages 3 to 9 of Exhibit A-12, Schedule B5.4 provides additional support including forecasting methodology and project lists. The most detailed support is provided in Exhibit A-23, where the Company provides detailed descriptions of each project or program listed in Exhibit A-12, pages 3 to 9. Figure 14 illustrates the increasing levels of detailed support the Company has provided for its needed capital.

Figure 14: Distribution Plant Capital Expenditures Support



<u>Exhibit A-12, Schedule B5 .4, page 1 and 2</u>

Q. What is provided in each of the columns Exhibit A-12, Schedule B5.4, page 1?

A. Column (a) includes a brief description of the expenditures included on the line, and column (b) includes the historical (2017) actual spending for each category. Between columns (a) and (b) is a list of footnotes that reference additional details for the spending and forecasting methodologies. Columns (c) to (e) include forecasts for each line item for 2018, 4-month period ending April 30, 2019 and 16-month period ending April 30, 2019, respectively, while column (f) includes forecasts for the 12-month period ending April 30, 2020 test year.

Q. What is provided in each of the columns Exhibit A-12, Schedule B5.4, page 2?

A. Page 2 provides increased detail to what is provided on page 1 by showing the normalization adjustment used to reconcile the historical 12 months ending December

31, 2017 to the projected calendar years of 2018, 2019 and 2020. Page 2 is structured in much the same way as page 1 with the following exceptions: columns (c) and (d) include adjustments to normalize emergent replacement capital to the five-year average and columns (e) to (g) provide forecasted spending for the 2018, 2019 and 2020 respectively. Page 2 provides the full-year forecasts that is most closely aligned to the Five-Year Plan and is the basis for the partial year forecasts provided on page 1.

Q. What is included in Base Capital Programs, lines 1 to 16 and Strategic Capital Programs, lines 17 to 21?

A. Base Capital Programs include spending to replace equipment as failures occur; the capital to respond to customer requests; and funding for equipment and tools required for the electrical system. Strategic Capital Programs include the funding for the programs described in the Five-Year Plan that are designed to reduce risk, improve reliability, and manage cost for DTE Electric's customers.

Q. Can you describe Emergent Replacements, lines 2 to 7, in more detail?

A. These costs are to perform emergency replacement work for retirement unit items on the overhead and underground subtransmission and distribution systems and in substations. Capital expenditures for the restoration associated with storms is included in line 3 and similar expenditures for non-storm restoration is included in line 4. In 2017, DTE Electric replaced approximately 3.6 million feet of wire and cable and 5,400 poles. Line 5 includes the expenditures to replace substation equipment that has failed. Line 6 is the forecasted reduction in emergent replacement spending that is projected to result from the Strategic Capital programs included on lines 17 to 21. Line 7 provides the total of lines 3 to 6. Page 3 of Exhibit A-12, Schedule B5.4 provides additional details on the historical spending and forecasting methodology for Emergent Replacements.

Q. Can you describe Customer Connections, Relocations & Other, lines 8 to 14 of page 1 of Exhibit A-12, Schedule B5.4, in more detail?

A. Each of the five categories of capital included in this area is described below:

- Connections and New Load, line 9: The capital to respond to customer requests for new service, which includes simple service connections, line extensions for commercial businesses or housing developments, and industrial substations for manufacturing facilities.
- Relocations, line 10: The capital to accommodate requests to relocate existing facilities. Examples include the Gordie Howe bridge project, road widening requests from the Michigan Department of Transportation, and customer property expansions.
- Electric System Equipment, line 11: The expenditures for meters, distribution transformers, large transformers and other equipment required for emergent replacements.
- NRUC and Improvement "Blankets" (small projects), line 12: Normal Retirement Unit Changeouts (NRUC) include projects to perform scheduled work for replacement of equipment on the subtransmission and distribution systems such as the replacement of pole top hardware determined to be at end-of-life. Small project "blankets" include installing, replacing or removing fuses and automatic sectionalizing equipment, installing disconnect switches, and removing electrical facilities no longer in use. Improvement blanket projects are focused on improving operating conditions to reduce the frequency and duration of outage cases. These "blankets" are established to provide funding for system strengthening projects that do not exceed $350,000.

Line No.

- General Plant, Tools & Equipment and Miscellaneous, line 13: The capital expenditures for tools and test equipment required to support field resources.

Q. What is included in line 15?

A. Customer Advances for Construction (Contribution in Aid of Construction or CIAC), includes the recovery of capital investments from the customer when the cost for the customer's requested method of service exceeds typical service requirements. It also includes recovery for work performed at the request of others. Line 15 offsets some of the expenditures represented in lines 9 and 10.

Q. Has the Company provided additional detail to support lines 1 to 16?

A. Yes. Pages 3 to 6 of Exhibit A-12, Schedule B5.4 and Exhibit A-23, Schedule M1 provide additional details on the historical spending and forecasting methodology for this category of distribution capital.

Q. Can you describe Strategic Capital Programs, lines 17 to 21, in more detail?

A. These are the programs that are the focus of the Five-Year Plan. Each of the major programs has been described in detail earlier in this testimony. Line 18 includes the funding to support Infrastructure Resilience & Hardening programs and projects; line 19 includes Infrastructure Redesign programs and projects; and line 20 supports Technology & Automation programs and projects. Pages 7 to 9 of Exhibit A-12, Schedule B5.4 provide additional details on the historical and forecasted spending for each set of programs supporting Strategic Capital programs with page 7 supporting Infrastructure Resilience & Hardening, page 8 supporting Infrastructure Redesign, and page 9 supporting Technology & Automation.

Q. What is included on line 24 of Exhibit A-12, Schedule B5.4, pages 1 and 2?

A. The regulatory asset funding associated with the ADMS work is included on this line. It is associated with the process development work, software maintenance fees while the systems are under development, and training that requires employees to work time outside of their normal work hours. Company Witness Uzenski supports the accounting treatment for this work.

<u>Exhibit A-12, Schedule B5.4, pages 3 to 9</u>

Q. Can you elaborate on page 3 of Exhibit A-12, Schedule B5.4?

A. Page 3 provides the details supporting the Company's forecast for the capital needed to replace overhead and underground equipment that has failed in storm and non-storm events as well as the expenditures to replace failed substation equipment. The forecast is based on the five-year average of these expenditures, which is carried to pages 1 and 2 of Exhibit A-12, Schedule B5.4 where an adjustment is made to reduce the forecast from the five-year average in consideration of the Strategic Capital spending that the Company is proposing.

Lines 3 to 11 support storm, lines 12 to 18 support non-storm, and lines 19 to 25 support substation emergent replacements. Line 4 includes an adjustment to 2013 storm spending due to an adjustment in capitalization policy that was originally described by the Company in MPSC Case U-17767. Line 5 sums lines 3 and 4, and line 6 includes an inflation adjustment to bring the historical values to their 2017 equivalents. Line 7 sums lines 5 and 6. Lines 8, 9 and 10 provide inflation adjustments to the five-year average and historical test year included in columns (h) and (i) respectively. The result of this adjustment is to bring the values to their equivalents in the 12-month period ending April

30, 2020. Lines 12 to 18 and 19 to 25 follow an identical method to the method that was used for lines 3 to 11 except for the adjustment for the capitalization change, which did not impact this spending.

Column (a) provides a brief description of what is included on the line, column (b) to (f) include the historical expenditures for each category of equipment replacement, column (g) average the five years of expenditures. Column (h) provides the forecasted spending for the test year, which is based on the five-year average and adjusted for inflation. Column (i) provides the capital expenditures included in the historical year and column (j) provides the adjustments needed to the historical test year to normalize the amount to the five-year average.

Q. Can you elaborate on the capitalization policy change that required the adjustment included on line 4?

A. Line 4 includes an adjustment for the capitalization of storm costs that had previously been expensed. These costs are associated with the evaluation of circuits prior to field crew arrival, dispatching field crews, and other activities, which was described in detail and accepted in previous rate proceedings.

Q. Can you elaborate on pages 4 to 6 of Exhibit A-12, Schedule B5.4?

A. Pages 4 to 6 of Exhibit A-12, Schedule B5.4 includes details to support lines 8 to 15 of pages 1 and 2 of Exhibit A-12, Schedule B5.4.

Regarding pages 4 and 5 of Exhibit A-12, Schedule B5.4, column (a) includes a brief description of the project, program or blanket category included on the remainder of the line. Column (b) provides the historical 2017 spending, columns (c), (d) and (e) provide the forecasted spending for 2018, 2019 and 2020 respectively. Column (f) provides the forecast for the 16-month period ending April 30, 2019, and column (g) provides the forecast for the test year (12 months ending April 30, 2020).

Page 6 of Exhibit A-12, Schedule B5.4 provides a list of specific new business projects completed in 2017 and supports line 42 on page 4. These projects are listed on a separate page from page 4 to make page 4 more readable but still include the historical detail about specific new business projects.

Q. Can you describe the forecasting methodology for pages 4 and 5 of Exhibit A-12, Schedule B5.4?

A. Table 21 describes the forecasting methodology for each item:

Table 21: Forecasting Methodology

Page and Line(s) from Exhibit A-12, Schedule B5.4		Forecasting Category	Forecasting Method
Page	Line(s)		
4	2	Small Load Growth Projects (Blanket)	2017 actuals plus inflation
4	4 to 6	Customer Connections	2017 actuals plus inflation
4	8 to 46	New Business Projects	2018: Engineering estimates for actual projects requested by customers as of April 2018. This is a conservative estimate considering that additional customer requests are expected during the remainder of 2018. 2019 and 2020: Line 44 and 45 provide the total new business and CIAC calculated by adding inflation to the 2018 values. Lines 9 to 41 provide the forecasts for spending for current customer requests. Line 43 provides the forecasted additional projects expected and is calculated by subtracting the project values for the year from the total new business, provided on line 44. This methodology is appropriate because New Business Projects have a very high likelihood of occurring, but are often identified only a few months before they are needed. Line 46 is calculated as line 44 plus line 45.
4	48 to 50	Total Connections and New Load	Line 48: Line 4 plus line 44 Line 49: Line 5 plus line 45 Line 50: Line 48 plus line 49
5	52	Small Relocations Projects (Blanket)	2017 actuals plus inflation
5	55	Gordie Howe International Bridge	Engineering estimates for the project net of the contributions from MDOT

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Page and Line(s) from Exhibit A-12, Schedule B5.4		Forecasting Category	Forecasting Method
Page	**Line(s)**		
5	57 to 70	Relocations Projects (excluding Major Infrastructure Projects)	2018: Engineering estimates for actual projects requested by customers as of April 2018. This is a conservative estimate considering that additional customer requests are expected during the remainder of 2018. 2019 and 2020: Line 68 and 69 provide the total relocations and CIAC calculated by adding inflation to the 2018 values. Lines 58 to 65 provide the forecasts for spending for current customer requests. Line 67 provides the forecasted additional projects expected and is calculated by subtracting the project values for the year from the total new business, provided on line 68. This methodology is appropriate because large Relocation projects have a very high likelihood of occurring, but are often identified only a few months before they are needed. Line 70 is calculated as line 68 plus line 69.
5	72 to 74	Total Relocations	Line 72: Sum of lines 52, 55 and 68 Line 73: Same as line 69 Line 74: Line 72 plus line 73
5	76 to 80	Electric System Equipment	Lines 77 to 79: 2017 actuals plus inflation Line 80: Sum of lines 77 to 79
5	82 to 88	NRUC and Improvement Blankets	Lines 83 to 87: 2017 actuals plus inflation Line 88: Sum of lines 83 to 87
5	90	General Plant, Tools & Equipment and Miscellaneous	2017 actuals plus inflation

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Page and Line(s) from Exhibit A-12, Schedule B5.4		Forecasting Category	Forecasting Method
Page	Line(s)		
5	92 to 94	Total Customer Connections, Relocations & Other	Line 92: Sum of lines 48, 72, 80, 88 and 90 Line 93: Line 49 plus line 73 Line 94: Line 92 plus line 93

Q. Can you elaborate on page 7 to 9 of Exhibit A-12, Schedule B.5.4?

A. Each page provides the projected spend profile for the projects and programs described in this testimony, with the following structure:

Page 7 - Infrastructure Resilience & Hardening

Page 8 - Infrastructure Redesign

Page 9 - Technology & Automation

Each page provides the project or program title in column (a) and the historical spend in column (b). The projected spending for 2018, 2019 and 2020 are in columns (c), (d) and (e) and columns (f) and (g) provide the forecasts for the 16-month period ending April 30, 2019 and the test year respectively. The projections are based on specific engineering estimates and the analysis provided in the Five-Year Plan.

Exhibit A-12, Schedule B5.4, page 10

Q. Do the capital expenditures you are supporting include an Allowance for Funds Used During Construction (AFUDC)?

A. Yes. Capital expenditures include an Allowance for Funds Used During Construction (AFUDC) for eligible projects that are in Construction Work in Progress (CWIP).

AFUDC is applied to projects greater than $50,000 and lasting more than six months. The calculation is based on the average balance of eligible projects in CWIP multiplied by the authorized cost of capital per the rate order in effect during that period.

Q. How much AFUDC is assumed in the projected test period for Distribution Operations related projects?

A. AFUDC for DO projects is included on Exhibit A-12, Schedule B5.4, page 10. The total DO related AFUDC is projected to be $16.8 million for the 12-month period ending April 30, 2020. The authorized cost of capital rate used was 5.34% per the U-18255 rate order.

<u>Exhibit A-23</u>

Q. Has the Company provided more detail to support its needed capital than what is provided in Exhibit A-12, Schedule B5.4?

A. Yes. Exhibit A-23 provides much greater detail for the projects and programs in Exhibit A-12, Schedule B5.4, which represents 100% of the Company total forecasted capital.

Q. How is Exhibit A-23 organized?

A. Exhibit A-23 is made up of five schedules as follows:

M1 Base Capital
M2 Infrastructure Resilience & Hardening
M3 Infrastructure Redesign
M4 Technology & Automation
M5 DO Five-Year Investment and Maintenance Plan

Each schedule in M1-M4 has one to several pages dedicated to each of the projects and

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programs that make up the category of spend. M5 represents the Five-Year Plan which was filed on January 31, 2018.

Q. What is included in the capital summaries that make up Exhibit A-23?

A. Each document, which can be one to several pages, includes the following:

- Program: As described in Exhibit A-12, Schedule B5.4, pages 4 to 9, column (a).
- Purpose and Necessity: A description of the driving forces for the work.
- Category: The pillar of Strategic Capital spending from the Five-Year Plan.
- Line Number: A reference to the page and line numbers supported.
- Scope: The scope of work.
- Customer benefits / Effect on cost of operation and reliability: How the Company's customers benefit from the program and a description of the how the project or program is expected to impact operations and reliability.
- Impact Dimensions: The dimensions from the GPM described in Table 6 that the project or program will impact.
- Current Projects: Current projects underway that support the described program.
- Budget Basis: A description of the how the funding was determined for the project or program.
- Cost: The expected cost of the program over a specific timeframe.
- Test Year: The expected cost of the program for the test year including a breakdown of the costs by labor, material and other costs.

Q. What is your opinion regarding the actual and projected expenditures shown in Exhibit A-12, Schedule B5.4?

A. These expenditures are reasonable and prudent. I base my opinion on the extensive analysis that was done for the Five-Year Plan, on my examination of past expenditures, on the projected requirements for labor and material needed the safe and reliable distribution of electric power, and on the investments that are needed to maintain and improve service to DTE Electric's customers.

Part VI: O&M Exhibit Description

Summary

Q. What does Exhibit A-13, Schedule C5.6, "Projected Operation and Maintenance Expenses – Distribution Expenses" show?

A. The expenses are shown for DO and additionally for street lighting for which Company Witness Mr. Johnston will provide testimony. DO's tree trimming expenses are supported by Company Witness Ms. Rivard, and I am supporting all other DO expenses. This schedule primarily reflects the operations and maintenance costs for Distribution Operations. The operations and maintenance costs are for tree trim, restoration, maintenance, and other associated costs for both the distribution and subtransmission systems and substations. Distribution Operations' O&M expenses are primarily driven by day-to-day trouble and storm restoration, tree trim work, and system maintenance requirements.

Details

Q. Can you provide a brief explanation of the items listed under Distribution Expenses in Exhibit A-13, Schedule C5.6?

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A. The costs associated with dispatching and coordinating restoration and tree trim efforts are included in accounts 580 (Operation Supervision and Engineering) and 581 (Load Dispatching). Accounts 582 (Station Expenses), 583 (Overhead Line Expenses), 584 (Underground Line Expenses), and 588 (Miscellaneous Expenses) incorporate the costs for developing and implementing training and work force planning for the Company's substation operators and maintenance personnel, apprentice lineman, splicers, technicians, engineers, riggers and planners as well as the staff groups to support these critical efforts. Job skills training is conducted for the safety of employees and the public. Witness Johnston supports account 585 (Street Lighting and Signal System Expense). Meter testing and distribution costs are incorporated into account 586 (Meter Expenses). Account 587 (Customer Installations Expenses) includes expenses to support the specific needs of customers served at primary voltages. Account 589 (Rents) reflects the expenses associated with leased facilities and DTE Electric attaching to poles not owned by the Company.

Q. What do the items listed under Maintenance in Exhibit A-13, Schedule C5.6 show?

A. The O&M portion of the Company's tree trim program, which is supported by Company Witness Heather Rivard, and maintenance expenses are included in this area. These costs are critical to providing safe and reliable service. Account 591 (Maintenance of Structures) is to support the maintenance of existing physical structures associated with the electric distribution system. Restoration, troubleshooting and reactive maintenance work associated with substation, overhead and underground equipment is also included in accounts 592 (Maintenance of Station Equipment), 593 (Maintenance of Overhead Lines), and 594 (Maintenance of Underground Lines) respectively. The supervision and other support costs for these important efforts are included in account 590 (Maintenance

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Supervision and Engineering). Witness Johnston supports account 596 (Maintenance of Street Lighting and Signal Systems).

Q. How are the 2017 historical O&M and the forecasted test period O&M expenses for DO shown on Exhibit A-13, Schedule C5.6?

A. Exhibit A-13, Schedule C5.6, page 1, summarizes the 12-month period ended December 31, 2017 actual O&M expense and the projected O&M expense for May 1, 2019 through April 30, 2020. Line 26, column (c) provides the total actual unadjusted O&M expenses for the 12-month historical test period ended December 2017.

Q. What are the adjustments in columns (d) and (e) of Exhibit A-13, Schedule C5.6, page 1?

A. The adjustments in column (d) reduce the total historical test year O&M expenses by the amounts related to the Transitional Reconciliation Mechanism (TRM) costs, which is included in accounts 566 and 588. As described by Witness Uzenski, the expenditures that the Company incurs for converting the City of Detroit's PLD distribution system to DTE Electric's distribution system, and the expenses to operate the PLD system during the transitional period are reconciled annually in a separate mechanism and excluded from this case.

The adjustment in column (e) on line 19 is to normalize restoration expenses. The adjustment in column (e) on line 15 is for an expense associated with the ADMS project that occurred in 2017 but is not expected to occur in the test period. The total results of columns (d) and (e) are added with column (c) to produce column (f).

Q. Can you elaborate on the adjustment in column (e) on line 15?

A. Yes. There was an expense associated with the EMS portion of the ADMS project in 2017 that is not expected after 2017. The expense was to complete the final scheduled upgrade of the previous EMS technology before the transition to the new EMS technology.

Q. How did the Company calculate restoration O&M expense for the projected periods?

A. As shown on Exhibit A-13, Schedule C5.6, page 2, the Company supports normalizing restoration expenses from $144.4 million, which is included in the historical test period with inflation applied, to $151.8 million. A five-year average method was used to normalize restoration expenses and is consistent with the methodology used in the Company's previous rate cases. This method addresses the variability in these expenses.

Q. What does Exhibit A-13, Schedule C5.6, page 2, "Restoration Expenses" show?

A. This page shows the details of the calculation to adjust restoration O&M expenses to the five-year average previously discussed. Line 2 shows the actual expenses from 2013 to 2017 associated with restoration related to storm conditions. Line 11 presents the actual expenses associated with non-storm restoration. Line 3 includes an adjustment for the capitalization of storm costs that had previously been expensed, which was described earlier in the description of Exhibit A-12, Schedule B5.4. Lines 4 and 12 include inflation adjustments for the historical expenses, and these adjustments are included on lines 5 and 13 for storm and non-storm costs respectively. The expenses for the 2013 to 2017 period are averaged in column (g) and inflation is applied to those amounts to determine the values in column (h). Column (i) shows the expenses included in the historical test period

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adjusted for inflation. Column (j) shows the difference between columns (h) and (i). Lines 18 to 24 summarize the calculations and shows on line 24 the $151.8 million five-year average (column (h)), the $144.4 million (column (i)) included in the historical test period and the difference of $7.4 million (column (j)), which is the adjustment needed in the test period for restoration costs in this case. The pre-inflation adjustment of $6.9 million included in column (j), line 19 is carried to page 1 of Exhibit A-13, Schedule C5.6 in column (e).

Q. How was the projected O&M expense amount in column (k) of Exhibit A-13, Schedule C5.6, page 1 derived?

A. The 12-month historical test year period ended December 31, 2017 adjusted expenses from column (f) were adjusted by inflation and other adjustments to derive projected O&M of $330.5 million column (l).

Q. What are the inflation adjustments in columns (g), (h) and (i) on Exhibit A-13, Schedule C5.6, page 1?

A. The labor and material inflation adjustment factors for 2018, 2019 and 2020, which are supported by Witness Uzenski, are applied to the 2017 adjusted values from column (f) to determine the values presented in columns (g), (h) and (i).

Q. What are the Other adjustments in column (j) on Exhibit A-13, Schedule C5.6, page 1?

A. These are known and measurable adjustments for a $4.9 million increase in tree trim, which is supported by Company Witness Heather Rivard and $309 thousand for LED Washing, which is supported by Company Witness Johnston.

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Q. What is your opinion regarding the actual and projected expenses shown in Exhibit A-13, Schedule C5.6?

A. These expenses are reasonable and prudent. I base my opinion on analysis of past expenses, projected requirements for labor and material for the safe and reliable distribution of electric power, and expectations and plans for maintaining and improving customer service.

Part VII: Risks

Q. What are the major risks to the projected costs included in your testimony and exhibits?

A. There are four major risks to the forecasts included in the testimony and exhibits that I am sponsoring: weather volatility, changes in new business and relocations requests, the continued impact of aging infrastructure, and the availability and cost of resources needed to execute the Five-Year Plan. Significant changes in any of these categories could drive spending and resource allocation in a direction that deviates from the projections contained in this case. At the same time, the Company takes proactive measures to manage these risks in a way that minimizes the likelihood that unforeseen events will cause the Company to deviate from the plan

Q. What are the risks associated with weather volatility?

A. The Company and the MPSC are aware of the impact that weather can have on expenditures and the deployment of resources as evidenced by the expenditure profiles for emergent capital and O&M over the past five years. To manage this risk, the Company plans for weather that is in line with historical averages so that a base level of resources is available plus the Company can pull additional resources from other utilities

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when needed. At the same time, an unprecedented storm such as the one on March 8, 2017 could impact the Company's ability to fully execute its Strategic Capital program.

Q. What risks are associated with new business and relocation requests?

A. The Company must respond to these requests in a timely manner to support customers and economic growth in southeastern Michigan. If there is an unexpected surge in development activities, (for example, as brought on by the Gordie Howe International Bridge project), the Company may have to reallocate resources, potentially impacting some of its planned Strategic Capital investments. However, the Company plans for these situations and can ramp up resources from other sources to minimize the impact on Strategic Capital programs.

Q. How can aging infrastructure introduce risk into the Company's forecasts?

A. The Company has been experiencing an acceleration in the quantity of equipment failures. There is a risk that equipment conditions may have reached an inflection point, and that significantly higher levels of reactive O&M and capital expenditures will be needed to respond to this situation. This increase in reactive expenditures would divert resources away from executing the strategic plan and absorb capital that would have otherwise been spent on proactive replacements of aging equipment and other system improvements. While in the Five-Year Plan the Company has laid out a strategy to replace aging, at risk equipment, it is challenging to predict exactly which equipment will fail and when.

Line No.

Q. Does DTE Electric have the resources to complete the Five-Year Plan?

A. Yes. The Company has or will acquire the resources needed to execute the Five-Year Plan. With the industry need for trained electrical workers growing across the country, the ability to staff the work described in the Five-Year plan is challenging. However, the Company has been taking proactive measures to support the execution of the plan. The Company has significantly increased its capacity to complete capital work since late 2016 and is continuing to grow capacity in the key resource categories required to complete the Five-Year Plan, which are listed below:

- Overhead Construction
- Underground Construction
- Substation Construction
- Engineering and Design

Q. How many overhead linemen does the Company require to complete the Five-Year Plan?

A. DTE Electric estimates that it needs between 860 and 910 overhead linemen to execute the Five-Year Plan. Between November 2017 and April 2018, the Company made significant progress in this area by increasing the number of linemen from 709 to 801. The Company has leveraged three countermeasures to increase the overhead linemen available to support the Five-Year Plan. First, the Company is building its direct workforce through hiring. Second, the Company has been working with its existing contractors to grow their workforces through hiring and apprenticeships. Third, the Company has been engaging new contractors in this work.

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Q. How does the Company plan to close the remaining gap?

A. The Company will continue following the paths that have already shown success in making resources available to execute the Five-Year Plan. Additionally, the Company is bundling work and extending the duration of contractual agreements to encourage contractors to build their workforces. The Company is particularly focused on working with contractors to build their local workforces to both reduce costs and to support Michigan economic growth.

Q. How is the Company building the workforce for underground work?

A. Underground is following a very similar model to what has already been described for overhead. However, because this work was not contracted in the past, additional emphasis has been needed on qualification processes for the new contractors. Also, given the emphasis on cable replacement in the Five-Year Plan, the Company has developed relationships with local and national firms to complete this work starting with conceptual design, progressing through detailed design, and eventually to construction. These firms provide project management for the work from end-to-end, which creates accountability for its completion. Having multiple firms creates a competitive environment focused on on-time completion and cost effective execution. The Company increased system cable replacement in 2017 to approximately 52,000 feet from 4,000 feet in 2016, and URD replacement to over 300,000 feet in 2017 from approximately 50,000 feet in 2016. The Company plans to continue to leverage the successes from 2017 to build to the increasing volumes of underground work described in the Five-Year Plan.

Line No.

Q. How is the Company building the workforce for new substation construction work?

A. For substation work, the Company is focused on three areas: new substations, substation expansions and switchgear replacements. To implement these projects, the work for approximately a five-year period is being bundled to bid design and construction services. This approach will provide more certainty and a higher volume of work to the selected firms so that they can recruit and maintain a highly capable staff.

Q. What are the Company's resource plans to address engineering and design?

A. To address the increased need for engineering and design to support the Five-Year Plan, the Company is taking two tracks. First, the Company is optimizing the existing internal engineering resources to focus on completing conceptual design, developing robust construction and design standards, and building the capacity to check and monitor the work of third-party engineering firms. The Company is also adding to the engineering and design teams through both new and experienced hires. These internal resources have the main responsibility for defining the standards to be used when making investments in the distribution grid, defining the strategic priorities for which investments must be made and designing the electric grid in a way that will guarantee, safe, reliable operations.

Second, the Company is leveraging both local and national engineering firms. In this case, the Company does not project specific personnel needs but instead assigns work to these engineering firms based on their experience related to the specific work as well as both their cost effectiveness and schedule compliance. This creates a competitive environment in which the strongest firms thrive and allows these partners to manage their workforces. Because of these measures, the Company has experienced significant increases in output which is allowing design to be pulled forward to the year ahead of

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construction.

Part VIII: Infrastructure Recovery Mechanism

Q. Why is an Infrastructure Recovery Mechanism (IRM) being proposed for Distribution Operations capital expenditures?

A. As described by Company Witness Stanczak, DO is proposing that a portion of the Company's Base Capital and Strategic Capital be included in an IRM as a means of supporting critical infrastructure improvements that will benefit customers.

Q. How did you select the programs and projects to be included in the IRM?

A. I reviewed planned distribution capital investments for 2020-2022 as described in the Five-Year Plan and in this testimony. I then selected investments that are either required (Base Capital) or that have a very high degree of certainty around execution given their priority in terms of their ability to reduce risk, improve reliability, and manage costs. Expenditures in both Base Capital and Strategic Capital were identified as candidates to be included in the IRM.

Q. What Base Capital expenditures should be included in the IRM?

A. Capital for Emergent replacements as well as certain types of new business connections, relocations and equipment purchases should be included in the IRM.

Q. What Emergent capital replacements do you believe should be included in the IRM?

A. Emergent capital expenditures to be included in the IRM are:

- Emergent Replacements – Storm
- Emergent Replacements – Non-Storm

Line No.

- Emergent Replacements – Substation Reactive

These emergent capital replacements can be included in the IRM because these expenditures are required to restore service to customers and return equipment to proper working condition.

Q. How did you determine the amount of Emergent capital expenditures to be included in the IRM?

A. Emergent capital expenditures can be highly variable from year to year. Because of this variability, the amount included in the IRM should be set at the lower end of likely expenditures to ensure the utility does not over recover throughout the period in which the IRM surcharge is in place. Therefore, DO is proposing that the lowest amount expended in any one of the past five full calendar years, adjusted for inflation, in each of the emergent replacement categories be included in the IRM, as there is a near certainty the Company will have to spend at least this level of Emergent capital given the continued aging of the electric distribution infrastructure. The details of this calculation are provided in Exhibit A-30, Schedule T2, page 2.

Q. Based on the reasoning provided above, what amount of capital related to emergent replacements do you believe should be included in the IRM?

A. The capital expenditures to be included in the IRM for emergent replacements are shown in Exhibit A-30, Schedule T2, page 1, lines 2-4.

Q. Are there other expenditures contained in Base Capital that should be included in the IRM?

Line No.

A. Yes. Other categories of spend that directly benefit customers and for which there is a high degree of confidence in the projected level of spend include customer connections, small load growth projects, relocations, and the purchase of electric system equipment.

Q. What amount of capital related to customer connections, small load growth projects, relocations, and the purchase of electric system equipment do you believe should be included in the IRM?

A. A conservative level of expenditures to be included in the IRM can be determined by looking at the average expenditures from 2013 to 2017. The capital expenditures to be included in the IRM related to Small Load Growth Projects, Customer Connections, Small Relocations and Electric System Equipment purchases are shown in Exhibit A-30, Schedule T2, page 1, line 5. The details supporting the calculation for this amount are shown on page 3 of the same exhibit.

Q. Why do you believe the amount proposed above is conservative?

A. As can be seen in Exhibit A-30, Schedule T2, page 3, spending in these categories has risen significantly over the past few years. When compared to 2013, expenditures in 2017 increased by 30% to more than 40% (after adjusting for inflation), depending on the specific category examined.

Q. What Strategic Capital projects and programs is the Company proposing to include in the IRM?

A. The Strategic Capital projects and programs shown in Table 22 are proposed for inclusion in the IRM. These projects and programs, which are part of the Five-Year Plan, are described in greater detail in Exhibit A-30, Schedule T2.1. For purposes of the IRM,

Line No.

they have been grouped into logical categories based largely on the types of resources needed to execute the programs.

Table 22: IRM Programs

Category	Programs
4.8kV Hardening	• 4.8kV Hardening
Overhead Programs	• Frequent Outage (CEMI, Circuit Renewal) • Subtransmission Hardening • System Resiliency – Efficient Frontier • Porcelain Fuse Cutout Replacement • Pole and Pole Top Hardware
Underground Programs	• System Cable Replacement • URD Cable Replacement • Network Secondary Cable Replacement
Breaker Program	• Breaker Replacement
City of Detroit Infrastructure (CODI) Upgrades	• Garfield • Charlotte • Kent / Gibson • Howard • Amsterdam
Substation Programs	• System Loading (3 projects) • Substation Risk Reduction (3 projects) • 8.3kV Pontiac Overhead Conversion • 4.8kV Conversion (7 projects) • Gramer substation and Tie 810 hardening
ADMS / SOC	• ADMS (OMS/DMS) • SOC

Q. Can you provide additional details related to the Strategic Capital programs and projects you believe should be included in the IRM?

A. The programs and projects included in the IRM are described in greater detail in Exhibit A-30, Schedule T2.1.

Q. Will additional information regarding projects and programs proposed for the IRM be available prior to the projects being executed?

A. Yes. As detailed engineering, design and procurement activities are completed for the various programs and projects, the Company will provide the following information:

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- Detailed scope, including planned units of work. For example, location and feet of system cable to be replaced, breakers to be replaced by substation, and CEMI circuits to be addressed.
- For new substations and substation upgrade projects needed for load relief and/or to meet customer load growth in specific pockets, the Company will provide load information for those areas and technical analysis justifying the need for the investment, such as Area Load Analysis.
- Cost information, and where applicable, unit costs to be used in the annual reconciliation process.
- Project schedules with key milestones as applicable.

Q. When will DO provide the more detailed information described above?

A. As described by Company Witness Stanczak, DO will provide this information in the fall annual plan review for the programs and projects to be executed the following year.

Q. Is there additional information around the scope of the projects and programs proposed for the IRM that can be provided at this time?

A. Yes. While detailed information will be provided in the year prior to execution, Exhibit A-30, Schedule T2.1 contains a description of the drivers, scope and customer benefits for the projects and programs. Table 23 below provides some additional, directional information on the scope of some of the programs.

Table 23: Directional 2020-2022 Scope

Category	Directional Scope
4.8kV Hardening	• Harden ~600 miles overhead circuit miles
Overhead Programs	• Harden / rebuild ~37 subtransmission circuit miles • Replace ~11,000 fuse cutouts • Details for programs such as CEMI and Circuit Renewal are highly situation dependent, as costs can range from $40K to $600K or more depending on the scope of the work
Underground Programs	• Replace ~930,000 feet of URD cable • Details for system cable replacement units are highly dependent on the specific circuits selected, as costs have ranged from $115K to $610K per 1,000 feet for this program depending on field conditions and other factors
Breaker Program	• Replace ~240 breakers
City of Detroit Infrastructure (CODI) Upgrades	• See Exhibit A-30, Schedule T2.1
Substation Programs	• See Exhibit A-30, Schedule T2.1
ADMS / SOC	• See Exhibit A-30, Schedule T2.1

Q. Is flexibility needed with respect to the timing of specific projects year within each IRM category?

A. Yes. While the Company has developed a clear prioritization of the projects and programs it intends to execute over the period covered by the IRM, there is inherent complexity and uncertainty that can impact the ability to execute them on a timeline or with a spending profile that is precisely consistent with the plan as defined in the initial stages of project development. For example, factors such as delays in obtaining easements and permits (as recently experienced in the Ann Arbor system improvement project), unplanned equipment failures or adverse weather can impact project schedules.

Q. How would the Company propose to manage the need for schedule flexibility within each IRM category?

Line No.

A. The Company is requesting the ability to switch the order of projects within each category of the IRM if operational or other circumstances necessitate it, as long as the projects are the same ones that are proposed as part of the IRM and consistent with the priorities identified in the Five-Year Plan. For example, a substation project originally planned for 2020 may encounter permit delays, so the Company would look for opportunities to pull forward a project planned for 2021, effectively swapping the projects.

Q. What additional forms of flexibility is the Company requesting within each IRM category?

The Company is requesting flexibility to redeploy resources across programs in the same category. For example, unexpected situations such as the failure of a system cable feeding a specific customer could make it impossible for the Company to work on the other cable feeding the same customer even though that work had been planned for the year. If a different system cable project could not be swapped for the planned one, the Company is requesting the flexibility to redeploy resources to work on URD or Network Secondary Cable Replacement in the City of Detroit, as this program is part of the broader Underground Programs category.

Q. Is the Company proposing any program metrics related to the IRM?

A. Yes. The Company is proposing program metrics shown in Table 24. Company Witness Stanczak discusses the reconciliation and reporting of these metrics.

Table 24: IRM Metrics

Row	Category	Program Metrics
1	**4.8kV Hardening**	• Miles hardened and expenditure levels (including unit costs) vs. targets provided in prior year
2	**Overhead Programs**	• Quantity of equipment replaced and expenditure levels (including unit costs) vs. targets provided in prior year
3	**Underground Programs**	• Feet of cable replaced and expenditure levels (including unit costs) vs. targets provided in the prior year
4	**Breaker Program**	• Number of breakers replaced and expenditure levels (including unit costs) vs. targets provided in the prior year
5	**City of Detroit Infrastructure (CODI) Upgrades**	• Feet of cable and wire replaced or converted and expenditure levels vs. targets provided in the prior year
6	**Substation Programs**	• Number of substations completed and expenditure levels vs. targets provided in the prior year • Number of circuit miles upgraded and costs (including unit costs) vs. targets provided in the prior year
7	**ADMS/SOC**	• Milestones achieved vs. milestones provided in the prior year

Q. Are there any additional metrics the Company will report to allow the MPSC Staff to assess the benefits of the programs in the IRM?

A. Yes. The Company will provide the MPSC Staff a yearly report on the average age and age range for key asset classes (breakers, switchgear, etc.), along with the risk assessments for priority asset classes, so that the extent to which aging and at risk equipment is being replaced can be evaluated. In addition, the operational performance indicators listed in Table 25 will be reported to the MPSC Staff.

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Table 25: IRM Operational Performance Indicators

Row	Category	Operational Performance Metrics
1	**4.8kV Hardening**	• Number of outages for hardened circuits compared to a control group
2	**Overhead Programs**	• Number of failures on replaced equipment compared to a control group
3	**Underground Programs**	• Number of failures on replaced cable compared to a control group
4	**Breaker Program**	• Number of failures on replaced breakers compared to a control group
5	**City of Detroit Infrastructure (CODI) Upgrades**	• Number of failures on replaced or converted cable and wire compared to a control group
6	**Substation Programs**	• Number of equipment failures in upgraded substations compared to a control group

Q. What mechanism will the Company utilize to report its progress with respect to the investments contemplated in the IRM?

A. The Company will utilize the mechanisms described below:

- An annual reconciliation as described by Company Witness Stanczak.
- Interim updates to Staff during the execution year to alert them to any material changes to the plan, the drivers of the changes, and their implications.

Q. Has the Company prepared an exhibit to support the Distribution Operations capital to be included in the IRM?

A. Yes. Exhibit A-30, Schedule T2 supports the Distribution Operations capital the Company is proposing should be included in the IRM.

Q. What is included on page 1 of Exhibit A-30, Schedule T2?

A. Page 1 of Exhibit A-30, Schedule T2 is an overview of the spending for each of the categories included in Table 22. Column (a) includes a brief description of the projects and programs and columns (b), (c), (d) and (e) include the forecasted spending for the 8

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months ending December 31, 2020; 12 months ending December 31, 2020; 12 months ending December 31, 2021; and 12 months ending December 31, 2022 respectively.

Q. What is included on page 2 of Exhibit A-30, Schedule T2?

A. Page 2 of Exhibit A-30, Schedule T2 provides the details of the calculations to determine the base level of Emergent Replacements to include in the IRM.

Q. What is included on page 3 of Exhibit A-30, Schedule T2?

A. Page 3 of Exhibit A-30, Schedule T2 provides the details of the calculations supporting the funding included on line 5, page 1 of Exhibit A-30, Schedule T2. The actual spending for each of the categories included is provided from 2013 to 2017 in columns (b) to (f) respectively. The values are adjusted for inflation and then averaged in column (g). Column (h) applies inflation to calculate expenditures in 2020.

Q. What is included on page 4 of Exhibit A-30, Schedule T2?

A. Page 4 includes the projects and programs that support lines 9 and 10 on page 1 of Exhibit A-30, Schedule T2. The columns follow the same format as page 1.

Q. What is included on page 5 of Exhibit A-30, Schedule T2?

A. Page 5 includes the projects that support line 12 on page 1 of Exhibit A-30, Schedule T2. The columns follow the same format as page 1.

Q. What is included on page 6 of Exhibit A-30, Schedule T2?

A. Page 6 includes the projects that support line 13 on page 1 of Exhibit A-30, Schedule T2. The columns follow the same format as page 1.

Q. What is included on page 7 of Exhibit A-30, Schedule T2?

A. Page 7 includes the projects that support line 14 on page 1 of Exhibit A-30, Schedule T2. The columns follow the same format as page 1.

Q. Can you describe the additional support for the distribution portion of the IRM included in Exhibit A-30, Schedule T2.1?

A. Each document, which can be one to several pages, includes the following:

- Program: As described in Exhibit A-12, Schedule B5.4, pages 4 to 9, column (a).
- Purpose and Necessity: A description of the driving forces for the work.
- Category: Category associated with Exhibit A-30, Schedule T2, page 1 of 7
- Line Number: A reference to the page and line numbers supported.
- Scope: The scope of the work.
- Customer Benefits / Effect on Cost of Operation and Reliability: How the Company's customers benefit from the program and a description of the how the project or program is expected to impact operations and reliability.
- Impact Dimensions: The dimensions from the GPM described in Table 6 that the project or program is expected to impact.
- Budget Basis: A description of the how the funding was determined for the project or program.
- Cost: The expected cost of the program for 2020 to 2022.
- IRM Spend: The funding for the project or program during the IRM periods.

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Part IX: Summary

Q. Can you summarize the key aspects of your testimony?

A. DTE Electric's distribution system is aging and, in many cases, is operating well beyond typical design life. A combination of increasing equipment failure rates, growth in economic activity, and redevelopment in the region will require higher capital expenditures to connect customers and to upgrade electric infrastructure in a way that reduces risk, improves reliability, and helps manage costs. Investments in technology are needed to improve preparedness for catastrophic events and provide better response time during outages, but also to support the evolving way in which customers will use the grid, as distributed resources continue to grow.

At the direction of the MPSC, the Company developed the Five-Year Investment and Maintenance Plan based on a careful evaluation of asset conditions and customer needs. With the goal of reducing risk, improving reliability and managing costs, the Company evaluated a broad portfolio of investments and prioritized them based on their ability to meet the goals which the Company feels are in the best interest of its customers.

The costs described in my testimony provide the needed funding to put the Company's electrical infrastructure on a strong path to supporting the current and future needs of the residents and businesses of southeastern Michigan. Risks will be significantly reduced and the projected reliability improvements will drive $6-9 billion in value to the region, as they move the Company firmly toward achieving the Governor's goal for Michigan utilities to be operating in the top half of their peers.

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Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ERIC W. CLINTON

DTE ELECTRIC COMPANY
QUALIFICATIONS OF ERIC W. CLINTON

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Q. Please state your name, title, business address, and by whom you are employed.

A. My name is Eric W. Clinton. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company as a Manager in the Electric Regulated Marketing Organization.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your education background?

A. I received a Bachelor of Business Administration degree in Finance in May 1999 from the University of Michigan - Flint. In addition, I have completed several courses and seminars related to utility accounting, economics, finance, and ratemaking.

Q. What work experience do you have?

A. In 1998, I was employed by Raymond James (formerly Roney & Co.) Investment Services as a Client Representative. In June 1999, I joined Consumers Energy Company ("Consumers") as a Rate Analyst in the Revenue Requirements Section of the Rates Department. In October 2001, I was promoted to a General Rate Analyst in the Financial Analysis and Planning Section of the Rates Department at Consumers. In April 2003, I accepted a position as a Financial Analyst with The Detroit Edison Company (DECo) in the Revenue Requirements Section of the Regulatory Policy and Operations Department. In November 2004, I was promoted to a Senior Financial Analyst in the Revenue Requirements Section of the Regulatory Policy and Operations Department at DECo. In December 2005, I accepted a position

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as a Manager at The Siegfried Group LLP, a professional services firm that delivers a wide range of accounting and finance capabilities on critical projects to primarily Fortune 1000 clients. In January 2008, I accepted a position as Principal Marketing Analyst in the Gas Supply and Planning organization at Michigan Consolidated Gas Company (MichCon). In April 2012, I was promoted to Principal Marketing Specialist in the Gas Supply and Planning organization at MichCon. In April 2013, I accepted a position as Principal Marketing Specialist in the Gas Sales and Marketing organization. In November 2014, I was promoted to Manager in the Gas Sales and Marketing organization. In February 2017, I accepted my current position as Manager in the Electric Regulated Marketing organization.

Q. Please describe your current position and duties.

A. As Manager of Electric Regulated Marketing, my primary responsibilities include developing new products and services, developing new electricity payment offerings, improving customer education and awareness related to electric vehicles, conducting customer research and overseeing the marketing budget.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony concerning Consumers' gas utility historical net plant investment and working capital requirement, as well as the projected working capital requirement, in Consumers' gas general rate proceeding, Case No. U-13000. I submitted testimony supporting Consumers' Title I Clean Air Act (CAA) investment, in addition to capital expenditures in excess of depreciation expense levels per year 2000 Public Act 141, Section 10d(4), in Consumers' accounting approval

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proceeding, Case No. U-13491. Also, I submitted testimony supporting MichCon's revenue deficiency, net operating income, and overall rate of return in Case No. U-13898. Most recently, I have provided testimony regarding DTE Gas' (formerly MichCon) gas supply strategy in GCR Case Nos. U-15451-R, U-15701-R, U-16146, U-16146-R, U-16482, U-16482-R, U-16921 and U-17131.

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Q. What is the purpose of your testimony?

A. The purpose of my testimony in this proceeding is to provide additional details and support on DTE Electric's proposed electric vehicle ("EV") program, two newly proposed electric pricing options, as well as Electric Regulated Marketing operations and maintenance ("O&M") expense. My testimony will cover the following subjects:

1) **EV Customer Education and Outreach –** I provide details on the education and outreach component of the Company's proposed EV program ("Charging Forward") including, (1) types of communications to be used; (2) estimated program costs; (3) program management; and (4) measures that will be used to track program effectiveness.

2) **EV Site Host Acquisition Strategy –** I provide details on the acquisition strategy that will be used to recruit potential site hosts for the Charging Forward program detailed in Company Witness Serna's testimony.

3) **Weekend Flex Pilot** – I will support the 5,000 residential customer pilot where customers would elect to pay the standard residential service rate D1 for their weekday electricity usage and a fixed monthly charge for their weekend electricity usage, thereby encouraging customers to shift usage from weekdays to weekends.

4) **Fixed Bill Pilot** – I will support the 5,000 residential customer pilot where customers would elect to pay a fixed monthly charge for their electricity usage for a period of 12 months and would not be subject to any adjustments resulting from usage, weather or commodity price fluctuations.

5) **Regulated Marketing O&M Expense** – I provide details and support the reasonableness of the Company's actual $11.0 million Electric Regulated Marketing O&M expenses in 2017 and projected $14.5 million of O&M

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expenses for the 12-month test period ending April 30, 2020.

6) **D1 time of use rate –** I also discuss the impacts of restructuring residential rate D1 to a time of use rate from a Regulated Marketing perspective.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit:

Exhibit	Schedule	Description
A-13	C5.8	Regulated Marketing O&M Expense

Q. Was this exhibit prepared by you or under your direction?

A. Yes, it was.

Charging Forward - EV Customer Education and Outreach

Q. Can you describe the Company's EV Education and Outreach Plan?

A. The Company is proposing a residential and commercial customer education and outreach plan across multiple channels including (but not limited to) social media, newsletters, email and direct mail. This plan will have two main objectives: (1) Increase EV adoption by educating customers on the associated lifetime economic and environmental benefits of EVs; and (2) Promote the Residential Smart Charger Support and Charging Infrastructure Enablement components of the Charging Forward program as described by Witness Serna.

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Q. What are the benefits associated with greater EV adoption?

A. As detailed in the testimony of Witness Serna, transportation electrification provides benefits to both EV drivers and the public at large. These benefits include reduced operating costs for EV drivers and affordability benefits for utility customers. Most EV charging takes place overnight at home, effectively utilizing distribution and generation capacity in the system during a low load period. Therefore, increased EV adoption puts downward pressure on rates by spreading fixed costs over a greater volume of electric sales. Benefits also include reduced carbon emissions, improved air quality, increased expenditures in local economies, and reduced dependency on foreign oil for the public at large.

Q. What is DTE Electric's experience in educating customers on options for energy efficiency and electrification?

A. The Company has educated customers on several energy efficiency and electrification options including prior work on EVs and EV charging equipment. Examples include geothermal HVAC solutions, energy efficient outdoor protective lighting, energy efficiency tips for both electric and gas usage, and energy efficiency rebates for qualified appliances and equipment. Prior EV education and awareness efforts included the creation of an EV specific webpage, facilitating ride and drive events, bill inserts, dealership direct mailings, and social media.

Q. What is DTE currently doing to educate customers about EVs?

A. Current primary efforts can be summarized in the following four categories:

1) The Company has redesigned its EV website - providing resources about the types of EVs and their associated benefits, available charging equipment, electric pricing options, and the overall charging installation process. The new and

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improved residential EV website launched in May 2018 while the commercial EV website launched in June 2018;

2) Charger inquiry experience – The Company has improved the customer experience for charging station installation inquiries and rate changes at the call center and elsewhere within the Company. For example, Electric Regulated Marketing updated the standard work instructions, provided updated resources for call center representatives, defined escalation paths for unclear questions, and defined a subject matter expert within the Major Account Services team to handle inquiries from commercial customers without an Account Manager;

3) EV promotion – The Company is executing campaigns to inform customers and other stakeholders of the EV information and resources available from DTE Electric;

4) EV dealer partnerships – The Company is coordinating workshops to increase knowledge of EV dealer's sales people and address EV sale pain points starting in Q4 2018.

Q. How will DTE further develop the EV Outreach and Education plan?

A. The Company will work with both internal teams and external stakeholders to develop campaigns that will:

1) Identify and address consumer and fleet concerns in converting to an EV;

2) Identify and address commercial, industrial, multi-unit dwelling (MUD), and municipal customer concerns in deploying EV charging infrastructure; and

3) Establish consistent messaging that helps overcome perceived barriers to EV adoption and concerns with deploying EV charging infrastructure.

Q. With what types of external entities does DTE plan to work?

A. The Company will work with a variety of stakeholders, potentially including:

1) Automotive Manufacturers;
2) Charging Infrastructure Providers;
3) Community Groups;
4) Business and Trade Groups;
5) Government entities;
6) Research firms;
7) Advertising agencies; and
8) Any other interested stakeholders

Q. What types of communications will DTE use and what are the associated costs?

A. The communication methods will be refined over the life of the program based on data provided through program evaluation efforts. The table below provides an overview of the types of communications and respective costs (in thousands) for 2019-2021:

Description	2019	2020	2021	Total
Digital and Broadcast Media	$ 100	$ 150	$ 150	$ 400
Owned Assets and Proprietary Channels	$ 70	$ 105	$ 105	$ 280
Print Materials and Content Development	$ 125	$ 188	$ 188	$ 500
Conferences, Sponsorship, and Events	$ 75	$ 113	$ 133	$ 300
Surveys and Program Evaluation	$ 30	$ 45	$ 45	$ 120
Total	**$ 400**	**$ 600**	**$ 600**	**$ 1,600**

These costs are included in Exhibit A-12, Schedule B5.9, line 14 supported by Witness Serna.

Q. How did DTE Electric develop the estimated costs for the EV Outreach and Education plan?

A. Costs were based on estimates provided by the Company's Corporate Communications team**.** As the Company's EV strategy continues to evolve, there will likely be some changes to the channels and tactics used, but DTE Electric believes it is reasonable to conclude that the overall amount included in this filing is necessary to achieve the goals of the Charging Forward program.

Q. How will the Charging Forward program be managed?

A. The Charging Forward program will be overseen by a full time dedicated program manager and a full time dedicated marketing specialist. These roles will coordinate the involvement of other DTE staff, departments, external partners and stakeholders. The table below provides the estimated program management costs (in thousands) for 2019-2021:

	2019	**2020**	**2021**	**Total**
Program Management	$ 233	$ 350	$ 350	**$ 933**

These costs are included in Exhibit A-12, Schedule B5.9, line 15 supported by Witness Serna.

Q. How will DTE Electric know if these efforts are successful?

A. The Company will evaluate the success of its outreach and education efforts using both qualitative and quantitative measures. Specific goals will be set for each campaign using metrics such as open rates, click through rates, time spent on the website, or responses received as appropriate to each campaign. Qualitative measures may include

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customer satisfaction verbatim responses and feedback from EV dealers regarding customer interactions.

Charging Forward - EV Site Host Acquisition Strategy

Q. Does DTE Electric need to promote the EV Program to potential charging site hosts?

A. Successful deployment of the make-ready charging infrastructure model in the Company's EV Program will depend on potential charging site host awareness and willingness to participate. The charging site host acquisition strategy will ensure that potential charging site hosts are not only aware of the program but also of the benefits of workplace and public charging. Witness Serna discusses this in more detail in his testimony.

Q. What is DTE Electric doing to prepare in this space?

A. The Company is conducting a variety of activities in 2018 to develop a greater understanding of the current interest in providing charging as well as the process of integrating charging infrastructure with the grid. Those activities include, but are not limited to the following:

1) The Major Account Services (MAS) team will be surveying non-residential customers in 2018 to begin gauging interest in providing EV charging. Survey results will be used to help target potential charging site hosts under the proposed EV program (Charging Forward);

2) The Company is pursuing three Direct Current (DC) Fast Charging pilots as outlined in Witness Serna's testimony to gain insights into both EV-grid integration and consumer preferences; and

3) The Company is meeting with developers, commercial and industrial customers, municipalities, Electric Vehicle Supply Equipment ("EVSE") manufacturers, EVSE installers, automotive manufacturers, government agencies, and other stakeholders.

Q. How does DTE Electric intend to recruit charging site hosts?

A. The Company will use two main approaches to recruit charging site hosts:

1) New make-ready program marketing; and
2) Continued support from existing MAS representatives.

Q. How will the make-ready program be marketed?

A. The make-ready program marketing will consist of dedicated campaigns on many of the same channels referenced for the overall EV education and outreach efforts and will be supported by DTE Electric's Regulated Marketing team. The Company will facilitate workshops to further educate customers and potential site hosts on the benefits of workplace and public charging as described by Witness Serna. DTE Electric web-based guidance will also be provided and will include a contact process for customers interested in becoming charging site hosts. In addition, the Company expects EVSE vendors and other stakeholders to promote the make-ready program to potential charging site hosts.

Q. How will MAS relationships help recruit charging site hosts?

A. The existing MAS team has strong and trusted relationships with our large commercial, industrial, and municipal customers. This team will have proactive conversations with

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customers to ensure they are aware of the program and provide guidance to the customers on next steps and installation if desired.

Q. How will DTE Electric select who can become a charging site host?

A. Potential site hosts must meet the following eligibility criteria, including, but not limited to:

1) Must be a non-residential customer;
2) Must be a customer of record for the electric meter serving the EVSE;
3) Must commit to keeping the EVSE maintained and in good working order for a period of 5 years from the date of installation;
4) Must commit to share utilization data with the Company; and
5) Must have accounts currently in good standing with the Company.

Q. Which type of charging site hosts will DTE be targeting?

A. Targeting and prioritization of potential EVSE site hosts will be performed in order to optimize program funding, public benefit, and charging station utilization. The company will utilize a number of characteristics to determine priority which include, but are not limited to:

1) Accessibility (site convenience);
2) Estimated cost to establish service;
3) Proximity to high-traffic highways or local routes;
4) Adjacent businesses or options (restaurants, retail, sports arenas, parks, etc.); and
5) Others as determined by the Company.

Weekend Flex Pilot

Q. What is the Weekend Flex pilot?

A. The Weekend Flex pilot is an elective provision offering that would allow up to 5,000 residential customers a new way to pay for their electricity. Households enrolled on the provision would pay the standard residential service rate D1 for their weekday usage and a fixed monthly charge for their weekend usage.

Q. How is the weekend fixed monthly charge determined?

A. The weekend time period is defined as 12AM Saturday to 11:59PM Sunday. Customers electing to enroll in the program would be grouped into an annual kWh usage tranche based on their prior overall 12-month site consumption history. There would be a total of seven usage tranches ranging from 2,001 kWh/year to 16,000 kWh/year in 2,000 kWh/year increments. The pricing in each 2,000 kWh tranche is based upon the average annual usage for all residential D1 customers within that tranche. A forecasted load shift, detailed by Witness Farrell, would be embedded into each usage tranche to determine the estimated annual weekend consumption. The estimated annual weekend consumption would then be priced out using the D1 rate (including all applicable surcharges) and divided by 12 to obtain a monthly fixed charge. Each tranche would have an associated weekend fixed monthly charge that applies to all customers within the tranche, inclusive of the monthly service charge and other per customer or per meter surcharges. Company Witness Dennis supports the calculation of the fixed monthly charge for each of the seven usage tranches as shown on Exhibit A-16, Schedule F8.

Line No.

Q. Why does DTE Electric have an interest in piloting Weekend Flex?

A. DTE Electric would like to pilot this provision for the following reasons:

1) Provide optionality to our residential customers;
2) Potential to increase customer satisfaction;
3) Potential to improve future affordability;
4) Potential to shift weekday peak usage to low load weekend off-peak periods; and
5) Ability to learn how a fixed price signal affects customer usage.

Q. What does DTE Electric intend to learn from the Weekend Flex pilot?

A. By conducting this pilot DTE Electric would expect to learn the following:

1) Customer interest in the provision
2) Customer satisfaction while on the provision
3) Financial impact to the customers and the Company
4) Amount and impact of on peak to off peak load shift

Q. How did DTE Electric determine that customers are interested in more electric pricing options?

A. DTE Electric conducted a survey of 700 residential customers in April 2018 and found that, regardless of their electric rate plan preferences, 83% believe it is a good idea for DTE Electric to offer a broad range of rate plans for residential customers.

Line No.

Q. Did DTE Electric perform any quantitative analysis to determine the customer's level of interest in the Weekend Flex pilot?

A. Yes. DTE Electric's survey of 700 residential customers in April 2018 found that 29% of respondents found the provision appealing and 6% would ultimately sign up for the plan when presented with 5 different ways to pay for their electric usage (Standard Residential, BudgetWise Billing, Time of Day, Fixed Bill, Weekend Flex). Of those who wanted to sign up, 34% believed the plan would be the lowest cost to them, 20% believed they could shift their usage, and another 20% thought their household energy usage patterns already fit this plan. Furthermore, potential subscribers would come disproportionately from standard rate customers in households earning less than $100,000 per year.

Q. How could the Weekend Flex pilot potentially shift peak weekday usage to weekends?

A. One of the potential benefits of the Weekend Flex pilot is a shift of on peak weekday load to off peak weekends. For customers enrolled on the provision, there is a financial incentive to shift their weekday usage to the weekends when the price of energy is fixed. The Company will monitor the amount and impact of peak to off peak load shift during the pilot once implemented in 2020.

Q. How could Weekend Flex help improve future affordability?

A. As demand increases during peak periods the need for additional (or more expensive) electric generation and distribution infrastructure increases. By incentivizing customers to shift their electric consumption to off peak periods, there is a potential to delay or decrease the need for dispatch of more expensive peaking generation,

Line No.

additional electric generation plants, and additional distribution infrastructure necessary to meet peak demand. As part of the learnings from this pilot, DTE Electric would likely be able to quantify the effect that this program may have on future infrastructure investment.

Q. How could this provision help improve customer satisfaction?

A. DTE Electric's customer survey in April 2018 found that 7% of survey participants somewhat agree, and 4% completely agree that their overall satisfaction with DTE would improve if they were able choose the Weekend Flex provision.

Q. What are the underlying assumptions surrounding the Weekend Flex pilot?

A. There are two primary assumptions that DTE considered when designing this provision structure discussed in Company Witness Farrell's testimony.

1) The average customer's current usage split between weekdays and weekends;
2) The average customer's anticipated load shift from weekdays to weekends under the Weekend Flex plan;

Q. Who would be eligible for the Weekend Flex pilot?

A. To be eligible for the Weekend Flex pilot, the customer must:

1) Be in good financial standing with the company
   i. No arrears in the past 12 months;
   ii. No nonpayment disconnections in the past 2 years;
   iii. No red bills in the past 12 months;
   iv. Not currently on a payment plan

2) Consume a minimum of 2,001 kWh of electricity annually but no more than 16,000 kWh annually;

3) Have a main premise meter currently enrolled on rate D1;

4) Have a 12-month usage history at the residence they desire to enroll; and

5) Have a functional, transmitting AMI meter installed for electric service at their residence

Participation will be limited to 5,000 customers. Retail Access Service customers will not be eligible for this program.

Q. What kind of commitment would a customer need to make when signing up for the provision?

A. Similar to DTE Electric's Dynamic Peak Pricing Rate D1.8, customers would need to make a 12-month commitment to this provision. If the Customer withdraws from Weekend Flex prior to the end of the one-year period, the Customer may be charged for the difference if the amount paid under Weekend Flex is less than what the Customer would have otherwise paid under rate D1.

Q. Will other customers subsidize Weekend Flex customers if higher than expected weekend usage occurs?

A. No. The provision is designed to be cost based and revenue neutral.

Line No.

Q. What steps will DTE Electric take to ensure this program aligns with the Company's Energy Waste Reduction (EWR) goals?

A. DTE Electric is taking several steps to ensure the provision is in alignment with the Company's EWR goals which include welcome kits, usage alerts, and a "reasonable usage" clause.

1) **Welcome Kits** - Once a customer is enrolled in the provision, a welcome kit will be sent to the customer which would explain some of the energy efficiency programs that are available to them.

2) **Usage Alerts** - If a customer increases their usage by pre-defined limits, usage alerts would be sent warning them of their increased electric consumption.

3) **Reasonable Usage Clause** - DTE Electric would have the option to terminate a customer's participation in the pilot and return them to their former or other eligible rate if their actual weekend usage in a given month is 30% greater compared to the same month the previous year, excluding load shift from weekday to weekend, and the effects of weather.

Q. Does the Company anticipate a customer on this provision will increase their usage?

A. The Company believes that the Weekend Flex pilot sends a long-term conservation signal because the offer covers a 12-month period and subsequent offers will incorporate usage changes. DTE Electric is not anticipating an overall increase in usage for the average customer enrolled in this plan. However, DTE Electric does anticipate and has appropriately priced in an increase in weekend usage to the fixed charge component as customers shift weekday usage to the weekend. The pilot will help to validate or invalidate these assumptions and if needed, adjust accordingly.

Line No.

Q. How will DTE Electric market this pilot provision to customers?

A. The Weekend Flex pilot will be targeted towards customer segments that indicated the greatest interest in the previously mentioned residential customer survey. Participation will be offered to customers meeting the previously stated eligibility criteria. DTE Electric has included $405,000 in the test year O&M expense related to this program. This includes technology implementation costs, the cost of soliciting pilot participation, enrollment, customer support, and marketing materials. Please see Exhibit A-13, Schedule C5.8 which references Weekend Flex Pilot O&M expense in the test period.

Q. How will Power Supply Cost Recovery (PSCR) and other surcharges be impacted under this offering?

A. The PSCR, Low Income Energy Assistance Fund (LIEAF), Energy Waste Reduction (EWR), Nuclear Decommissioning, and Transitional Recovery Mechanism (TRM) will be kept whole by assigning first priority on the revenue stream generated by the Weekend Flex program to those surcharges. The PSCR and other applicable surcharges would be fully funded monthly based on the customer's actual usage versus the forecasted usage on which the programs are predicated.

Q. Would the arrears, shutoff and collection process be different for customers enrolled on Weekend Flex?

A. No. Customers on Weekend Flex would be subject to the same terms and conditions governing nonpayment or partial payments as standard residential customers.

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Q. How will enrollment, renewals, or customers leaving the pilot be handled for the Weekend Flex provision?

A. All eligible Weekend Flex offers will be updated based on previous years' consumption, and contracts will automatically renew for the following year, unless the Customer notifies the Company. Renewals for Weekend Flex offers will be provided to customers in their 11-month bill. Customers may choose to change rates and leave the Weekend Flex provision at the end of the contract year at no charge. If the Customer withdraws from Weekend Flex prior to the end of the one-year period, the Customer may be charged for the difference if the amount paid under Weekend Flex is less than what the Customer would have otherwise paid under rate D1. No credits or refunds for early termination will be given if the Weekend Flex payments are greater than what the customer would have otherwise paid under rate D1. In addition, the Weekend Flex provision will not be available to Customers for a period of 12 months immediately following their early withdrawal. If DTE exercises the option to remove a Customer from Weekend Flex due to excessive usage (as referenced in the "reasonable usage clause" stated earlier in my testimony), the return to rate D1 or other eligible rate will operate under the same provision concerning voluntary Customer withdrawal stated above. If a Customer moves (and thereby ceases to receive service at the same location) before the end of the contract term and is in good financial standing with the Company at that time, no additional charges will apply. In order to limit the Weekend Flex pilot provision enrollment and study the effects on an adequate customer population in the time allotted for the pilot, the Company would reserve the right to cease enrollment no earlier than June 30, 2020, or once the 5,000 customer enrollment cap is reached.

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Q. Is DTE Electric requesting a waiver of any existing residential rules to facilitate this pilot?

A. Yes, to facilitate this pilot, the Company is requesting the waiver of the following Residential Rules contained in the Consumer Standards and Billing Practices for Electric and Gas Residential Service:

R 460.125 which states that a utility shall bill each customer for the amount of electricity consumed. Customers enrolled on the Weekend Flex pilot will pay a fixed monthly charge for their weekend electricity usage.

R 460.121 which states that a utility shall bill a customer with satisfactory payment history on an equal monthly billing program if requested. Customers enrolled on the Weekend Flex pilot will not be eligible to be enrolled on an equal monthly billing program.

Q. When would DTE Electric implement this new Weekend Flex pilot provision?

A. DTE Electric will implement this provision when feasible, after programming and modifications to the customer billing system have been made. The Company estimates this to take approximately 8 months following approval to move forward with the Weekend Flex pilot. The estimated date for the Company to begin enrollment of the new Weekend Flex pilot provision would be January 1, 2020.

Q. Are you supporting a tariff sheet for the new Weekend Flex pilot program?

A. Based on the discussion above, Company Witness Dennis has included a proposed tariff sheet as shown in Exhibit A-16, Schedule F10.

Line No.

Fixed Bill Pilot

Q. What is the Fixed Bill pilot?

A. Fixed Bill is a pilot offering that allows up to 5,000 residential customers to elect and pay a fixed monthly amount for a period of one year that is not subject to any adjustments for actual usage. The proposed provision will be available to customers who take service on residential rate D1.

Q. Did DTE perform any quantitative analysis to determine the customer's level of interest in a Fixed Bill offering?

A. Yes. DTE conducted a survey of 700 residential customers in April 2018 and found that 11% of respondents would choose the Fixed Billing offer over their current rate. The primary reason stated by those who would choose Fixed Billing over their current rate was "Consistent bill/No surprises". Further, 28% of respondents found the offering appealing and would want to investigate further. The results also show this type of offering resonates with those that are currently on the BudgetWise Billing program.

Q. How are Fixed Bill offers calculated?

A. The Company will estimate kWh usage for the ensuing 12-month contract period based upon Customer's historical 12-month metered usage, adjusted to reflect normal weather and any expected changes in usage. The applicable usage charges included in the residential service rate D1 at the beginning of the contract period will be applied to this annual kWh amount. The resulting sum will be increased by a risk adder not to exceed 10% to appropriately price the risk associated with weather variability and commodity price fluctuations. Applicable service charge(s) will be added, and the total will be divided by 12 to establish the Fixed Bill monthly charge.

Q. Which customers would be eligible?

A. This provision would be available to customers taking service under residential service rate schedule D1 who have been in their current residence over the previous 12 months and are currently in good financial standing with the Company. This provision will not be available to Retail Access Service customers. Fixed bill offers will not be made to accounts where the customer's monthly calculated fixed bill payment would be less than $25 per month. At the time of renewal, pilot participants will remain eligible if they have had continuous service in the pilot and maintain good financial standing. Participation in this billing provision will be limited to a maximum of 5,000 total residential customers currently taking service on rate D1.

Q. Why does DTE Electric want to pilot Fixed Billing?

A. This pilot will provide DTE Electric the opportunity to assess customer satisfaction with this billing and payment option and the program's ability to assist the customers in managing monthly utility costs.

Q. If a customer is enrolled in the Fixed Bill program, how will renewals or customers leaving the program be handled?

A. All eligible Fixed Bill offers will be updated based on previous years' consumption, and contracts will automatically renew for the following year, unless the Customer notifies the Company. Renewals for Fixed Bill offers will be provided to customers in their 11-month bill. Customers may terminate their Fixed Bill Provision at the end of the contract year at no charge. If the Customer withdraws from the Fixed Bill

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Provision prior to the end of the one-year period, the Customer may be charged for the difference if the amount paid under Fixed Bill is less than what the Customer would have otherwise paid under rate D1. No credits or refunds for early termination will be given if the fixed bill payments are greater than what the customer would have otherwise paid under rate D1. In addition, this provision will not be available to Customers for a period of 12 months immediately following their early withdrawal. If a Customer moves (and thereby ceases to receive service at the same location) before the end of the contract term and is in good financial standing with the Company at that time, no additional charges will apply.

Q. Under what circumstances would the Company terminate a customer's participation in the Fixed Bill pilot?

A. The Company may terminate a Customer's participation in the Fixed Bill pilot if the Customer's actual usage in a given month is 30% greater as compared to the same month the previous year, excluding the effects of weather. The Company would then return the Customer to standard tariff provisions for which the customer qualifies. The return to the standard tariff will operate under the same policy concerning early customer withdrawals where the Customer may be charged for the difference if the amount paid under Fixed Bill is less than what the Customer would have otherwise paid under rate D1 but no credits or refunds for early termination will be given if the fixed bill payments are greater than what the customer would have otherwise paid under rate D1.

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Q. Does the Company anticipate that customer usage will change when on Fixed Billing?

A. One goal of the Fixed Bill pilot is to determine the extent to which customers may change their behavior when enrolled in a Fixed Bill program. Since Fixed Bill offers are calculated on the previous 12 months' usage, customers are, over the long term, incentivized to use less as this may decrease their monthly renewal price for the next 12-month term. Enrolled customers will receive a Fixed Bill welcome package which includes energy saving tips and educational materials on available Energy Waste Reduction (EWR) programs. In addition, Customers will continue to see current month actual usage charted and compared to the same month last year in order to proactively inform the customer of the potential for an increased Fixed Bill renewal offer.

Q. Will other customers subsidize Fixed Bill customers if higher than expected usage occurs?

A. No. DTE has not and would not impute a loss associated with the Fixed Bill program. Under a full program, DTE would impute either zero or some level of positive revenue which would offset the residential rate class revenue requirement thereby improving affordability.

Q. How will PSCR and other surcharges be impacted under this provision offering?

A. Consistent with the discussion above related to the Weekend Flex pilot, the PSCR, LIEAF, EWR, Nuclear Decommissioning, and TRM will be kept whole by assigning first priority on the revenue stream generated by the Fixed Bill pilot program to those surcharges. The PSCR and other applicable surcharges would be fully funded monthly based on the customer's actual usage versus the forecasted usage on which the programs are predicated.

Q. Would the arrears, shutoff and collection process be different for customers enrolled on Fixed Bill pilot?

A. No. Customers on Fixed Bill pilot would be subject to the same terms and conditions governing nonpayment or partial payments as standard residential customers.

Q. When would DTE Electric implement the Fixed Bill pilot program?

A. DTE Electric will implement this provision when feasible, after programming and modifications to the customer billing system have been made. The Company estimates this to take approximately 8 months following approval to move forward with the Fixed Bill pilot. The estimated date for the Company to begin enrollment of the new Fixed Bill pilot provision would be January 1, 2020.

Q. What steps will DTE take to ensure the Fixed Bill program aligns with the Company's EWR goals?

A. DTE is taking several steps to ensure the program is in alignment with the Company's EWR goals which include welcome kits, usage alerts, and a "reasonable usage" clause.

1) **Welcome Kits** - Once a customer is enrolled in the provision, a welcome kit will be sent to the customer which will explain some of the energy efficiency programs that are available to them.

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2) **Usage Alerts** - If a customer increases their usage by pre-defined limits, usage alerts will be sent warning them of their increased usage. These messages would also provide information related to the implications this would have when their monthly fixed bill is recalculated should they wish to stay on the provision for another 12 months.

3) **Reasonable Usage Clause** - DTE Electric would have the option to terminate a customer's participation in the provision and return them to their former or other eligible rate if their actual usage in a given month is 30% greater compared to the same month the previous year, excluding the effects of weather.

Q. Are there any other utilities that are offering a similar type of plan?

A. Yes. Georgia Power, Gulf Power and Oklahoma Gas and Electric all offer similarly situated programs. Each of these utilities have offered their programs for 10 years or more and achieved significant enrollment with their residential customers. The table below shows each utility's average enrollment for 2017 on their respective Fixed Bill offering as evidenced by their respective 2017 FERC Form 1 data.

Utility	**Fixed Bill Customers**	**Total Residential Customers**	**% Fixed Bill**
Georgia Power	236,218	2,173,557	10.9%
Oklahoma Gas & Electric	45,315	660,803	6.9%
Gulf Power	12,580	401,793	3.1%
Total	**294,113**	**3,236,153**	**9.1%**

Q. How will DTE Electric market this Fixed Bill pilot provision to customers?

A. A Fixed Bill pilot will be targeted towards customer segments that indicated the greatest interest in the previously mentioned residential customer survey.

Participation will be offered to customers meeting the previously stated eligibility criteria through both direct mail and email. DTE Electric has included $1.0 million in the test year O&M expense related to this program. This includes technology implementation costs, the cost of marketing the Fixed Bill pilot, enrollment and customer support. Please see Exhibit A-13, Schedule C5.8 which references Fixed Bill Pilot O&M expense in the test period.

Q. What additional cost and performance monitoring will be required?

A. The Company will track and monitor a variety of metrics to evaluate the Fixed Billing pilot. The metrics to be monitored will include the following:

1) Customer satisfaction pre and post Fixed Bill enrollment
2) Participation response rates
3) Annual attrition
4) kWh usage pre and post Fixed Bill enrollment
5) Revenue compared to equivalent usage under standard D1 rate
6) Late payments and arrears analysis

Q. Is DTE Electric requesting a waiver of any existing residential rules to facilitate this pilot?

A. Yes, to facilitate this Fixed Bill pilot, the Company is requesting the waiver of the following Residential Rules contained in the Consumer Standards and Billing Practices for Electric and Gas Residential Service.

R 460.125 which states that a utility shall bill each customer for the amount of electricity consumed. Customers enrolled on the Fixed Bill pilot will pay a fixed price for their monthly electricity usage.

R 460.121 which states that a utility shall bill a customer with satisfactory payment history on an equal monthly billing program if requested. Customers enrolled on the Fixed Bill pilot will not be eligible to be enrolled on an equal monthly billing program.

Q. Are you supporting a tariff sheet for the new Fixed Bill program?

A. Based on the discussion above, Company Witness Dennis has included a proposed tariff sheet as shown in Exhibit A-16, Schedule F10.

Regulated Marketing O&M Expense

Q. What was the Regulated Marketing O&M expense for the 2017 historical test year?

A. As shown on Exhibit A-13, Schedule C5.8, line 15, Regulated Marketing total O&M expense for the 2017 historical test year was $11.0 million.

Q. What does Regulated Marketing historical O&M expense include?

A. The $11.0 million of 2017 Regulated Marketing O&M expense includes Major Account Services which manages new and existing customer relationships for commercial and industrial customer classes. Regulated Marketing also includes Electric Marketing which manages marketing campaigns to educate customers, develops new product and service offerings and measures business performance. Lastly, Regulated Marketing includes Demand Side Management costs which are supported by Company Witness Dimitry and amortization of plug in electric vehicle pilot costs approved in Case No. U-17767 and supported by Witness Uzenski.

Q. What known and measurable changes is DTE Electric proposing to the historical test year amount?

A. DTE Electric is proposing the following known and measurable changes to the historical 2017 test year Regulated Marketing O&M expense:

1) Inflation for 2018, 2019 and 4 months of 2020 in the amount of $0.7 million;
2) Weekend Flex Pilot expenses of $0.4 million as discussed earlier in my testimony;
3) Fixed Bill Pilot expenses of $1.0 million as discussed earlier in my testimony;
4) Charging Forward consumer education and outreach of $0.6 million as discussed earlier in my testimony;
5) Charging Forward program management of $0.3 million as discussed earlier in my testimony;
6) Demand Side Management expenses of $0.3 million as discussed by Witness Dimitry; and
7) Charging Forward regulatory asset amortization of $0.2 million as discussed by Witness Uzenski

Q. What were the assumed labor and material inflation adjustment factors for 2018, 2019 and 2020?

A. The assumed labor and material annual inflation adjustment factors were 3.0% for 2018, 2.9% for 2019 and 3.0% for 2020 as supported by Witness Uzenski.

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Q. What are the Regulated Marketing O&M expenses for the projected test period that DTE Electric is seeking to recover?

A. As shown on Exhibit A-13, Schedule C5.8, DTE Electric is seeking to recover $14.5 million of Regulated Marketing O&M expenses in the projected test year.

Q. Why is the level of Regulated Marketing O&M expense for the projected test period reasonable and prudent?

A. The Regulated Marketing O&M expense is a reasonable and prudent level necessary to support the new programs proposed by the company in this proceeding as well as maintain the existing level of customer support to commercial and industrial major account customers and to educate all customers of regulated Company offerings.

Rate Schedule D1 Time of Use

Q. Are you familiar with the Commission's Order in U-18255 regarding the change in the residential rate structure for rate schedule D1?

A. Yes I am. The Commission Ordered the Company in its next general rate case to include proposed tariffs for non-capacity charges based on summer on-peak rates. In other words, approximately 1.9 million customers would be defaulted to time based rates.

Q Will this change have an impact on the Company from a Regulated Marketing perspective?

A. Yes it will. The Company will need to develop comprehensive marketing and advertising plans across all of DTE Electric's available channels in order to communicate this change in customer bills. From a cost perspective, we have

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estimated that this change would result in approximately $9.3 million in the first year the rate is implemented. The $9.3 million includes market research, paid media, production costs and associated labor, community engagement and employee training. These costs have not been incorporated into my projected test year O&M expense.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL S. COOPER

DTE ELECTRIC COMPANY
QUALIFICATIONS OF MICHAEL S. COOPER

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Q. What is your name, business address, and by whom are you employed?

A. My name is Michael S. Cooper. My business address is DTE Energy Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I received a Bachelor of Business Administration Degree with a major in accounting and finance from the University of Toledo in 1994. I received a Master of Arts Degree in educational administration from Michigan State University in 1997.

Q. What is your current position and work experience?

A. My current position is Director of Compensation, Benefits & Wellness. I joined DTE Energy Corporate Services LLC full time in 2008 and held positions with increasing responsibility in Human Resources. In 2012, I became the Manager of Compensation and assumed my current position in 2017. Prior to joining DTE Energy, I was employed by Manpower as an on-site Staffing Program Manager and in other related positions for Visteon Corporation. I was previously employed at Robert William James & Associates as a recruiter with an emphasis in accounting and finance related positions.

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Q. What are your responsibilities as Director of Compensation, Benefits & Wellness?

A. As Director of Compensation, Benefits & Wellness, I have overall responsibility for the design, implementation and administration of DTE Energy's compensation and employee benefits' policies and practices.

Q. Have you participated in DTE Electric or DTE Gas proceedings before the Michigan Public Service Commission (Commission)?

A. Yes. I sponsored testimony in DTE Electric's most recent general rate case (Case No. U-18255) and in DTE Gas's general rate case (Case No. U-18999).

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Q. What is the purpose of your testimony?

A. My testimony will present an overview of employee compensation practices and benefit expense for DTE Electric for the 2017 historical test period and the May 1, 2019 through April 30, 2020 projected test period. I will:

- Provide support for the Company's pension costs, other post-employment benefits (OPEB), active employee health care costs and other employee benefits;
- Support the Company's labor cost escalation assumptions used in Company Witness Ms. Uzenski's development of the composite inflation factors for the projected test period;
- Provide an overview of the Company's compensation philosophy for non-represented employees and the role that the Company's incentive plans play in the overall reasonableness of its total compensation policies;
- Describe the components of the Company's short and long-term incentive plans and support the inclusion of such costs in the Company's revenue requirement, exclusive of the costs related to DTE Energy's top five Executive Officers; and
- Demonstrate that the quantifiable customer benefits of the Company's incentive plans exceed the expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

In summary, my testimony will support the reasonableness and validity of the projected employee benefits and compensation expense to be incurred by DTE Electric for the projected test period.

Q. Are you sponsoring any exhibits?

A. Yes, I am supporting information on the following exhibits:

Exhibit	Schedule	Description
A-13	C5.10	Employee Pensions and Benefits
A-13	C5.10.1	Aon Hewitt Healthcare Trend
A-13	C5.10.2	PwC 2018 Medical Inflation Projection
A-13	C5.11.1	Pension Costs - Qualified
A-13	C5.11.2	Other Post-Employment Benefits (OPEB)
A-21	K1	2018 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Electric
A-21	K2	2018 Annual Incentive Plan and Rewarding Employees Plan Metrics: Nuclear Generation
A-21	K3	2018 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Energy Corporate Services LLC
A-21	K4	2018 Long-Term Incentive Plan Metrics
A-21	K5	Incentive Compensation Cost/Benefit Analysis

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

EMPLOYEE PENSION COSTS

Q. What are pension costs?

A. Pension costs are those costs related to pension benefits DTE Electric provides to the majority of its employees. The Company's defined benefit pension costs are recognized under U.S. GAAP Accounting Standard Codification (ASC) section

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715-30 (ASC 715-30). Costs for the Company's Savings Plan and other defined contribution benefits are recognized separately.

Q. What are the components of pension costs?

A. Pension costs are measured at the beginning of each fiscal year, under ASC 715-30, and include the following four pension cost components:

Service cost: Service cost represents the pension benefits earned by active employees, on a present value basis, during the current period. Service cost is based on expected benefits to be paid based on actuarial assumptions including current and projected salaries, expected employee turnover, and life expectancy.

Interest cost: Interest cost is the increase in the Projected Benefit Obligation (PBO) due to the passage of time during the current period. The PBO is the actuarial present value of benefits attributable to the pension benefit formula and service accrued to date discounted back to current dollars at a discount rate selected at each prior year-end. A discount rate of 3.70% was used in determining the PBO at the end of the historical test year and interest costs during the projected test year are similarly based on 3.70%. Measuring the PBO as a present value at the beginning of each fiscal year requires the accrual of an interest cost for the current period at a rate equal to the current year's discount rate. The discount rate used in measuring interest, as well as service costs for the 2017 historical test period, was 4.25%, based on information about the interest rate environment at the end of 2016 and projected benefit payments from the pension plan matched against a yield curve of corporate bond rates, rated Aa or higher, provided by our independent actuarial

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firm, Aon Hewitt and reviewed by the Company's independent public accounting firm, PriceWaterhouseCoopers, in connection with its audit of the Company's 2017 financial statements as filed with the Securities and Exchange Commission. The 3.70% discount rate used for determining interest and service costs during the projected test year reflects the assumption that high-quality corporate bond interest rates at the end of 2019 will remain essentially unchanged from those in December 2017.

<u>Expected return on assets:</u> Expected return on assets is an estimate of the expected investment return, during the current period, on the Market Related Value of the assets invested in the pension trust at the beginning of the year plus any planned funding for the year. While actual year-to-year investment returns can vary significantly, the expected return is determined based on long-term financial market expectations to avoid large swings in pension costs based on short-term investment performance. DTE Electric's expected annual return was 7.50% for the historical test year, as developed by Aon Hewitt and reviewed by PricewaterhouseCoopers in connection with its audit of the Company's 2017 financial statements as filed with the Securities and Exchange Commission. The expected return is reduced to 7.30% in 2019 in recognition of overall lower market returns.

<u>Amortization</u>: In addition to current period costs described above, pension costs also include the effect of the delayed recognition of prior period costs. This includes prior service costs and unrecognized gains and losses. Prior service costs arise from pension plan changes that will affect future benefits. When a plan provision is changed that will affect future benefit payments for existing employees

or retirees, the incremental change in the PBO liability is amortized over the average remaining years of service life of the active employees. Unrecognized gains and losses are changes in the amount of either the PBO or the plan's assets resulting from experiences different from those assumed in the actuarial assumptions. Most notably, since the discount rate and return on assets assumption are based on either point in time measurements or estimates, differences arise whenever a change is made in the discount rate or when the actual asset returns differ from long-term expectations. These gains and losses accumulate and the amount of the unrecognized balance in excess of a corridor equal to 10% of the greater of the PBO and the Market Related Value of assets is amortized based on a period equal to the average remaining service life of employees covered by the plans.

Q. How are these pension costs expected to change between the historical test year and the projected year?

A. As summarized on Exhibit A-13, Schedule C5.11.1, the Company's pension costs are projected to decrease from $127.0 million in the historical test year to $68.1 million in the projected test year. The decrease in pension costs between the two periods is due primarily to an increase in the Expected Return on Assets resulting from higher asset balances ($33.5 million) and a decrease in the amortization of losses ($23.2 million), partially offset by a lower long-term expected rate of return on assets ($7.5 million).

DTE Electric made pension contributions of $185 million in 2017 and $175 million in 2018, and is projecting contributions of $100 million in 2019 and $20 million in 2020.

The service cost component is expected to increase by $1.0 million between the historical and projected test years.

Interest costs are anticipated to decrease by $9.8 million between the historical and projected test years, primarily due to the reduction in the discount rate from the 4.25% rate used in measuring interest expense in 2017 to the 3.70% rate used in the projected test period.

Expected returns on plan assets are projected to increase by $26.0 million between the historical test year and the projected test year, thereby lowering pension cost, due to increases in pension assets arising from Company contributions during the projected period and the actual return on assets in 2017. These increases are partially offset by the reduction in the long-term expected asset return assumption from 7.50% in the historical period to 7.30% in 2019 and 2020.

The amortization of actuarial losses is projected to decrease by $23.2 million between the two periods. This decrease in the amortization of actuarial losses is due to the reduction in the balance of unrecognized losses as such losses are reflected in pension costs and the impact of actual return on assets in 2017 in excess of the expected return.

The prior service cost amortization is projected to decrease by $0.9 million between the historical test period and the projected test year, as prior service cost balances related to prior plan changes become fully reflected in cost.

The total projected pension cost of $68.1 million is subsequently adjusted for the impact of costs transferred and capitalized, as described by Witness Uzenski.

OTHER POST-EMPLOYMENT BENEFITS

Q. What are OPEB Costs?

A. For DTE Electric, OPEB costs are related to the provision of retiree medical, dental, prescription drug and life insurance benefits. OPEB is a cost recognized under U.S. GAAP Accounting Standard Codification (ASC) section 715-60. Similar to ASC 715-30, OPEB costs are determined under ASC 715-60 at the beginning of each fiscal year.

Q. What are the cost components of OPEB?

A. OPEB has the same basic cost components as pension costs. They are:

Service cost: Service costs are the portion of the expected post-retirement benefit obligation, on a present value basis, attributable to employee participation service during the current period. Service cost reflects actuarial assumptions of employee turnover, age at retirement and expected longevity. Service cost also depends on the estimated costs of providing these benefits subsequent to retirement and thus is impacted by both current medical cost levels and expected medical cost inflation.

Line No

Interest cost: Interest costs are the costs arising from the current period interest on the discounted Accumulated Post-Retirement Benefit Obligation (APBO). The APBO was discounted to today's dollars based on a discount rate of 3.70% at the end of the historical test year and the interest cost on the APBO during the projected test year is similarly based on 3.70%.

Expected return on assets: The expected return on assets is an offset to the costs of OPEB, based on the expected long-term return on assets invested in the qualified trust. The expected annual rate of return was 7.75% during the historical test year and is projected to remain unchanged through the end of the projected test year. The expected rate of return on the OPEB assets is higher than the rate assumed for pension assets because of a more aggressive investment strategy taken for the OPEB assets due to the longer duration of the OPEB liabilities and greater uncertainty of the total liability resulting from exposure to uncertain long-term healthcare cost inflation.

Amortization: This cost component includes the amortizations related to unrecognized gains and losses and prior service costs. Gains and losses, outside the 10% corridor described for pension expense, are amortized over the current estimated remaining service lives of active participants. Prior service costs are amortized over the estimated remaining service lives of active participants, at the time of the last plan change, to the age at which they are fully eligible for the benefits.

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No

Q. How are these OPEB costs expected to change between the historical test year and the projected test year?

A. As reflected on Exhibit A-13, Schedule C5.11.2, the Company's OPEB costs are projected to decrease from a negative $16.3 million in the historical test year to a negative $21.3 million during the projected test year for a decrease in OPEB costs of $5.0 million. This reduction in OPEB costs is primarily due to an increase in the Expected Return on Assets resulting from higher asset balances ($11.1 million) partially offset by a reduction in the amortization of Prior Service Costs ($9.8 million).

Q. What are the underlying causes of the changes in OPEB costs between the historical test year and the projected test year?

A. The cost components for OPEB are reflected on Exhibit A-13, Schedule C5.11.2 for the historical test year and projected test year. These include the following changes:

Service costs are estimated to decrease by $0.7 million between the two periods. This decrease reflects the impact of updated retiree health care inflation assumptions and updated mortality tables.

The interest cost is expected to decrease by $2.8 million between the two periods due to the reduction in the interest rate from the 4.25% rate used in 2017 in measuring interest costs to the 3.70% rate used in the projected test year.

The expected return on assets is projected to increase by $11.1 million between the two periods due to the growth in assets from both actual returns in 2017 and expected return in subsequent years.

The amortization of (gains)/losses are essentially unchanged between the two periods. Finally, the amortization of prior service costs is projected to increase by $9.8 million between the two periods due to the amortization of balances related to the significant benefit plan changes made in 2012 and 2013 being completely amortized in 2017.

The total projected OPEB cost of negative $21.3 million is adjusted for the impact of the costs transferred and the portion of OPEB costs capitalized, as described by Witness Uzenski.

Q. Has DTE Electric externally funded its OPEB costs?

A. Yes. DTE Electric has funded the OPEB costs included in the Company's revenue requirement adopted by the Commission in previous orders through a VEBA trust and an IRC Section 401(h) trust.

Q. Will the Company externally fund its OPEB liability in the future?

A. No. Since the Commission approved the Company's proposal in Case No. U-18255 to continue the deferral of the projected negative OPEB expense initially approved in by the Commission in Case No. U-17767, the Company's current and projected revenue requirement reflected does not include any OPEB expense and thus there is no obligation for the Company to externally fund its OPEB liability.

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No

Q. Is the negative OPEB expense included in the Company's proposed revenue requirement?

A. No. Witness Uzenski sponsors the Company's proposal to continue to defer the projected negative OPEB expense to the accumulated regulatory liability. Thus, the projected negative OPEB expense is not reflected in the Company's proposed revenue requirement.

Q. What is the basis for the projected cost increase in the New Hire Retiree VEBA?

A. The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.10 reflect the costs of the plans that are offered in lieu of the traditional retiree healthcare plan for eligible employees. The increase in New Hire Retiree VEBA expense from $4.2 million in the historic test year to $7.5 million in the projected test year, which reflects a 28% per year average increase, is primarily due to the increase in plan participants arising from the hiring of new employees, based on recent experience.

Q. What other post-retirement benefits are offered by the Company?

A. The Company also offers an Employee Savings Plan, commonly referred to as a 401(k) plan. The Employee Savings Plan allows eligible employees the opportunity to put aside a certain percentage of their annual earnings that the Company matches up to 6% of annual salaries and wages for non-represented employees and for most represented groups. In addition, employees, hired after the defined benefit pension plan was closed to new hires, receive an additional employer contribution of 4% of annual salaries and wages. The Employee Savings Plan costs, on Exhibit A-13, Schedule C5.10, are projected to increase from $27.2 million in the historic test year to $34.0 million in the projected test year based on the projected 3.0% annual pay increases, as well as the impact of the higher employer contributions for newly hired employees that participate exclusively in the defined contribution retirement plan. The combined effect of higher salaries and the increase in new employees is expected to increase the Company's Employee Savings Plan costs by 10% per year.

ACTIVE EMPLOYEE BENEFIT PROGRAMS

Q. What other benefit programs are offered to active employees?

A. The Company offers a competitive active employee benefits package for the attraction and retention of a skilled workforce. The major components of the benefit package include a choice among several health care plans, dental plans, vision care and life insurance. The components of these benefits are summarized on Exhibit A-13, Schedule C5.10, on lines 9 through 15. The Health Care, Dental and Vision costs are projected to increase from $50.3 million in the historic test year to $59.3 million in the projected test year based on the projected medical plan trend of 7.00% in 2018 and 7.50% in 2019 and 2020. Benefit Plan Administration Fees are projected to increase from $8.3 million in 2017 to $8.7 million for the projected test year due to the overall rate of inflation as measured by the Consumer Price Index. Life Insurance costs are projected to increase from $1.4 million in the historical test year to $1.5 million in the projected test year, which reflects the 3.0% annual labor escalation assumption, since employer paid life insurance provided to employees is based on the employee's annual pay.

Q. What is the basis for your future medical plan trend for active health care costs used for the projected period in this proceeding?

A. Annual medical plan trend factors of 7.0% for 2018 and 7.5% for 2019 and 2020 were applied to the actual active healthcare costs expensed in 2017. This escalation assumption is based on projections for health care trends provided by the health care experts at Aon Hewitt, as reflected on Exhibit A-13, Schedule C5.10.1.

Q. How is this trend factor determined?

A. Aon Hewitt's Allowed Trend is based on its internal guidance, which represents a consensus expectation for medical and prescription drug cost the Aon Health and Benefits practice developed across all of their sub-practices including actuarial, pharmacy, health transformation and innovation. Other medical and prescription cost sources taken into consideration include government reports, Standard & Poor's DJI Healthcare Indices and other trend surveys. Current and anticipated market developments are also modeled for their expected impact on trend. The Allowed Trend is subsequently adjusted for the Company's average fixed plan design leveraging in order to develop the future Medical Plan Trend.

Q. How are medical trends defined?

A. There are three different types of medical trends. The first type of medical trend is **Allowed Trend**, which includes unit cost, utilization and mix/severity of claims. Unit cost encompasses the cost of medical service charged by healthcare providers and is affected by the contracts between medical providers and insurance carriers. Other factors that can affect unit cost include, but are not limited to, medical providers seeking higher reimbursements from private insurers/companies to

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No

compensate for lower Medicare and Medicaid reimbursements. Utilization involves the number of medical and prescription services performed. The mix/severity of claims refers to the complexity or intensity of the medical services rendered. This category is best viewed as simple versus complex procedures and the frequency of the simple or complex procedures.

The second type of medical trend is **Medical Plan Trend**, which includes the Allowed Trend adjusted for fixed plan design leveraging. Medical Plan Trend is what the Company uses for forecasting its future medical costs. One part of projecting medical costs is to assume the current healthcare plan design will remain fixed in the forecasted periods.

Plan design and employee contributions are assumed to not change in the forecast period for two reasons. First, it is standard practice when establishing baseline healthcare cost to assume the current plan design and employee contributions will remain the same for the forecast period because those are the current plan provisions that will automatically continue unless mandated to change by another contract provision such as a collective bargaining agreement or an unforeseen future regulation. Second, union employee benefits are set by collective bargaining agreements and can only be changed through negotiations and agreement between the Company and the unions. Third, even though non-represented employee benefits are not subject to a collective bargaining agreement, the Company does not anticipate any further significant plan design or employee contribution changes in the near future.

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No

Fixed plan design leveraging reflects the effect that cost-sharing plan design features, such as deductibles, coinsurance, copays and out of pocket maximums, have on the Company's costs.

The third type of medical trend is **Medical Plan Trend After Changes**, which includes Medical Plan Trend plus employer-specific changes such as the effect of the aging of beneficiaries, other demographics changes, expected plan design changes and program changes, which may cause Medical Plan Trend After Changes to vary from Medical Plan Trend.

Q. Do you have any collaborating sources that support the reasonableness of Aon Hewitt's projection that active health care costs will increase by 7.0% in 2018?

A. Yes. A study released by PwC's Health Research Institute projects that medical costs in 2018 will increase by 6.5% relative to 2017. This report is reflected in Exhibit A-13, Schedule C5.10.2.

Q. Have the Company's managed care carriers provided their 2018 cost projections for the Company's active employee medical plans?

A. Yes. The Company's three managed care providers' active health care premium increases for non-represented employees in 2018 compared to 2017 were 7.6% for HAP, 7.5% for Priority Health and 5.5% for Blue Care Network.

Q. Did the Commission adopt the use of the Company's projected escalations in active health care expense in DTE Electric's most recent rate case?

A. No. In the Commission's Order issued April 18, 2018 in Case No. U-18255 the

Line No

Commission adopted a three-year average of actual percent changes over the prior year for 2014 through 2016.

Q. Is the use of historical increases in active health care expense a reliable predictor of future increases?

A. No. The Company's actual active health care expenses can vary from year to year for several reasons. First, the actual expense is impacted by the mix and severity of medical treatments administered to employees and their eligible dependents. Since the Company is self-insured for a majority of its active healthcare benefits, the impact of changes in usage can have a dramatic impact on the Company's annual costs. Second, the Company's active health care expenses are also impacted by the number of employees and dependents eligible for coverage, which can vary from year to year due to both changes in the number of employees and the number of employees that opt out of the Company's medical plan. Third, plan design changes can have a significant impact on annual changes in active health care expenses. For example, in 2014 the Company implemented significant increases in the level of employee cost sharing with health care plan design changes including increases in deductibles and co-pays that were designed to produce about a 3% reduction in the Company's annual active healthcare costs in the year implemented.

All of these factors can have a significant impact on year-to-year changes in the Company's active health care expenses, but it is not reasonable to presume the changes in employee plan participation, healthcare plan utilization or plan design changes will recur in the future.

Line No

Q. Why is it unreasonable to presume these historical changes will recur in the future?

A. First, variations in actual usage in medical services can result in year-to-year volatility that can mask long-term health care cost trends. For example, while the actual change in active healthcare claims per employee was down 0.6% in 2017 compared to 2016, the claims per employee was up 9.0% in 2015 compared to 2014. This demonstrates the inherent volatility in health care costs.

Plus, the number of employees that have opted out of the Company's medical plans has increased in recent years, and thus lowered the Company's healthcare costs. Specifically, since 2012, the impact of employees opting out of the Company's health care plans has reduced the Company's active health care expense in 2017 by over $3.5 million. The growth in the level of employees opting out over the last five years is simply unsustainable.

Second, future government health regulations may affect the unit cost of medical and prescription services. For example, if additional medical services are required to be covered by individual and employer medical plans, the overall utilization and demand may increase for those services and put upward pressure on unit costs. If pharmaceutical drug patents scheduled to expire in the near term are extended due to Federal Drug Administration patent extension rulings or patent legal proceedings, pharmaceutical drug competition of lower cost generic prescriptions may be delayed. Additionally, if Medicare or Medicaid substantially reduce payments to providers or eliminate preferred drugs, the providers and pharmaceutical companies may negotiate with insurance carriers to increase their

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No

payments for services and prescriptions that are paid by private employer sponsored medical plans.

Further, while plan design changes can produce a reduction to the rate of annual increase in active health care costs in the year of implementation, the impact on the annual rate of change is non-recurring which cannot be presumed to impact the rate of change in future health care cost levels. Current costs reflect plan design changes that have already been implemented. As a result, in order for the Company to realize the same savings from plan design changes that it has experienced in the past, the Company must implement additional plan design changes. However, plan design changes are limited by how high employers can set medical out-of-pocket maximums as defined under the Affordable Care Act as well as by the competitive market. The Company must have competitive benefits to be able to attract and retain a skilled and qualified workforce. Since the Company's benefit programs are already benchmarked to the midpoint of its peers, it is simply unrealistic to expect the Company to continue to reduce health care benefits at the same pace as it has in the past. Moreover, since health care benefits are subject to collective bargaining agreements for the Company's unionized employees, any further changes in plan design are dependent on the results of future negotiations.

For these reasons, historical annual changes in the Company's actual active health care expenses are unreliable predictors of the rate of change in future active health care expenses.

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No

Q. What are Other Employee Benefits Costs?

A. The costs of the Company's Other Employee Benefits are reflected on Exhibit A-13, Schedule C5.10. These costs include a variety of other benefits including Accrued Vacation, Supplemental Severance Plan, Long-Term Disability claims, costs associated with the Affordable Care Act (ACA), General Benefits expenses, the Company's Wellness Program as well as the Supplemental Savings Plan and Deferred Compensation Plan.

Q. What is the basis for your projection of the Company's Accrued Vacation expense?

A. Accrued Vacation expense can vary from year to year based on the timing of the usage of earned vacation time by employees as well as forfeitures and the value of unused vacation at year-end. The MPSC Staff has recognized this volatility in DTE Electric's most recent rate case wherein the Staff proposed the use of an historical average of the annual expense. Accordingly, the projected Vacation Accrual expense reflected on Exhibit A-13, Schedule C5.10 is based on the average of the recorded expense for the most recent five years, which is then escalated by the projected 3% labor annual cost increases through the end of the projected test year.

Q. What is the basis for the Supplemental Severance Plan cost projections?

A. Aon Hewitt developed the projected cost of this plan. The Supplemental Severance Plan is a pension benefit enhancement adopted in 2016 that provides certain eligible employees that are covered by the MCN Energy Group, Inc. (MCN) Traditional pension plan a lump sum payment that is designed to provide retirement benefits comparable to DTE Energy's. Since certain employees of both DTE

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Electric and DTE Energy Corporate Services LLC are covered by the traditional MCN pension plan because they were employees of MCN or its subsidiaries at the time of DTE Energy's merger with MCN, the cost of this supplemental severance plan is borne by DTE Electric to the extent the labor costs for the affected employees is recognized by DTE Electric.

Q. How have you developed the projections for the other items included in Other Benefits Costs?

A. Generally, these items have all been projected based on the actual amounts recorded in 2017 escalated at the overall rate of inflation as measured by the Consumer Price Index through the end of the projected test year. Disability Expenses have been escalated at the 3.0% annual labor cost rate recognizing that disability claims relate to employee labor. The elimination of the ACA costs reflects the expiration of the transitional reinsurance fee that expired in 2016.

Q. What is the basis for the adjustments to the Supplemental Savings Plan costs for the projected test year?

A. The adjustments to the Supplemental Savings Plan (SSP) costs reflect an increase in the Company's matching contributions based on the 3.0% projected salary escalations and the earnings on the designated investments. Since the Company does not separately fund the Company's matches to the employees' contributions, the earnings and losses from the employees' directed investments is a cost incurred by the Company. The projection reflects an annual return on the investments of 7.30%, consistent with the expected long-term return on investments used in the determination of the Company's pension costs in the projected test year.

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No

Q. Did the Commission address the recoverability of the SSP in the Company's most recent rate case?

A, Yes. In its Order issued on April 18, 2018 in Case No. U-18255 the Commission approved the inclusion of SSP costs in the Company's revenue requirement, but suggested that in future cases it would be helpful if more details on the SSP were presented, including whether it is available exclusively to high-level Executives.

Q. What is the SSP?

A. The SSP is a non-qualified benefit plan that does not meet the requirements under the Internal Revenue Code to be eligible for certain tax advantages, such as the deductibility by the Company of any contributions. Each year, the Internal Revenue Service establishes the limitations on employee annual eligible compensation and annual contributions to tax advantaged plans. To the extent an employee's annual eligible compensation or annual contributions, including the Company's match, to the Company's qualified plan exceed the IRS limitations, employees that are Director level and above are eligible to participate in the SSP. By participating in the SSP, employees are able to accrue benefits that are identical to the benefits available under the qualified savings plan. As such, the SSP is a "make-whole" benefit plan that merely puts the participating employees in the same place they would be in the absence of the IRS limitations.

Q. Is participation in the SSP limited to high-level Executives?

A. No. Participation in the SSP is available to all Director level and above employees that have exceeded the annual earnings and contribution limits prescribed by the IRS. Thus, of the total active participants at December 31, 2017 of 117 employees,

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No

more than 75% of the participants are in positions below the Vice President level.

Q. What is the basis for the adjustments to the Deferred Compensation costs?

A. Similar to the Supplemental Savings Plan, the Company's recorded costs are based on the return on the investment directives of the participating employees since the deferrals are not funded by the Company. The projected Deferred Compensation costs are based on the expectation that the designated investments will earn an annual return of 7.30%. The increase in the projected expense is based on the higher investment balances arising from accumulated earnings on the investments.

Q. Does the Company have other retirement benefits?

A. Yes. The Company also offers an Executive Supplemental Retirement Plan (ESRP) and a Supplemental Retirement Plan (SRP). Due to the Commission's traditional disallowance of the costs of these plans in prior rate cases, the Company has not included the cost of these plans in the Company's proposed revenue requirement.

Q. What is the Company's total projected employee pensions and benefits expense for the projected test year?

A. The total projected employee pensions and benefits costs of $161.9 million is adjusted for the impact of the portion of these costs to be capitalized, the costs transferred, and the elimination of costs allocated to the Company's surcharge programs, as described by Witness Uzenski, resulting in a net employee pensions and benefits expense of $146.9 million.

Line No

LABOR COST ESCALATION

Q. What annual labor cost escalation assumptions are appropriate for the projected test period?

A. Annual labor cost escalation assumptions are required for both the Company's represented and non-represented employees. Based on existing Collective Bargaining Agreements, the Company is obligated to increase pay rates by approximately 3.0% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions.

Non-represented employee compensation is generally adjusted annually based on a review of pay practices of other employers, overall price level changes and internal pay equity. Pursuant to these reviews, the Company implemented base pay adjustments in March 2018 that resulted in an overall pay increase of 3.0%. In addition to the annual pay adjustment program, employees also receive pay increases based on promotions.

Based on the above, I have determined that annual escalations of 3.0% for 2018, 2019 and 2020 are a conservative estimate of the Company's expected increase in its labor rates.

EMPLOYEE COMPENSATION

Q. What is the Company's compensation philosophy and framework for non-represented employees other than Executives?

Line No

A. Non-represented employees are those employees not covered by Collective Bargaining Agreements with union organizations whereas Executives are generally defined as those at the Vice President level and above. DTE Electric's compensation philosophy is to provide pay programs that: 1) attract, retain and motivate employees; 2) ensure that pay is externally competitive; and 3) differentiate total rewards based on both organizational unit and individual contributions and results.

At DTE Electric, total annual compensation for non-represented employees has two primary components: base pay and variable pay. Employee base pay is reviewed annually and adjusted (if appropriate) based on the position relative to what the external market pays for similar positions and individual performance. Variable pay is based on the achievement of Company, departmental and individual results reflecting a balance of customer, operational and financial objectives. Variable pay consists of short-term incentive plans and a long-term incentive plan. Participation in the long-term incentive plan is open to all Managers, Directors and Executives as well as an additional 10% of non-represented employees that are eligible for discretionary awards.

Q. How does the Company's philosophy regarding variable pay compare with that of its peer group?

A. Variable pay is a component of total compensation practices for the vast majority of energy companies for their non-represented employee population. Base pay is set lower than it otherwise would be because of the variable pay component. Thus, when considered in tandem, the Company's base and variable pay plans provide a framework of market-based total annual compensation pay opportunities for non-represented employees. It is the total annual cash compensation, as represented by these two components, that prospective and current employees use to gauge whether or not DTE Electric's compensation is competitive with other potential employers.

Q. How does the Company's non-represented compensation philosophy and framework provide benefits to customers?

A. DTE Electric's compensation philosophy and framework provide a benefit to customers by attracting and retaining employees with the requisite skills and experience to ensure safe, reliable and high quality customer service delivery, and by recognizing and rewarding effective and efficient performance. A competitive compensation policy also serves to effectively retain employees so as to minimize the risks and costs of high employee attrition. This philosophy directly benefits all customers by providing a high level of service at a competitive cost and provides incentives to focus future job performance on those activities that provide the most benefit to customers.

Q. What is the comparative market used by the Company to determine the external market for compensation?

A. The comparative market for positions varies based on the specific job. Some jobs are compared to those in utilities of similar size (e.g. revenue, number of employees, etc.), other jobs to general industry located in Southeastern Michigan, and yet other jobs to general industry located within the United States. The relevant market will depend upon the requisite skills and abilities required of the job and the nature of the recruitment source. For example, the comparative market for an administrative assistant is the general industry within Southeastern Michigan while the comparative market for a manager of nuclear operations is utilities within the Midwestern United States (primarily), or within the entire United States (secondarily).

Q. How is benchmark data obtained from the comparative market?

A. The Company participates in and/or purchases many published salary surveys from a number of different organizations. The surveys typically report median base salary, target incentives and median total cash compensation by job classification.

Q. How are base salaries determined?

A. Base salaries are targeted around the median base salary levels of the comparative market as adjusted for differences in company size and scope where appropriate. All non-executive positions are placed in a salary zone based on external benchmarking. The mid-point of the salary zone is based on the market median for comparable work in comparable companies. A range is provided above and below the midpoint to allow for differentiation based on applicable skills and experience, as well as demonstrated performance. The ranges are reviewed periodically to ensure they remain competitive in the external market.

Q. Does the Company benchmark the variable component of compensation?

A. Yes. The Company reviews several surveys that provide information on a number of variable pay indices. In addition, the surveys report data for employee groupings like exempt employees, non-exempt employees, managers and executives.

Line No

Q. Could DTE Electric raise employees' base pay to the market levels for total compensation in lieu of providing variable pay opportunities to maintain a competitive total compensation levels?

A. Yes, it could. However, raising employees' base pay to the total compensation market levels would result in a higher level of fixed costs tied to base salaries, such as certain defined contribution benefit plans, life insurance, disability insurance and other salary-based employee benefits. Moreover, given the well-recognized motivational value of variable pay compensation programs, as described below, delivering employee compensation solely in fixed salary would diminish the performance incentive for employees to provide superior service to customers. Annual incentives ensure that individuals have an element of "at risk" compensation that allows DTE Electric to differentiate pay based on performance and allocate compensation to those employees that are most deserving.

EXECUTIVE COMPENSATION

Q. How do you define an Executive?

A. Executives are generally defined as employees at Vice President level and above.

Q. How does the compensation program for Executives differ from that for non-executives?

A. The compensation program for Executives differs in three respects. First, the comparative market for compensation benchmarking is defined as a specific group of peer companies from which data are obtained through a custom study performed every two years. Second, a higher proportion of Executives' compensation is delivered in the form of variable pay. The third way in which the Executive compensation program differs is with respect to governance. The compensation programs for Company Executives must be approved by the Organization and Compensation Committee of the DTE Energy Board of Directors.

Q. What is the comparative market for Executive compensation?

A. The comparative market for Executive compensation consists primarily of utilities (including utility holding companies), broad-based energy resource companies and certain non-energy related companies selected on the basis of revenues, financial performance, geographic location and availability of compensation information.

Q. What are the key components of the Executive Compensation Program?

A. The key elements of the Executive Compensation Program are base salary and variable pay (annual incentive plan and long-term incentive awards).

Q. How are base salaries determined?

A. Base salaries are targeted around the median of the comparative market. Appropriate methods of measurement are used to take into account differences in company size and scope. In addition, midpoints are established for those Executives whose jobs cannot be easily matched in the comparative market. These midpoints are designed to allow adequate differentiation for (i) individual potential, (ii) contributions made, and (iii) the length of time the Executive has been in his or her position, and are assessed periodically to keep pace with market movement.

Line No

VARIABLE PAY PROGRAMS

Q. Has the Commission previously addressed the issue of the inclusion of variable pay program expense in the Company's revenue requirements?

A. Yes. In the Commission's Order in the Company's most recent general rate case (Case No. U-18255), the Commission found that while the customer benefits of the operating measures exceeded the expense of the short-term incentive compensation plans, there was not sufficient evidence to show that the benefits of the financial measures were significant, and thus the Commission did not authorize recovery of the short-term incentive compensation expense related to the financial measures. The Commission also disallowed the long-term incentive compensation plan expense on the basis that the financial measures included in the plan were too closely aligned with shareholder interests.

Q. Does the inclusion of financial measures in variable pay programs provide benefits to customers?

A. Yes. While financial performance metrics such as operating earnings and cash flow may seem to be exclusively focused on creating increased value to shareholders, such a conclusion ignores that the motivation provided to employees to operate cost efficiently with a focus on continuous improvement, while benefitting a company's financial metrics, also benefits customers through lower revenue requirements and higher quality customer service. That is, if a company wishes to create a performance based culture by use of variable pay programs designed to improve an organization's overall effectiveness, financial metrics are often used to create a common motivating driver that has the advantage of being measured on a comprehensive, timely and comparable basis. Thus, financial based measures

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motivate employees to improve their work processes to use fewer resources thereby simultaneously producing improved performance. The resulting improved cost effectiveness benefits customers through lower revenue requirements. While the salutary effects of superior financial performance made possible through the company's improved cost efficiencies may result in temporary benefits to shareholders, the benefits to customers of the resulting reduced revenue requirements is permanent as new revenue requirements reflecting the lower cost levels are set by the Commission in subsequent rate cases. Thus, due to the setting of revenue requirements based, in part, on historical costs, the long-term benefits to customers will exceed the short-term benefit to shareholders.

Q. Are there any indicators that the Company has created cost efficiencies in recent years?

A. Yes. DTE Electric's normalized O&M expenses from 2009 through the end of the projected test year are substantially less than they would have been had the Company's O&M expense increased by the rate of inflation. Indeed, the Company's projected O&M expenses for the 12 months ended April 30, 2020 are over $226.2 million less than they would have been had the Company's 2009 O&M increased by the Consumer Price Index. This indicates the Company has realized both significant savings and improvements in operating efficiencies through the deployment of a Continuous Improvement campaign throughout the Company. I believe that the motivational value of the Company's incentive compensation plan was a key enabler in the success of the Continuous Improvement program and the cost efficiencies derived from its deployment.

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Q. Are there other customer benefits to the use of financial measures in the Company's variable pay programs?

A. Yes. In addition to the motivational value of connecting total compensation to the Company's earnings, an emphasis on cash flow metrics allows the Company to maintain its existing credit ratings, which results in lower cost of capital to the Company and thus lower revenue requirements. Moreover, a financially strong company will have greater access to the capital markets, which is especially important in light of DTE Electric's significant capital investment programs.

Q. Are there any employee motivational advantages to including an incentive based compensation component in a company's overall compensation design?

A. Yes. The underlying principle of incentive compensation plans is to provide a motivational impetus for improved organizational performance. That is, an effective incentive compensation plan provides a "pay-for-performance" environment that seeks to motivate individual and team achievement of measurable goals.

Q. Is there any evidence that incentive based compensation is effective in motivating improved organizational performance?

A. Yes. A comprehensive analysis of the impact of incentive compensation plans on organizational performance concluded that programs that provide tangible incentives for achievement of certain goals leads to a 27% increase in organizational performance. (Incentives, Motivation and Workplace Performance: Research & Best Practices, The International Society for Performance Improvement, Spring 2002). This study observes that the source for such

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organizational performance improvements are that employees 1) value their work tasks more, 2) have more self-confidence and esteem for their employers, 3) are more persistent at work tasks, and 4) strive for high levels of accomplishments. Moreover, this study notes that long-term incentive plans provide even greater performance improvements.

Q. Are there other advantages of a variable pay compensation program?

A. Yes. The opportunity for annual incentive rewards ensures that individuals have an element of "at risk" compensation that allows the Company to differentiate pay based on performance and allocate compensation to those employees that are most deserving. Thus, incentive-based compensation is an important tool to drive performance improvement, particularly in a service-based industry like the utility industry.

Q. Are variable pay programs a typical element in compensation at other companies?

A. According to a February 2014 WorldatWork and Deloitte Consulting study, 99% of companies had short-term incentive programs in 2013 and 88% of companies had long-term incentive programs in 2013, representing an increase from 95% and 61%, respectively, as reflected in a similar study for 2011. This indicates that variable pay programs are an increasingly prevalent practice among the vast majority of companies. (Incentive Pay Practices Survey: Publicly Traded Companies, WorldatWork and Deloitte Consulting, February 2014).

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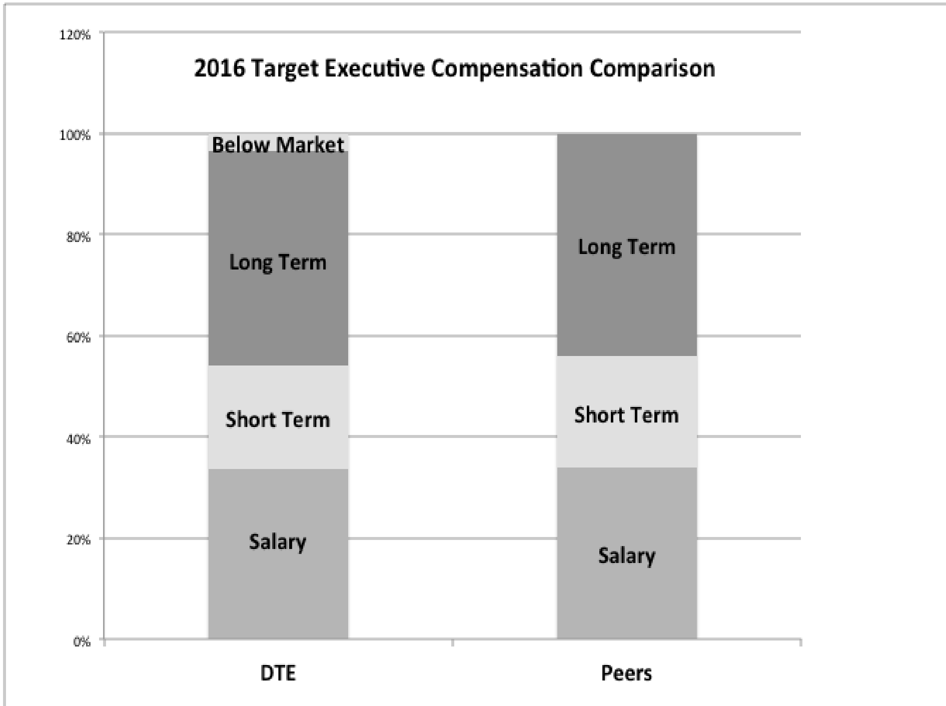
Q. Does the Company's variable pay program result in unreasonable compensation?

A. No. As explained above, the Company benchmarks its total compensation for both Executive and non-executive employees against relevant peers, inclusive of the variable component related to incentive compensation, that establishes a mid-point salary range based on the median market level. Moreover, based on a recent survey by Aon Hewitt, the total compensation of DTE Energy's Executives is about 4% less than the average of its peers based on Target level performance, inclusive of the long-term incentive compensation. Thus, the Company's variable pay programs are merely a component of the total compensation policies required for the Company to be competitive with its peers, rather than a supplement. Indeed, in the absence of the variable pay programs, total compensation for DTE Energy's Executives would be substantially less than its peers, since about 65% of total compensation is delivered through variable pay programs, by both DTE and its peers.

Q. How do the components of the Company's total compensation practices compare to the Company's peers?

A. Based on the Aon Hewitt survey referenced above, a comparison of the relative magnitude of the Company's salary, short-term and long-term pay components for Executives to the 50 percentile of its peers is reflected in the table below.



Q. What are the specific components of the Company's variable pay programs?

A. The Company provides variable pay programs to both its Executive and non-represented employees. Short-term incentive plans are provided through the Annual Incentive Plan (AIP) and Rewarding Employees Plans (REP). Additionally, a multiple year incentive plan, which is available to all managers and above and up to 10% of other non-represented employees, is provided through the Long-Term Incentive Plan (LTIP).

Q. What is the AIP?

A. The AIP is a short-term variable pay program available to senior management level employees to motivate performance. The defined measures and weightings in this plan for DTE Electric, other than Nuclear Generation, and DTE Energy Corporate

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Services LLC include financial performance (40%), customer satisfaction (15%), employee engagement (15%) and operating excellence (30%). The specific 2018 measures and performance targets for DTE Electric are reflected on Exhibit A-21, Schedule K1. For each measure, a Target is established for which a "normal" payout will be earned. Performance less than Target but above a minimum Threshold results in a pay out between 25% of Target and Target, and performance up to the Maximum level results in a pay out of up to 175% of Target. The measures and weightings for Nuclear Generation are reflected on Exhibit A-21, Schedule K2. For Nuclear Generation, the weighting of the financial measures is reduced to 20%, the measures related to customer satisfaction are eliminated, employee engagement weighting is set at 15% and operating excellence is increased to 65%. The differences in weightings for Nuclear Generation reflects the heightened importance of operations at Fermi 2. The measures and weightings for DTE Energy Corporate Services LLC are reflected on Exhibit A-21, Schedule K3.

Q. Which employee classification is eligible to participate in the AIP?

A. All Executive level employees, generally Vice President and above, and Directors participate in the AIP. All other non-represented employees are eligible to participate in the Rewarding Employees Plan (REP).

Q. What are the components of the REP?

A. The REP is identical to the AIP except that Threshold performance is at 50% of Target and the Maximum performance payout is 150% of Target. In addition, the Gallup survey of employee engagement measure is excluded in recognition that the Company's leadership is responsible for providing an environment of high employee engagement. The total Customer Satisfaction weighting is increased to 20% for DTE Electric. The weightings of the measures for the OSHA Recordable Incident Rate and the OSHA DART rates both increased to 5% for DTE Electric and 7.5% for DTE Energy Corporate Services LLC. The total Operating Excellence measure is increased to 25% for DTE Energy Corporate Services LLC, with each of the individual measures increased proportionately, to reflect the direct impact employees can have on such measures.

Q. What are the financial measures included in the AIP and REP?

A. There are three financial measures for DTE Electric and Nuclear Generation employees that are designed to create a clear line of sight for all employees to focus on performance excellence by rewarding employees when the Company is financially successful.

1) DTE Electric's Operating Earnings objective is based on realizing a 10.1% return on equity, which was the authorized return on equity adopted by the Commission in its Order issued January 31, 2017 in Case No. U-18014.

2) DTE Electric's Adjusted Cash Flow is similarly based on the authorized return on equity but reflects the higher capital expenditures arising from the significant investments required to upgrade DTE Electric's system. The inclusion of a cash flow measure recognizes the importance of DTE Electric maintaining a high credit rating to allow continued access to the capital markets at reasonable costs and terms.

3) DTE Energy's Operating Earnings per Share measure is based on the midpoint of current earnings guidance and is intended to create a whole-enterprise orientation for all operating unit employees. The financial measures for DTE Energy Corporate Services LLC reflect DTE Energy's Operating Earnings per Share and Adjusted Operating Cash Flow.

Q. What are the measures related to customer satisfaction?

A. Four customer satisfaction measures are intended to focus leaders and employees on improving the experience that our customers have in their interactions with the Company.

1) The Customer Satisfaction Index measure relates to six key drivers of customer satisfaction, including reliability and pricing, as measured by J.D. Power. The 2018 Target is to achieve an 86th percentile ranking in the J.D. Power National Peer Set.

2) The first Customer Satisfaction Improvement Program measure is based on customer complaints collected through the operation of the DTE Cares program as determined by use of Defects per Million Opportunities (DPMO) analysis. The DPMO calculation includes defects identified through a variety of customer interactions, including call center, field operations and home energy consultations. The 2018 Target reflects an 8% decrease in the DPMO from 2016 results.

3) The second Customer Satisfaction Improvement Program measure relates to the measurement of how successful the Company is in increasing the proportion of delighted customer interactions based on call center activity as well as field and self-service interactions. The 2018 Target for the measure, referred to as +1PMO,

is a 5.0% improvement in the number of highly satisfied customer interactions compared to 2017 results.

4) The MPSC Customer Complaints measures the number of formal complaints made to the MPSC regarding DTE, as reported to the Company by the MPSC. The 2018 Target of 1,681 represents about an 8% decrease in the number of complaints made to the MPSC in 2016.

Q. Why do some of the Customer related performance measures reflect Targets that reference 2016 performance rather than 2017 actual results?

A. In April 2017, the Company deployed a new Customer Relationship and Billing System, entitled Customer 360. As a result, the Company experienced a significant surge in customer call volumes and increased time required to resolve customer issues as the Company's customer service representatives became more acclimated to the features and capabilities of the new system. Since the results for the customer satisfaction related measures were distorted by the implementation of Customer 360 in 2017, the performance improvements for 2018 were set based on 2016 results.

Q. What are the Employment Engagement measures?

A. The three Employee Engagement measures encompass the areas of employee engagement as measured by the Gallup survey and is complemented by two employee safety related measures.

The Gallup measure of Employee Engagement is reflective of the direct correlation between the level of active employee engagement and the performance of an organization. The 2018 Target of 4.32 represents a grand mean of the results of the semi-annual Gallup surveys of employees. Employee Engagement is a statistically significant measure of the level of commitment employees have to an organization's success and thus should not be confused with a measure of mere employee satisfaction. The 2018 Target of 4.32 represents the continuation of top decile performance.

The Company has two safety related measures.

1) Recordable injuries per 100 employees divided by the actual number of hours worked, as defined by the Occupational Safety and Health Administration (OSHA). This is a standard measure of safety performance used nationwide. The measure is intended to create a heightened focus on the importance of safety in the workplace. The .62 Target for 2018 represents top decile performance and a 6% improvement compared to 2017 results.

2) OSHA Days Away, Restricted or Transferred (DART) rate. Target performance in 2018 reflects a DART rate of .33 per 100 employees divided by the actual number of hours worked. The 2018 Target represents a continuation of top decile performance and an almost 3% improvement compared to 2017 results.

Q. What are the Operating Excellence measures for 2018?

A. DTE Electric has seven Operating Excellence measures that reflect specific operating priorities for 2018 to motivate the achievement of certain operating objectives important to the Company, its customers and the Commission.

Electric Distribution Reliability measures pertain to the average number of minutes of interruption for all customers served in all weather conditions (All Weather System Average Interruption Duration Index (SAIDI)) and average number of minutes per interruption for customers experiencing an interruption when there is not a declared storm ("Blue Sky Customer Average Interruption Duration Index (CAIDI)). The All Weather SAIDI 2018 Target is 240 minutes and the Blue Sky CAIDI Target is 129 minutes.

The Fossil Power Plant Reliability measure reflects the percentage of time the plants are not available for power production due to a random outage, referred to as the Random Outage Factor (ROF). The 2018 Target is 7.3%, which represents first quartile performance of the industry benchmark, as compiled by the North American Electric Reliability Corporation.

Nuclear Power Plant Reliability measure addresses the percentage of time that Fermi 2 is available to generate power, exclusive of planned outages. The 2018 Target of 95% reflects a performance level that is higher than the actual performance at Fermi 2 over four of the past five years.

The three additional Operating Excellence measures that relate solely to nuclear generation include measures focused on nuclear plant performance. The nuclear generation measures relate to Refuel Outage Duration, Nuclear Power Plant Performance Matrix and Nuclear Power Plant Reliability Matrix. The Target for Refuel Outage Duration is for the 2018 refueling to be completed within 32 days. The Nuclear Power Plant Performance Matrix and Reliability Matrix performance measure reflect a number of specific measures that are highly correlated to plant performance and reliability.

Q. Are there other AIPs and REPs that impact DTE Electric's expenses?

A. Yes. In addition to the DTE Electric measures described above, there are also separate AIPs and REPs in place for the Nuclear Generation unit of DTE Electric and for corporate staff employees at DTE Energy Corporate Services LLC (LLC) that provide services to all DTE Energy business units.

Q. Do the measures reflected in the Targets require superlative performance?

A. Yes. All of the targets will require excellent organization performance levels. Moreover, since the actual payouts to employees are subject to adjustment for individual performance, employees are provided with a clear line of sight regarding the importance of their individual contributions to the achievement of the Company's objectives, and thus are motivated to exceed their individual job performance expectations.

Q. What is the Company's Long-Term Incentive Plan?

A. The Long-Term Incentive Plan (LTIP) provides certain individuals the opportunity to receive retention-oriented and/or performance-based rewards delivered via shares of DTE Energy common stock, through either Restricted Stock or Performance Shares, which are based on the achievement of multiyear performance objectives. For Executives and Director level employees, 30% of the value of awards is through Restricted Stock and 70% is through grants of Performance Shares, while 100% of the awards to employees below the Director level are through Performance Shares. The objective in granting shares through this program is to both motivate superior results as well as provide a means to retain key employees.

Q. What are the performance share measures reflected in the 2018 LTIP?

A. The measures used in 2018 for the Performance Shares are shown on Exhibit A-21, Schedule K4.

Q. What is the rationale for the use of these measures?

A. These measures reflect the long-term financial performance of DTE Energy and are intended to motivate employees of the individual operating companies, such as DTE Electric, to keep in mind the role of their own contributions to the overall long-term success of DTE. Accordingly, the predominate measure (60%) is the total return to DTE Energy shareholders (i.e., capital appreciation and dividends) relative to a group of peer companies over the next three years. This three-year focus is designed to motivate decisions and actions that produce sustainable benefits rather than short-term actions that may entail long-term risks. An additional 20% is based on the balance sheet health of DTE Energy as measured by the Funds from Operations (FFO) to Debt ratio. This measure recognizes the long-term importance of maintaining a healthy balance sheet and the benefits of sound credit rating agency debt ratings that enable continued access to the debt markets at reasonable terms and conditions. The third measure that contributes 20% to the weighting is DTE Electric's Average Return on Equity for 2018 through 2020. The focus on DTE Electric's three-year return on equity provides a longer-term emphasis that encourages sustained performance.

The measures applicable to the DTE Energy Corporate Services LLC plan are based on an 80% weighting of the total return to shareholders and a 20% weighting of the FFO to Debt ratio.

Q. What is the basis for the Long-Term Incentive Plan expense?

A. The LTIP expense relates to grants of Performance Shares and Restricted Stock. While the expense related to the Restricted Stock is not conditional on any Company performance measures, the expense for Performance Shares is contingent on the achievement of specific performance objectives over a three-year period. The expenses for both the Restricted Stock and Performance Shares are based on the number of shares granted at the market price of DTE Energy's common stock at the date of grant. Witness Uzenski describes the adjustments to the actual 2017 LTIP expense to normalize for the impact of actual awards for the Performance Shares to Target performance.

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Q. What is the net expense of the variable pay programs if the Company achieves its Financial and Operating Targets?

A. The net expense to DTE Electric in the projected test period of the Company achieving all of its Financial and Operating Targets for the short-term and long-term plans, exclusive of the expense to the top five Executive Officers, is $46.4 million. The table below summarizes the expense for the projected test period by the nature of the plans, the classification of the employees eligible and the basis of the metrics used.

	LTIP	AIP (000's Omitted)	REP	Total
Financial				
DTE Electric	$4,793	$325	$4,302	$9,419
Nuclear Generation	0	66	669	735
DTE LLC	10,651	2,173	4,105	16,929
	15,444	2,564	9.076	27,083
Operating				
DTE Electric	0	487	6,453	6,940
Nuclear Generation	0	264	2,676	2,941
DTE LLC	0	3,259	6,157	9,416
	0	4,011	15,286	19,297
Total				
DTE Electric	4,793	812	10,754	16,359
Nuclear Generation	0	330	3,346	3,676
DTE LLC	10,651	5,432	10,262	26,345
	$15,444	$6,574	$24,362	$46,380

Q. Why do the expenses for DTE Energy Corporate Services, LLC represent a majority of the variable compensation expenses?

A. DTE Energy Corporate Services, LLC provides a variety of administrative and other services that are common to both DTE Electric and DTE Gas for which the costs are billed to the operating companies, as explained by Witness Uzenski. In

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addition, DTE Energy Corporate Services, LLC employs all of the Executives of DTE Energy, including the Executives of DTE Electric.

Q. How have you the reflected the Operating Excellence measures related DTE Gas included in the AIP and REP for DTE Energy Corporate Services, LLC?

A. While the AIP and REP expense allocated to DTE Electric in the historic period from DTE Energy Corporate Services, LLC include some measures related to DTE Gas, the majority of the AIP and REP expenses recognized at DTE Energy Corporates Services, LLC are not reflected in DTE Electric's projected expense. Accordingly, the AIP and REP weightings for DTE Energy Corporates Services, LLC have been adjusted to exclude the measures specifically related to DTE Gas.

Q. Are all of the incentive compensation expenses variable based on the Company's financial or operating performance?

A. No. As described earlier, a portion of the DTE Energy shares granted under the LTIP are in the form of Restricted Stock. Unlike the Performance Shares, the quantity of Restricted Stock is not variable based on either the Company's financial or operating performance. The only contingency is that the employee forfeits the Restricted Stock if they leave the Company, other than through retirement or the event of death. Thus, $3.988 million of LTIP expense related to Restricted Stock is excluded from the table above because it is not dependent on future performance.

Q. Is the Company requesting recovery in rates for all Executive compensation expenses?

A. No. While the Company believes that all its compensation expenses are reasonable, the Company has excluded $10.2 million of incentive compensation expense for DTE Energy's top five Executive officers that are listed as Named Executive Officers in DTE Energy's proxy materials filed annually with the Securities and Exchange Commission. This exclusion is reflected on Exhibit A-3, Schedule C-17 as supported by Witness Uzenski and has been excluded from the table above.

Q. Has the Commission provided any criteria for the inclusion of the expenses of variable pay programs in revenue requirements?

A. Yes. The Commission has indicated in all of its recent Orders that addressed the topic of variable pay programs that recovery of such expenses is dependent on a showing that the variable pay plans provide benefits to customers in excess of the expense to be included in the company's revenue requirements.

Q. Has the Company performed an analysis of the customer benefits of the Company's variable pay programs?

A. Yes. The Company performed a comprehensive analysis of the customer benefits that would be derived from the achievement of the financial and operating metrics included in the Company's short and long-term incentive plans relative to their expense. This analysis, as reflected on Exhibit A-21, Schedule K5, demonstrates that the total calculated customer benefit of $123.7 million exceeds the total variable pay program expense of $46.4 million by $77.3 million. While certain individual measures, such as customer satisfaction and certain safety related measures, provide benefits that defy precise quantification; there should be little serious dispute as to the qualitative value of such metrics. Indeed, the Company is well aware of the frustration experienced by customers when outstanding issues are not promptly resolved, even though the value of the elimination of that customer frustration is not readily estimated. However, the inability to quantify the precise customer benefit in no way diminishes the value of improving customer satisfaction.

Since the measurable customer benefits exceed the costs of the variable pay programs, without regard to the value of the immeasurable benefits of the more qualitative metrics, the Commission should include the total variable pay program expense within the Company's revenue requirement.

Q. How are the benefits of the Financial Measures reflected on Exhibit A-21, Schedule K5 computed?

A. The primary observable customer benefits of the financial measures relate to the O&M savings created through a workforce motivated to improve operating efficiencies, which is the focus of the metrics related to DTE Electric earnings (as measured through DTE Electric's Average Return on Equity and DTE Electric Operating Earnings). In addition, customers benefit from the avoided increase in interest costs through the Company maintaining its existing long-term debt ratings, which is the focus of the cash flow related metrics (as measured through FFO to Debt and Adjusted Cash Flow).

Q. Have the Company's incentive metrics that measure financial performance produced cost savings for customers?

A. Yes. As an electric utility, DTE Electric has little direct control over its revenue because the Commission sets its rates and the Company's sales volumes are largely

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dependent on regional economic activity and weather. Because the Company cannot control either of these factors, DTE Electric's primary ability to improve its financial performance is its ability to control its costs; lower costs directly benefit customers through lower rates. Therefore, the elements of the Company's variable pay programs that focus on financial metrics lead to tangible net benefits for customers, which is realized by customers through both the postponement of rate increases and through lower revenue requirements in this case. As described above, the Company's projected O&M expenses are $226.2 million less than if the Company's normalized 2009 O&M expenses had increased by the rate of inflation, or an annual O&M expense savings of $21.9 million ($226.2/10.33 years). These benefits are allocated to the LTIP, AIP and REP in proportion to the related expense.

Q. How did you calculate the interest cost savings from the retention of the Company's existing debt ratings?

A. The FFO to Debt measure within the LTIP and the annual Adjusted Cash Flow measure within the AIP and REP are both focused on the Company maintaining its A debt rating from Standard & Poor's and comparable ratings by the other major debt rating firms for its Secured Debt. The yield spread in early 2018 between utility bonds rated A compared to BBB is 24 basis points. Based on the long-term debt included in the projected capital structure sponsored by Company Witness Slater, as reflected on Exhibit A-14, Schedule D1, a downgrade to BBB would increase the Company's annual interest costs by $15.6 million. The benefit of this avoided cost is allocated to the cash flow related measures for the LTIP, AIP and REP similar to the earnings related benefits.

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Q. How are the benefits of the Operating Measures reflected on Exhibit A-21, Schedule K5 computed?

A. The benefits of the operating measures are computed based either on the avoided costs to the Company, which results in lower future revenue requirements, or based on the value to customers of improved performance. The reference points to determine improvement are, in most instances, based on the Company's actual performance in the 2017 historical test year or when 2017 results are not representative, a five-year average is used. The benefits of achieving Target performance are allocated between the AIP and REP components based on the relative AIP and REP expense for each measure.

Q. How did you quantify the benefit of achieving Target performance levels in the Customer Satisfaction measures?

A. While achieving the 86^{th} percentile relative to J.D. Power's National Peer Set is an ambitious Target, there is currently insufficient comparative data to derive a quantified customer benefit of achieving this Target.

The customer benefits of attaining Target performance in the Customer Satisfaction Improvement Program and MPSC Customer Complaints is based on the avoided costs to both the Company and its customers based on the reduced time spent by employees and customers resolving complaints for a total savings of $.3 million.

While the quantified benefits of the Customer Satisfaction measures are less than the related expense, there can be little doubt that an emphasis among the Company's leadership and employees on improving the experiences customers have with the Company results in significant non-quantifiable benefits to both customers and the Commission. Moreover, as the Company is able to continue to improve its distribution service reliability, as reflected in the Operating Excellence measures, it will have a salutary effect on customer satisfaction, since service outages are a key component of customers' satisfaction with the Company and the service it provides.

Q. How did you determine the benefits of the Employee Engagement measures?

A. The quantifiable benefits of a highly engaged workforce are based on three critical dimensions identified by Gallup: absenteeism, productivity and safety incidents. According to Gallup, a 0.1 improvement in the grand mean will result in a 3.1% reduction in absenteeism, a 1.8% increase in productivity and a 3.8% reduction in safety incidents. Compared to an average of recent actual Gallup survey results, achievement of the 2018 Target Gallup survey results will generate O&M savings at DTE Electric of $6.5 million, inclusive of savings allocated from LLC and net of the savings capitalized.

Q. What are the expected benefits of the Company achieving Target level performance regarding the OSHA Recordable Incident Rate (RIR)?

A. The benefits of achieving the OSHA Recordable Incident Rate (RIR) and the Nuclear Total Industrial Safety Accident Rate goal are based on the estimated direct costs of non-fatal incidents, as developed by OSHA, and a study by Liberty Mutual that estimates the indirect cost of an OSHA recordable is about 3.5 times the direct costs, resulting in a total cost of $139,500 per incident. Thus, based on Target level performance, the net O&M savings relative to an average of the Company's performance in recent years are estimated to be $.7 million, net of the savings

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capitalized. Because the benefits of achieving the OSHA RIR Target are similar to the OSHA DART, half of the benefit is assigned to the OSHA RIR measure and the rest is assigned to the OSHA DART Target.

While the quantified savings of the safety related metrics are less than the related costs, much like the customer service related measures, the benefits of maintaining an organizational focus on the safe operation of the Company's system for the benefit of its employees, customers and the communities where the Company operates are undoubtedly substantial.

Q. How did you quantify the savings related to improvements in distribution system reliability?

A. The benefit of achieving the Blue Sky CAIDI of 129 minutes is based on comparing the 2018 Target to the five-year average of actual Blue Sky CAIDI of 163 minutes, which represents a reduction of 34 minutes, or over 20%. The derivation of the benefits to customers was determined based on the Interruptions Cost Estimation Calculator as developed by Nexant, Inc. and the Lawrence Berkeley National Lab, as more fully described by Company Witness Bruzzano. A reduction of 34 minutes in the Blue Sky CAIDI produces an annual customer benefit of $51.8 million. The benefits of achieving Target performance in the Blue Sky CAIDI measure have been allocated equally to the Blue Sky CAIDI measure and the All Weather SAIDI measure.

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Q. How did you quantify the benefits of the Fossil Power Plant Reliability measure?

A. The benefit of the Fossil Power Plant Reliability measure reflects the impact of decreasing the Random Outage Factor from a five-year average of about 8.0% to the 2018 Target of 7.3%. The savings computed reflect the impact of the increases in power generation relative to the avoided market energy purchases and increased capacity value. This produces annual savings of $2.6 million.

Q. What are the benefits of an increase in the Nuclear Power Plant Reliability?

A. The benefits of an increase in the Nuclear Power Plant Reliability reflect an increase from the On Line Unit Capability Factor at Fermi 2 from the five-year average of 87.5% to the 2018 Target of 95%. Because Fermi 2 has the lowest marginal costs of production within the DTE Electric fleet, increased utilization can have a significant impact on the overall cost of power generation. The savings computed are based on the differential between Fermi 2’s marginal fuel costs and the average market price of avoided energy purchases combined with increased capacity value for a total annual savings of $19.4 million.

Q. How did you determine the value of the Company completing the 2018 refueling of Fermi 2 within 32 days?

A. The savings created by limiting the 2018 refueling outage period to 32 days is based on an 8-day reduction from the refueling period assumed in the 2018 PSCR filing of 40 days. The annual savings from achieving the Target of 32 days are $5.1 million.

Q. Have you quantified any savings related to the other measures related to

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Nuclear Power Plant Reliability Matrix?

A. No. The On Line Unit Capability Factor and refueling measure represent the only quantifiable benefits of the Company meeting its Target performance levels. While there is indisputable value in the various specific measures within the Nuclear Power Plant Performance and Reliability matrices, the short-term effect of achieving Target performance in these measures is the higher availability of Fermi 2. Therefore, the benefit of Fermi 2 achieving its Target On Line Unit Capability Factor level has been attributed to both the Nuclear Power Plant Performance and Reliability matrices measures.

Q. What is your conclusion regarding the cost effectiveness of the Company's variable pay programs?

A. While not every individual measure included in the variable pay program has quantified benefits in excess of the variable pay expense of the measure, it is clear that in aggregate, the quantified customer benefits of the Company achieving Target performance levels for both the financial and operating measures are substantially greater than the related expense. Moreover, in those instances where the quantified benefits are less than the related expense (i.e., customer satisfaction and safety), the non-quantifiable benefits are undoubtedly substantial. Thus, the Company's total incentive compensation expense should be included in the revenue requirements adopted by the Commission in this proceeding as a reasonable and prudently incurred expense.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

EXHIBITS

OF

MICHAEL S. COOPER

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

WORKPAPERS

OF

MICHAEL S. COOPER

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JEFFREY C. DAVIS

DTE ELECTRIC COMPANY
QUALIFICATIONS OF JEFFREY C. DAVIS

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No.

Q. What is your name, business address and by whom are you employed?

A. My name is Jeffrey C. Davis. My business address is: 6400 North Dixie Highway, Newport, Michigan, 48166. I am employed by DTE Electric Company at the Fermi 2 Nuclear Power Plant as Manager of Nuclear Strategy and Business Support.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I graduated from the University of Michigan with bachelor's degrees in nuclear engineering and radiological sciences (NERS) and engineering physics. I have also earned a master's degree and doctorate in NERS from the University of Michigan.

Q. What is your DTE Electric work experience?

A. I have been employed by DTE Energy since 2008. Prior to my current position, I was a principal financial analyst with responsibility for budgeting, forecasting, and reporting operations and maintenance (O&M) and capital expenditures for the Nuclear Generation organization.

Q. What is your current position?

A. In 2015, I was promoted to the role of Manager – Nuclear Strategy and Business Support with responsibility for developing the strategic financial plan and goals for the Nuclear Generation organization.

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Q. Are you a member of any professional organizations?

A. I am a member of the American Nuclear Society.

Q. Have you previously been involved in DTE Electric general rate case filings?

A. I have provided support to other DTE Electric witnesses in support of nuclear fuel expenses, nuclear O&M expenses and nuclear capital expenditures in the following DTE Electric rate cases: U-16472, U-17767, U-18014 and U-18255.

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Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss and support the reasonableness of the Company's actual nuclear O&M and capital expenditures for the 12-month historical test period ended December 31, 2017. I will also discuss and support the reasonableness of the projected nuclear O&M and capital expenditures for the interim forecast period and a twelve month projected test period ending April 30, 2020. In addition, I will discuss and support the reasonableness of the projected Nuclear Surcharge for the projected test period ending April 30, 2020. Finally, I will propose and support the reasonableness of a Nuclear Generation Infrastructure Recovery Mechanism (IRM) for capital expenditures beyond the projected test period and ending December 31, 2022.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.3	Projected Capital Expenditures Nuclear Production Plant & Nuclear Fuel
A-13	C5.3	Projected Operation and Maintenance Expenses Nuclear Power Generation
A-13	C5.16	Nuclear Power Generation Projected PERC O&M Expenditures
A-20	J1	Proposed Nuclear Surcharge Projected Test Period – 12 Months Ending April 30, 2020
A-30	T4	Infrastructure Recovery Mechanism Capital – Nuclear Generation Expenditures 2020 - 2022

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Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How do you plan to proceed with your testimony?

A. I will begin my testimony with the Nuclear Generation capital expenditures; discussing and supporting the actual capital expenditures for the historical test year ended December 31, 2017, the projected capital expenditures for the interim forecast period and the 12-month projected test period ending April 30, 2020. I have divided my Nuclear Generation capital expenditure discussion into four sections of expenditures: routine capital, non-routine capital, capital fuel and Allowance for Funds Used During Construction (AFUDC).

I will then discuss and support the actual O&M expenses for the historical test year ended December 31, 2017 and the forecasted O&M expenses for the 12-month projected test period ending April 30, 2020 for Nuclear Generation. I have divided my Nuclear Generation O&M expenses discussion into three sections: rate case adjustments, adjusted historical test period and projected adjustments.

I will then discuss and support the Nuclear Surcharge for the 12-month projected test period ending April 30, 2020 for Nuclear Generation. I will describe and support adjustments for Nuclear Security and Radiological Protection and Low-Level Radiological Waste (LLRW) Disposal Fund.

I will then discuss and support the Nuclear Generation Infrastructure Recovery Mechanism (IRM) capital expenditures for the forecasted period May 1, 2020 through December 31, 2022.

The Fermi 2 Power Plant is licensed by the Nuclear Regulatory Commission (NRC) to operate through 2045. The capital and O&M expenditures discussed for the historical and projected test periods throughout my testimony reflect appropriate measures to ensure safe and reliable operation of the Fermi 2 Power Plant through 2045.

Nuclear Generation Capital Expenditures

Q. Can you please provide an outline of your Nuclear Generation capital expenditures discussion?

A. My testimony will begin with the 2017 – 2020 Capital Projects Overview and then discuss and support the additional details regarding:

- Routine and Small Capital Expenditures
- Non-Routine and Large Capital Expenditures
- Nuclear Fuel Capital Expenditures
- AFUDC Forecast

2017 - 2020 Capital Projects Overview

Q. Can you please provide an overview of the Nuclear Generation capital expenditures supported by your testimony?

A. I refer you to Exhibit A-12, Schedule B5.3, page 1 - this exhibit depicts the capital expenditures for the historical test year ended December 31, 2017, projected capital expenditures for the interim forecast period and projected expenditures for the 12-month projected test period ending April 30, 2020.

Total capital expenditures are composed of Routine and Small Projects, Non-Routine and Large Projects, and Total Nuclear Fuel. Nuclear Generation actual capital expenditures for historical test year ended December 31, 2017 totaled \$161.2 million as shown on line 11, column (b) of the exhibit. Nuclear Generation forecasts total capital expenditures for the interim forecast period at \$284.3million as shown on line 11, column (e) and for the 12-month projected test period ending April 30, 2020 at \$253.5 million as shown on line 11, column (f).

A portfolio of discrete projects and capital fuel expenditures provides the basis to support the forecasted Total Capital Expenditures for January 1, 2018 through April 30, 2020. I will discuss these discrete projects and capital fuel expenditures next in my testimony.

Q. Before you discuss the discrete projects, can you please summarize the principles and conduct of asset maintenance at a nuclear generation unit such as Fermi 2?

A. Nuclear safety is our overriding priority at Fermi 2 and, indeed, throughout the nuclear industry. Our operational and strategic decisions preserve this priority.

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Q. What do you mean by nuclear safety?

A. Nuclear safety is focused on ensuring that we maintain and operate this nuclear asset with the utmost respect. Conservatism is necessary to minimize risk and requires a commitment to the safe use of nuclear material.

Q. How does Nuclear Generation manage nuclear safety risk?

A. Nuclear Generation manages nuclear safety risk through training, procedures and governance, operating the plant with a healthy nuclear safety culture, and maintenance of the asset.

Q. What are the key principles Nuclear Generation uses for maintaining the nuclear asset?

A. I would summarize our key maintenance principles as:

1. Capital replacements and modifications are proactive and condition- or time-based to preclude a failure. Unanticipated equipment failures challenge plant operators; our strategies are designed to minimize the probabilities of unanticipated equipment failures.
2. Capital replacements and modifications are implemented when the plant is in the safest condition to do so. For most of our work at Nuclear Generation, that safest condition is when the Fermi 2 plant is shut down for a refueling outage.

Q. Why is it safest to perform maintenance on the Fermi 2 plant during a refueling outage?

A. Refueling outages are the safest time to perform maintenance for the following reasons:

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1. Nuclear safety - our operating license issued by the NRC requires the plant to be shut down prior to taking many systems out of service for maintenance. These licensing requirements align with minimizing risks to the health and safety of the public.
2. Personnel safety – many areas of the plant are behind locked doors during operations due to the radiological or atmospheric conditions of the area. Refueling outages offer opportunities to access these otherwise inhospitable areas of the plant for maintenance.

Q. What is the cadence for the Fermi 2 plant refueling outages?

A. The Fermi 2 plant currently operates on an 18-month cycle, meaning every 18 months the Fermi 2 plant shuts down for a refueling outage. Our last refueling outage was in the spring of 2017; our next refueling outage is scheduled for fall of 2018. Our refueling outages are numbered sequentially and named as such, so – our upcoming fall of 2018 refueling outage is named Refueling Outage 19 or RF19. Refueling Outage 20 (RF20) is scheduled 18 months after RF19 in spring of 2020 and Refueling Outage 21 (RF21) is scheduled 18 months after RF20 in the fall of 2021.

I note here RF21 will be the last refueling outage before Fermi 2 is scheduled to begin 24-month cycles. Refueling Outage 22 (RF22) will be in the fall of 2023; subsequent refueling outages are scheduled for the fall of the odd numbered years. I will discuss the 24-month cycle in more detail later in my testimony.

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Q. What is the typical planning cadence for a Fermi 2 plant refueling outage?

A. Refueling outages are highly complex and require an integrated work plan to execute thousands of activities in a relatively short duration.

Planning for a refueling outage is a two-year effort with many intermediate milestones guiding the planning effort. The two most relevant of these milestones for capital expenditures is 1) two years prior to the refueling outage (T+24 months), Nuclear Generation confirms the non-routine and large projects for implementation in the outage and 2) at one year prior to the refueling outage (T+12 months), Nuclear Generation confirms for the routine and small projects the exact number of units to be completed in the outage.

Routine and Small Capital Projects

Q. Can you please expand your discussion for the Routine and Small Projects summarized on line 2 of Exhibit A-12, Schedule B5.3, page 1?

A. Routine and Small Projects are those capital expenditures associated with maintaining the various assets that support the safe operation of the Fermi 2 asset and includes work such as pump, motor, valve and reactor control component replacements and can typically be expressed in number of units replaced. As I have discussed above, nuclear safety is our overriding priority; these types of replacements are reasonable and prudent because they are the core of our proactive maintenance regime.

Pages 2-3 of Exhibit A-12, Schedule B5.3 provide a listing of the Routine and Small Projects that support page 1, line 2.

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Q. Can you please explain the Routine and Small Projects detailed in Exhibit A-12, Schedule B5.3, pages 2-3?

A. Exhibit A-12, Schedule B5.3, pages 2-3 shows the by-project capital expenditures for Routine and Small Projects for the historical period, forecasted expenditures for the 16-month interim forecast period ending April 30, 2019 and the 12-month forecast test period ending April 30, 2020 total $111.2 million, $113.9 million, and $73.4 million respectively.

The expenditures and project make-up are consistent for the historical test year, the interim forecast period and the forecasted test period because of the regulatory and safety requirements governing Routine and Small Projects.

Q. Can you please discuss the expenditures and rationale for the Integrated Plant Computer System (IPCS) project shown on line 5 of Exhibit A-12, Schedule B5.3, page 2?

A. The Integrated Plant Computer System (IPCS) capital expenditures for the historical test year, projected interim forecast period and projected forecast test period are $5.9 million, $13.6 million and $0.1 million respectively. The purpose of this major plant computer system is to provide the capability of monitoring, recording and displaying plant parameters. Just like any computer, periodic replacement is necessary to address aging and obsolescence of this key digital asset.

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Non-Routine and Large Capital Projects

Q. Can you please expand your discussion for the Non-Routine and Large Projects summarized on line 3 of Exhibit A-12, Schedule B5.3, page 1?

A. Non-Routine and Large Projects are large capital projects that I would consider above and beyond normal routine capital expenditures that are necessary to maintain the asset.

Refer to Page 4 of Exhibit A-12, Schedule B5.3 for a listing of the projects that support page 1, line 3.

Q. Can you please explain the Non-Routine and Large Projects detailed in Exhibit A-12, Schedule B5.3, page 4?

A. Yes. This exhibit shows the by-project capital expenditures for Non-Routine and Large Projects, as noted by line 3 of Exhibit A-12, Schedule B5.3, page 1. These projects for the historical period, planned expenditures for the 16-month interim forecast period ending April 30, 2019 and the 12-month forecast test period ending April 30, 2020 total $49.5 million, $96.0 million, and $102.4 million respectively.

Q. Can you please explain the main drivers for the $52.9 million increase in Non-Routine and Large Project capital expenditures from the historical test period ended December 31, 2017 and projected test period ending April 30, 2020 as shown on Exhibit A-12, Schedule B5.3, page 1, line 3?

A. This increase of Non-Routine and Large Project capital expenditures is driven primarily by the replacement of the Fermi 2 Main Unit Generator.

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The Main Unit Generator capital expenditures for the historical test year, projected interim forecast period and projected test year are $10.7 million, $30.0 million and $47.3 million respectively as shown on line 2 of Exhibit A-12, Schedule B5.3, page 4. The forecasted project expenditures peak in 2020 due to the labor intensive installation of the new generator in the spring of 2020.

Q. Can you explain the rationale for the Main Unit Generator Replacement project?

A. The replacement of the main unit generator is necessary to address both a design vulnerability and overall reliability with this particular model generator. Replacement of this model generator is the identical approach other nuclear asset owners have taken to mitigate operational risk. To support reliable operation of Fermi 2 through 2045, major refurbishments and replacement of the existing generator asset is reasonable and prudent.

Q. Can you please discuss the expenditures and rationale for the Underground Safety-Related Service Water Piping project shown on line 13 of Exhibit A-12, Schedule B5.3, page 4?

A. The Underground Safety-Related Service Water Piping capital expenditures for the historical test year, projected interim forecast period and projected test year are $1.5 million, $7.7 million and $12.3 million respectively. The Underground Safety-Related Service Water Piping project will replace nuclear safety-related piping that delivers cooling water to various components that support the operation of the nuclear reactor. The replacement of the underground service water piping is necessary to address degrading pipe-wall thickness and to ensure this pipe will

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continue to support plant operations through the end of the operating license in 2045.

Q. Can you please discuss the expenditures and rationale for the drywell cooler projects shown on lines 9, 11 and 26 of Exhibit A-12, Schedule B5.3, page 4?

A. The drywell cooler projects are a series of drywell cooler replacements that we have grouped by refueling outage implementation. The replacement of these coolers is necessary to address end of life; these coolers are original plant equipment. The Fermi 2 Power Plant has 14 drywell coolers which provide the containment structure that surrounds the reactor with atmospheric cooling during normal operations. During postulated accident conditions, drywell coolers also provide air circulation to disperse any hydrogen accumulation within this containment structure.

Drywell Coolers #5 and #6, as depicted on line 9, were replaced in Refueling Outage 18 in 2017 and have capital expenditures for the historical test year, projected interim forecast period and projected test year of $2.7 million, $0.0 million and $0.0 million respectively.

Drywell Coolers #7 and #9, as depicted on line 11, are forecasted to be replaced in Refueling Outage 19 in 2018 and have capital expenditures for the historical test year, projected interim forecast period and projected test year of $1.9 million, $4.3 million and $0.0 million respectively.

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Drywell Coolers #10, #14 and #8, as depicted on line 26, are forecasted to be replaced in Refueling Outage 20 in 2020 and have capital expenditures for the historical test year, projected interim forecast period and projected test year of $0.0 million, $3.5 million and $8.7 million respectively.

Q. Do any of the projects listed in Exhibit A-12, Schedule B5.3, pages 2-4 contain contingency amounts?

A. No. The capital expenditures as shown in Exhibit A-12, Schedule B5.3, pages 2-4 do not include contingencies.

Nuclear Fuel Capital Expenditures

Q. Can you please explain Total Nuclear Fuel summarized on line 10 of Exhibit A-12, Schedule B5.3, page 1?

A. Yes. Total Nuclear Fuel includes those capital expenditures for the various components of the nuclear fuel cycle: 1) Uranium, 2) Conversion, 3) Enrichment and 4) Fabrication.

Uranium refers to the costs associated with mining and milling uranium. Natural uranium is obtained from the exploration and mining of uranium ore. Milling is the mechanical and chemical process of extracting uranium from the mined ore in the form of U_3O_8, commonly referred to as yellowcake. The U_3O_8 is the feed material for the conversion process.

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Conversion refers to the costs associated with chemically converting U_3O_8 into UF_6, uranium hexafluoride. The UF_6 is the gaseous compound used as a feed in the enrichment process.

Enrichment refers to the costs to enrich the uranium from a natural 0.7% U^{235} content to a 4% to 5% U^{235} content required for light water reactor fuel. The enriched UF_6 is used as a feed in the fabrication process.

Fabrication refers to the chemical conversion of the enriched UF_6 to UO_2 (uranium dioxide) powder which is then pressed and sintered into hard ceramic fuel pellets that are loaded into long, narrow zirconium alloy tubes called fuel rods; fuel rods are then assembled into fuel bundles using spacers and end fittings to hold the fuel rods together. The Fermi 2 reactor core requires 764 of these fuel bundles to operate.

The amount of fuel purchased is determined by the design of the fuel and by the expected generation during the life of the fuel. Nuclear fuel capital expenditures are developed on an 18-month fuel cycle basis.

Q. Can you please explain the Total Nuclear Fuel expenditures as shown on Exhibit A-12, Schedule B5.3, page 1, line 10?

A. Yes. The Total Nuclear Fuel capital expenditures for the historical test year, projected interim forecast period and projected test year are $0.4 million, $74.4 million and $77.7 million respectively.

Q. Can you explain why Total Nuclear Fuel expenditures vary from year-to-year?

A. Yes. Total Nuclear Fuel expenditures vary from year-to-year because Fermi 2 operates on an 18-month fuel cycle and fuel costs are fixed in time relative to that 18-month fuel cycle (most fuel expenditure costs occur approximately 6 months prior to a refueling outage); therefore, Total Nuclear Fuel expenditures oscillate on a three-year pattern.

Q. How would you characterize the level of expenditures for Fermi 2's Total Nuclear Fuel?

A. I believe Fermi 2's fuel expenditures are reasonable and prudent. I expect fuel expenditures to continue to be reasonable as the Company has secured contracts for uranium, conversion, enrichment and fabrication through the projected test period ending April 30, 2020.

AFUDC Forecast

Q. Can you please explain the Allowance for Funds Used During Construction (AFUDC) as shown in Exhibit A-12, Schedule B5.3, page 5?

A. Nuclear Generation capital expenditures include an Allowance for Funds Used During Construction (AFUDC) for eligible projects that are in Construction Work in Progress (CWIP); eligible projects are those projects greater than $50,000 and lasting more than six months. The actual historical period Total AFUDC – Nuclear Production Plant was $5.7 million as shown in Exhibit A-12, Schedule B5.3, page 5, line 33, column (b). The forecasted Total AFUDC – Nuclear Production Plant for the projected test period is $7.4 million as shown in Exhibit A-12, Schedule B5.3, page 5, line 33, column (c).

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Q. How did you forecast the AFUDC as shown Exhibit A-12, Schedule B5.3, page 5?

A. The Nuclear Production Plant – Routine Expenditures AFUDC forecast uses a historical trend to estimate AFUDC as the mix of eligible projects is fairly consistent year-to-year. The Nuclear Production Plant – Project Specific AFUDC forecast explicitly calculates AFUDC for eligible projects using project-specific CWIP balances multiplied by the AFUDC rate where the AFUDC rate is the authorized cost of capital rate of 5.34% per the U-18255 rate order.

<u>2018 – 2020 Capital Projects Summary</u>

Q. What is your opinion regarding the reasonableness of the forecasted capital expenditures for Nuclear Generation?

A. I believe the forecasted capital expenditures for Nuclear Generation are reasonable and prudent. I have outlined the forecasted expenditures for nuclear fuel and those associated with the non-routine and routine capital expenditures, and explained why they are reasonable and prudent. I believe the forecast as depicted by line 11 of Exhibit A-12, Schedule B5.3, page 1, accurately represents the capital expenditures that can reasonably be expected in order to continue operation of nuclear assets of similar age and vintage. My summation of projects reflects DTE Electric's commitment to ensure the safe and reliable operation of Fermi 2 through its current operating license expiration in 2045. As I have expressed previously, these capital expenditures are prudent and reasonable given the regulations, goals and conditions under which Fermi 2 operates.

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Nuclear Generation O&M Expense

Q. Can you please provide an outline of your Nuclear Generation O&M discussion?

A. Yes. My testimony will begin with the O&M Expenses Overview and then discuss and support the additional details regarding:

- Rate Case Adjustments
- Adjusted Historical Test Period
- Projected Adjustments

O&M Expenses Overview

Q. Can you please provide an overview of the Nuclear Generation O&M expenses supported by your testimony?

A. Exhibit A-13, Schedule C5.3, page 1, line 24 from left to right depicts the O&M expenses for the 12-month historical test period ended December 31, 2017, adjustments and then the forecasted O&M expenses for the 12-month projected test period ending April 30, 2020.

The actual O&M expenses by FERC account for the 12-month historical test period ended December 31, 2017 were $171.0 million as shown in column (c). Rate case adjustments are made in column (d) to reduce O&M by $27.5 million to account for Nuclear Surcharge and in column (e) to reclassify Performance Evaluation Review Committee (PERC) nuclear O&M project expenditures. These rate case adjustments result in $143.5 million of adjusted O&M for the 2017 historical test period as shown in column (f).

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Projected adjustments of $4.2 million, $4.1 million and $1.5 million in columns (g), (h) and (i) respectively account for inflation. The $0.8 million in column (j) is added to account for outage accrual adjustments and O&M is increased by $12.7 million in column (k) to account for PERC amortization. These projected adjustments total $23.3 million as shown in column (l).

With the above adjustments to the adjusted historical O&M, the forecasted O&M expenses for the 12-month projected test period are $166.8 million as shown in column (m).

Q. Are you supporting projected Total Nuclear Power Generation O&M expenses of $166.8 million?

A. Yes, I am supporting projected Total Nuclear Power Generation O&M expenses of $166.8 million as shown in Exhibit A-13, Schedule C5.3, line 24, column (m).

Rate Case Adjustments

Q. Can you please explain the basis for the rate case adjustments in column (d) of Exhibit A-13, Schedule C5.3, page 1?

A. Site security and radiation protection costs were removed from base rates and recognized in the Nuclear Surcharge as established in DTE Electric Case No. U-14399. The complete elimination of all financial statement impacts of the Nuclear Surcharge are supported by Company Witness Ms. Uzenski.

The Nuclear Surcharge reduction of $27.5 million as shown on line 24, column (d) accomplishes this requirement.

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Q. Can you please explain the basis for the rate case adjustments in column (e) of Exhibit A-13, Schedule C5.3, page 1?

A. The reclassify PERC adjustment nets to zero as shown on line 24, column (e). This reclassification is performed to make explicit the $4.9 million PERC base expense is not inflated in the projected adjustments. I will explain the PERC regulatory asset mechanism later in my testimony.

Adjusted Historical Test Period

Q. Can you please explain the components that constitute the actual Total Nuclear Power Generation O&M expenses for adjusted historical test period in line 24, column (f) of Exhibit A-13, Schedule C5.3, page 1?

A. Total Nuclear Power Generation O&M of $143.5 million consists of the Nuclear Organization, regulatory assessments and dues, and refueling outage expenses. I detail these expenses for the 2017 historical period on page 2 of Exhibit A-13, Schedule C5.3.

Q. What is the need for and basis for the "Nuclear Organization" expenses that are included in the 2017 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 1?

A. Nuclear Organization expenses are the baseline employee, services and material expenses required to safely and reliably operate the Fermi 2 Power Plant. The Nuclear Organization expenses for the historical test period ended December 31, 2017 were $105.1 million.

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Q. What is the need for and basis for the "PERC Base Expense" expenses that are included in the 2017 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 2?

A. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 approved an annual base level of PERC expenses of $4.9 million for nuclear O&M projects; the PERC Base Expense of $4.9 million depicted on line 2 accounts for this base approval.

Q. What is the need for and basis for the "Regulatory Assessments and Dues" expenses that are included in the 2017 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 3?

A. A majority of these assessments and dues are regulatory driven, such as those assessments and dues required by the NRC to cover oversight of the plant. In addition, assessments and dues are associated with licensing requirements including Emergency Response Organization (ERO) and various industry groups.

Industry groups include the Institute of Nuclear Power Operations (INPO), which assists utilities in operating nuclear plants to the highest safety standards, the Nuclear Energy Institute (NEI), which assists in common issues impacting the nuclear industry, the Electrical Power Research Institute (EPRI) and the General Electric Boiling Water Reactor Owners' Group, both of which sponsor research that is used by nuclear plants to operate more safely and economically.

The ERO supports the Fermi 2 Emergency Plan which is a license requirement necessary to ensure the health and safety of the public during emergency response events. The ERO funds federal, state and local county emergency facilities in support of the Fermi 2 Emergency Plan.

Q. Which assessments and dues are non-discretionary (i.e. mandated)?

A. NRC, INPO and ERO assessments and dues are non-discretionary.

Q. Why does the Company pay the discretionary assessments and dues?

A. Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development including sharing of products to ensure nuclear asset owners benefit as a whole from shared information. These products and services would be unaffordable without group participation and funding. The role provided by NEI is valuable to plant owners and operators in helping to shape important industry issues and regulation through a coordinated and solidified approach. The nuclear industry clearly recognizes that any one plant can abruptly upset the entire industry due to performance issues. As a result, this industry believes in significant group participation and knowledge sharing to help preclude such an event.

Q. What is the need for and basis for "Total Refueling Outage" expenses for the 2017 historical period on Exhibit A-13, Schedule C5.3, page 2, line 9?

A. The Fermi 2 Power Plant operates on an 18-month refueling cycle; every 18 months Fermi 2 shuts down to refuel the reactor. The "Total Refueling Outage" expenses are those costs necessary to 1) refuel the Fermi 2 reactor and 2) perform offline

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maintenance to ensure Fermi 2 can operate safely and reliably for the next operating cycle.

The "Total Refueling Outage" expense consists of the actual refueling outage costs (line 6), the refueling outage accrual (line 7) and the refueling outage accrual reversals (line 8) for the 2017 historical period. Line 9 nets these three component lines and represents an accounting practice of levelizing incremental refueling expenses by accruing the anticipated refueling expenses over the term of an operating cycle.

Q. Why does DTE Electric levelize its incremental refueling outage expenses?

A. DTE Electric levelizes its incremental refueling outage expenses so that the difference in expense between outage and non-outage years does not burden DTE Electric customers with large rate fluctuations or create financial swings for the Company. For example, if the Company bases the rate request on the projections for a refueling outage year and all the expenses of that outage appear in that year's projections, then the Company would be presenting an unnecessarily high cost of providing Fermi 2 generation over the period the rates are in effect. The inverse is also true if the Company used a non-refueling outage year projection for the same purpose. This is consistent with the treatment in prior cases where the Commission has allowed levelized refueling outage expenses in setting rates.

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Q. What is the basis for the "Refuel Outage" expense at $31.8 million for the 2017 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 6, column (b)?

A. This is the actual O&M expenditures within the historical test period for Refueling Outage 18 (RF18).

Q. What is the basis for the "Refuel Outage Accrual" expenses at $25.1 million for the 2017 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 7?

A. This is the actual amount accrued in the historical period for refueling outages. Included in this accrual is four months of Refueling Outage 18 accrual and eight months of Refueling Outage 19 (RF19) accrual. The RF19 accrual is consistent with forecasted expenditures of $34.0 million.

Q. How did DTE Electric manage incremental refueling outage expenses?

A. The Company managed these incremental expenses through structured planning and preparation that is consistent with industry standards and processes. We implemented rigorous financial controls that supported daily management of resources during the execution phase of the refueling outage. This management of resources included daily reviews of scope completion, schedule and budget. As work completed, contracted resources exited promptly from the site to ensure that costs were controlled.

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Projected Adjustments

Q. Can you please explain the basis for the inflation adjustments in columns (g), (h) and (i) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A. The labor and material prorated inflation adjustment rates of 3.0% for 2018, 2.9% for 2019 and 1.0% for 2020 are supported by the testimony of Witness Uzenski. Nuclear Generation applied these forecasted inflation rates to the adjusted historical test period costs in column (f).

Q. Can you please explain the basis for the outage accrual adjustment in column (j) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A. The forecasted O&M expenditures for Refueling Outage 20 (RF20) are $34.0 million – same as the forecasted O&M expenditures for RF19 and actual O&M expenditures for RF18; the 12-month test period proration of this RF20 forecast is $22.7 million. This $0.8 million adjustment shown on line 24, column (j) is the difference between the forecasted $22.7 million accrual and the $20.4 million historical period accrual adjusted for inflation as discussed above. This Outage Accrual adjustment reflects our commitment to improving refueling outage performance and holding refueling outage expenditures relatively flat through the projected test period.

Q. What duration have you assumed for future refueling outages?

A. The PSCR Plan assumes an outage duration of 40 days for Refueling Outage 19 (2018) and Refueling Outage 20 (2020). Execution of intended work scope is important to ensure the preservation of equipment health to maintain nuclear safety margins and overall station reliability. Maintaining this focus minimizes operational

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and financial risks. The planned durations are consistent with known maintenance scope for plant equipment and systems.

Q. Can you please explain the basis for the PERC amortization adjustment in column (k) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 not only approved an annual base level of PERC expenses of $4.9 million for nuclear O&M projects, but also provided deferral treatment for any expenses over or under the $4.9 million amount. The derivation of the PERC amortization is shown on Exhibit A-13, Schedule C5.17 and is sponsored by Witness Uzenski; I detail the projects comprising line 2 of Exhibit A-13, Schedule C5.17 in Exhibit A-13, Schedule C5.16, page 1.

Q. Can you please explain the Total PERC O&M Expenditures detailed in Exhibit A-13, Schedule C5.16, page 1?

A. This exhibit shows the by-project PERC O&M expenditures for the 2017 historical period, projected Calendar Year 2018, projected Calendar Year 2019 and projected Calendar Year 2020 planned expenditures totaling $27.0 million, $31.5 million, $19.5 million and $16.8 million respectively.

Q. How does the Total PERC O&M Expenditures on line 53 of Exhibit A-13, Schedule C5.16, page 1 relate to Exhibit A-13, Schedule C5.17?

A. As an example, the actual total PERC O&M expenditures of $27.0 million for Calendar Year 2017 shown in Exhibit A-13, Schedule C5.16, page 1, line 53, column (b) flows to Exhibit A-13, Schedule C5.17, page 1, line 2, column (b).

Line
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Q. How does the PERC amortization expense on line 10 of Exhibit A-13, Schedule C5.17, page 1 relate to Exhibit A-13, Schedule C5.3, page 1?

A. Exhibit A-13, Schedule C5.17 shows the calculation for PERC amortization that was derived from Exhibit A-13, Schedule C5.16, Page 1. Exhibit A-13, Schedule C5.17, page 1, line 10, column (f) shows $12.7 million as the calculated amortized portion of PERC O&M for the test period. This $12.7 million flows to Exhibit A-13, Schedule C5.3, page 1, line 22, column (k).

Q. Can you please explain the main drivers for the increase in Total PERC O&M Expenditures from the Calendar Year 2017 and projected Calendar Year 2018 as shown in Exhibit A-13, Schedule C5.16, page 1?

A. The main driver for the increase in Calendar Year 2018 PERC O&M Expenditures is the 24-Month Operating Cycle project. The 24-Month Operating Cycle expenditures for the actual Calendar Year 2017, forecasted Calendar Year 2018, forecasted Calendar Year 2019 and forecasted Calendar Year 2020 are $0.2 million, $8.7 million, $6.2 million and $4.0 million respectively as shown on line 26 of Exhibit A-13, Schedule C5.16, page 1.

Q. Can you please discuss the rationale for the 24-Month Operating Cycle project shown on line 26 of A-13, Schedule C5.16, page 1?

A. A 24-month operating cycle will result in additional generation over a six-year cycle due to fewer refueling outages. Operating on a 24-month cycle results in three refueling outages every six years; operating on an 18-month operating cycle results in four refueling outages every six years.

Fermi 2's cycle length is limited by our NRC license. The 24-Month Operating Cycle project performs analysis to ensure the plant is capable of operating 24 months between refueling outages and submits that analysis as a license amendment request to the NRC to update the Fermi 2 license to allow a 24-month cycle. We expect final NRC approval in early 2021 which means Refueling Outage 21 (RF21) in the fall of 2021 will be the last refueling outage following an 18-month cycle.

Q. What are the Total Nuclear Power Generation O&M expenses that you support for the projected test period ending April 30, 2020?

A. I support Total Nuclear Power Generation O&M expenses of $166.8 million for the projected test period as shown in Exhibit A-13, Schedule C5.3, page 1, line 24, column (m). As I have discussed previously, these projected Total Operation and Maintenance expenses are required for the safe and reliable operation of the Fermi 2 Power Plant for the projected test period. I consider these expenses to be prudent and reasonable.

<u>Nuclear Surcharge</u>

Q. Is the Company requesting a change to the Nuclear Surcharge?

A. Yes. The company is proposing an updated Nuclear Surcharge based on the same approach approved by the Commission in Case No. U-17767, Case No. U-18014 and Case No. U-18255 and depicted in Exhibit A-20, Schedule J1.

The Site Security and Radiation Protection portion of the surcharge has been updated to reflect 2017 historical expense plus inflation on line 2. The inflation rate is supported by Witness Uzenski on Exhibit A-13, Schedule C5.15.

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The Nuclear Decommissioning Funding portion of the surcharge shown on line 3 is unchanged.

The Low Level Radioactive Waste (LLRW) Disposal Funding portion of the annual surcharge has been updated to reflect an additional $2.0 million of forecasted LLRW expenditures on line 5.

The resulting nuclear surcharge is supported by Company Witness Mr. Bloch on Exhibit A-16, Schedule F6.

Q. Can you please explain the basis for requesting a $2.0 million increase to the LLRW Disposal Funding portion of the annual surcharge?

A. The annual LLRW Disposal Funding level of $4.0 million was established in 1994 by Commission Order U-10102; this is the first request to increase the LLRW Disposal Funding level since that original 1994 order. Disposal costs have increased at a rate well above general inflation since this time.

The $2.0 million per year increase supports an annual LLRW Disposal Funding level of $6.0 million. Nuclear Generation is forecasting $60.0 million in LLRW expenditures from 2020 through 2029; this $60.0 million will allow Fermi 2 to maintain minimal LLRW on-site.

Q. How does the $2.0 million per year increase of the LLRW Disposal Fund minimize risk?

A. Without the requested additional funding, more LLRW will likely accumulate on-site. There are a limited number of LLRW disposal sites and those sites are highly regulated and subject to closure from time to time. The Company seeks to minimize the accumulation of LLRW at Fermi 2 and strives to properly dispose of LLRW in a timely fashion to minimize the possibility of losing access to LLRW disposal sites. Additionally, the Fermi 2 site has a certain capacity to store LLRW on-site; if not shipped, the plant would eventually have to build additional capacity.

Fermi 2 currently has access to two LLRW disposal sites: 1) Clive, Utah and Andrews County, Texas. Access to these disposal sites is not guaranteed, in fact, Fermi's access to the Barnwell, South Carolina LLRW disposal site was lost in 2008 after South Carolina enacted a state law prohibiting LLRW disposal from generators outside of South Carolina's three-state compact.

Q. What are the benefits of the LLRW Disposal Fund?

A. The LLRW Disposal Fund mitigates the financial, regulatory and environmental risks associated with keeping LLRW at the Fermi 2 site.

The LLRW Disposal Fund is a fund that carries two benefits: 1) The LLRW fund is dedicated for the sole purpose of disposing of LLRW and 2) should Fermi 2 lose access to a disposal site, the LLRW fund can accumulate monies until such time a new disposal site becomes available to Fermi 2.

Line No.

Q. What is the Nuclear Surcharge that you support for the 12-month projected test period ending April 30, 2020?

A. I support the Proposed Nuclear Surcharge of $38.3 million for the projected test period as shown in Exhibit A-20, Schedule J1, page 1, line 6, column (b); this represents an increase in the Nuclear Surcharge expense of $2.7 million as shown in line 8, column (b). The Proposed Nuclear Surcharge funds Fermi 2 site security, radiation protection, nuclear decommissioning and the disposal of LLRW; these activities are required for safe and secure operation of the Fermi 2 Power Plant for the projected test period. I consider the Proposed Nuclear Surcharge to be prudent and reasonable.

Nuclear Generation Infrastructure Recovery Mechanism Capital

Q. What are the Nuclear Generation Infrastructure Recovery Mechanism (IRM) capital expenditures you support for the period May 1, 2020 through December 31, 2022?

A. I support Nuclear Generation IRM capital expenditures of $74.0 million, $99.1 million and $46.8 million for the 8-month period ending December 31, 2020, Calendar Year 2021 and Calendar Year 2022 respectively as shown in Exhibit A-30, Schedule T4, line 3.

Q. How did you develop your estimates for the IRM capital expenditures?

A. Forecasted Nuclear Generation IRM expenditures were developed using a continuation of the asset maintenance philosophy previously discussed in my testimony. The forecasted IRM expenditures follow from the forecasted capital expenditures for the projected test year listed in Exhibit A-12, Schedule B5.3.

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Project specific scope and costs will be shared during the fall Annual Plan Review. See Witness Stanczak's testimony where he describes the Annual Plan Review.

Q. Can you please discuss why Nuclear Generation is being included in the IRM?

A. Witness Stanczak discusses the need for the overall IRM. However, having Nuclear Generation included in the IRM will allow recovery of the Nuclear Generation capital expenditures required to maintain the Fermi 2 Power Plant's current level of safe and reliable operation beyond the projected test period, which ends April 30, 2020. As previously discussed in my testimony, nuclear safety is our overriding priority at Fermi 2. The IRM supports our operational and strategic decision-making that preserve this priority to ensure the health and safety of our surrounding communities.

Q. Can you please discuss the programs Nuclear Generation is proposing to include in the IRM?

A. Nuclear Generation is proposing two programs to include in the IRM: 1) Routine and Small Projects and 2) Non-Routine and Large Projects. The requested expenditures for these two programs are included in Exhibit A-30, Schedule T4.

Q. Why is Nuclear Generation proposing these two programs for the IRM?

A. We are proposing Routine and Small Projects and Non-Routine and Large Projects as the two programs for two reasons:

1. These two programs have been used by Nuclear Generation to broadly group our capital expenditures in our past rate cases, as well as this proceeding. See

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Exhibit A-12, Schedule B5.3 for types of projects that could be included in the IRM.

2. As I described earlier in my testimony, these two programs best align how Nuclear Generation thinks about work, especially in the context of planning for a refueling outage.

Q. Can you please discuss the type of work included in the proposed Non-Routine and Large Projects program shown on line 1 of Exhibit A-30, Schedule T4?

A. Non-Routine and Large Projects are those projects Nuclear Generation expects to implement only once for the life of the Fermi 2 asset though 2045. I would like to use two examples to illustrate the types of work included in our proposed Non-Routine and Large Projects program: 1) Fire header restoration and 2) Emergency Diesel Generator (EDG) control relays.

Q. Can you please discuss the fire header restoration project?

A. Fire is a significant risk requiring mitigation in a nuclear power plant; the Fermi 2 Fire Water Suppression System is an operating license requirement to mitigate this fire risk. The Fermi 2 Fire Water Suppression System distributes firefighting water from the normal or alternate sources of water to the scene of a postulated fire; the Fermi 2 Fire Water Suppression System is fed by the Fire Protection Header.

The Fire Protection Header itself is approximately a mile of underground 12" unlined ductile iron pipe "ring header" circling the plant. The pressure in the Fire Protection Header is maintained at 150 psig. The pipe was installed early in the plant's construction and has been underground for roughly 45 years.

Line No.

The piping of the Fire Protection Header is reaching the end of its useful life and we are starting to see degraded Fire Protection Header performance.

The objective of the fire header restoration project is to replace the piping of the Fire Protection Header. We anticipate replacing this piping in sections over several years – this plan allows the Fire Protection Header to remain operational while work is being performed, it allows replacement during the summer months which is typically a good time of year to perform this type of excavation work, and it spreads these expenditures over a period of time, thereby minimizing rate impacts.

Replacing this pipe is the best method to remediate pipe degradation and to ensure the Fire Protection Header will be able to perform as it is designed and fulfill its safety function through 2045.

Q. Can you please discuss the Emergency Diesel Generator (EDG) control relay project?

A. Loss of AC power is a risk to a nuclear power plant; the operating license requirement of the Fermi 2 Emergency Diesel Generator (EDG) System is to mitigate this loss of offsite power (LOP) risk by providing a reliable source of on-site AC electrical power to maintain the ability to safely shutdown the reactor under all conditions; the EDG System is automatically controlled by control relays.

The EDG system consists of four EDG units separated into two independent divisions and each EDG unit is completely independent from the other units. Each of the four EDG Control Circuits contains 40 control relays (EDG control relays) that support the operation of each EDG.

The EDG control relays are an example of obsolescence where the asset is currently operating as expected however the relays themselves are no longer manufactured and like-for-like replacements are not available. Fermi 2 does have a limited amount of these control relays in stock; however, it is not a good long term strategy to rely on the existing stock to maintain such an important system as the EDGs, especially given Fermi 2 is licensed to operate until 2045.

The objective of the EDG control relay project is to update the design of the EDG Control Circuit to use modern, readily available relays. We anticipate replacing one EDG Control Circuit at a time to maximize EDG availability.

Replacing the EDG control relays with modern relays is the best method to resolve the obsolescence problem and to ensure the EDG System will be able to perform as it is designed and fulfill its safety function through 2045.

Q. How will you measure the output of the Non-Routine and Large Projects?

A. Given the types of projects I have just used to explain Non-Routine and Large Projects, I propose using "number of projects complete" as the Non-Routine and Large Projects program metric. Witness Stanczak discusses the reporting and reconciliation of the program metrics.

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For both examples used, and similar for all projects within this program, Nuclear Generation will commit to providing the specific scope and projects to be completed one year prior to the refueling outage during the fall Annual Plan Review. Witness Stanczak discusses the fall Annual Plan Review process.

Q. Can you please discuss the type of work included in the proposed Routine and Small Projects program shown on line 2 of Exhibit A-30, Schedule T4?

A. Routine and Small Projects are those projects Nuclear Generation expects to implement two or more times throughout the remaining life of the Fermi 2 Power Plant. Many of the projects within Routine and Small Projects are implemented every operating cycle. I again would like to use two examples to illustrate the types of work included in our proposed Routine and Small Projects program: 1) Control rod blades and 2) snubbers.

Q. Can you please discuss the control rod blades project?

A. Control rod blades are the mechanism used to control reactor power. The Fermi 2 Power Plant has 185 control rod blades and each control rod blade has a useful life expectancy.

The control rod blade project replaces the control rod blades that have reached the end of their useful life each operating cycle. Each blade replacement represents a unit of work complete; typical units replaced is 15 – 30 blades per refueling outage. This work can only be performed during a refueling outage because the control rod blades are only accessible during that time.

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Q. Can you please discuss the snubbers project?

A. Snubbers are shock absorbers used to restrain safety piping and other important piping and components during a seismic or line break event. The Fermi 2 Power Plant has approximately 650 snubbers and each snubber has a useful life expectancy. Each operating cycle a random sample of snubbers are selected for replacement so that they can be inspected per code to ensure operability.

The snubber project replaces snubbers that have reached the end of their useful life or have been selected for inspection replacement each cycle. Each snubber replacement is a unit of work complete; typical units replaced is 90 – 130 snubbers per outage. This work is performed during a refueling outage because the snubbers are accessible during that time.

Q. How will you measure the output of the Routine and Small Projects?

A. Given the types of projects I have just used to explain Routine and Small Projects, I propose using "number of units complete" as the Routine and Small Projects program metric.

For both examples used, and similar for all projects within this program, Nuclear Generation would be able to confirm and commit the number of units proposed one year prior to a refueling outage. Witness Stanczak discusses the reporting and reconciliation of the program metrics.

Q. Is there an operational need for flexibility between the two Nuclear Generation IRM categories?

A. The proposed values for each IRM category represents Nuclear Generation's good faith effort to forecast capital expenditures through 2022. As I have discussed earlier, nuclear safety is our overriding priority and changes in plant conditions and regulatory requirements necessitate some flexibility to be able to reallocate Routine and Small Projects funding into Non-Routine and Large Projects or the opposite. Witness Stanczak discusses the details around what is being proposed for the flexibility in capital expenditures.

Q. Can you please illustrate the need for flexibility in capital expenditures with an example?

A. The Fermi 2 Power Plant must remain in compliance with all NRC regulations. Following the 2011 events at the Japanese nuclear power plant Fukushima Dai-ichi, the NRC issued new regulations to improve systems to safely vent pressure during an accident and improve the industry's ability to cope with a beyond design basis event; these new regulations necessitated billions in industry capital expenditures and U.S. nuclear plants had only four years to comply.

To comply with these new NRC "Fukushima" regulations, Nuclear Generation initiated several non-routine and large capital projects. Our ability to be flexible in distribution of capital expenditures was key to the Fermi 2 unit meeting the NRC deadlines.

Line No.

Q. How will you measure the performance of the Nuclear Generation IRM?

A. In addition to the two program metrics I described, I propose also using a performance indicator called "Total Number of Unplanned Power Losses per 7,000 Critical Hours" as a means of measuring Nuclear Generation's IRM performance. For brevity, I'll refer to "Total Number of Unplanned Power Changes per 7,000 Critical Hours" as "Unplanned Power Change Events." Witness Stanczak discusses how the Company will annually report the results of the performance indicators.

Q. Can you further define "Unplanned Power Change Events?"

A. "Unplanned Power Change Events" counts the number of unplanned automatic and manual scrams (reactor shutdowns) and the number of unplanned power changes in reactor power of greater than 20% of full power per 7,000 hours of operation.

Unplanned changes in reactor power for the purposes of this indicator is a change in reactor power that was initiated with less than 72 hours of planning.

The 7,000 hours is used because it provides a reference that is an industry standard in the U.S. commercial nuclear industry.

Q. Can you please provide guidance or key insights to understand "Unplanned Power Change Events?"

A. "Unplanned Power Change Events" is a measure of organizational effectiveness. The lower the value, the more effective the nuclear organization is operating and maintaining a nuclear asset.

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The "Unplanned Power Change Events" indicator is an industry metric.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

PHILIP W. DENNIS

DTE ELECTRIC COMPANY
QUALIFICATIONS OF PHILIP W. DENNIS

Line
No.

Q. Please state your name, business address and by whom you are employed.

A. My name is Philip W. Dennis. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company as Manager, Regulatory Economics.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your education background?

A. I received a Bachelor of Science Degree in Business Administration from Central Michigan University. In addition, I received a Master of Finance Degree from Walsh College.

Q. What work experience do you have?

A. In 1981 I was employed by ANR Pipeline Company (ANR) as a Finance Trainee. ANR is an interstate natural gas (gathering, storage and transmission) company regulated by the Federal Energy Regulatory Commission (FERC). I had varying and increasing responsibilities within ANR, including positions in their Controller's organization, Regulatory Affairs and Marketing groups. While working in the Regulatory Affairs organization, I assisted in the preparation and analysis of general rate cases, purchased gas adjustments, and various surcharge recovery filings. While in Regulatory Affairs, I presented testimony at the FERC sponsoring various cost of service components and participated as a witness in ANR's rate case hearings. In 1994 I was promoted to Manager of Transportation Rates. I transferred to ANR's Marketing department in 1999 as Manager of Market Analysis. I remained there until early 2001, when ANR, as part of a merger, was moved to Houston and I left the Company. In 2001, I began working for Michigan Consolidated Gas Company (MichCon) as a Principal Financial Analyst in the Regulatory Affairs department. In 2001, MichCon's parent, MCN Energy, was acquired by DTE Energy, DTE Electric's (formerly The Detroit Edison Company) parent. In 2005, I was promoted to Regulatory Affairs Consultant and was project manager for DTE Electric's general rate cases Case Nos. U-15244, U-15768 and U-16472. In 2011, I assumed my present position of Manager, Regulatory Economics.

Q. What are your current duties and responsibilities with DTE Electric?

A. My responsibilities include the management of regulatory activities relative to DTE Electric's Load Research, Tariffs, Pricing, and Rate Design.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony and exhibits in the following DTE Electric cases:

Case No.	**Description**
U-17437	Transitional cost recovery plan associated with the disposition of the City of Detroit Public Lighting System
U-17761	Years 2013/2014 Reconciliation of Transitional Reconciliation Mechanism associated with the disposition of the City of Detroit Public Lighting System.
U-18005	Year 2015 Reconciliation of Transitional Reconciliation Mechanism associated with the disposition of the City of Detroit Public Lighting System.

U-18248	Implementation of Section 6w of 2016 PA341 (“Capacity Filing”)
U-18251	Year 2016 Reconciliation of Transitional Reconciliation Mechanism associated with the disposition of the City of Detroit Public Lighting System.
U-18262	Years 2018/2019 Energy Waste Reduction Plan Filing
U-18419	Certificate of Necessity Filing
U-20051	Year 2017 Reconciliation of Transitional Reconciliation Mechanism associated with the disposition of the City of Detroit Public Lighting System.
U-18232	Renewable Energy Plan (REP) Proceeding

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the proposed rate design and language modifications for the Company's residential rate schedules, which includes incorporating the following:

- Modify Rate Schedule D1 to change the current power supply non-capacity rate structure from a flat per kWh charge, to a time of use (TOU) based charge, in compliance with the directive set forth by the Commission in its April 18, 2018 Order in Case No. U-18255.
- Design variable distribution rates to approach a uniform rate for all residential secondary rate schedules, with individual variable distribution rates capped at a 20% increase.
- Propose service charges for the D1, D1.2, D1.6, D1.8, and D2 rate schedules of $9.00.
- Propose new D1 provisions including the Weekend Flex Pilot Provision and the Fixed Bill Pilot Provision, as supported by Company Witness Mr. Clinton.
- Propose new Rider 18 (Distributed Generation Rider), as supported and directed by Company Witness Mr. Serna

I also support the modification to tariff language, consistent with billing rule R460.113, clarifying that in cases where the Company is missing interval meter data that customers on time of use rate schedules, are to be charged the off-peak (lower) rate. In addition, I propose a modification to Section C6.5 (c) (4) of the Company's tariff with respect to customer line extension.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring in whole, or in part, the following exhibits:

Exhibit	Schedule	Description
A-16	F3	Present and Proposed Revenues by Rate Schedule – 12 months ending April 30, 2020
A-16	F4	Comparison of Present and Proposed Monthly Bills– 12 months ending April 30, 2020
A-16	F7	D1 Fixed and Variable Portion of Bill
A-16	F8	Weekend Flex Pilot Provision Rate Calculation
A-16	F9	System Access Contribution (SAC)
A-16	F10	Proposed Tariff Sheets
A-16	F10.1	U-18383 Required Distributed Generation Tariff Filing

With respect to Exhibit A-16, Schedule F3, I am sponsoring the residential class which includes pages 2 through 12 of this exhibit. On Exhibit A-16, Schedule F4, I am sponsoring the typical monthly bills comparison for the residential class shown on pages 2 through 22. Company Witnesses Mr. Bloch, Ms. Holmes, and Mr. Johnston are sponsoring the remaining customer classes in Schedules F3 and F4. On Exhibit A-16, Schedule F10, I am sponsoring the proposed changes related to the residential class and the proposed Distributed Generation Program tariff, along with other tariff changes as noted above. Witnesses Bloch, Holmes, and Johnston are sponsoring the remaining sheets contained in this exhibit.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Line No.

Q. What residential rate schedules does the Company currently offer?

A. Rate Schedule D1 is the Company's standard residential service rate. Rate Schedule D1.1 is a separately metered interruptible space conditioning service rate. Rate Schedule D1.2 is a product with rates that vary dependent on season and time of day. Rate Schedule D1.6 is a product available to qualifying low income customers and supplies them with a $40 monthly credit. Rate Schedule D1.7 is a separately metered rate available for supplemental geothermal electric service with rates dependent on season and time of day. Rate Schedule D1.8 is a dynamic peak pricing product that has three pricing periods based on time of day and that is periodically subject to critical peak pricing. Rate Schedule D1.9 is a separately metered product for supplemental service to charge electric vehicles. Rate Schedule D2 was available to customers for all electric service if all space heating was total electric and installed on a permanent basis, but is now only available to dwellings being served on the rate prior to December 17, 2015. Rate Schedule D5 is a separately metered interruptible electric water heating product.

Q. Will you please describe Exhibit A-16, Schedule F3?

A. This exhibit shows the present and proposed rate design and corresponding revenue by rate schedule based on the billing determinants for the 12-month period ending April 30, 2020. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The billing determinants were developed based on historical data and relationships, as well as known and measurable changes, and are consistent with Company Witness Mr. Leuker's sales forecast. The existing rates, as approved by the MPSC's Order in Case No. U-18255 on April 27, 2018, are in column (c), and are used to calculate the

Line No.

present revenues in column (d). The rates proposed in this proceeding are in column (e), with the resulting revenues in column (f).

Q. What is the basis for the Company's proposed residential rate levels in this proceeding?

A. The basis for the proposed rate levels are the functionalized power supply and distribution deficiency amounts supported by Company Witness Mr. Lacey as shown in his Exhibit A-16, Schedule F1.1, page 2 (for power supply) and his Exhibit A-16, Schedule F1.2, page 1 (for distribution). The proposed residential power supply and distribution charges were designed to meet the power supply and distribution deficiencies shown in these exhibits. The proposed residential power supply capacity and non-capacity rates were designed to recover the revenues pursuant to Witness Lacey's Exhibit A-16 Schedule F1.5, which shows how much of the power supply revenue requirement for each rate class is capacity and non-capacity related.

Within the power supply cost of service, Witness Lacey identifies three separate residential cost classes: "D1/Other", "D1.2", and "D2". All residential rate schedules except D1.2 and D2 are included in D1/Other. For the D1/Other rate schedules the power supply deficiency was allocated based on each rate schedule's percentage contribution to the present D1/Other power supply revenue. For those rate schedules with their own cost of service class (D1.2 and D2), the deficiency was directly allocated to the corresponding class. This was the same method used to develop the approved residential power supply rates in the Company's last rate case, Case No. U-18255.

Q. Is the Company proposing to modify its Rate Schedule D1 (D1) power supply rate structure?

A. Yes. In its April 18, 2018 Order in Case No. U-18255, the Commission directed the Company in its next general rate case to include a proposed D1 tariff that included power supply non-capacity charges based summer on-peak / off-peak rates. Thus, as described further below, the Company is proposing to modify its current D1 non-capacity charge structure from the current flat per kWh rate structure, to a rate structure with summer on peak and off peak rates.

Q. What is the Company's proposed time of use periods for the D1 non-capacity rate?

A. The Company is proposing the D1 non-capacity rate structure consist of two rates: a summer on peak rate, and an off-peak rate as reflected on Exhibit A-16, Schedule F3, page 3. The Company is proposing that "summer" include the four months of June, July, August, and September. As discussed by Company Witness Mr. Farrell, the Company is proposing that the "on-peak" period for D1 be 4:00 p.m. through 9:00 p.m., Monday through Friday. Thus, the D1 summer on peak non-capacity rate would apply to all energy usage that takes place in June through September, between 4:00 p.m. and 9:00 p.m., Monday through Friday, and the D1 off peak non-capacity rate would apply to all other usage.

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Q. How did the Company select the 4:00 p.m. through 9:00 p.m. summer period for its on-peak non-capacity rate?

A. Witness Farrell discusses how the Company selected the on-peak period by looking at highest residential customer and system demands during the summer months in order to align a price signal with the highest peaking hours.

Q. Are there other ancillary benefits to using 4:00 p.m. through 9:00 p.m. as the on-peak period?

A. Yes. By providing customers rate options, it gives them the best opportunity to select the rate more appropriate for their home and work schedules. Time of use rate D1.2 has an on-peak period of 11:00 a.m. to 7:00 p.m., and Rate D1.8 has an on-peak period of 3:00 p.m. to 7:00 p.m. (along with a mid-peak rate). As Company Witness Mr. Clinton states, customers appreciate the Company offering them various options when it comes to managing their energy portfolio.

Q. How was the price differential between the non-capacity summer on peak rate and non-capacity off peak rate as shown on Exhibit A-16, Schedule F3, page 3 determined?

A. The proposed differential between the non-capacity summer on peak rate and non-capacity off peak rate is cost based, based on historic summer Midcontinent Independent System Operator (MISO) locational marginal price (LMP) as provided to me by Witness Farrell. The size of the on peak and off peak differential is an important consideration for customer acceptance as well, as this Commission ordered change would require the automatic transition of 1.9 million customers currently not subject to a TOU rate structure to TOU rates.

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Q. How would a larger price differential between the non-capacity summer on peak rate and non-capacity off peak rate impact customers' bills and risk to the Company and customers?

A. Without doing a smaller pilot study, I cannot be sure. However, a larger differential could have a negative impact on customer acceptance/satisfaction associated with this change, and would significantly increase revenue recovery risk (i.e. the larger the differential, the higher the impact on revenue should customers change usage behavior differently than expected).

Q. Based on the parameters discussed above related to on-peak hours and price differential, is the Company forecasting any load shift away from the on-peak hours?

A. No. Based on the timing associated with implementing information technology (IT) changes related to this massive change to our billing systems as discussed briefly by Company Witness Mr. Griffin, the uncertainty with respect to how fast customers can be moved to the new rate structure, more than likely the forecasted test year will have been completed, or near completion. In addition, given the proposed pricing differential, it would be premature to forecast any shift. Ideally, the Company should have had a chance to study customer behavior due to this change in order to have more information. If this TOU structure is implemented for D1, the Company will study how customers react to this rate structure and analyze whether the structure should be modified in future rate cases.

Q. Were any other rate schedules impacted by the D1 TOU change?

A. The Company is proposing the same structural changes to Rate Schedule D1.6, the Special Low Income Pilot Rate, which has historically mirrored D1's rate structure.

Q. Did the Company request rehearing of the Commission's Order in U-18255 related to this structural change for D1?

A. Yes. Company Witness Mr. Stanczak discusses the Company's rehearing request and the Commission's order on rehearing issued on June 28, 2018.

Q. Did the Company also design rates for D1 and D1.6 that follow the existing rate structure?

A. Yes. Exhibit A-16, Schedule F3, pages 2 and 6 contain rate designs for D1 and D1.6 that follow the existing rate structure (i.e. a flat non-capacity rate per kWh). The Company designed these rates to recover the same total D1/D1.6 revenue as the new TOU versions.

Q. Why did the Company design rates for D1 and D1.6 that follow the existing non-capacity rate structure?

A. As mentioned by Witness Stanczak, the Company is requesting in the present case, that the Commission eliminate the directive to convert the D1 non-capacity rates to a TOU rate structure. Should the Commission grant the Company's request, the D1 and D1.6 rate designs utilizing the existing rate structure can be used.

Line No.

Q. If the Commission does not modify its previous direction on D1 rates as the Company requests, should the traditionally designed D1 and D1.6 rates be disregarded?

A. No. Should the Commission not modify its Case No. U-18255 directives as described above, the Company is requesting that the new D1 and D1.6 TOU rate structure not become effective on the date rates change pursuant to an Order in this case. As discussed above, the Company will need to maintain its current rate structure until all IT work can be completed and customers can be transitioned.

Q. How does the Company's D1 and D1.6 TOU rate structure proposals relate to customers who opt out of advanced metering infrastructure?

A. The Commission's Order in Case No. U-18255 issued on April 18, 2018 stated the Company should propose allowing customers who opt out of advanced metering infrastructure to retain the existing D1 rate structure. The Company notes that time of use consumption information continues to be available via manual meter reads for customers who opt out of advanced metering infrastructure. Therefore, the Company is able to bill the TOU rate as proposed herein for D1. Thus, the Company proposes that customers who opt out of advanced metering infrastructure be subject to the same rate options as all other residential customers.

Q. Can you describe the Company's proposed residential distribution rate design?

A. In the Company's rate case filed in 2014, Case No. U-17767, MPSC Staff recommended, and the Commission approved, variable distribution rates designed such that all customers in the Residential Secondary class would have the same rate, with the caveat that a 20% cap was applied to limit the increase of any specific variable distribution rate. This method was again proposed and approved in the Company's subsequent rate cases, Case Nos. U-18014 and U-18255. The Company designed the variable distribution rates for each residential rate schedule in this case using this same premise.

Q. Is the Company proposing any changes related to residential service charges?

A. Yes, for residential rate schedules which are not for supplemental electric service (D1, D1.2, D1.6, D1.8, and D2) the Company is proposing to increase the service charge from $7.50 to $9.00 per customer, per month[1]. These revised service charges will recover a greater portion of the residential customer related costs, as supported by Witness Lacey. Witness Lacey's testimony and his Exhibit A-16, Schedule F1.4, supports residential fixed distribution costs (that do not vary with energy (kWh) consumption) of over $45 per customer per month, but in the interest of gradualism, the Company is proposing a $9.00 residential service charge in this case. The remaining distribution costs will still be recovered through an energy based charge. This is a reasonable approach that steps towards recognizing that distribution demand related costs should not be recovered 100% through an energy based charge. If in the future, the Company explores three part rates for residential customers (customer charge, demand charge and energy charge), this approach should be re-visited again.

Q. Are there any other changes the Company is proposing related to residential service charges?

A. Yes. The Residential Income Assistance Service Provision (RIA), part of the D1 tariff, currently provides a $7.50 per customer per month credit for participating customers.

[1] The Company is not proposing to change the service charges for residential rates for supplemental service (D1.1, D1.7, D1.9, and D5).

The Company is proposing to increase this credit to $9.00 per customer per month, in order for it to continue to fully offset the D1 service charge for RIA customers. The Residential Senior Service Provision, also part of the D1 tariff, currently provides a $3.75 per customer per month credit for participating customers. The Company is proposing to increase this credit to $4.50, so that it continues to offset half of the D1 service charge.

Q. Does the proposed increase to the residential service charges increase the distribution revenue deficiency supported by Witness Lacey's Exhibit A-16, Schedule F1.2?

A. No. As described above, the Company's proposed residential distribution rates are designed to recover the distribution deficiency shown in Witness Lacey's Exhibit A-16, Schedule F1.2. The residential rate design in this case recovers these distribution revenues by changing both the fixed service charges and the variable distribution rates. Therefore, if the residential service charge was not proposed to increase, the variable distribution rate would be higher than what is proposed, in order for the Company's residential distribution rates to recover the same amount of revenue. The Commission has recognized this concept in the past. In its June 10, 2008 Order, in a Consumer Energy rate case (Case No. U-15245) on page 74 it stated, "*The Commission is persuaded that the proposed $6.00 per month system access charge is appropriate.* ***It does not increase the residential customer class' cost of service. Rather, it merely reflects the fact that a flat customer charge, rather than an energy related charge, is a more appropriate way of collecting the fixed costs associated with serving each residential customer at any usage level***." (Emphasis added)

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Q. Will the Company's proposed residential service charge increase from $7.50 to $9.00 significantly affect the composition of customers' bills regarding fixed versus consumption (kWh) based charges?

A. No**.** The majority of the revenue collected from residential customers will continue to come from rates dependent on usage. Exhibit A-16, Schedule F7 shows how much of a Rate Schedule D1 Residential Service bill, excluding surcharges, is due to fixed and variable charges, under the Company's current and proposed rates for (1) a customer who consumes 600 kWh per month, and (2) a customer who consumes 300 kWh per month. For some historical perspective, the exhibit also shows the associated data for D1 rates approved in Case No. U-15244, which was the Company's general rate case in which the customer service charge was initially established, at a level of $6.00.

The exhibit shows that for a 600 kWh per month customer, the Company's proposal to modify the service charge increases the proportion of the bill due to fixed costs from 8% to 9%, meaning that 91% of the customer's bill is still due to variable kWh charges. For a 300 kWh per month customer, the Company's proposal to modify the service charge increases the proportion of the bill due to fixed costs from 15% to 17%, meaning that 83% of the customer's bill is still due to variable kWh charges (lines 36, 37). The exhibit also shows that when the D1 service charge was initially established at $6.00 in Case No. U-15244, that the proportion of a D1 customer's bill due to fixed costs was 9% for a 600 kWh per month customer and 17% for a 300 kWh per month customer. Therefore, the proposed residential service charges in this case would result in a proportion of customers' bills due to fixed costs for the examples shown in the exhibit that are very close to the proportions that existed when

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the service charges were initially established in Case No. U-15244. In summary, Exhibit A-16, Schedule F7 shows that although the portion of the bill attributable to fixed charges marginally increases under the Company's proposal from current levels, for the examples provided, a D1 customer's bill is still significantly (83% - 91%) driven by variable versus fixed charges.

This notion can be further illustrated from Exhibit A-16, Schedule F3, page 2 and 3, which shows the D1 present and proposed rates and revenues. Revenue from consumption (kWh) based charges accounts for over 90% of the total D1 revenue, under both present and proposed rates.

Q. Will you please describe Exhibit A-16, Schedule F4?

A. This exhibit shows a comparison of typical monthly bills by rate schedule based on present and proposed rates. For each rate schedule, the exhibit calculates the amount of a bill under existing rates and proposed rates across a broad range of energy consumption levels. The difference is representative of the impact of the proposed rate changes.

Proposed Residential Tariff Changes

Q. Can you please describe Exhibit A-16, Schedule F10?

A. This exhibit contains the proposed residential rule and tariff sheet changes which result from the pricing changes described above and language modification described below.

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Q. Is the Company proposing any tariff modifications in addition to the proposed price changes discussed above?

A. Yes. The Company is proposing the following tariff modifications/additions:

- Additional language to clarify what rate applies when there is missing interval data.
- Modification to the Company's line extension policy
- A new Weekend Flex Pilot provision on Rate Schedule D1
- A new Fixed Bill Pilot provision on Rate Schedule D1
- Distributed Generation Tariff (Rider 18)

Q. What additional language is being proposed to clarify what rate applies when there is missing interval data?

A. The Commission approved billing rule language in its November 21, 2017 Order in Case No. U-18120. Section R 460.113(2) of those rules states a utility shall outline in its tariff a process that addresses missing or invalid usage data affecting the amount billed to a customer that ensures the amount billed during the billing period is appropriate, and R 460.113(6) states a utility shall not use estimated meter reads to deny residential customers the benefit of lower-tiered rate, if available. The Company is already in compliance with these rules. However, I am proposing to add the following language to Section C4.5 of its tariff book, to clarify its already-existing practice: "*In the event that a customer's hourly usage data is not retrievable, such usage for the billing period shall be applied to the lowest hourly rate in the customer's current rate schedule,* should the customer be on a time of use based *rate.*"

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Q. What additional language is being proposed to the Company's line extension policy?

A. The Company is modifying Section C6.5 (c) (4) to reflect that costs associated with the relocation of Company facilities to accommodate load additions, will be treated the same as other line extension costs associated with the load addition. The new language added is consistent with Consumers Energy Company's tariff, Section C1.6 A.

Q. What new residential pilot provisions on D1 is the Company proposing in this case?

A. As directed and supported by Witness Clinton, I have added a Weekend Flex Pilot provision and a Fixed Bill Pilot provision language to Rate Schedule D1.

Q. How were the additional fixed monthly charges for the Weekend Flex Pilot provision developed?

A. As directed and supported by Witness Clinton, I developed the Weekend Flex Pilot provision additional fixed monthly charges as shown in Exhibit A-16, Schedule F8. Column (a) of this exhibit shows the seven customer tranches, as directed by Witness Clinton. Column (b) shows the annual average weekend usage (kWh) for each customer tranche. Witness Farrell supplied me with the annual average weekend usage for each customer tranche, including the anticipated load shift. Column (c) then calculates the annual revenue to be recovered through the Weekend Flex Pilot fixed charge, by using the proposed D1 consumption-based (kWh) rates, and the usage shown in column (b). Column (d) then calculates the monthly Weekend Flex fixed charges, by dividing column (c) by 12. Columns (c) and (d) reflect the fixed

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charge using the proposed D1 rates with a non-capacity rate that is TOU based, and columns (e) and (f) reflect the annual revenue to be recovered through the Weekend Flex Pilot fixed charge and the fixed monthly charge, respectively, using the proposed D1 rates utilizing the existing rate structure (a flat per kWh non-capacity charge). The tariff that is contained in Exhibit A-16, Schedule F10, utilizes the pricing that results from the existing D1 rate structure. The Company proposes that these rates be used until such time that the D1 TOU rate structure is implemented, at which point the rates in column (d) should be implemented for Weekend Flex.

Proposed Distributed Generation Tariff

Q. Is the Company proposing a new distributed generation program Rider in this case?

A. Yes. Exhibit A-16, Schedule F10 contains the Company's proposed Rider 18, Distributed Generation Program. I designed this tariff as instructed and supported by Witness Serna.

Q. Can you please explain the charging components of the new Rider 18?

A. As discussed and supported by Witness Serna, the new Rider utilizes an "inflow/outflow" pricing mechanism, with a System Access Contribution (SAC) charge, as described below.

Q. Can you please explain the inflow and outflow charging components of the new Rider 18?

A. For all energy which a Distributed Generation Program customer (DG customer) inflows (i.e. receives from the Company), the customer will be charged the full retail rate of the rate schedule the customer is attaching the rider to. So, for instance, a Rate

Schedule D1 customer would pay the D1 retail rate for all inflow.

For all energy that a DG customer outflows (i.e. sends on to the Company's distribution system), the DG customer will receive a credit. The outflow credit is the monthly average real-time locational marginal price for energy at the DTE Electric-appropriate load node. Outflow credits can be used in each billing period to offset power supply charges of the bill. Should the outflow credits accumulated in a billing period exceed the power supply portion of a customer's bill, the excess credit amount will be banked and be able to be used in future billing periods to offset power supply charges. Credit balances will be carried forward indefinitely. If a customer ceases to participate in the Distributed Generation Program, any remaining credit balance will be forfeited.

Q. Can you please explain how the proposed Rider 18 SAC charge was calculated?

A. The SAC is a monthly per kW of installed nameplate capacity charge. The proposed SAC charges per kW of installed nameplate generation on the customer's site is calculated on Exhibit A-16 Schedule, F9. Lines 1, 2, and 3 of the exhibit show annual average kWh of inflow, outflow, and generation based on 2017 historic customer data for customers with generation meters. Using this data, line 4 calculates the amount of annual average on-site usage, including energy inflowed and generation used on site. As part of the residential and secondary commercial distribution rate design, the Company in this case (and in past cases) is moving toward universal consumption based (kWh) distribution charges for all residential secondary customers, and for all commercial secondary customers with a per kWh distribution charge. The Company is doing this gradually, capping the distribution charge increase for any rate schedule

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in each rate case. Line 5 of Exhibit A-16, Schedule F9 shows the universal distribution charge that would exist if all residential secondary paid the same distribution charge, and if all commercial secondary customers paid the same distribution charge. Using these charges, line 6 calculates the total average DG site distribution revenue requirement, and line 7 calculates the amount of distribution revenue that would result from the total average inflow. The difference between these two values (line 6 less line 7) is shown on line 8, which represents the annual distribution revenue deficiency. Line 9 reflects the monthly distribution revenue deficiency. Line 10 shows the average installed nameplate capacity ratings, based on the same customers used to gather the inflow, outflow, and generation data. Line 11 then calculates the monthly SAC per kW of installed nameplate capacity. Separate SAC charges are developed for residential secondary DG customers and commercial secondary DG customers.

Q. What rate schedules would the proposed Rider 18 SAC be applied to?

A. The SAC would apply only to DG residential and commercial secondary customers on a rate schedule which has distribution charges based on kWh consumption. In other words, customers on rate schedules with demand based distribution rates would not be subject to the SAC, as demand charges more appropriately recover distribution costs.

Q. Can you please describe Exhibit A-16, Schedule F10.1?

A. The Commission's April 18, 2018 Order in Case No. U-18383 stated that in any rate case filed after June 1, 2018, utilities must file the Distributed Generation Inflow/Outflow tariff attached to that Order (the required tariff was attached to the

Order as Exhibit A). The Company's Exhibit A-16, Schedule F10.1 fulfils that obligation. This exhibit contains some redline changes made by the Company to the tariff included in Case U-18383 as Exhibit A. The redline changes were made to (1) conform with DTE's general tariff structure (headings, numbering, etc), (2) to fill in some placeholders that were in the required tariff, as they are now known (e.g. case number and dates), (3) add clarifying language and proper references to Company's existing rate book and IEEE standard, and (4) to include the Company's proposed outflow compensation method, which in Exhibit A to the Commission's U-18383 Order stated would be determined in a contested case proceeding.

Q. Is the Company requesting approval of the Distributed Generation tariff filed as Exhibit A-16, Schedule F10.1?

A. No. The Company has only included the tariff as shown on Exhibit A-16, Schedule F10.1, in compliance with the Commission order mentioned above. The Company does not support the approval of the tariff contained in Exhibit A-16, Schedule F10.1. The Commission's Order in Case No. U-18383 stated utilities may also file their own distributed generation tariff, which the Company has done in this case. The Company is requesting approval of its DG Program tariff which is included as part of Exhibit A-16, Schedule F10.

Q. What changes to the Inflow/Outflow tariff attached to the Commission's Order in Case No. U-18383 as Exhibit A, is the Company proposing as part of its DG Program tariff?

A. Other than changes related to pricing, the Company is generally in agreement with the tariff attached to the Commission's Order in Case No. U-18383. The changes

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proposed by the Company to the tariff can be seen by comparing the Company's proposed Rider 18 contained in Exhibit A-16, Schedule F10, to Exhibit A-16, Schedule F10.1. The Company's proposal contains different charging component mechanics, which are described in my testimony above, and other changes resulting from language that was unclear, or needed further support. These changes include:

- Eliminating the language associated with unused credits at termination, and replacing with the Company's proposal.
- Added language stating, that Company approval is required for any subsequent changes in the interconnection configuration before those changes are allowed. Similar language is contained in the Company's current net metering tariff (Rider 16), and it is the Company's position such language is reasonable and should be included in the new Rider 18.
- Added language to clarify that for any generation additions to existing customer sites who are billed under Rider 16, the entire site load will be subject to the new DG tariff.

Q. Is the Company proposing any changes to its existing net metering tariff, Rider 16?

A. Yes, additional language is proposed to be added to Rider 16, to state it will be unavailable for new customer on-site generation after the new Distributed Generation Program (Rider 18) is implemented. This is reflected in Exhibit A-16, Schedule F10.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

IRENE M. DIMITRY

DTE ELECTRIC COMPANY
QUALIFICATIONS OF IRENE M. DIMITRY

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Q. Please state your full name, title, business address and by whom you are employed?

A. Irene M. Dimitry, Vice President of Business Planning & Development, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I graduated from Wayne State University in 1989 with a Bachelor of Arts Degree in Business Administration. In 1994, I received a Masters Degree in Business Administration from the University of Michigan.

Q. Please describe your work experience?

A. I began my career with GM in the GMC Truck Division and worked there from 1989-1992. I served in several roles within the division's Marketing organization. My employment with DTE Electric began in 1994 as part of the Company's Professional Opportunity Program. Over the years, I held a number of positions with increasing leadership responsibilities in areas that include: Business Planning, DTE Electric's Ann Arbor Service Center, the President's Staff organization, Customer Marketing, Customer Billing, and Enterprise Performance Management.

I also served as the Director of Strategy and Planning for DTE Electric. In this role, I was responsible for Integrated Resource Planning, Customer Research, general rate case support and strategic initiatives related to the Company's business plans.

Prior to my current position, I was the Vice President of Marketing and Renewables. In this role, I was responsible for planning and executing energy efficiency and renewable energy activities for DTE Electric and DTE Gas consistent with 2008 Public Act 295 (2008 PA 295 or PA 295). I have been responsible for planning and executing DTE Electric's renewable energy activities since the enactment of 2008 PA 295, and for planning and executing DTE Energy's energy efficiency / energy waste reduction activities since 2010.

Q. What is your current position and what are your current responsibilities?

A. Currently, I am the Vice President of Business Planning and Development. In this role, I am responsible for Renewable Energy, Energy Waste Reduction, Corporate Energy Forecasting, Business Planning, Integrated Resource Planning, and Customer Choice functions.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I sponsored testimony in the following cases:

U-15806-RPS	DTE Electric's 2009 Renewable Energy Plan case
U-16356	DTE Electric's 2009 Renewable Cost Reconciliation case
U-16582	DTE Electric's 2011 Renewable Energy Plan
U-17767	DTE Electric's 2014 Rate Case

U-18014	DTE Electric’s 2016 Rate Case
U-18255	DTE Electric’s 2017 Rate Case
U-18419	DTE Electric Certificate of Necessity
U-18441	Capacity Demonstration
U-18444	Process for Forward Locational Requirement

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to:

1) Discuss the development of the demand side management (DSM) efforts that DTE Electric is conducting and provide support for the expenditures and activities associated with the continuation of existing DSM programs and the start of future DSM programs; and
2) Discuss the economic analysis completed by the Company regarding the continued operations of River Rouge Unit 3 until its planned retirement in 2020

Q. Are you sponsoring any exhibits in the proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.6	Demand Side Management Capital Expenditure
A-12	B6	River Rouge Unit 3 NPVRR Analysis

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How is your testimony organized?

A. My testimony consists of the following two parts:

Part I Demand Side Management Programs

Part II River Rouge Unit 3 Evaluation

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Part I: Demand Side Management Programs

Q. How much has the Company invested in Demand Side Management (DSM) programs?

A. The Company has spent $25.4 million in capital expenditures associated with DSM programs from 2016 through December 31, 2017. DTE Electric's existing programs during that time include:

- Interruptible Air Conditioning (IAC)
- Programmable Controllable Thermostat (PCT)
- DTE Energy Insight

Shown below in Figure 1 is the Company's historical capital expenditures since 2016.

Figure 1: Historical DSM spend from 2016

$ Thousand	**Historical 12 Mo. Ended 12/31/2016**	**Historical 12 Mo. Ended 12/31/2017**	**Historical 2016-2017 Total**
Interruptible Air Conditioning	$7,353	$4,304	$11,657
Programmable Controllable Thermostat	$0	$2,074	$2,074
DTE Energy Insight	$5,349	$6,295	$11,644
Total	$12,702	$12,673	$25,375

Q. How much is the Company forecasting to spend on DSM programs during 2018, 2019, and through the end of the projected test year April 30, 2020?

A. The Company is forecasting to invest $15.5 million through the bridge period of January 2018 through the month ending April 2019 and $15.0 million in the projected test year ending April 2020 on DSM programs. A detailed breakdown of these capital expenditures by program is shown in Exhibit A-12, Schedule B-5.6, page 1 of 2, column (e) and (f). The Company is planning to continue investing in IAC, PCT and DTE

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Energy Insight programs. In 2018, DTE Electric began deployment of the Bring Your Own Device (BYOD) program and will continue developing additional DSM pilots. In addition, the Company is forecasting to spend $0.4 million in operation and maintenance (O&M) expenses in support of DSM programs. Associated O&M expenses are shown on CompanyWitness Mr.Clinton's Exhibit A-13, Schedule C-5.8, page 1 of 1, line 9, column (k).

Q. How do the O&M expenses support DSM programs?

A. The expense reflects the funding needed to support the marketing and development of the DSM portfolio of programs, including staffing requirements of the exisitng programs.

Q. Why has the Company been investing in DSM programs?

A. Planned or unplanned power plant retirements, new energy legislation, regulatory requirements, and changing environmental regulations have been driving change to the energy landscape in the State of Michigan. As coal plants retire and new resources must be built, developed, or acquired to ensure resource adequacy, DSM will be an important part of DTE Electric's resource portfolio. These DSM programs are designed to help reduce enrolled customers' energy use during peak hours, providing value to both the utility and the customer through lower capacity costs.

The Company believes that DSM programs belong in a utility system framework and within the comprehensive context of an integrated resource planning process. The DSM Organization within DTE Electric develops, validates, and manages these technologies and programs. The DSM Organization works with the Company's generation strategy and integrated resource planning teams to determine the timing and the amounts of new or additional DSM programs that are viable alternatives within the Company's integrated resource plan, and with the Company's generation optimization team to operate the DSM programs.

Each DSM program outlined below offers customers a range of options consisting of products, customer incentives, tariff structures, and education based on their risk profiles and willingness to curtail energy usage during peak hours. As part of the development of the DSM programs in integrated resource planning, DTE Electric evaluates new programs, customer effectiveness, program acceptance and validates technologies that deliver benefits to utility customers. By developing a portfolio of functioning DSM programs, the Company expects to continue providing secure, reliable, and sustainable energy supply to its customers under a changing generation capacity and energy landscape in the coming years.

Interruptible Air Conditioning (IAC)

Q. What is the status of the Company's IAC program?

A. Beginning with approval requested in the December 2014 general rate case, Case U-17767, the Company embarked on a long-term plan to improve programs and repair existing IAC equipment. The goal of this plan was to extend the equipment life and increase available Midcontinent Independent System Operator (MISO) acknowledged capacity. This program upgrades the existing IAC infrastructure from an antiquated one-way radio system to a two-way communication protocol enabled Load Control Device (LCD) that utilizes the existing advanced metering infrastructure (AMI) technology. The new two-way communication infrastructure provides significant

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advantages over the one-way radio system that has been in the field since the 1970s, and is prone to malfunctioning, difficult to service, and in need of repair. The new LCDs reside within and utilize the existing AMI device, provide a two-way communication tool, deliver improved diagnostic capabilities, as well as provide more effective remote equipment control. The Company intends to replace all the old IAC switches with new LCDs, adding up to 278,000 replaced units by 2026 and translating into a total of 221 MW of MISO acknowledged nameplate capacity for DTE Electric.

Q. Why is the Company making these improvements?

A The Company is making these improvements for several reasons. The existing one-way radio paging infrastructure is quickly becoming obsolete. The equipment currently in use by the Company is no longer being manufactured and replacement parts are very difficult to find for the outdated 56K modem technology. Additionally, by utilizing a two-way communication infrastructure, the Company has the ability to validate the status of each LCD remotely. This functionality allows for the Company to identify and diagnose non-operational LCD units through the AMI network without having to physically visit the customer location. The limitations of the antiquated one-way infrastructure interfere with the ability to receive full capacity credit for the program in MISO. The Company has increased the MISO acknowledged capacity on the IAC program as the replacement of the old technology is occurring. The Company is currently claiming 135 MW of available capacity for the program in 2018.

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Q. What are the Company's planned efforts in managing the IAC program going forward?

A. Under its long-term IAC capital improvement plan, DTE Electric installed new devices and is currently planning to purchase and install additional devices. Figure 2 below details historical and projected installations.

Figure 2: Historical and Projected LCD Installations

	Historical 12 Mo. Ended 12/31/2017	**Projected 12 Mo. Ending 12/31/2018**	**Projected 4 Mo. Ending 04/30/2019**	**Projected 16 Mo. Ending 4/30/2019**	**Projected 12 Mo. Ending 4/30/2020**
New or Planned LCDs Installed	28,190	29,000	8,000	37,000	30,000
Cumulative Total Installed	60,190	89,190	97,190	97,190	127,190

The Company continues to use Continuous Improvement opportunities to drive program cost efficiencies. One recent example was a process change to implement a route optimization process. This approach decreases drive time, maximizes installations and saves money.

The forecasted expenditures in Exhibit A-12, Schedule B-5.6, page 1 of 2, line 1, column (e) and (f) for the projected bridge period January 2018 through April 2019 ($5.9M), and the projected test year period through April 30, 2020 ($4.9M) reflect the continuation of the existing IAC replacement as approved by the Commission in its Orders dated December 11, 2015 for Case No. U-17767, January 31, 2017 for Case No. U-18014, and April 18, 2018 for Case No. U-18255. The Company plans to continue increasing the capacity of the program, and thus accelerating the replacement of the obsolete technology (one-way radio system) to meet its targeted completion in 2026.

Programmable Controllable Thermostat (PCT)

Q. What is the PCT Program in which DTE Electric is investing?

A. The Programmable Controllable Thermostat (PCT) pilot program is available to residential customers and requires customers to enroll in the Dynamic Peak Pricing (DPP) tariff. The customer's enrollment allows the Company to send a pricing signal to a PCT installed in the customer's home during a DPP event. Per the D1.8 tariff, customers are notified by 6 PM the day prior to the initiation of a DPP event. During a DPP event, the PCT is sent a pricing signal and raises the thermostat by 4 degrees. The PCT uses Wi-Fi to receive the signal from the utility during an event. The customer can override this action by adjusting their thermostat settings during DPP events. However, as part of participating on the DPP tariff, such manual over-rides of the utility PCT signals will drive a customer's bill to be notably higher.

The Company does not shut off the Heating Ventilation and A/C system or any other appliance in the home as part of the PCT program. The thermostat control only occurs between 3 PM and 7 PM Monday through Friday (excluding holidays) and is limited to 20 events per year.

Q. Why has the Company been investing in the PCT Program?

A. The purpose of the program is to lower peak-hour electric consumption by residential customers. DTE Electric continues to implement the PCT program to leverage the results and valuable customer behavioral information gained from the SmartCurrents pilot study conducted during 2010-2013, which was funded by an American Reinvestment and Recovery Act Smart Grid Investment Grant (SGIG). The results of the pilot suggested that customers can reduce their electricity usage by up to 40% during

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on-peak hours and save up to 15% on their electric bills by making small changes in their behavior while participating in a dynamic peak pricing program in conjunction with a PCT.

Q. How did the Company pursue implementation of the PCT program it set forth in Case No. U-18014?

A. After the MPSC order in Case No. U-18014 was issued in January 2017, the Company issued a Request for Proposal (RFP) to third Party Implementation Contractors. Evaluations of the RFP responses were conducted during the second quarter, and contract negotiations began in the third quarter of 2017. Additionally, the Company implemented a 50-unit technology test in the third quarter of 2017 to gauge customer interest and the ability to deliver signals to devices in the field. The initial large-scale purchase of the thermostats occurred in late fourth quarter 2017 and DTE Electric began marketing the program to recruit and enroll customers in the first quarter of 2018.

Q. What was the Commission's ruling in Case No. U-18255 for the PCT Program?

A. In its April 18, 2018 Order Case No. U-18255 the Commission observed, "Staff contends that the installation of 50 PCTs does not demonstrate success or justify the need for 25,000 more, noting that the utility still has another 9,950 to install from the last rate case". The Commission then adopted the recommendation of the ALJ, which denied the $6.133 million requested to expand the PCT program beyond the expenditures approved in Case No. U-18014 rates to support the installation of 10,000 units. The Commission agreed that complete installation was not necessary to support increased funding, but a showing of initial success is required.

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Q. What is the actual and forecasted progress in enrolling customers in the PCT program?

A. The Company has enrolled 2,000 customers on PCTs since the launch of the program in 2018 and is forecasting to enroll 7,000 customers by the end of 2018 as well as complete the enrollment of 10,000 units by the summer of 2019. The Company is proposing an additional investment in the PCT program as shown by the forecasted expenditures in Exhibit A-12, Schedule B-5.6, page 1 of 2, line 2, column (e) and (f) for the bridge period January 2018 through April 2019 ($6.2M), and the projected test year period through April 30, 2020 ($3.4M) given the enrollment success of the program since inception and the performance of the 2017 PCT pilot, as described in more detail below. These additional investments would enable enrollment of a total of 17,000 customers in the PCT program, up from the 10,000 customer level supported by the funding approved in Case No. U-18014 and reaffirmed in Case No, U-18255, as shown in Figure 3 below.

Figure 3: Historical and Projected PCT Enrollments and Capital Spend

	12 Months Ending 12/31/2018	**4 Months Ending 4/30/2019**	**16 Months Ending 4/30/2019**	**12 Months Ending 4/30/2020**
Phase 1 Units	7,000	3,000	10,000	
Phase 1 Capital	$4.6M	$1.6M	$6.2M	
Phase 2 Units				7,000
Phase 2 Capital				$3.4M

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Q. What information is the Company relying on to support its current rate request for the PCT program?

A. The Company ran a 50-customer technology-test pilot program in the fall of 2017 and the results of the pilot are similar to the 2013 SmartCurrents pilot. For the fall 2017 pilot, the Company collected data for 3 DPP events in September during which the average peak temperature reached 89 degrees. The Company saw an average reduction of 1.0 kW per participating customer over the course of the 3 DPP events called in 2017. This value is higher than the Company's results in the 2012 Smart Grid Investment Grant program of 0.75 kW per customer and higher than the impacts projected in Case Nos. U-18255 and U-18419. The Company sees the increased reduction as a positive performance indicator and believes it is supportive of additional investment in the program. Figure 4 below showcases the data collected for one of those 3 DPP events. The representative data below shows that in a DPP event where the PCT program is called upon by the Company, the PCT customers show a steep decline in usage during the critical hours of the event when compared to DPP-only customers. During the September 26, 2017 DPP event, the average PCT customer reduced their consumption by 1.05 kW.

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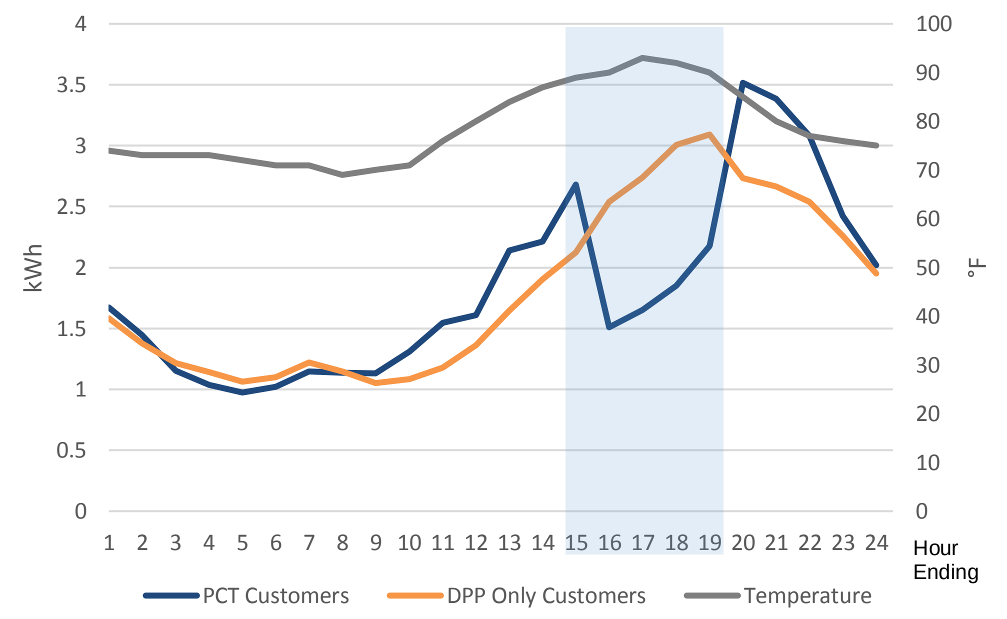
Figure 4 - 9/26/17 PCT results



Q. How is the Company proposing to measure the performance of the PCT program?

A. The Company is following existing measurement and verification processes to establish the peak demand reduction of those customers enrolled in the PCT program. The Company separates those customers with PCT technology from those without PCTs on the existing DPP rate and measures the relative load reductions at the meter for the peak events. The Company verifies and analyzes a customer's actual load profile before, during, and after an event with hourly data to determine reductions. Per the Commission reporting requirements in Case No. U-18441, this information will be included as Internal Demand Response Programs that are applied as an adjustment to the Peak forecast in the annual reporting template for Capacity Demonstration filings.

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Q. As part of the PCT program development, is the Company evaluating the possibility of requiring customers to pay some amount for the thermostat devices?

A. Yes. Under the current PCT program, the Company purchases the thermostats for installation in the customer's home. The thermostats are currently provided to the customer free of charge and the customer self-installs the unit or can request installation assistance from the Company. The Company will continue to monitor and evaluate all options for customer participation, including having customers pay for a portion of the hardware or device in order to have enrolled customers more invested in the program. During the small-scale pilot in 2017, all customers enrolled in the program installed and connected their device. Of those customers, 74% participated in the 3 DPP events called last fall by not overriding the signal to the thermostat. In 2018, as a consequence of the program set forth in U-18014 and the associated rate approvals, the Company has enrolled 2,000 customers and 65% of those PCTs distributed were installed and connected by customers through May 25, 2018. The Company is currently following up with the remaining customers who have enrolled in the program but not yet installed the PCTs to encourage installation or provide assistance with the installation of the PCT on an as needed basis.

The Company will continue to monitor customer engagement and installation of the program's PCTs and reserves the option to begin charging customers for the hardware in the future, if needed, to increase customer engagement and result in better participation during DPP events (e.g., create more "skin in the game" for customers). If customer charges are implemented, the Company would use the funds collected from customers to reinvest in the program, by acquiring hardware or increasing marketing efforts.

Q. What are the Company's planned efforts to manage the PCT Program going forward?

A. As of May 31, 2018, the Company has enrolled 2,000 customers in the PCT program. The Company is forecasting to have 7,000 customers enrolled by year end 2018 as well as 10,000 customers enrolled by the summer of 2019. The Company is requesting funding in rates to enable enrollment of an additional 7,000 customers in the PCT program by the end of the test year in April 2020. Continued investment in this program will reduce the impact of residential load on peak demand, lowering the Company's need to secure additional generation capacity, and improving customer affordability. The PCT program further leverages the Company's involvement in new technology, including the existing AMI infrastructure, which provides the interval data needed for billing and hourly pricing under the PCT program. It also positions DTE as an industry leader in DSM and provides another program in a portfolio of options for customers to manage their electricity usage and bill.

Given the results of the 2017 pilot program and the 2,000 units enrolled at the time of this filing, DTE Electric is requesting $6.2 million in capital expenditures during the bridge period January 2018 through April 2019 and $3.4 million through the projected test period ending on April 30, 2020, to purchase approximately 7,000 additional PCTs. Based on the filing of this request and the timing of the expected approval in the resulting final Order, the Company would install an additional 7,000 units by the summer of 2020 with the capacity being available by the summer of 2020 for planning purposes. This quantity reflects a reasonable estimate as a continuation of the program. Please, refer to the Exhibit A-12, Schedule B5.6, page 1 of 2, line 2, column (e) and (f), for the total capital expenditure request.

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DTE Insight

Q. What is the DTE Insight Program?

A. The DTE Insight program centers on a mobile application that is integrated with AMI and helps residential customers monitor and manage their energy use. Users of the DTE Insight mobile application can view their prior day's energy usage on an hour-by-hour basis, which helps customers better understand how recent weather and behaviors can impact energy usage and savings. When paired with an Energy Bridge (EB) device, the DTE Insight program participants can obtain real-time energy information. EB devices collect energy consumption data by connecting wirelessly to the automated meter and storing highly granular interval data in the EB at the customers' home, allowing customers to gain access to this data through their smart phone or other device. As part of integrated resource planning, broad deployment and usage of the DTE Insight app and EB devices can reduce peak demand and potentially mitigate or defer the need for future supply side resources. The DTE Insight program generated 1,818 kW of coincident peak savings in 2017 as stated in Exhibit A-14, column (j), row 12 in the Energy Waste Reduction (EWR) reconciliation for program year 2017 Case No. U-20029 included with Company Witness Brannan testimony.

Q. What did the Commission approve in Case No. U-18255 for the DTE Energy Insight Program?

A. The MPSC approved $9.9 million in capital in rates over the 22-month period ending October 31, 2018 to continue to invest in the DTE Insight program to enhance successful demand side management options. From January 2017 through October of 2018, the Company is forecasted to spend $6.9 million in capital for the DTE Insight program. The lower than planned spend is driven primarily by a new vendor contract for field support expenses. As these lower field support expenses are reflected in our request for capital expenditures included in this case, the Company does not expect to underspend again on the DTE Insight program.

Q. What are the most updated metrics regarding the development and implementation of the DTE Insight program?

A. The Company continues the development and implementation of the DTE Insight program throughout 2018. As shown in Figure 5, the following metrics reflect the continuous and increasing customer engagement and participation in the program:

Figure 5 DTE Insight Metrics

	Cumulative Data as of Dec 31, 2015 (a)	Cumulative Data as of Dec 31, 2016 (b)	Cumulative Data as of Dec 31, 2017 (c)	Cumulative Data as of Apr 30, 2018 (d)	Increase in Year 2017 (c) – (b)
Unique Household Downloads	59,080	115,741	157,372	165,634	41,631
Total Customer Downloads	119,607	245,533	365,687	393,149	120,154
EBs Purchased	35,000	65,000	106,000	106,000	41,000
EBs Requested	25,261	51,833	68,569	70,054	16,736
EBs Shipped	16,377	36,815	58,999	59,795	22,184
EBs Returned	0	853	5,619	6,243	4,766

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Q. Has the Company made any improvements in calendar year 2017 for the DTE Insight program?

A. During 2017, the Company improved the success rate of customers that connected their energy bridge device to the AMI without assistance from 82% to 93%. The primary driver was a new generation of energy bridges with much more sophisticated software/hardware that simplifies the process of wirelessly connecting the energy bridge to the customers' AMI meter (i.e., the binding process). In addition, a customer engagement campaign began in February 2017 and ran through December 2017. As described in Case U-18255, EB devices shipped to customers that were not installed amounted to 12,731 as of December 31, 2016. At the end of this customer engagement campaign, the Company saw approximately 1,800 targeted customers connect their devices and almost 4,800 targeted customers return their devices, thereby minimizing waste and ensuring more actual program benefits.

Q. What progress has the Company made with analyzing charging customers for the energy bridge devices?

A. The Company has completed its research and design work on instituting a new customer charge for the energy bridge device. In 2018, the Company plans to test a charge approach that offers a six-month free trial period and then charges $0.99 per month in perpetuity. There will also be a $25 one-time charge placed on the bill when customers move or contact the Company to report the device lost or damaged. In the case of move-outs, this one-time fee will be waived when the energy bridge device is returned to the Company. The intent of this design is to improve customers' engagement with the program without making it too complicated or prohibitively expensive. It is not the Company's intent to charge each participant the full cost of the energy bridge. Money

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collected through this charge will be used to offset program expenses and DTE Electric's overall revenue requirement. The timing for implementing this charge is aligned with the release of the new vendor platform for the DTE Insight mobile application.

Q. Has the Company considered the impact the energy bridge device charge will have on participation in the DTE Insight program?

A. Yes. In late 2017, the Company initiated work to transition to a more robust and reliable mobile app platform. This new version of the app has been designed to provide an improved customer experience. As of March 2018, the Company tested the new platform and messages with a small number of customers, about 1,200, before asking the remaining customers to transition to the new app. These customers accepted the new app terms and conditions, will go through a six-month free trial and then begin to receive a charge in the latter part of 2018. Based on the initial test results, the Company expects the new platform, coupled with the newer generation of energy bridge devices, to deliver sufficient customer value to support the device charge and help manage any negative impacts on program participation due to the initiation of charges. The new app platform became available to customers in May 2018. Efforts to move all customers to the new platform will continue through 2018. Toward the end of 2018, the Company will study the impact on program metrics to guide a final customer charging approach beyond 2018 and will update its participation forecast.

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Q: How will the new DTE Insight app platform help with program participant's engagement?

A: New features available in the new app platform that the Company expects will contribute to improved participant engagement include:

- An improved energy bridge installation customer experience that leverages Bluetooth technology (included only in the newer generation of energy bridge devices)
- Terms and conditions related to the device charge that must be accepted in the app before an energy bridge is approved for shipping and which are expected to reduce the number of customers asking for the energy bridge and then not actually using the energy bridge
- Usage disaggregation displayed on the app dial showing separately "always on" usage. "Always on" usage is usage from devices that are always plugged in to the power source, such as computers, cable boxes, internet routers, game consoles, etc.
- A robust platform that can better facilitate the introduction of new functions to be released in the future to keep customers engaged and motivated to continue logging into the app for information

Q. What are the Company's planned efforts with respect to the DTE Insight program going forward?

A. In 2018, the priority is to finish the transition work to the new app platform. The Company will also continue to improve on its marketing and communications campaigns to support the move to the new platform and to encourage deeper customer engagement.

The Company began migrating all other customers to the new app platform in May of 2018 and ramped up its marketing efforts. All customers migrating from the old platform to the new platform have been asked to accept the new terms and conditions if they want to keep or receive the energy bridge device. All new customers will be directed to the new platform and must accept terms and conditions before receiving the energy bridge.

Q. Based on these plans, what is the forecasted number of energy bridge purchases required?

A. Based on 2018 beginning inventory, expected returns, and forecasted demand for new shipments (including the bridge period and the projected test year) the Company only expects to purchase approximately 20,000 additional devices through the end of the projected test year. The Company slowed down its marketing efforts at the end of 2017 and the beginning of 2018 and ramped back up its efforts in May 2018 after launching the new app platform. This resulted in a beginning inventory for year 2018 of approximately 52,600 units (see Figure 5 above, cumulative purchased less cumulative shipped plus cumulative returned). Forecasted returns for the projected test year are estimated at 7,400 units. These units will then be refurbished and put back in inventory to fulfill new requests. Energy bridge device demand was minimal between January and April 2018 while marketing was scaled back; is forecasted at approximately 34,000 from May 2018 to April 2019; and is forecasted at approximately 41,000 from May 2019 to April 2020. These movements in inventory would leave the Company with approximately 5,000 units in inventory by April 30, 2020. In order to continue expanding the DTE Insight program, the Company is planning to spend $1.0 million during the bridge period January 2018 through April 2019 and $2.9 million for projected

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test year period ending April 30, 2020 for the DTE Insight program. Please, refer to the Exhibit A-12, Schedule B5.6, page 1 of 2, line 5, column (e) and (f), for the total capital expenditure request.

Other Demand Side Management Programs

Q. Is the Company planning to implement any additional Demand Side Management programs?

A. Yes. The Company plans to implement multiple demand side management pilots, including the expansion and refinement of an existing Bring Your Own Device (BYOD) pilot and multiple new pilots that involve storage technologies. In order to implement these pilot programs, the Company is forecasting to spend $2.6 million during the bridge period January 2018 through April 2019 and $3.7 million for projected test year period ending April 30, 2020 for the Other DSM programs. Please, refer to the Exhibit A-12, Schedule B5.6, page 1 of 2, line 3, column (e) and (f), for the total capital expenditure request for other DSM programs.

Q. What was the initial design of the Company's BYOD pilot program as launched in 2017?

A. The Company enrolled approximately 200 customers in a BYOD pilot program in the fall of 2017. The Company provided customers with a $50 incentive to enroll in the program and have their thermostats configured to allow the Company to send a control signal during BYOD events up to 5 times a year. During a BYOD event, the Company sends a pricing signal to BYOD thermostats to raise the set-point by 4 degrees between 3 PM and 7 PM, Monday through Friday. BYOD customers are notified a day prior to a scheduled BYOD event so that these customers have the opportunity to make additional behavioral changes, such as delaying the dishwasher or washing machine to run during off-peak times.

Q. What have been the initial results of the Company's BYOD pilot?

A. The customers in the 2017 pilot were on the standard D1 Residential tariff and their usage was compared against customers on the Dynamic Peak Pricing rate. The Company's measurement and verification results indicate that customers enrolled in the BYOD program reduced their peak load by 20% during BYOD events. The average per customer reduction was 0.7 kW across all 3 events that occurred in fall 2017. This value is higher than the Company's projected (or estimated) impact of 0.5 kW per customer as proposed in Case U-18419. This includes the impacts of average customer participation per event of 76% across all 3 events, meaning that 76% of the enrolled customers did not manually over-ride the utility initiated thermostat control set-point change. The representative data below shows that in a peak event, where the BYOD program is called upon by the Company, the participating BYOD customers show a steep decline in usage during the critical hours of the event when compared to DPP-only customers on a non-DPP event day. Figure 6 is actual event day data from September 26, 2017 for the BYOD pilot customers compared to DPP only customers.

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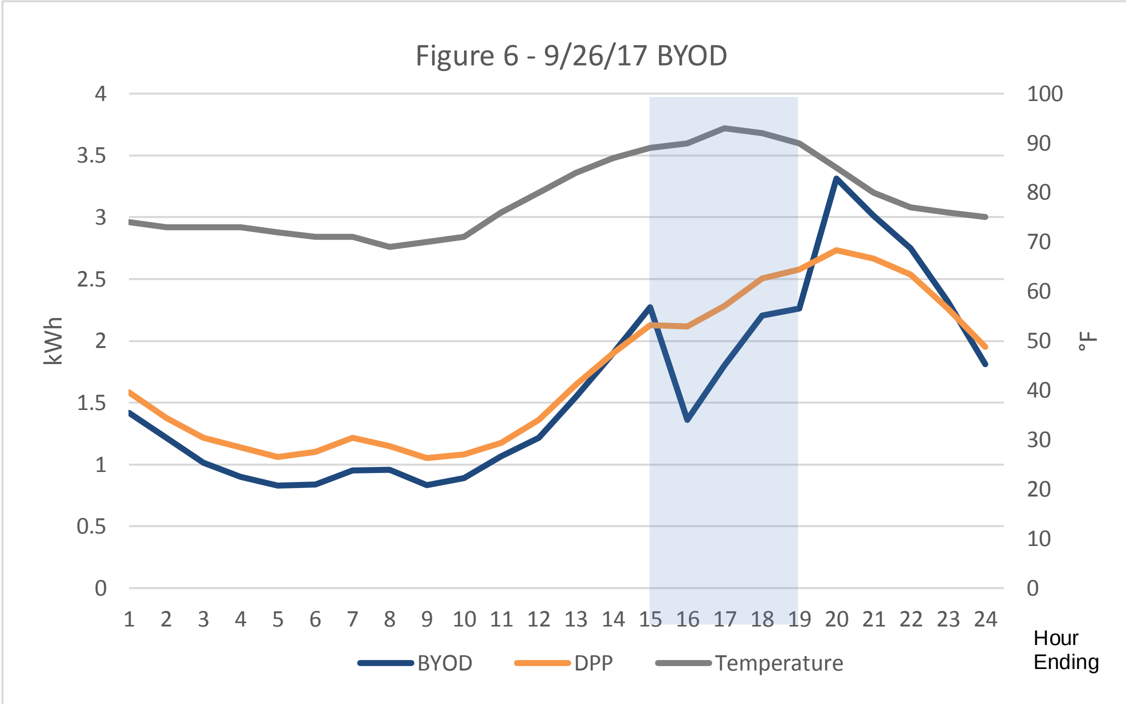

Q. What are the Company's plans for the BYOD pilot program going forward?

A. The Company plans to refine and expand the BYOD pilot that started in 2017 with the funding approved in rates in Case U-18255 under the category of "Other DSM". As the pilot continues, the Company will seek to better understand factors that drive initial customer enrollment in such a program and re-enrollment in subsequent years. The company will also seek to validate performance during BYOD events with a larger set of customers, to better forecast how often customers may over-ride the Company's thermostat set-point changes under various circumstances and also how much peak load reduction occurs during BYOD events under various circumstances. While the 2017 performance results were higher than originally forecast, the Company recognizes that these results are based on a small 200-customer pilot. The Company does not intend to make significant changes to the forecasted value of the BYOD program until such time that a statistically significant number of devices have been deployed and additional BYOD event measurement and verification has occurred. The Company will request funding for expansion of the BYOD program in future rate cases as needed.

Q. What are the proposed additional demand side management pilot programs?

A. The Company has currently identified additional pilot programs centered around Energy Storage options. The first two pilots would be behind the meter projects with Commercial and Industrial (C&I) customers to understand the actual operation and performance of batteries in the field and the impact on customer load, the ability to peak shave, and the reliability of the battery system. The Company is investigating 2 approaches, with one pilot installation designed to offset the manufacturing class peak hours between 11 AM and 3 PM and the second pilot installation focusing on the overall system peak hours between 3 PM and 7 PM. The third pilot is a proposed Non-Wires Solution (NWS) using a customer sited and utility controlled storage solution to potentially defer investment in substation equipment by dispatching the storage unit as needed. It should be noted that these customer-sited storage pilots funded as "Other DSM" are separate from the storage pilots discussed by Witness Bruzzano that will be sited at company owned facilities or properties. While information and lessons learned will be shared and the two teams will collaborate, the funding requests are separate.

Q. What is the expected timing associated with the Energy Storage DSM pilot programs?

A. Existing funding within the current Other DSM programs will be used throughout the bridge period of January 2018 through April 2019 to develop customer specific site information, battery size, battery chemistry and use case options, such as customer demand reduction, energy abatement, and an assessment of options to use storage plus renewables to provide a more consistent generation profile. The Company also plans to find customer locations for these pilots throughout 2018 and perform needed site investigation work. The funding requested for the projected test year will be for the purchase of the physical assets and installation costs upon program approval. The procurement of the hardware and installation would begin in late 2019, assuming approval of the requested funds in rates, to begin operation by the summer of 2020.

Q. What are the Company's planned efforts to develop and manage the DSM pilots?

A. The Company aims to remain flexible enough to efficiently redeploy DSM pilot spending and resources as capacity needs or other more cost-effective technologies arise in the near future. DTE Electric will be well positioned to expand existing or future programs to respond to changing capacity market conditions. With these objectives as goals, the Company will continue to evaluate other alternative DSM programs that may emerge as a result of insights from pilot programs or utility benchmarking efforts. In the coming years, the Company expects to continue developing new DSM programs that may become economic alternatives to generation capacity, have an appropriate level of customer adoption potential, and are cost-effective for the Company's customers.

Q. Does the Company intend to keep the MPSC apprised of the results of the Demand Side Management programs and capital expenditures approved in U-18255?

A. Yes. The Company fully intends to provide DSM updates and comply with all reporting requirements as part of the Commission's adoption of Staff's three phased approach for DSM programs in Case No. U-18369 on September 15, 2017. The Company will file a full reconciliation report on all expenditures approved in Case No. U-18255 by April 30, 2019 detailing customer participation and demand reductions.

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Part II: River Rouge Unit 3 NPVRR Analysis

Q. Has the Company completed an economic analysis regarding continued operations of Unit 3 at the River Rouge Power Plant?

A. Yes. In the recent Order in Case No. U-18255 issued April 18, 2018, the Commission did not agree that the Company's strategic evaluation and resulting conclusion to maintain the planned 2020 retirement date for River Rouge Unit 3 (RR Unit 3) represented adequate support for the Company's requested level of O&M and capital expenditures to maintain operations at RR Unit 3. The MPSC instead indicated that a Net Present Value of Revenue Requirement (NPVRR) analyzing RR Unit 3 was required to provide sufficient support for recovery of expenditures to maintain operations at RR Unit 3. While the Company believes that continued operation of RR Unit 3 through May 2020 was and remains justified based on its obligations to provide sufficient and reliable generation supplies to its customers, the Company has completed such an NPVRR analysis, the results of which are summarized on Exhibit A-12, Schedule B6.

Q. How did the Company structure its NPVRR analysis?

A. The NPVRR analysis of the RR Unit 3 consisted of two options:

1. Operate RR Unit 3 until the planned retirement date in May 2020
2. Retiring RR Unit 3 as soon as practical which is December 31, 2018, after the Company complies with the required retirement request filing process with MISO

For this evaluation, the Company assessed the incremental benefits and costs for both options, and calculated the net difference between the NPVRR of each option. A net positive difference indicates that the NPVRR associated with operating the RR Unit 3 through 2020 is more costly to customers; conversely, a net negative difference

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indicates that the NPVRR of operating the RR Unit 3 through 2020 is less costly to customers. It should be noted that the difference in retirement dates between the two options is only seventeen months.

A total of three NPVRR sensitivities were examined, as shown in Exhibits A-12, Schedule B6 page 2 of 5. In each sensitivity, both retirement options incorporate the incremental benefits and costs of specific value components. On pages 3-5 of that same exhibit, the total benefit and cost of each component for each option is summarized in line 4-5, columns (b) through (g) with the total and overall NPVRR listed in column (h) line 6. Line 7, columns (b) through (j) list each year and line 10-15, column (a) provides the value components that are included: operation and maintenance (O&M) expense, fuel costs, energy and capacity purchases, capital investment and property tax expense. The resulting net difference between the NPVRR of each component is listed in column (k) and summed up in line 16.

Each NPVRR evaluation considered assumptions listed on Exhibit A-12, Schedule B6, page 1 of 5. The assumptions for this analysis have been assessed by the respective subject matter experts in the Company's Generation Optimization, Fossil Generation, Tax and Business Planning and Development departments.

Q. What sensitivities did the Company perform regarding the inputs for the NPVRR analysis?

A. The Company performed sensitivity calculations for the capacity price input in the NPVRR analysis. For the capacity purchases in the case of necessary capacity replacement for the option of retiring the unit in 2018, the Company considered a range of pricing alternatives that go from a low forecast of capacity prices based on modeling conducted by PACE Global[1], an energy industry consulting firm, to the Cost of New Entry (CONE) at $90.7 / kW-year. As stated in the answer above, an NPVRR evaluation was conducted for each capacity price value and the results were examined. A summary of the sensitivities for the analyses is shown in Exhibit A-12, Schedule B6, page 2 of 5.

Q. What are the results of the NPVRR analyses performed for RR Unit 3?

A. The results of the NPVRR analyses for RR Unit 3 show a range of net present value outcomes consistent with the selected capacity price. The NPVRR results in Exhibit A-12, Schedule B6, page 2 of 5, column (c) range from $15 million more costly to $10 million less costly to customers to maintain the planned 2020 unit retirement date. Column (b) present the three sensitivities for different capacity prices. A more detailed NPVRR summary for each capacity price sensitivity can be found in Exhibits A-12, Schedule B6, page 3-5 of 5.

Q. What factors has the Company taken into consideration in its decision-making process regarding the timing of the retirement of RR Unit 3?

A. An economic cost and benefit analysis can provide a general guideline for the reasonableness and prudency of continued operations of a generating unit, although there are several other factors that need to be considered. As Company Witness Mr. Paul indicates in his direct testimony, there are several additional factors to consider when determining whether a generating unit should be retired. Witness Paul discusses the Company's conclusion that the best option is to continue operating RR Unit 3 until its planned retirement date of May 2020.

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[1] Pace Global, a Siemens business

Q. Has the Company completed similar NPVRR analyses regarding the continued operations of the remaining Tier 2 units?

A. No. The Order issued in MPSC Case No. U-18419 dated April 27, 2018, p. 48-49 concluded that "[t]he Commission agrees with DTE Electric that, although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the Company's 2019 Integrated Resource Plan (IRP) analysis and the results of MISO's Attachment Y reliability study…". DTE Electric has been assigned the date of March 29, 2019 to file an IRP pursuant to MCL 460.6t. The Company will conduct such an analysis in the planned IRP, consistent with recently issued MPSC guidance. The Michigan Integrated Resource Planning Parameters presented in Case No. U-18418 describe compliance guidelines for utilities for future IRP's and/or Certificate of Necessity proceedings. Under Scenario 2, the Commission states "Company-owned resources retirements may be defined by the utility…coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics". The Company will make decisions on the timing of retirement of units based on economics as well as other planning principles that include flexibility and reliability.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEEGAN O. FARRELL

DTE ELECTRIC COMPANY
QUALIFICATIONS OF KEEGAN O. FARRELL

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Q. What is your name, business address, and by whom are you employed?

A. My name is Keegan O. Farrell. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Services, LLC (DTE Energy) as a Principal Financial Analyst - Load Research.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I graduated from Michigan State University, with a Bachelor of Arts Degree in Communication. In addition, I received a Master of Science Degree in Decision Technologies from the University of North Texas.

Q. What is your professional experience?

A. From 2008 until 2012, I was employed by DTE Gas Resources, LLC in Fort Worth, Texas where I held positions of increasing responsibility, ultimately serving as a Decision Support Analyst. In this role, I was responsible for assisting with calculating reservoir economics, monitoring daily oil and natural gas production, and overseeing the compliance and emission calculations for the Environmental Protection Agency's Greenhouse Gas Reporting Program (Subpart W). In 2012, I joined DTE Energy as a Senior Business Financial Analyst – Load Research.

Q. What is your current position?

A. In 2014, I was promoted to Principal Financial Analyst – Load Research. In this position, I am responsible for developing and implementing statistical sampling programs used to evaluate customer class usage characteristics, developing allocation schedules for use in cost-of-service studies and rate design, and for measuring and evaluating demand response programs offered by the Company.

Q. Do you participate in any industry associations?

A. Yes. I am the course coordinator for the Association of Edison Illuminating Companies (AEIC) Fundamentals for Load Data Analysis course.

Q. Have you received any additional training?

A. Yes. I have completed the AEIC Fundamentals of Load Data Analysis course. I have also attended various courses at Michigan State University Institute of Public Utilities Annual Regulatory Studies Program.

Q. Have you testified previously before the Michigan Public Service Commission?

A. Yes, I have sponsored testimony and exhibits before the Michigan Public Service Commission (MPSC) in the following DTE Electric cases:

Case No.	Description
U-18014	DTE Electric 2016 General Rate Case Proceeding
U-18255	DTE Electric 2017 General Rate Case Proceeding

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is: 1) to support and justify the May 2019/April 2020 forecast allocation schedules; 2) to support and justify the methodology DTE Electric used to include the demand associated with the electric choice loads in forecast distribution allocation schedules; 3) to support and justify the hours used for the summer on-peak non-capacity charge for Rate Schedule D1; 4) to support and justify the anticipated load shift by residential customers in the Weekend Flex Pilot Program.

Q. Are you supporting any exhibits in this case?

A. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-5	E2	Cost of Service Allocation Methodology Diagram
A-5	E3	Allocation Schedule Description
A-17	G1.1	2019/2020 Forecast Energy Allocation Schedules
A-17	G1.2	2019/2020 Forecast Allocation Schedules

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. What are the sources of data used for the allocation schedules?

A. The 2019/2020 forecast allocation schedules are based on 2017 customer class sales data obtained from the 2017 Total System Analysis (TSA) and do not include sales to customers who were previously served under the Detroit Public Lighting Department (PLD). The 2019/2020 forecast allocation schedules are based on the net energy sales forecast for the residential, commercial and industrial classes supported by Company

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Witness Mr. Leuker, the street lighting and traffic signals sales forecast supported by Company Witness Mr. Johnston, and the forecast billing determinants supported by Company Witnesses Mr. Bloch, Ms. Holmes, Mr. Johnston, and Mr. Dennis. These sales levels are shown without losses on Exhibit A-17, Schedule G1.1.

Background and Basis for Allocation Schedules

Q. Are there any technical terms used in your testimony that may require explanation?

A. Yes. To aid in understanding and to avoid confusion, I am defining the following terms that I use throughout my testimony:

- Customer Class or Class of Service – A set of customers with similar characteristics who have been grouped for the purpose of setting an applicable rate for electric service. Common classifications include Rate Schedules D1, D3 and D11.
- Total System Analysis (TSA) – The study of all customer classes that identifies the hourly demand values for all hours of the year. This is the foundation of allocation schedules.
- Energy – The kilowatt-hours (kWh) supplied to or used by an individual customer or customer class.
- On-Peak Energy – The kilowatt-hours (kWh) supplied to or used by an individual customer or customer class between 0700 and 2300 hours (MISO on peak schedule), Monday through Friday exclusive of holidays as currently defined in the DTE Electric Rate Book for Electric Service.
- Demand – The rate at which electric energy is used at a given instant or averaged over a designated time interval. Typically, demand is expressed in kilowatts (kW) or megawatts (MW), one megawatt equals 1,000 kilowatts. The Company uses

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average hourly demands in the development of allocation schedules.

- Service Area System Peak Demand – The highest total hourly demand (MW) for all customers served on the DTE Electric distribution system within a specific period (day, month, year, etc.). Service Area System Peak Demand is commonly referred to as the 'system peak.'
- Bundled Peak Demand – The highest total hourly demand (MW) for all customers served by DTE Electric production system within a specific period (day, month, year, etc.). Bundled Peak Demand is commonly referred to as 'bundled peak.'
- Coincident Peak Demand (CP) – the demand of any customer class within a specific period (day, month, year, etc.) that occurs at the same time as the system peak or the bundled peak demand for the same period.
- 12CP – the demand value derived by averaging the actual demand values registered on the monthly system or bundled peak hours for January through December for each customer class.
- 4CP – the demand value derived by averaging the actual demand values registered on the monthly bundled peak hours for June through September for each customer class.
- Non-Coincident Peak Demand – the maximum demand of any customer class within a specific period but not necessarily occurring at the time of the system peak demand for that period.
- Losses – A term used to define the difference between the electrical energy delivered to a customer (or a given point on the electrical distribution system) and the amount of electrical energy that must be generated at the power plant to serve that customer. In other words, losses refer to the amount of power lost in transferring power from the power plant to the point of delivery.

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- Load Factor – The ratio, in percent, of the total energy over a designated period of time to the maximum hourly demand (bundled or system) occurring in that period. Load factor is calculated by the formula:

  LF (%) = (Total Energy / (Peak Demand * No. of Hours)) * 100
- Customer-Owned – Industrial customers that use customer owned substations.
- DTE-Owned – Industrial customers that use DTE Electric single customer or joint-use general distribution substations.
- Transmission Voltage Level – served directly from the transmission system at 120 kV or above, or from the transmission system through a DTE-owned substation dedicated or primarily providing service to the customer and located on or immediately adjacent to the customer's premises.
- Sub-transmission Voltage Level - served directly from the sub-transmission system at voltages from 24 kV to 41.6 kV or from the sub-transmission system through a DTE-owned substation dedicated or primarily providing service to the customer and located on or immediately adjacent to the customer's premises.
- Primary Voltage Level - served directly from the primary distribution system at a nominal voltage between 4.8 kV and 13.2 kV who does not qualify as either a transmission voltage customer or a sub-transmission voltage customer.
- Secondary Service – served directly from the secondary distribution system at a nominal voltage less than or equal to 4.8 kV and who does not qualify as either a transmission voltage customer, sub-transmission voltage customer or a primary voltage customer.

Q. What is the purpose of the allocation schedules you have developed?

A. Allocation schedules are developed using customer class sales, data from Advanced Metering Infrastructure (AMI), and quantitative methods to determine the extent (expressed as a percentage) that each customer class uses the various portions of the electrical system. In this case, the customer class usage percentages determined in the allocation schedules are one of the inputs used by Company Witness Mr. Lacey to determine customer class cost responsibility. Because all customer classes do not utilize the full distribution system to take delivery of electrical service, the allocation schedules are developed to assign only the portions of the system actually used by each customer class. Exhibit A-5, Schedule E2, is a diagram which reflects the applicability of allocation schedules to customer class.

Q. What effect has AMI data had on TSA and Allocation Schedules?

A. Previously, statistically significant samples and models were used to generate load curves for rate classes where interval data was unavailable. With the implementation of AMI, a load curve for each rate class can be generated based on actual customer data. While the samples that were used in the past were statistically significant, using the AMI data to develop load curves for TSA makes for a more accurate representation of a class's load curve. Increased accuracy of TSA yields an increase in accuracy of the allocation schedules which will then be reflected in the cost-of-service study.

Q. How did you develop the allocation schedules?

A. There are 13 forecast allocation schedules that I develop for use in cost-of-service studies (see Exhibit A-5, Schedule E3 for a description of each schedule). Each schedule was developed to allocate to each customer class' utilization of a particular part of the electrical system, which is the industry standard practice for developing allocation schedules. Furthermore, Schedule 100 is based on the energy that is produced at the production plant and the remaining 12 allocation schedules schematically shown on Exhibit A-17, Schedule G1.2, are based on the demand that a customer class places on the various portions of the electrical system. The schedule numbers and the associated portion of the electrical system they represent are shown on Exhibit A-5, Schedule E2.

Q. Why does the measurement basis differ for each allocation schedule?

A. The measurement basis for each allocation schedule is based on the design and service requirements for each portion of the electrical system. Specifically, energy is used for Power Plant Energy Production (Schedule 100) required to serve customers. As customers use energy, they create a demand (rate at which energy is used and/or delivered) on the system.

The output capacity of power plant production is designed considering the peak demand requirements of the production system, measured as the coincident demand, which is the demand at the time of, or coincident with, the bundled peak. Therefore, production Schedules 200A and 200B are measured based on the bundled coincident peaks. Schedule 201 – Distribution is based on the 12 coincident demands of the of the Service Area.

Schedules 202A, 202B, 202C, 203A, 203B, 203C, 204 and 205 refer to substations, high voltage lines and transformers, which are designed to carry the maximum load required by the customer classes they serve regardless of whether the class maximum demand occurs at the same time or a different time as the system peak. The maximum demand of any customer class measured during a period, but not necessarily at the time of the system peak, is the non-coincident peak demand and is the measurement basis for these allocation schedules.

Low voltage secondary lines are designed to serve the absolute maximum demand level of the customers they feed. Therefore, Schedule 300 is based upon the sum of the individual customer maximum demands.

Allocation of Electric Choice Demands

Q. Were demands for customers served by suppliers other than DTE Electric included in the 2019/2020 allocation schedules?

A. Yes. To account for the total service territory distribution level demands, demands of electric choice customers are included at the point of delivery to the DTE Electric distribution system.

Q. How were demands of electric choice customers determined and included in the distribution allocation schedules?

A. Consistent with Case No. U-18255 and other previous Company general rate case filings, demands of electric choice customers were extracted from the 2017 TSA by customer class and voltage level. The demands for these customers were then assigned to the appropriate customer classes.

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Forecast Allocation Schedules

Q. How was the 2017 TSA used to develop the demand values determined for the forecast allocation schedules?

A. The basis for the forecast allocation schedules developed for this case are the forecasted net 2019/2020 sales values presented in Witness Leuker's Exhibit A-15, Schedule E1. However, because Witness Leuker's system peak demand forecast does not contain the associated customer class level demand values necessary for allocation schedule development, it was necessary to develop these corresponding demand values by customer class. This was done based on historic statistics applied to the forecast energy values using industry standard load research principles to derive demand values using energy and load factor. Therefore, 2019/2020 forecast demands were calculated by dividing the 2019/2020 net forecast energy values, shown on Exhibit A-17, Schedule G.1 with losses, by the product of the historic load factor and annual hours (8,760 hours per year).

Q. How were the appropriate historic load factors determined?

A. A 3-year average load factor derived from years 2015-2017 and used for each rate class.

Q. Why is using the 3-year average load factor a better representation of the class' performance than the actual 2017 historic load factor?

A. Using the 3-year average load factor accounts for any abnormalities in 2017 that would result in having a larger than normal change in load factor that may have resulted due to weather or other anomalies.

Q. Were any other changes made to the forecast allocation schedules?

A. Yes. During the forecasted test year, three large customers in the Primary Schools (D6.2) rate class will be adding additional generation displacing approximately 25% of the class load. To adjust for this change, I went back and recalculated the 3-year average load factor for D6.2 with these three customers removed.

Q. Why is using historical load factors a reasonable method of determining forecast demand values?

A. This approach is reasonable because it utilizes industry standard load research principles that are defined in the "The Art of Rate Design", Pages 49-50, published by the Edison Electric Institute (EEI) and taught in the EEI Rate Fundamentals Course and published in Chapter 7 of the Association of Edison Illuminating Companies (AEIC) Load Research Manual, 3rd Edition, Pages 25-26. These sources define the relationship of load factor to demand and the principle of using energy and load factor to calculate demand.

Q. How did you develop the 2019/2020 forecast allocation schedules?

A. I applied the load factors that were calculated from the 2017 Total System Analysis to the forecasted net energy received from Witness Leuker to produce the 2019/2020 forecast schedules shown in Exhibit A-17, Schedule G1.1.

Q. Are the allocation schedules defined in your testimony developed using established principles and methods?

A. Yes. I used the industry recognized and accepted load research principles supported by EEI and AEIC. The methods I used are consistent with the methods used by the

Company in its most recent electric general rate case filings Case Nos. U-17767, U-18014 and U-18255.

<u>Rate Schedule D1 Time of Use</u>

Q. Is the Company proposing to modify its Rate Schedule D1 (D1) power supply rate structure?

A. Yes. In its April 18, 2018 Order in Case No. U-18255, the Commission directed the Company in its next general rate case to include a proposed D1 tariff that included power supply non-capacity charges based summer on-peak / off-peak rates.

Q. What input did you provide to assist the Company in complying with the Commission's Order?

A. As instructed by Company Witness Mr. Dennis, I analyzed interval data for residential customers who take service under rate D1 in order to determine an appropriate on-peak period associated with the D1 on-peak non-capacity charge. The result of my analysis is that 4:00 p.m. to 9:00 p.m. is the appropriate on-peak period.

Q. How did you come up with an on-peak period of 4:00 p.m. to 9:00 p.m.?

A. During the summer months (June through September) of 2017, Residential customers averaged their highest demand between the hours of 5:00 pm and 9:00 pm. During those same months, the four monthly system coincident peaks occurred between 4:00 to 5:00 pm (1 time) and between 5:00 to 6:00 pm (3 times). By using a period of 4:00 pm to 9:00 pm, the four highest summer peaks for D1 customers are included as well as the four highest system peak hours. Starting the on-peak period at 4:00 pm also discourages D1 customers from shifting their energy consumption into an hour that

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makes up the 4CP, further taxing the production and distribution systems.

Q. Were you asked to provide any other analysis related to the new D1 time of use rate?

A. Yes. Witness Dennis requested I analyze the market price difference between the on and off peak hours associated with the new D1.

Q. How did you calculate the on and off-peak rate differential?

A. I looked at historic hourly day-ahead Locational Marginal Prices (LMP) at the DECO.NEC Pricing Node over a three-year period from 2015 through 2017. Using the weekday on-peak period of 4:00 pm to 9:00 pm during June through September, the average LMP differential between off and on-peak was $0.01 per kWh. This pricing difference can be seen on workpaper KOF-2.

Q. Based on this outcome, did you build any assumed shift by D1 customers into allocation schedules as a result of the summer on-peak period being priced higher than the off-peak periods?

A. No, I did not. As discussed by Company Witness Mr. Griffin and Witness Dennis, by the time the IT portion of the billing system is completed and fully implemented for the D1 TOU component, my understanding is that the forecasted test year will have been completed, or near completion.

<u>Weekend Flex Pilot Program</u>

Q. What was your input into the development of the Weekend Flex Pilot Program?

A. At the direction of Company Witness Mr. Clinton, I calculated the anticipated load shift

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for a customer who would take service under the Weekend Flex Pilot Program. The average anticipated load shift by customers participating in the pilot is 5%.

Q. How did you calculate a 5% load shift?

A. I compared data from customers who take service under rate D1 with data from customers who take service under the D1.2 Time-of-Day rate. Using the same on and off-peak schedule as D1.2 (the on-peak period being weekdays from 11:00 a.m. to 7:00 p.m.), the average D1 customer uses 25% of their energy on peak compared to 22% for D1.2 customers. For an average D1 customer to reduce their on-peak usage from 25% to 22%, the average D1 customer would have to shift 13% of their on-peak load to the off-peak period. Relative to the Weekend Flex Pilot, annually there are less off-peak hours than there are relative to D1.2. The weekend flex has 2,520 hours that can be defined as “off-peak” compared to 6,680 hours that are defined as “off-peak” in rate schedule D1.2. This equates to the weekend flex having 38% of the available “off-peak” hours compared to D1.2. To adjust for the fewer hours in the Weekend Flex Pilot Program, I multiplied the anticipated13% shift from on-peak to off-peak (or from weekday to weekend) by 38% (the amount of available “off-peak” hours compared to D1.2) to calculate an average 5% forecasted shift for customers participating in the Weekend Flex Pilot Program as illustrated by workpaper KOF-4.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT D. FELDMANN

DTE ELECTRIC COMPANY
QUALIFICATIONS OF ROBERT D. FELDMANN

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Q. What is your name, business address and by whom are you employed?

A. My name is Robert D. Feldmann and I am currently employed at DTE Electric Company (DTE Electric or Company). My business address is One Energy Plaza, Detroit, Michigan 48226.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric.

Q. What is your educational background?

A. I possess both an Honors Bachelor of Commerce degree and an MBA from the University of Windsor, Ontario. In addition, I have taken numerous energy related courses including the Gas Technology Institute's Gas Distribution Program in Chicago as well as the Executive Utility Leadership program at Stone and Webster in New York.

Q. What work experience do you have?

A. I have over 30 years of utility experience at DTE Electric, DTE Gas Company (DTE Gas) and Union Gas Ltd., Chatham Ontario. My experience includes senior leadership roles in Sales, Marketing, Gas Operations, and Customer Care.

Q. What is your DTE work experience?

A. I became a DTE Gas employee in November of 2008 as the Director of Gas Operations for the Southeast Michigan area and in January 2011, I assumed the role of Director, Gas Sales and Marketing. In September 2017, I was promoted into my current position as the Executive Director Electric Sales and Marketing.

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Q. What is your current position?

A. My current position is, Executive Director, Electric Sales and Marketing.

Q. Have you previously provided testimony to the Commission?

A. Yes. I developed and submitted testimony in Case Nos. U-15985, U-16999, U-17999, U-17531, and U-17532. In addition, I have sponsored testimony and appeared as a witness in front of the Ontario Energy Board docket RP-2000-0078**.**

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Q. What is the purpose of your testimony?

A. The purpose of my testimony in this proceeding is to provide details on DTE Electric's investment in a pilot, Combined Heat and Power (CHP) plant that will be located on Ford Motor Company's (Ford) Research and Engineering (R&E) campus in Dearborn, Michigan. In addition, my testimony will support this facility's inclusion as an asset into DTE Electric's generation fleet and seek a return on and of this investment.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-28	R1	Ford Campus Gross Margin Summary
A-28	R2	HDR study

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

COMBINED HEAT AND POWER (CHP) PLANT

Q. What is the Combined Heat and Power (CHP) plant?

A. DTE Electric is investing in a pilot CHP plant that will be located on Ford's R&E campus in Dearborn, Michigan. CHP is the cogeneration of electricity and heat (i.e. steam) and CHP systems come in a variety of configurations. These systems combine the equipment of a conventional power plant with heat recovery equipment, greatly increasing the efficiency of these "combined" systems relative to separate conventional electric generation and heating systems. At this site, DTE Electric will

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contract for the construction of a 34 megawatt (MW) CHP plant to be incorporated into its generation fleet. The steam generated through power generation will be sold to Ford, while the power generated will be directed into DTE Electric's high voltage electric distribution system to meet the power supply needs of the Company's bundled customers.

Q. Why did you locate the asset at Ford's new Research and Engineering campus?

A. The location allows DTE Electric to have a host steam customer for the steam generated by the facility, as well as to pilot the development of a small cogeneration asset.

Q. What does DTE Electric expect to learn from this pilot?

A. DTE Electric expects to gain operational insights on how a CHP unit will interact with our integrated system; how the operating characteristics can be employed to balance the electrical system; and to determine if steam energy sales could be effectively leveraged to the benefit of our customers in other applications of this technology. In addition, we anticipate that this pilot facility will provide a basis to assess the development of similarly situated projects that may be a catalyst for other industrial investment and new revenue for the benefit of DTE Electric's customer base.

Q. How did the CHP plant pilot originate?

A. Ford conducted a comprehensive study that concluded their 70-year old Dearborn R&E campus was a barrier to employee collaboration, productivity and sustainability. The study further concluded that the existing infrastructure required significant upgrade and replacement to support the next 50-year design life of the R&E complex. Based on the study, Ford initiated a plan to transform its Dearborn based R&E site into a flexible, smart, healthy, green and engaging campus to address aging infrastructure and attract next generation talent to the State of Michigan.

Overall, Ford will invest $1 billion over 10 years to construct or upgrade over nine (9) million square feet of space which will impact approximately 30,000 employees located in Southeast Michigan. As part of the R&E campus transformation, Ford made the decision to outsource an integrated energy solution to address its energy requirements at the site including process steam, heating and cooling with a focus on reliability, efficiency and environmental sustainability at this site.

Q. Did Ford issue a Request for Proposal (RFP) for an integrated energy solution?

A. Yes, Ford undertook a RFP process for the campus's non-automotive related operations for the design, build, ownership, operation and maintenance (DBOOM) of the complex's Central Energy Plant (CEP), which includes the central heating, cooling and a CHP plant. Ford requested that DTE provide an integrated "DTE Energy Corporate" (i.e. DTE Electric, DTE Power and Industrial and DTE Gas) solution for the onsite central energy plant as part of its RFP Process.

Q. Did DTE Energy participate in Ford's RFP process?

A. Yes, DTE Energy responded to the RFP and DTE Electric, DTE Gas, and DTE Power and Industrial (P&I) Group collaborated to create an integrated DTE corporate solution to meet Ford's needs.

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Q. What did DTE Energy propose?

A. DTE Energy proposed and was awarded a contract to provide a 30-year solution that included a CHP plant, chilled and hot water systems, on site energy storage, steam generation, steam distribution, as well as geothermal energy.

Q. What is DTE Electric's role as part of the Corporate Solution?

A. DTE Electric will develop a 34 MW CHP plant as an addition to its generation fleet that will be constructed by DTE's P&I Group for $62.3 million under a fixed price agreement. The steam generated through power generation will be sold to Ford, while the power generated will be directed into DTE Electric's high voltage distribution system to meet the power supply needs of DTE's bundled customers.

Q. How did DTE Electric ensure that the $62.3 million purchase price was reasonable and prudent?

A. As this was recognized as an affiliate transaction, DTE engaged HDR, an architectural, engineering, and consulting firm, that developed an independent cost estimate for a 34 MW CHP plant at $84.6 million. This study has been provided as Exhibit A-28 Schedule R2. In summary, the transaction price is significantly below the estimated market price.

Q. If an unaffiliated third party had offered a similar deal would DTE have entertained it?

A. Yes, DTE would have considered an agreement with an unaffiliated third party had a similar or better offer been available.

Q. What are the economics associated with this investment?

A. At the time the project was developed, the levelized cost of energy (LCOE) was in a competitive range with alternative generation technologies such as solar, wind, and combined cycle natural gas. The LCOE included steam sales to Ford at a cost that was adjusted for the energy efficiency of the cogeneration units. Ford bears the risk associated with natural gas commodity prices and pipeline transportation rates used in the production of steam.

Q. What is DTE Gas's role?

A. DTE Gas will construct a new gas line that will serve the natural gas supply needs of the CHP plant.

Q. Who is the DTE P&I Group?

A. The DTE P&I Group, a subsidiary of DTE Energy, was started in the mid 1990's. The Industrial Services organization within the P&I Group provides products and services to large, energy-intensive industrial, commercial and institutional customers. One of the areas of focus for this group is the provision of on-site energy for commercial and industrial organizations. P&I Group's on-site energy product offerings include cogeneration of electricity and steam, compressed air, hot and chilled water, waste water treatment, backup power, electrical distribution and energy efficiency programs. The P&I Group has extensive experience with similarly situated projects.

Q. What is DTE P&I Group's role in this project?

A. DTE P&I Group's role is to design, build, operate and maintain the CHP plant along with responsibility for design, construction, operation and maintenance of the entire CEP. P&I incurs the risk associated with the construction of the facility.

Q. Why did DTE Electric enter into these arrangements?

A. DTE Electric was interested in this pilot project for the following reasons:

1) Retains Ford (DTE Electric's largest customer) as a bundled customer which provides benefits to all ratepayers.

2) Provides an estimated 62 million kWh of annual load growth over the next 10 years and associated margin value over the 30-year contract life with a present value of $15.4 million.

3) Provides an opportunity for DTE Electric to learn and gain experience from the CHP plant as a demonstration pilot and it collects information for use of this generation technology in future applications.

4) Provides information that could potentially be applied to other large campuses or industrial projects that require a sustainable, environmentally friendly energy solution.

5) Allows DTE Electric to add a new and efficient generation resource to its generation fleet.

6) Assists in fulfilling Michigan's anticipated electric generation needs.

7) Allows DTE Electric to access the site, water and wastewater from Ford at no cost to serve the Central Energy Plant.

8) Improves the air quality of the area, once Ford retires the existing boilers used to service the current facilities.

9) Allows CHP to synchronize to the electric grid, as black-start generation is already located on-site.

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10) Provides approximately 500 electric vehicle (EV) chargers and 5 MW of chilled water storage for peak-electric load shedding to help mitigate DTE Electric's peak demand requirements.

11) The project will free up over 34 MW of Brock Substation electric distribution capacity for use by other DTE Electric customers.

12) The investment allows DTE to retire a 63-year old substation and 16 miles of underground cable currently feeding the site. This eliminates the need for future maintenance and or replacement of these aged assets at a cost of approximately $5 million.

13) To address other major commercial and industrial developments that are incremental to the requirements of the R&E campus. Ford is also making significant investments in a Vehicle Performance Electrification Center, a data center at its world headquarters and Wagner Place development on Michigan Avenue Dearborn. In addition to these projects there are several other commercial projects that are under development.

Q. What is the net impact on other DTE customers?

A. In the event Ford were to contract with a third party for its campus wide integrated solution with the CHP unit located behind the DTE meter and directly serving Ford's electrical requirements for this site, DTE Electric estimates that remaining bundled customers would have had to pay $102.1 million more on a present value basis over the 30-year contract life to make up for Ford's lost margin. As detailed in the table below, the $102.1 million is comprised of the retained margin based on Ford's 2015 usage profile plus the margin associated with 62 million kWh of projected load growth in addition to the estimated replacement cost of the 63-year old substation

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and 16 miles of underground cable currently feeding the site.

Description	Estimated Present Value ($ millions)
Retained Margin (based on 2015 usage)	$81.7
Projected Load Growth Margin (62 million kWh)	$15.4
Substation and Underground Cable Replacement	$5.0
Total Customer Value	**$102.1**

Q. How was the $81.7 million of retained margin value calculated in Exhibit A-28, Schedule R1?

A. DTE Electric's remaining bundled customers would have had to pay $7.2 million more per year, which equals a present value of $81.7 million over the 30-year contract life to make up for this lost margin. The $81.7 million of retained value is the total revenue collected from Ford at this location is based on their 2015 usage history less the variable power supply costs incurred to serve this load and the value of the standby revenue that would accrue if Ford (or a third party on behalf of Ford) self-generated at this site and contracted for standby power from DTE Electric. In the event Ford were to contract with a third party for its campus wide integrated solution, there is a high probability that DTE would have lost the entire campus load which has a maximum demand of 47.5 MW and total annual usage of 265,000 MWh. This is due to the fact that Ford was looking for an integrated energy solution. Due to the significant economies of scale associated with a CHP plant installation, it is logical that a third party would have sized the CHP plant to meet the maximum demand and projected load growth for the entire campus and subsequently Ford would have had the opportunity to eliminate the requirement to be served by DTE Electric at this site.

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Q. How will this project impact capacity in the West Dearborn area?

A. This unit will assist in offsetting the planned retirements at the Trenton Channel and River Rouge facilities by providing up to 34MW of power to DTE Electric customers in the West Dearborn area. In addition, this capacity was included in DTE Electric's 2017 Integrated Resource Plan.

Q. Why is this CHP Plant project reasonable and prudent?

A. The Ford CHP project is reasonable and prudent as it offers significant benefits including the preservation of $102.1 million in value for customers which positively impacts customer affordability. The project also allows DTE to retain Ford as a bundled customer while supporting their efforts to modernize their facilities. Finally, the project allows DTE to modernize distribution infrastructure which positively impacts reliability.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DANIEL J. GRIFFIN

DTE ELECTRIC COMPANY
QUALIFICATIONS OF DANIEL J. GRIFFIN

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Q. What is your name, business address and by whom are you employed?

A. My name is Daniel J. Griffin. My business address is One Energy Plaza Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, as Director – Information Officer within the Information Technology Services (ITS) organization.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I have a Bachelor of Business Administration in Operations Research Information Systems from Eastern Michigan University.

Q. What is your work experience and what position do you currently hold at DTE Energy?

A. I have worked for DTE Energy or one of its regulated utilities for over 14 years in various Information Technology (IT) and Business Operational positions. I am currently the IT Director of Operations & Infrastructure for the LLC as well as for DTE Electric Company and the DTE Gas Company. As the IT Director of Operations & Infrastructure, I am responsible for all aspects of ITS Operational matters as well as being the Infrastructure owner for all DTE Shared ITS assets and asset classes. My department designs, integrates and operates all the common ITS assets including, but not limited to, the DTE Corporate Network, DTE Energy Data Centers, Server and Storage assets and Endpoint Devices. My department also supports other Company IT related assets such as Operational Technologies (OT) used by various

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business units to operate the gas and electric distribution networks located in dispersed facilities and locations. Examples of this would include technology at power plants, substations, service center locations, dedicated field sites and data centers. Prior to my current position, I was the ITS Chief of Staff, ITS Operations Manager and a Manager of DTE Gas.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored rebuttal testimony in the Case No. U-18255, DTE Electric Rate Case 2017.

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Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to:

1) Provide an overview of the IT organization and discuss the planning process – business cases and approval process

2) Discuss the importance of Information Technology investments within DTE Electric and the benefits to customers.

3) Specifically support the reasonableness of DTE Electric's IT capital expenditures in the amount of $86.7 million for the historical test year ended December 31, 2017 and projected capital spend of $169.3 million from January 2018 through the projected test period ending April 30, 2020.

4) Provide details on the impacts to DTE Electric of emerging technology trends such as Cloud Computing benefits and challenges.

5) Discuss the impacts of restructuring residential rate D1 to a time of use rate.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.7	Projected Capital Expenditures – IT Summary
A-12	B5.7.1	Corporate Application Projects
A-12	B5.7.2	Customer Service Projects
A-12	B5.7.3	Plant & Field Projects
A-12	B5.7.4	Shared Infrastructure Projects
A-12	B5.7.5	Information Technology for IT Projects

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Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Overview of the Information Technology Organization

Q. How would you characterize the IT organization at DTE Energy?

A. The IT Department at DTE Energy is responsible for delivering reliable, maintainable and secure information technology services and solutions. These services and solutions are to be delivered in a manner that provides the highest possible overall business value while offering excellent customer experiences.

Q. How would you categorize the functions that the IT organization performs?

A. The IT organization provides a variety of services and solutions across the entire range of the Company's business and operating units. Specifically, IT identifies, designs, implements, operates and maintains business technology and software solutions while providing architectural, infrastructural and information security services across the full range of all our information technology assets.

IT is also responsible for a full range of operational support for all the users of information technology regardless of where in the company this support is required. This support ranges from software solutions to technology hardware, both in the office environment and in field and vehicle applications.

Q. How are Information Technology capital expenditures prioritized and approved?

A. At DTE Energy IT capital expenditures are identified, prioritized and approved through the Annual Planning Cycle (APC). Each of the business units that IT

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supports, including IT itself, is assigned a Business Relationship Management team (BRM) that is responsible for collaborating with the business unit leadership to jointly develop Business Technology Frameworks (BTF) and Investment Roadmaps. The BTF and the Investment Roadmaps form the basis for describing, prioritizing, selecting, planning, and funding the technology investments that make up the solutions and services to be undertaken in any given year. The BTF and the Investment roadmaps are the output of collaboration with the business units and are focused on using IT resources and expertise to deliver the business outcomes and value that the Company has determined best fit the needs of the enterprise and the customer base that we serve. They provide a strategic multi-year investment plan which informs the Company's leadership on when and how business outcomes will be recognized.

With this plan as the basis for decision making, each business unit, in collaboration with their BRM, produces business cases for the coming year and submits them into the approval process for that cycle. The plan coupled with the business roadmaps and the general funding targets for each area comprise the overall ITS investment recommendation.

Q. How are Information Technology capital expenditures classified?

A. The Company classifies IT capital spending into three primary categories each with its own functional and value drivers. The three categories of IT investment are:

1. Expenditures that are specifically targeted at maintaining and improving service reliability.

2. Expenditures that are focused on maintaining and improving customer satisfaction.
3. Expenditures that are specifically targeted at containing costs.

Q. **What types of investments are included in the service reliability category?**

A. Service reliability investments are those expenditures that are undertaken to ensure electrical service reliability. This category covers a significant portion of the overall Information Technology spend and includes a diverse set of hard assets and systems. Broadly, these assets include, but are not limited to, control systems for delivery of electricity (Supervisory Control and Data Acquisition (SCADA)), work management platforms (Maximo, Service Suite and InService), grid monitoring systems (AMI, Field Control Network (FCN), SCADA), automated mapping systems (ESRI), supply chain systems (SAP) and security systems (NERC). Like any other suite of capital assets these systems provide critical business value through their designed functions and undergo planned updates, improvements and revisions in response to changing business needs and technology advancements. Managing these dynamics requires strategic investment roadmaps and investment cycles to ensure that they remain fit for purpose and up to date.

The service reliability category also includes both general and specialized IT support systems and asset classes such as Networking, Datacenter, Endpoints, Server Engineering assets and the Cyber Security Suite that protect them all.

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Q. Why is it important to ensure that these IT capital assets are upgraded to current standards?

A. As technology advances within the Utility Industry it is increasingly important that IT assets are up to date to operate effectively. As with other types of capital equipment these assets have a planned useful life and are subject to a regular update and replacement cycle as they wear out or become obsolete just like any other capital infrastructure component. More and more of the overall operational capability and agility of our Electrical Grid performance depends on vigilant management of these assets and the access and control they enable. This is especially true in the areas of Grid Modernization and Outage restoration as the mainstream grid control devices become even more heavily computer automated and dependent on effective cyber security controls.

Q. What types of investments are included in the customer satisfaction category?

A. Customer service improvements rely heavily on our ability to offer an ever-increasing number of automated services. Customer systems and interaction channels continually move to greater and greater information intensive processes, channels and methods. Changing trends in how our customers are choosing to interact with us are closely following overall global technology options which means that given choices, they consistently opt to transact business with DTE Electric via technological means. Electronic interactions on mobile devices via web based channels and custom applications are by far the preferred methods and fastest growing technological means by which customers communicate with their service providers. The Company, like any service provider, is aware of these trends and is investing in those systems and technologies that will best serve the customer's needs,

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reduce errors in the interactions, reduce unwanted repeat interactions and improve customer satisfaction with our offerings.

Q. What types of investments are included in the cost containment category?

A. The Company has an obligation to its customers to ensure that the costs of our service offerings remain affordable while prudent capital investments are being made to both improve service reliability and customer satisfaction. This affordability imperative is enhanced by IT capital investments. Healthy assets present less maintenance challenges, are less costly to operate, provide greater uptime and afford the operating arm of DTE Electric a robust set of tools with which to operate the electrical system. IT investments are a force multiplier in an operational sense in that they allow systems and human operators alike to perform their tasks more efficiently, effectively and in a significantly shorter timeframe where deployed. This has a direct effect on cost containment in terms of work force size, travel time and expense and system responsiveness. Implementing prudent capital investments that leverage the use of emerging technologies improve the overall understanding of our grid performance, allow us to better understand and isolate system issues and reduce the amount of physical intelligence gathering that is needed to make critical operational decisions.

Q. Where will Information Technology capital investment occur within DTE Electric for the projected test year and how will it be explained?

A. DTE Electric IT capital investment will occur in many different areas of the Company. It can be most clearly explained by expressing these investments in terms of the Business unit portfolios within IT that work in conjunction with DTE Electric

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business units. A dedicated portfolio exists for each of the major collections of business units within DTE Electric as noted below.

Overview of planned investment by portfolio

Q. What are the IT project portfolios you are supporting?

A. As shown on my summary Exhibit A-12, Schedule B5.7, the IT capital is divided into five portfolios: Corporate Applications, Customer Service, Plant & Field, Shared Infrastructure and Information Technology for IT. I will discuss each one of the portfolios.

I. Corporate Applications Portfolio

Q. Can you describe the Corporate Applications Portfolio shown on Line 2 of Exhibit A-12, Schedule B5.7?

A. The Corporate Applications portfolio supports the following corporate support functions for DTE Electric: Corporate Services, Enterprise Applications, Financial Management, and Human Resources (HR), as more fully described below. Broadly, capital investments in the Corporate Applications Portfolio fall into two general areas: providing enhanced capabilities and maintaining application stability/security. Specifically, Corporate Services is focused on providing enhanced business capability for the Supply Chain, Facilities and Real Estate business units. Enterprise Applications will continue to focus on the deployment of collaboration tools and refresh two legacy applications that are beyond end of life. Financial Management is focused on providing enhanced business capability for the Financial business units surrounding critical business processes such as budgeting, forecasting and month-end financial close consolidations. Human Resources is focused on providing

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enhanced HR capabilities. This period encompasses years two through four of the implementation of SuccessFactors which is a completely new consolidated human resources product that will encompass all aspects of the HR lifecycle for DTE Employees. As reflected on Line 2 of Exhibit A-12, Schedule B5.7, capital expenditures for Corporate Applications total $7.3 million in 2017, and $20.5 million in the 28 months ending April 30, 2020. The detailed Corporate Application projects across all business functions are shown on Exhibit A-12, B5.7.1.

Q. What are the most significant investments being made in Corporate Applications?

A. During the 28-month period ending April 30, 2020, the most significant investments in Corporate Applications cover areas in Corporate Services, Enterprise Applications, Finance and Human Resources.

Q. What are the most significant investments being made in Corporate Services?

A. The Company is planning to invest $3.3 million to implement technologies to improve functionality for internal Supply Chain, Facilities, and Fleet organizations. The investment covers implementation of systems such as Ariba which will provide improvements for Inventory Collaboration, greater efficiency for Purchase to Payment, supplier and contractor management, and inventory management processes. This investment also includes implementation of Energy Efficiency and Building automation for Facilities which will manage, monitor and regulate heating, cooling, water and lighting remotely for all DTE Electric property locations. Finally, with this investment the Company will implement a single system to consolidate real

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estate records and rights-of-way for DTE Electric. These investments are detailed in Exhibit A-12, Schedule B5.7.1 on lines 1- 3.

Q. What are the benefits of the investments planned in support of Corporate Services?

A. The planned investments in this portion of the portfolio are directly related to providing new business capabilities and better business insight with enhanced access to data. The Ariba implementation will improve Supply Chain's ability to procure and manage inventory. The Energy Efficiency project will provide a new application that will collect data on energy utilization at DTE facilities and the new real estate system will enable faster access to documents to support DTE access to right of ways and owned property. Moving to cloud-based applications also provides DTE Electric the opportunity to improve hardware and software currency and minimize downtime.

Q. What are the most significant investments being made in Enterprise Applications?

A. The Company is planning to invest $9.9 million to implement the in-flight ConnectUs phases and Quest re-platform initiatives which include collaboration functionality for video, audio, web conferencing, document sharing, adoption of the Skype for Business Audio/Video conferencing capabilities, and an upgrade to the internal intranet to include analytics functionality and address aging hardware and software. The investment also covers sustainment activities for Enterprise applications, Enterprise collaboration, and the Core ERP environment. These activities ensure that critical support and application maintenance services are provided such as system restoration and recovery, fail over testing, data corrections, master data updates, minor enhancements, interface support, system monitoring, addressing defects, system upgrades and patches. These investments are detailed in Exhibit A-12, Schedule B5.7.1 on lines 4- 15.

Q. What are the benefits of the investments planned in support of Enterprise Applications?

A. Most of the planned investments in this portion of the portfolio are directly related to increasing communications and collaboration for employees. These investments will increase the capability of DTE employees to work wherever they are, in the office, in the field, at a remote location or from home. These products will allow multiple people to update and collaborate on work products simultaneously, share access to documents without sending email attachments.

The second focus of this portion of the portfolio is to replace out of support applications as in the case of the Quest Portal re-platform and the Electronic Data Interchange (EDI). Both projects will replace legacy hardware and software with current products that provide enhanced capability, and more reliability for key business processes. Quest is an internal communication website with connections to SuccessFactors, time entry and other key business process. This project will streamline technology into a single platform by replacing the multiple products used to deliver the current experience, adhere to Americans with Disabilities Act (ADA) requirements and provide for an improved capability to update information. The project will provide a better way to connect with employees by providing more relevant and timely information which is accessible from any device regardless of location. EDI, our electronic data interchange software is currently out of support

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and operates on aging infrastructure. This increases the risk of unplanned outages with the potential to negatively impact the receipt of customer payments. There are few resources available on the open market for hire to support the current software. The replacement of this software will prevent customer payment concerns, as a result of EDI failures.

The impact of the ConnectUs program is to provide a highly integrated suite of applications which will increase the ability to share information without making hardcopies or sending email attachments which will provide the Company with better control over work products. Moving to a cloud-based application provides DTE Electric the opportunity to improve hardware and software currency, and minimize downtime.

Q. What are the most significant investments being made in Finance?

A. The Company is planning to invest $2.7 million to upgrade the fixed asset financial accounting system, PowerPlan, to the latest release to maintain support and update the interfaces with the Maximo application. Support for the current version of this application expires in June 2018. The investment also includes updates to the Business Warehouse (BW) and Business Planning and Consolidation (BPC) systems to bring them to the current version, as support has expired. The applications are experiencing performance issues. This upgrade will provide flexibility for capacity planning, improved processing, a suite of tools to create more data views and reports, reduce frequency and run time of month-end consolidation and reduction in run time for standard recurring reports. These investments are detailed in Exhibit A-12, Schedule B5.7.1 on lines 16 - 19.

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Q. What are the benefits of these investments planned in support of Finance?

A. These investments ensure application support, improve functionality, increased automation, and reduce the complexity of performing financial and accounting processes. These projects will improve the processing times associated with the current business processes and will provide a more reliable and integrated suite of applications for the business units. The goal of these projects is to improve the amount of time currently required to process month end close and asset accounting, reduce Construction Work In Progress (CWIP) backlog and improve controls and the efficiency of financial, tax and regulatory reporting. The finance staff will be able to spend less time processing data and more time creating actionable information for business operation leaders.

Q. What are the most significant investments being made in Human Resources?

A. The Company is planning to invest $4.6 million to continue the delivery of SuccessFactors, an end-to-end integrated set of business capabilities related to core Human Resource functions for the Human Resource business unit and for the employees within the company. Human Resource staff and leaders will be able to manage the workforce without moving across multiple applications. Enhanced workforce analytics and planning capabilities will be available across the integrated suite to allow leaders to gain better insight into employee trends. Mobile capabilities will be provided to enable employees and leaders to process transactions remotely. Leaders are required to process certain transactions within a specified timeframe per NERC CIP regulations (eg. Revocation of access for terminated resources). Delivering mobile capabilities enables leaders to process these key transactions right in the HR system of record, from any device and any location. This new capability

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will improve our ability to comply with NERC CIP regulations. This investment is detailed in Exhibit A-12, Schedule B5.7.1 on line 20.

Q. What are the benefits of the investments planned in support of Human Resources?

A. The benefits of the planned investments in this portion are directly related to providing an end-to-end integrated set of business capabilities related to core HR functions for the HR business unit and for the employees within the company.

The most significant impact of this investment is the shift to cloud based computing; reducing the amount of IT effort on upgrading, patching and maintaining the application.

The SuccessFactors implementation will provide HR with insight into the entire workforce from hire to retire within one application. New business capabilities will be provided to support talent management and onboarding of new hires. HR and leaders will be able to identify and monitor trends within the workforce. Enhanced reporting and workforce planning capabilities will allow leaders to more proactively develop plans around events like workforce attrition. The enhanced user interface will provide users with an intuitive application that requires minimal training. The mobile capability will allow users and leaders the ability to perform transactions at the point of activity. This has a positive impact to productivity, engagement and compliance to NERC CIP regulations by providing users the ability to process key transactions and work from anywhere.

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II. Customer Service Portfolio

Q. Can you describe the Customer Service Portfolio shown on Line 3 of Exhibit A-12, Schedule B5.7?

A. The Customer Service portfolio supports the following functions: Business Planning & Development, Core Customer Service, and Electric Sales and Marketing. Broadly, capital investments in this portfolio fall into two general areas: delivering new and enhanced features to DTE Electric customers that will improve the customer experience and delivering technological solutions that reduce the total cost of service within the meter-to-cash process.

Q. What are the projected costs for investments in this category?

A. As reflected on Line 3 of Exhibit A-12, Schedule B5.7, capital expenditures for Customer Service Portfolio total $30.0 million in 2017, and $59.9 million in the 28 months ending April 30, 2020. The detailed Customer Service projects are shown on Exhibit A-12, Schedule B5.7.2.

Q. What are the most significant investments being made in Customer Service?

A. During the 28-month period ending April 30, 2020 the most significant investments in Customer Service include:

Business Planning and Development (BPD) – The Company is planning to invest $2.1 million for various enhancements to systems supporting our Corporate Energy Forecasting, Renewable Energy and Demand Response initiatives. These enhancements will be delivered throughout the year and include projects such as an enhancement to increase forecast accuracy by class of electric customer, leveraging the AMI infrastructure to modernize our Interruptible Air Conditioning (IAC) program, and automation of the enrollment and billing process for our Michigan Green Power program. These investments are detailed in Exhibit A-12, Schedule B5.7.2 on lines 1-7.

Collection Strategy – The Company is planning to invest $8.1 million for the Collection Strategy projects to develop and implement the capability to process customer collection transactions through all digital channels (Kiosk, Web, Mobile, and IVR). This request comprehends all elements of planning, analysis, design, architecture, development, and implementation to provide customers with the option to perform collection transactions in all digital self-service channels. The transactions in scope for this project include: enrollment in payment programs, restoration of service after being disconnected and request shutoff protection. Collections in the Digital Channels will enable customer collection transactions to be accomplished in all our self-service channels in a standardized manner. In 2016 call data was analyzed and it showed that 35% of all calls were related to collections transactions which amounted to approximately 2.1 million calls of this type. The Company has estimated that the enablement of this functionality will allow 18% of the collections calls to be deflected from the call center reducing this type of call volume by 380,000 per year. Once in place and fully implemented it is projected that this level of deflection is expected to reduce annual call center costs by over $2 million annually.

The Low-Income Self-Sufficiency Program (LSP) portion of the Collections Strategy is targeted at making meaningful improvements to the LSP enrollment process, and

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improvements to the LSP customer experience. It will accomplish this by accommodating enrollment changes and supporting LSP communications through billing and letters. Operational improvements to the LSP enrollment process contained within this effort will close enrollment and customer satisfaction gaps and remove major LSP growth obstacles. These improvements are projected to improve the LSP success rate by 5%, reduce LSP participants disconnect rate by 5% and reduce uncollectable expense arrears by 2%. At the same time Defects and complaints related to this process would fall by 1%.

Finally, the Commercial Fraud Deterrence portion of the Collection Strategy is directly related to a 2016 finding that there was $18 million in payment arrears at that time that were attributable to customers that turned-on service with DTE but never made a single payment. The arrears can be attributed to turning on service in fraud or name switching. Today, commercial customers can turn on service by calling a customer service representative (CR) only. When a commercial customer attempts to turn on service, there is no Experian validation done so we are unable to determine the risk of accepting that service turn-on from that customer. As a result, we are hampered when making decisions on when to deny service and when to assess a deposit. This lack of verification also limits our ability to offer web turn-ons for commercial customers. Implementation of this portion of the strategy would reduce uncollectibles and reduce call handle time for these types of transactions. This effort has a direct effect on our many commercial customers as they interact with customer service representatives in that it will provide Customer Service Representatives a streamlined process for commercial setup. This process will result in a significantly lower number of accounts set up in error due to identity theft and reduce the number

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of interactions with customers that are currently occurring as those customers attempt to correct these fraudulent billings. It will also reduce our average call handling time (AHT).

The expected benefits of the project include increased self-service options, improvements in first contact resolution and reduction in call volume which would lead to decreased operational expenses. These investments are detailed in Exhibit A-12, Schedule B5.7.2 on lines 8-12.

Customer Asset Health – The Company is planning to invest $7.9 million for our customer asset health initiatives which will ensure appropriate scalability, reliability and risk management for customer systems. These investments will ensure that customer IT systems will not fall behind in support due to obsolescence and will decrease risk related to system stability for both internal and external customer applications including but not limited to contact center and customer channels. Failure to implement any of the above scope will result in degradation of customer experience as these investments are required to stay current on application capability. These investments are detailed in Exhibit A-12, Schedule B5.7.2 on lines 13-20.

Customer Sustainment – The Company is planning to invest $22.5 million to perform necessary enhancements to further leverage and extend the capability of the core Customer platforms. This will include the delivery of additional business capability related to Billing & Rates, Metering, Revenue Management & Protection, and Customer experience.

These expanded capabilities will positively impact the customer experience by delivering a Fixed Bill and Weekend Flex pilot programs enabling eligible customers to opt to pay a fixed monthly charge for their electricity usage for a period of 12 months (Fixed Bill) or a fixed monthly charge for their weekend electricity usage (Weekend Flex). Outage reporting will be enhanced for the customer allowing them to be more specific when reporting service conditions improving the Company's ability to respond more quickly and effectively. New automated calling features will be enabled in upcoming IVR enhancements to dynamically route calls to specialized groups to fulfill specific types of requests reducing call backs and improving first call resolution. Outbound communications will continue to be improved across the channels to ensure that interactions with our customers are ever more timely and informative. Finally, the tools in the hands of our customer representatives will benefit from updates that deliver additional features and capabilities allowing more information to be incorporated into every customer interaction through thoughtful integration of multiple sources of information.

The overall benefits include improved customer experience for integrated voice response, customer outage events, new features in customer billing systems and improved performance. Failure to implement will result in a lagging customer experience due to lack of information about billing, account management and critical customer experiences during customer outage events. These investments are detailed in Exhibit A-12, Schedule B5.7.2 on lines 21-37.

Payment Experience - The Company is planning to invest $13.0 million to implement a full gateway/processor solution offered by the vendor of choice, as selected through a vendor Request for Proposal (RFP) process. Vendor service level agreements (SLAs) and vendor management best practices will be incorporated into the solution to provide a scalable, secure, and robust foundation to solve existing constraints and build a new customer payment experience. The current Customer Payments Platform (CPP), which consists of a partial payments gateway with custom customer interfaces, lacks in reliability, sometimes resulting in poor customer experience. SLAs with key third party payments vendors do not exist, creating pain points and degraded customer satisfaction. Additionally, insufficient vendor management capabilities further hamper our ability to improve the customer experience. These investments are detailed in Exhibit A-12, Schedule B5.7.2 on lines 38-40.

<u>Regulatory initiatives</u> – The Company is planning to invest $2.3 million to implement enhancements and improvements required for adherence to regulatory requirements resulting from a rate cases and billing practice rules. It also includes an initiative necessary to comply with Payment Card Industry (PCI) regulation as it relates to customer payments taken in all customer channels, including the contact center. Failing to provide these changes will severely limit our ability to change our IT systems to comply with regulatory rulings. These investments are detailed in Exhibit A-12, Schedule B5.7.2 on lines 41-42.

<u>Electric Sales and Marketing (ESM)</u> – The Company is planning to invest $2.4 million for various projects to begin a phased implementation of capability that will serve to augment our core customer platform allowing for speed to market and lower costs. The platform will also support the ability to separate out billing for value added products and services such as applying rebates to customer energy bills for shopping

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at their favorite stores, on bill financing for energy saving home improvements and a flat fee insurance service for trees. Failure to implement the platform will lead to more costly, unsustainable custom solutions to achieve the same business value. These investments are detailed in Exhibit A-12, Schedule B5.7.2 on lines 49-52.

Q. What are the benefits of the investments planned in support of Customer Service?

A. The new CPP will provide for a more robust payment experience, eliminating the custom interfaces and multiple points of failure prevalent in the current system. Additionally, the CPP will simplify the management of payment methods and provide the capability to add additional methods of payment in the future. Improvements realized through the implementation of the collections strategy initiatives will expand the capabilities of self-serve channels (web, IVR, and mobile) to include self-service collection transactions, deflect calls from the call center and overall will provide a more efficient means for customers to complete their collection transactions. The introduction of more payment options will help to reduce the overall uncollectible expense. Fraud deterrence implementation will give the call center representatives a powerful tool to assist them in detecting turn-on requests that represent an unacceptable risk thereby reducing the number of agreements established that do not result in payment. Finally, the asset health and sustaining efforts will ensure that the systems remain technologically current and feature rich as we work to increase our system availability and customer satisfaction.

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III. Plant and Field

Q. Can you describe the Plant and Field Portfolio shown on Line 4 of Exhibit A-12, Schedule B5.7?

A. The Plant and Field portfolio has three major sub-groups: Electric Distribution, Legacy Generation (Nuclear Generation, Fossil Generation, Fuel Supply, and Generation Optimization), as well as Work & Asset Management. Broadly, capital investments in the Plant and Field portfolio fall into four general areas: Modernization and Monitoring of our Electric Grid, Availability and Service Reliability of our existing Assets, Productivity Investments for our DTE Business Organizations, as well as Portfolio Rationalization and Platform investments.

Q. What are the projected costs for investments in this category?

A. As reflected on Line 4 of Exhibit A-12, Schedule B5.7, capital expenditures for Plant and Field total $21.5 million in 2017, and $25.4 million in the 28 months ending April 30, 2020. The detailed project listing is on Exhibit A-12, Schedule B5.7.3.

Q. What are the most significant investments being made in Plant & Field?

A. During the 28 months ending April 30, 2020 our most significant investments in Plant & Field include:

<u>Advanced Metering Infrastructure</u> - Advanced Metering Infrastructure (AMI) is critical to DTE as it provides remote monitoring and control meters, faster customer outage resolution, as well as supports automated customer billing and usage reports. The Company is planning to invest $4.0 million for AMI system upgrades and support to address capacity and processing shortages to prevent failures due to capacity limitations. To maintain an uninterrupted operation of all components of

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the AMI landscape and related business processes, the objective is to keep assets healthy and in compliance by upgrading to vendor supported versions. DTE has 2.6 million AMI meters in the electrical system that are being supported. Enhancements to these systems are typically delivered monthly. Failing to provide these monthly changes would severely limit the ability to maintain the stability of our systems as well as limit our ability to tailor IT systems to internal Company user feedback. These investments are detailed in Exhibit A-12, Schedule B5.7.3 on lines 1-2.

<u>Electrical Distribution Sustainment</u> – the Company is planning to invest $3.2 million for Enhancement and Sustainment of various systems in DTE's Electrical Distribution Operation Portfolio. These efforts will keep assets healthy and in compliance by upgrading to vendor supported versions. These enhancements are typically delivered monthly and include changes to 27 applications in our Electrical Distribution Operation portfolio. Failing to provide these monthly changes would severely limit the ability to maintain the stability of our systems as well as limit our ability to tailor IT systems to internal Company user feedback. This investment is detailed in Exhibit A-12, Schedule B5.7.3 on line 3.

<u>Enterprise Content Management System</u> - The Company is planning to invest $2.9 million to replace end of life records management systems to industry standard platform, which will provide business and IT efficiencies. The application is currently unsupported and has very limited capacity for changes to the environment. This current system handles key documentation for day to day operations and system diagrams. Failing to provide will limit the ability to increase

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capacity, system stability and configuration changes for the business growth. This investment is detailed in Exhibit A-12, Schedule B5.7.3 on line 4.

Field Service Management - Field Service Management (FSM) is critical to DTE as it provides scheduling, planning, dispatching of work as well as real-time location tracking. The Company is planning to invest $2.5 million for FSM system implementation to empower field employees at the point of activity and increase customer's safety. The system will be robust enough to sustain a one million customer outage load. Failing to provide will limit the ability to increase capacity, allow real-time ability to capture work status at the point of activity and will decrease customer safety. These investments are detailed in Exhibit A-12, Schedule B5.7.3 on lines 5-6.

Work Management Sustainment – The Company is planning to invest $4.6 million for Enhancement and Sustainment of various systems in our Work and Asset Management Platform. These efforts will keep assets healthy and in compliance by upgrading to vendor supported versions. These enhancements are typically delivered monthly and include changes to applications in our Field Operations, Engineering and Plant Operations. These investments are detailed in Exhibit A-12, Schedule B5.7.3 on lines 7-11.

Security Screening Information System and Ready to work - The Company is planning to invest $1.3 million for the Security Screening Information System and Ready2Work (SSIS-R2W) project which will replace complex manual legacy processing capability with an industry state of the art computer system. This will

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reduce the time to in-process people during refueling outages (as refueling outages cost DTE $2 million per day) and reduce the risk of Personal Identifiable Information (PII) leakage. This will eliminate 15 individual databases, spreadsheets, and hard copy environments. Implementation of this product will aid in meeting the Nuclear Energy Institute (NEI) strategic plan as well as advancing safety, reliability and economic performance. This investment is detailed in Exhibit A-12, Schedule B5.7.3 on line 25.

<u>Legacy Generation Sustainment</u> – The Company is planning to invest $3.6 million for Enhancement and Sustainment of various systems in DTE's Legacy Generation Portfolio. These efforts will keep assets healthy and in compliance by upgrading to vendor supported versions. These enhancements are typically delivered monthly and include functional improvements to up to 45 applications in our Nuclear generation, Fuel Supply, Generation Operations and Fossil Generation portfolio's. Failing to provide these monthly changes would severely limit the ability to maintain the stability of our systems as well as limit our ability to tailor IT systems to internal Company user feedback. These investments are detailed in Exhibit A-12, Schedule B5.7.3 on lines 24 and 32-34.

Q. What are the benefits of these investments?

A. These expenditures are targeted at prudent system investments designed to ensure that our existing systems are upgraded to comprehend both increased load and to handle expanded demand. This demand is manifesting as a result of taking systems originally designed to handle automated meter reads and expanding their role into both a reliability measurement and an outage restoration role. These systems require

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both physical expansion and system replacement as they reach either capacity or the end of their functional design life. Our investments in these areas will continue to improve data availability and accuracy, expand our field force management capabilities and allow the Company to provide additional features and options to the customer as they interact with DTE. It will also introduce improved customer facing technology allowing the customer to achieve greater visualization and management of their own energy usage data. As specifically detailed above, this will have multiple beneficial effects from operational improvement, outage response and cost containment.

IV. Shared Infrastructure Portfolio

Q. Can you describe the Shared Infrastructure Portfolio as shown on Line 4 of Exhibit A-12, Schedule B5.7?

A. The Shared Infrastructure portfolio has three major sub-groups: Architecture, Information Security, and Infrastructure Operations. Broadly, capital investments in the Shared Infrastructure Portfolio fall in to two general areas: Availability and Service Reliability and IT Platform investments.

Currently there is an emphasis in this portfolio to focus on initiatives that improve Availability and Service Reliability by investing in the overall asset health of the Information Technology infrastructure to return it to acceptable levels. Beyond asset health, the IT Platform continues our planned investments in the tools that are required to ensure that the IT workforce has the means to manage and operate the overall IT infrastructure in an effective and efficient manner.

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As reflected Line 5 of Exhibit A-12, Schedule B5.7, capital expenditures for Shared Infrastructure total $26.6 million in 2017, and $35.8 million in the 28 months ending April 30, 2020. The detailed Shared Infrastructure projects are shown on Exhibit A-12, Schedule B5.7.4.

The following breakdown will illustrate the investments in each sub-group.

Architecture

Q. What is the projected costs for investments in this category?

A. Capital Expenditures for Architecture are projected to be $0.5 million of the $36 million reflected on Line 5 of Exhibit A-12, Schedule B5.7 during the 28 months ending April 30, 2020. An explanation of these expenditures is found below with projected costs by project available in Exhibit A-12, Schedule B5.7.4 on lines 1-4.

Q. What types of investments are included in this category?

A. Architecture ensures IT solutions are build, deployed, and run in accordance to business objectives. The overall investment themes for Architecture are Foundational and Transformational Capability. Foundational Capabilities are necessary to run Architecture operations – without a solid foundation the Architecture function is ineffective at its mission. Foundational Capabilities are inward facing to the Architecture function. Transformational Capabilities provide an opportunity for a step change in business outcomes (e.g. productivity, quality, satisfaction, etc.). These capabilities are outward facing to the organization at large.

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Q. What are the planned business value, impacts and outcomes of these investments?

A. The Foundational investments are focused on asset health. These investments will keep the Troux application healthy. The business value for Troux is that the system can correlate information in such a way as to answer key questions around the technology portfolio. For example, it can answer – “Which IT systems are impacted by next year’s business cases?” or “Which IT applications are impacted by a product that has recently reached its end-of-life?” – these questions and others like them are important to successfully run technology, so keeping the application that can answer those questions healthy is also important.

The Transformational investments are focused on Applied Innovation. The value for Innovation is in harnessing employees’ and the market’s good ideas and transforming them into business results. The current innovation program has approximately 75% hit rate on prioritized ideas yielding results. The value for Data comes from being able to govern and analyze it.

Information Security

Q. What is the projected costs for investments in this category?

A. IT capital expenditures for Information Security are projected to be $6.8 million of the $36 million reflected on Line 5 of Exhibit A-12, Schedule B5.7 during the 28 months ending April 30, 2020. An explanation of these expenditures is found below with projected costs by project available in Exhibit A-12, Schedule B5.7.4 on lines 5-12.

Line No.

Q. What types of investments are included in this category?

A. During this period information Security investments are focused on reliability of security infrastructure and improving DTE Security posture. Like any other capital asset, the IT Security Infrastructure has a well understood useful life and operates on a normal cadence of asset replacement as aging components are retired and new components are procured and installed to replace them.

The cybersecurity landscape is rapidly changing as cyber threats and successful attacks are becoming increasingly more sophisticated. Achieving a safe, secure, and resilient cyber environment demands that DTE adopt innovative approaches and a full range of best practices. Maintaining strong security operations and defense capability is key to protect against significant cyber events. DTE is making investment in new cyber security technologies that prevents, deters, detects, and is resilient against cyberattacks, and minimizes the vulnerability of systems and networks.

There are three key focus areas within information security that will seek investments in this period to improve DTE security posture: Identity and Access, Network Security, and Asset / Endpoint Security. These areas will focus on the refreshing the security technologies, building strong defenses and secure broader technology landscape which will continue to dramatically improve our overall Risk posture and preparedness against cyber threat. An enumeration of those efforts is found below with detailed financials available in Exhibit A-12, B5.7.4 Projected Capital Expenditures – IT.

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Q. What Security needs does the company anticipate emerging within the period that will affect IT?

A. Based on the Company's stated security goals and our intent to respond to technology advancements that allow us to link physical and Cyber security systems together into an integrated whole, the Company anticipates a future need for investment in a Physical Access Control System (PACS). While planning is just newly underway, and specific IT projects have not yet been identified, it is clear there will be a significant level of IT participation including software, infrastructure and labor. The benefit of this system will be realized in the form of integration between the physical access system at all the DTE facilities that require badged access and intelligent data systems that will allow the Company to compare access requests with employee behavioral models, historical access patterns, work schedules and geographical/time span analytics. This will make it much more likely that the Company can clearly differentiate legitimate access requests from fraudulent ones. This effort is anticipated to expand as the Company implements physical security improvements according to its facilities improvement plans.

Q. What are the most significant investments being made in Information Security Operations and why?

A. During the 28-month period ending April 30, 2020 Security Operations will make approximately \$6.8 million of capital investments. These investments include:

1. Asset Health - The Asset Health project is planning to invest \$2.9 million for replacing "End of Life" cybersecurity hardware to focus on reliability of security infrastructure. Like any other capital asset, the IT Security Infrastructure, such as firewalls, security appliance and proxy servers have a well understood useful

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life and operate on a normal cadence of asset replacement as aging components are retired and new components are procured and installed to replace them. This project will also fund adding capacity to existing hardware and software to meet the normal growth. Not doing this work will incur additional risk as it creates an obsolete cybersecurity platform, leaving the company, its customers and employees vulnerable to cyber attacks. The intent of this project is to ensure continual vendor support and required capacity of cybersecurity technology deployed at company. Benefits are expected to be reduction in risk to system downtime related to cyber incidents and vulnerabilities as well as operating performance to meet customer expectations. This investment is detailed in Exhibit A-12, Schedule B5.7.4 on line 5.

2. <u>Cyber Security Defense Center (CSDC)</u> - The CSDC Enhancements project is planning to invest $0.5 million to make investment in new cyber security technologies to enhance our capabilities to detect cyber attacks, slow attackers' progress, and provide more visibility into the threat landscape. This project will provide funding to build threat hunting, improve Advanced Threat Protection (ATP) and enhance User Behavior Analytics (UBA) capabilities. As adversaries are taking malware to unprecedented levels of sophistication and becoming more adept at evasion and weaponizing cloud services, DTE's cybersecurity defense team will enhance detection use cases to capture intel from external sources and automate remediation steps. Not doing this project will increase the time before detection and resolution for cyber incident, and more damage will be inflicted. Benefits are expected to build resiliency against cyberattacks and security agility

speeds our ability to respond and recover from significant cyber events. This investment is detailed in Exhibit A-12, Schedule B5.7.4 on line 6.

3. Process Automation - The Process Automation for Configuration management project is planning to invest $1.6 million to implement a configuration management tool, Tripwire, for SOX and PCI assets. Any change to the configuration baseline must be approved, tested and documented to remain compliant with SOX and PCI requirements. Failure to implement this project will result in the continuation of repetitive, time-consuming and error prone tasks that have higher support cost. Configuration management for SOX and PCI assets is a manual process and approval and testing documentation is not always maintained, thereby, increasing the risk of non-compliance. Tripwire can deliver effective change management, reduction in human error and operation cost saving or cost avoidance to manage configuration for PCI and SOX assets. DTE has already seen benefits for this solution in configuration management for NERC/CIP assets. Applying automation to some of the repetitive task will free-up work force to work on higher value activities. These investments are detailed in Exhibit A-12, Schedule B5.7.4 on lines 7-8.

4. Risk and Compliance – The Risk and Compliance program is planning to invest $1.8 million to implement a three-tier security model that will maintain SAP ISU security roles, improve the user experience in GRC ARM (Access Request Management) model to request and approve security access. This project will also focus on security standards and controls for Non-NERC assets to reduce security risk. The scope of the project is to develop a long-term security design solution

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to decrease support and maintenance of SAP security authorizations. The current security model grants excessive access to users. DTE Energy's preferred model entails "least privileged" access. Not doing this work will incur additional risk of non-compliance with SOX and PCI requirements. This would result in limited visibility to security posture. Benefits are expected to build single roles and job composite security roles which will reduce multiple role owner approvals to one job role owner and reduce risk in the compromise of cybersecurity across fleets. In addition, the three-tier security model will improve the user experience by reducing time to request, approve, and provision security roles in GRC (Governance Risk and Compliance). These investments are detailed in Exhibit A-12, Schedule B5.7.4 on lines 9-10.

Q. What are the planned business value, impacts and outcomes of these investments?

A. During this period for the expected business value, impact and outcomes for making investments in cybersecurity hinges on the increasingly sophistication of cyber attacks and cyber threat actors targeting the energy sector. Critical infrastructure companies must perform due diligence in protecting and defending our cyber systems and protection of customer personally identifiable information through acquisition and implementation of security tools, technologies, and services. In doing so, we are able to better ensure resiliency and continuity of our services to our customers.

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Infrastructure Operations

Q. What is the projected cost for investments in this category?

A. IT capital expenditures for Infrastructure Operation are projected to be $27.8 million of the $36 million reflected on Line 5 of Exhibit A-12, Schedule B5.7 during the 28 months ending April 30, 2020. An explanation of these expenditures is found below with projected costs by project available in Exhibit A-12, Schedule B5.7.4 on lines 13-47.

Q. What are the Overall investment themes and rationales for this portfolio?

A. During this period, Infrastructure Operations is focused overwhelmingly on Availability and Service reliability. Specifically, this test period encompasses years two through four of our overall Infrastructure Return to Asset Health plan. Like any other capital asset, the IT Infrastructure has a well understood useful life and operates on a normal cadence of asset replacement as aging components are retired and new components are procured and installed to replace them. There are five distinct asset classes or operational areas within Infrastructure operations that will see investments in this period: Datacenter, Endpoints, Network/Telecommunications, Server, and Operations Center. These classes/areas will focus on the replacement of aging assets with up to date equipment which will continue to dramatically improve our overall infrastructure reliability, availability and in many cases redundancy. As reflected in Exhibit A-12, Schedule B5.7.4, Capital Expenditures for Infrastructure Operations total $19.8 million in 2017, and $27.8 million in the 28 months ending April 30, 2020.

Q. What are the most significant investments being made in Infrastructure Operations and why?

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A. During the 28-month period ending April 30, 2020 Infrastructure Operations will invest approximately $27.8 million on capital improvements.

1) **Asset Health** - These investments include approximately $25.5 million in scheduled equipment replacements: servers, data storage, networking equipment, data center equipment, desktop and laptop computers, capital software licenses and field computing assets, due to those assets reaching the end of their useful lifecycle. Each year a portion of these assets reach the end of their useful life and are replaced with new modernized assets to ensure the reliable operation of the infrastructure. These investments are detailed in Exhibit A-12, Schedule B5.7.4 on lines 13-31.

2) **Operational Improvement** – These investments include a combined $1.5 million for SNOW Phase II, our license management software to further refine our ability to remain compliant with our licensing spend and Wireless Local Area Network expansion into substations. These investments are detailed in Exhibit A-12, Schedule B5.7.4 on lines 32-35.

3) **Strategic Innovation** - The remaining approximately $0.9 million in investments constitute the addition of strategic capability such as a Pilot Cloud computing implementations for data analytics and network routing redesign to account for network technology advances in the field. These investments are detailed in Exhibit A-12, Schedule B5.7.4 on lines 36-37.

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Q. What are the benefits of these investments?

A. Most of the planned investments in this portion of the portfolio are directly related to the ongoing health and operability of the IT infrastructure assets.

IT is using these planned investments to return its infrastructure to a 95% asset health level which is targeted for completion by the end of the 2020 calendar year. Assets operated at this level of health will perform more reliably, require less maintenance, operate within standard warranty levels rather than requiring extended warranties and thereby reduce overall operational expenses.

The impacts of this investment include avoiding the time and expense of remediating infrastructure outages and the loss of productivity that results in system down time throughout DTE Electric. The loss of critical or key systems to unplanned outages can affect a wide range of DTE Electric Employees and customers.

Improved IT system availability is a positive driver for customer satisfaction especially in the self-service channels like the Mobile and Web channels which have been and continue to be an area of significant investment within the company.

V. <u>Information Technology for IT</u>

Q. Can you describe the Information Technology for IT as shown on Line 6 of Exhibit A-12, Schedule B5.7?

A. The Information Technology for IT implements and supports systems and solutions which provide the tools that are required to operate a professional and industry class IT department.

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Q. What are the projected costs for investments in this portfolio?

A. IT capital expenditures for the Information Technology for IT are $1.4 million in 2017, and $27.8 million in the 28 months ending April 30, 2020 as reflected on Line 6 of Exhibit A-12, Schedule B5.7.

Q. What are the Overall investment themes and rationales for this portfolio?

A. During this period, the Information Technology for IT will focus on expanding and increasing IT Service capabilities. The capital investments and the associated initiatives planned during this period will ensure the ability to securely expand to Cloud based computing, increase the depth and breadth of operations monitoring, enhance compliance, govern and deliver applied innovations and establish a platform to more effectively deliver and manage IT Services The outcomes achieved over the next three years will significantly improve service level availability across the entire IT portfolio and will establish a foundation on which to automate the delivery, management and monitoring of IT services.

Q. What are the most significant investments being made in the Information Technology for IT?

A. During the 28 months ending April 30, 2020 our most significant investments in the Information Technology for IT include:

1. Cloud Computing – the Company is planning to invest $0.8 million to implement a Cloud Security project. This effort will implement a security structure aimed at securing our cloud computing environments to prevent unauthorized access and protect company information. This investment is detailed in Exhibit A-12, Schedule B5.7.5 on line 1.

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2. Compliance – The Company is planning to invest $2.0 million to implement systems aimed at protecting and securing access to accounts. The efforts in this space, Cyber Ark and Identity Access Management, protect privileged accounts against threats and improves account access security. The focus is to secure privileged access to system accounts for servers, centralizing and improving password management, and improved processing of User Access Reviews, audit and compliance. These investments are detailed in Exhibit A-12, Schedule B5.7.5 on lines 2-3.

3. Innovation – The Company is planning to invest $7.0 million to identify and deliver rapid value opportunities with a short duration to business benefit realization. This effort includes Agile development to deliver innovative solutions that respond to emergent needs, quickly delivering value to improve DTE Energy employees' efficiency and effectiveness, leading to improved customer affordability. These investments are detailed in Exhibit A-12, Schedule B5.7.5 on lines 4-5.

4. IT Platform – The company is planning to invest $8.4 million to realize meaningful movement in key operational metrics including Meantime-to-Resolution (MTTR) and System Availability through the implementation of Network automation, the IT Service Management Platform, and the implementation of the Enterprise Monitoring Strategy. These efforts focus on critical and key system and transaction monitoring, improved detection, prevention and response times, prevention of network performance problems, and implementation of a consolidated service management platform. This

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series of investments will ultimately lead to improvements that enable DTE Energy employees to operate more efficiently and effectively and improve customer affordability. These investments are detailed in Exhibit A-12, Schedule B5.7.5 on lines 6-9.

5. Network Targeted projects – The Company is planning to invest $2.3 million to secure critical applications within the corporate data centers from corporate and other general user networks by implementing network segmentation to control access and improve threat-defense and visibility. Additional investments in this area include replacing the aging PBX phone infrastructure to improve reliability and minimize unplanned outages which negatively impact productivity. These investments are detailed in Exhibit A-12, Schedule B5.7.5 on lines 10-12.

6. Work Anywhere – The Company is planning to invest $4.6 million to enable flexibility in work locations and device types, enabling employees and vendors secure remote access from cost optimal devices. This investment area includes replacing the both the aging Employee Remote Access and Vendor Remote Access systems to improve our security posture and connectivity from remote locations. Other investments, Endpoint Security and Windows 10 deployment, will ensure secured privileged system accounts for endpoints, centralize and improve password management, and maintain support and security for our operating environment. These investments will enable DTE Energy to optimize facilities costs, reduce endpoint acquisition and support costs in future years and reduce and mitigate cost to DTE

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Energy's customers. These investments are detailed in Exhibit A-12, Schedule B5.7.5 on lines 13-17.

Q. What are the projected benefits of these investments?

A. There are 3 main value themes driving the planned investments. The first drives how IT delivers services, focused on the deployment and integration of an IT Service Management platform tool to automate IT service requests and fulfillment. Integration with other platforms such as monitoring will enable the triggering of self-healing technologies when problems are detected. The full automation of these lifecycles is focused on reducing response/cycle times, improving productivity, and eliminating or reducing service disruption.

The second area of focus is the continued maintenance and improvement to the security posture of IT operations. The expansion of the operating environment which includes Cloud (Saas/PaaS) for compute and storage requires security operation investments to ensure appropriate management and protection. IT Operations requires new and expanded capabilities to manage and secure network and endpoints required to meet workplace transformations. Technology trends such as bring-your-own-device (BYOD) bring new challenges in the management of personal devices accessing corporate networks. The initiatives focused on the IT security posture are set to enable the expansion of the operating environment to the meet the needs of business partners and customers while maintaining a high level of security vigilance.

The third area is directly related to the ongoing health and operability of the IT Core assets. The planned investments will continue to provide an available and reliable

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environment to manage and operate the business of IT while maintaining our ability to contain operational costs and provide improved uptime availability to employees and external customers.

Q. What major industry or technology trends are currently impacting DTE Electric Capital investments?

A. The most prominent technology trend impacting DTE Electric in terms of Information Technology investment is the shift of major service offering into the Cloud.

Q. Fundamentally what is Cloud Computing?

A. In its most basic form Cloud computing is simply using technology: hardware, software and services, for a service fee without taking direct ownership of those assets within a company owned facility or data center.

Q. Why are most companies adopting it?

A. There are several major drivers that factor into this answer. The first is that a company investing in Cloud computing can potentially reduce its capital outlay required in purchasing technology in the data center. This reduced capital investment allows the downsizing of a company's data center footprint which can offer a corresponding reduction in operational overhead. As the data center footprint is reduced the need for associated operations personnel is reduced, maintenance contracts for hardware are reduced, and power consumption decreases. The number of skilled operators needed to maintain these assets may reduce allowing them to be redeployed on other important endeavors.

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Second, the Cloud provider delivers some or all the asset health aspects of the operations of Cloud assets in accordance with their service level agreements as negotiated with each company further reducing overall operational expenses.

Another advantage is the ability to design systems with far more flexibility in terms of capacity. A traditional on premise solution will normally have multiple system environments including development, test, training, quality assurance and production. These environments are normally built and sized in proportion to the size and requirements expected of the production footprint. That footprint also must contemplate sizing for both normal operations and any needs for a peak capacity scale up. This often results in capacity being idle on non-peak cycles or when there is little development or training occurring. Most of these concerns are dealt with efficiently in the Cloud by purchasing capacity for each of these areas on demand and only paying for what is in use rather than all this capacity all the time.

Lastly, the Cloud offers the ability to buy surge capacity in an emergency. If there is a situation that calls for capacity or availability beyond the design specification the cloud provider can add this capacity rapidly on demand to a level that a single company cannot normally match out of existing resources in short timeframes.

Q. What are the benefits of Cloud adoption to DTE Electric and to the rate payers?

A. All the capabilities described above are potentially beneficial to DTE Electric and its rate payers. The Cloud provides an ongoing operational and financial flexibility in terms of its IT investments. It allows the Company to only pay for what is actually consumed rather than continuously paying for emergency capacity that often sits idle.

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Q. What are the barriers to implementing cloud computing faced by utilities in general and by DTE Electric specifically?

A. As with the benefits there are several barriers to adoption specific to the utility industry in general and DTE Electric specifically. The first is the nature of some of the systems that a utility operates. There are very clear regulatory and operational imperatives that make a number of IT systems at a utility unsuitable for cloud deployment. At this time, there are many NERC CIP and Plant or Grid Control systems suitable only for non-cloud deployments for safety, security and operational reasons. With these constraints, it limits the scope of the benefits that can be obtained as a prudent level of the Datacenter operations and services must be retained.

Secondly, and now most significantly, current regulatory treatment of Cloud computing in terms of capitalization and rate case treatment is a disincentive to adoption. While there has been considerable discussion between many utility companies and their regulators, no common consensus surrounding guidance in this area of investment has emerged. This leaves each company in the position of holding those discussions with their respective regulatory bodies without the benefit of any treatment precedents to assist in guiding the construction of rate cases that favor equitable treatment of this investment. Without such treatment, the adoption of Cloud computing remains an often-untenable option for DTE Electric despite its allure and the benefits it could deliver.

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Q. What external means does the Company employ to ensure that its IT capital expenditures are in line with other utility IT departments?

A. The Company actively participates in a recognized consortium of utility companies known as UNITE. This participation offers an unbiased structured comparison of IT costs across all common aspects of the IT landscape. Our participation allows us to evaluate our performance to other peer companies within our industry to understand how we compare to others within our sector. It allows us to identify both strengths and opportunities to improve. In the most recent published results, benchmark year 2016, the Company ranked in the 2nd Quartile in terms of overall spend. DTE's IT function was ranked 6th overall out of 18 companies in terms of our costs.

Q. What methods does the IT organization use to contribute to the control of costs and the achievement of customer value?

A. The Company employs a formal Continuous Improvement (CI) methodology based on lean techniques to both improve the quality of our deliverables and to ensure that waste is driven out wherever possible. These practices are incorporated into all projects and operations to minimize capital costs were possible.

The IT organization recognizes that in order to successfully contain costs, IT project work must be well controlled and delivered with a professional degree of precision in terms of value delivery, timing and overall spend. Consequently, IT has made it a priority to adopt and employ industry recognized project management methods and skills. IT employs a mature and effective standard project management methodology which has resulted in the IT department delivering IT projects within projected costs and timeframes on a very consistent basis.

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Rate Schedule D1 Time of Use – IT Impacts

Q. Are you familiar with the Commission's Order in U-18255 regarding the change in the residential rate structure for rate schedule D1?

A. Yes I am. The Commission ordered the Company in its next general rate case to include proposed tariffs for non-capacity charges based on summer on-peak rates. In other words, approximately 1.9 million customers would be defaulted to time based rates.

Q. Will this change have an impact on the Company from an IT perspective?

A. Yes, it will have a very definite effect on the Company and especially on the IT Organization.

Q. In what ways will this order affect the IT Organization?

A. There are four specific areas that will require investment within the IT organization if this order goes into effect:

1. The Core billing system installed in 2017 is designed to handle a D1 rate structure that is predicated on a "register" based calculation which is to say that the system uses a value calculated by comparing starting and final reads of the meter and calculating a register differential as the basis for the usage to be billed for the period. If the order goes into effect, it would no longer be possible to use this method. Rather the Company would have to gather "interval" readings at a specified frequency, transmit those to the billing system and do an aggregation of all the interval reads to determine the correct billing determinants over that time period in order to produce an accurate bill. This is a major change to the billing system logic and this part of the effort

alone is estimated to cost approximately $6 million to design, test and implement.

2. The AMI system which gathers the metering data today does not collect the volume, frequency or granularity of the data needed to implement the above described read data. Further, the system in its current configuration was never designed to handle the sheer volume of data that would now need to be collected and processed. To implement the order, the system would need to be reprogramed for this requirement and it would need a substantial capacity upgrade to be able to process the dramatically increased volume of data. The entire meter population would need to be reprogramed to this new functionality and any devices that did not take that programing remotely would have to be physically visited and remediated. Finally, the network that is used to transport the data would need to receive an investment to upgrade the bandwidth for the data back haul to this new standard rather than its original design specification. This portion of the effort is estimated at approximately $9 million.

3. With the advent of the new rate structure there would need to be investment in all channels that allow customers to view, utilize and manipulate their usage data. None of these channels (Web, Mobile, IVR etc.) currently have the capability to provide this type of billing presentment to our customers. This would need to be implemented in tandem with the new rates for our customers to be able to understand and act upon their usage information. This portion of the effort is estimated at $6 million.

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4. Finally, with the advent of the new rate, the infrastructure used by the non-AMI involved systems would need some degree of improvement to handle and store the dramatically increased amount of data that this feature will generate. This underlying infrastructure component is estimated at approximately $3 million.

In conclusion, the IT portion of this effort will involve a significant cross organizational technical team, span an estimated 22 months to achieve and cost an estimated $24 million for system redesign and programming. IT operational maintenance and support costs may also increase beyond what the systems in question require now, putting pressure on the Company's non-capital spend in the years after implementation.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KELLY A. HOLMES

DTE ELECTRIC COMPANY
QUALIFICATIONS OF KELLY A. HOMES

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Q. What is your name, business address and by whom are you employed?

A. My name is Kelly A. Holmes. My business address is One Energy Plaza, Detroit, MI 48226-1221. I am employed by DTE Energy Corporate Services LLC within Regulatory Affairs as Principal Financial Analyst – Regulatory Economics.

Q. Who are you testifying on behalf of?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background and business experience?

A. I received a Bachelor of Business Administration with an emphasis on accounting from the University of Michigan Business School in 1997. From 1997 until 2001, I was employed by Plante Moran LLP as a financial auditor. While employed at Plante Moran, I passed the Certified Public Accountant (C.P.A) examination in 1997 and became a licensed C.P.A in 1999 upon satisfying the work experience requirement. I had several positions of increasing responsibility, ultimately serving as the Senior Auditor on client engagements. In this role, I was responsible for tailoring each audit based on a client's industry and the risks inherent in their operations, supervising the audit fieldwork, and communicating the audit issues and results with client management.

In 2001, I joined Kmart Corporation as a Senior Operations Auditor. My responsibilities included planning and performing operational audits within various departments of Kmart, and making recommendations to improve Kmart's efficiency and reduce costs.

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In 2002, I joined DTE Electric as a Financial Accountant within the Controller's Organization. My responsibilities included accounting, budgeting and reporting for electric revenues as part of the Gross Margin Analysis group. In 2003, I was promoted to Senior Financial Analyst within Gross Margin, and my responsibilities expanded to include detailed financial modeling of the electric revenue to analyze the impact of regulatory and pricing changes, as well as forecasting related to DTE Electric's Power Supply Cost Recovery Clause. I was also involved in preparing supporting schedules and exhibits for Case No. U-14838 and Case No. U-15244. In December 2008, I accepted my current position as a Principal Financial Analyst in Regulatory Affairs Pricing and Rate Design. My current responsibilities include the development of customer rates and the development, application and administration of the Company's tariffs, rules and regulations.

Q. Have you testified previously before the Michigan Public Service Commission (Commission or MPSC)?

A. I have sponsored testimony in the following cases:

U-15806-EO	2009 Energy Optimization Plan
U-15890-EO-A	Amended Energy Optimization Plan
U-15677-R	2009 PSCR Reconciliation
U-16047-R	2010 PSCR Reconciliation
U-16246	2009 Restoration Expense Tracking Mechanism
U-16263	RARS Reconciliation
U-16358	2009 EO Reconciliation
U-16472	DECo General Rate Case
U-16578	2010 Restoration Expense Tracking Mechanism

U-16671	2011 Amended Energy Optimization Plan
U-16780	Revenue Decoupling Mechanism Reconciliation
U-16813	Choice Implementation Surcharge Reconciliation
U-16434-R	2011 PSCR Reconciliation
U-16956	2011 Restoration Expense Tracking Mechanism
U-17049	Amended Energy Optimization Plan
U-17146	Low Income and Energy Efficiency Fund/Vulnerable Household Warmth Fund Reconciliation
U-16892-R	2012 PSCR Reconciliation
U-17097-R	2013 PSCR Reconciliation
U-17319-R	2014 PSCR Reconciliation
U-17680	2015 PSCR Reconciliation
U-17689	DTE Electric Public Act 169 of 2014 Filing
U-17762	2016 Energy Optimization Plan
U-17767	DTE Electric General Rate Case
U-17920-R	2016 PSCR Reconciliation
U-18014	DTE Electric General Rate Case
U-18248	DTE Electric Section 6w of 2018 PA 341 Filing
U-18255	DTE Electric General Rate Case
U-18344	DTE Electric U-18014 Self-Implementation Refund
U-20069	2017 PSCR Reconciliation

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the development of the proposed rate design for the commercial secondary tariff offerings, incorporating the following:

- Revised customer charges designed to recover a greater portion of the fixed costs of serving these customers. The proposed customer charge for Rate Schedules D3, D3.2, D3.3, D4 and R8 is $15 per month.
- Power supply rates designed to include a capacity charge, pursuant to the requirements on 2016 PA 341 and consistent with the methodology approved in Case No. U-18248 and Case No. U-18255.
- Distribution rates designed to approach a uniform rate for all commercial secondary tariff offerings.
- I am also supporting the calculation of power supply costs for the Company's projected test period in this case. This includes the projected base transmission expense, and base fuel and purchased power expense necessary for the sales forecast.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring in whole, or in part, the following exhibits:

Exhibit	Schedule	Description
A-13	C4	Calculation of Power Supply Expenses
A-13	C5.14	Test Period Operation and Maintenance Expense – Power Supply Related Expenses
A-16	F3	Present and Proposed Revenues by Rate Schedule – 12 months ending April 30, 2020

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A-16	F4	Comparison of Present and Proposed Monthly Bills– 12 months ending April 30, 2020
A-16	F10	Proposed Tariff Sheets

Within Exhibit A-16, Schedule F3, I am sponsoring the pages specific to the commercial secondary customer class. This includes pages 13 through 25. On Exhibit A-16, Schedule F4, I am sponsoring the typical monthly bills comparison for the commercial secondary customer class, on pages 21 through 28. In both of these exhibits, Company Witness Mr. Bloch is sponsoring the pages related to primary customer classes, Company Witness Mr. Dennis is sponsoring the pages for the residential classes, and Company Witness Mr. Johnston is sponsoring the pages for the municipal, residential and commercial outdoor lighting classes. On Exhibit A-16, Schedule F10, I am sponsoring all of the commercial secondary tariffs, while Witnesses Bloch, Dennis and Johnston sponsor the tariffs for the remaining customer classes.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Fuel and Purchased Power

Q. Is DTE Electric proposing to re-set the base power supply cost in this proceeding?

A. No, the Company is not proposing to re-set the base power supply costs. The current Power Supply Cost Recovery (PSCR) base amount was established by the Commission in its Order in Case No. U-15244. The Company is proposing to continue using the 31.26 mills/kWh base and the loss factor of 6.8%, for a total base amount of 33.39 mills/kWh. Since the PSCR revenues and expenses are reconciled on an annual basis, and the maximum PSCR factor for 2018 in DTE Electric's recently filed 2018 PSCR Plan case (U-18403) is a credit of (0.087) cents/kWh, the Company does not believe it is necessary to reset the base at this time.

Q. Have you projected any under or over recovery of power supply costs in this proceeding?

A. No. For the purpose of this case, the power supply costs equal the associated power supply revenues so there is no projected under or over recovery. Any actual under or over recovery of power supply costs are reconciled annually in the PSCR reconciliation filings. For purposes of this filing, Witness Bloch, Witness Dennis, Witness Johnston and I have calculated both present revenues using the existing base rates approved by the Commission on April 27, 2018 in Case No. U-18255. These rates include the PSCR base of 33.39 mills/kWh, and we have used a zero PSCR factor to calculate revenues for the projected period.

Q. Has the Commission, in previous DTE Electric rate case orders, approved this approach?

A. Yes. In all of the Company's general rate case proceedings that have been ruled on since the current PSCR base was established, (Case Nos. U-15768, U-16472, U-17767, U-18014 and U-18255), the Commission has agreed with the Company's use of the existing PSCR base of 33.39 mills and a zero PSCR factor in calculating the power supply costs.

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Q. Will you please describe Exhibit A-13, Schedule C4?

A. This schedule calculates the power supply expense for the test period. As stated earlier, the power supply costs and revenues are equivalent in this filing, so the projected costs are a function of the current PSCR base shown on line 3 and the projected power supply sales volumes on line 5. The transmission expense on line 7 is the amount included in the current base, as originally approved in Case No. U-15244. The power supply costs as attributable to specific Rider 10 and Rider 3 sales, which are not subject to the PSCR, are shown on lines 20 and 21. The total expense for the test period including transmission is $1,386 million, as shown on line 28. Line 31 through line 37 show the split of the total power supply expense between capacity and non-capacity, based on the PA295 and PURPA related generation costs, capacity purchases and the net energy market sales supported by Company Witness Mr. Arnold.

Q. Will you please describe Exhibit A-13, Schedule C-5.14?

A. This schedule details the historical test period power supply expense with the projected test period power supply expense. Column (c) reflects the actual costs booked to the various MPSC accounts associated with power supply expenses for the 12-month period ended December 31, 2017 as supported by Company Witness Ms. Uzenski. Column (g) is the projected power supply expense for the projected test period, 12 months ending April 30, 2020, as calculated on Exhibit A-13, Schedule C4. This amount was provided to Witness Uzenski for use on her Exhibit A-13, Schedule C1.1.

Line No.

Commercial Secondary Customer Rate Design

Q. Can you please provide a brief description for each of the Company's commercial secondary customer rate schedules?

A. Yes, the following descriptions are in the order of the corresponding pages I sponsor within Exhibit A-16, Schedule F3 (pages 13 through 25). Rate Schedule D1.1 is a separately metered interruptible space conditioning service rate. Rate Schedule D1.7 is a separately metered rate available for supplemental geothermal electric service with rates dependent on season and time of day. Rate Schedule D1.8 is a dynamic peak pricing product with three time of day pricing periods. Rate Schedule D1.9 is a separately metered product for service to charge electric vehicles. Rate Schedule D3 is our general service rate for non-residential customers that typically have loads less than 3,000 kWh per month. Rate Schedule D3.1 is an unmetered general service rate available to customers for loads which are impractical to meter. Rate Schedule D3.2 is a secondary educational rate available for school, college, or university customer locations. Rate Schedule D3.3 is available to customers desiring interruptible service. Rate Schedule D4 is the Company's large general service rate and includes a demand charge. Rate Schedule D5 is an interruptible electric water heating rate available to commercial customers based on certain size criteria. Rate Schedule E1.1 is for any metered energy provided to municipality-owned streetlights. Rate Schedule Rider 7 is available to customers with high intensity lighting requirements, such as greenhouses. Finally, Rate Schedule Rider 8 is available to customers with total electric commercial space conditioning needs.

Line
No.

Q. Will you please describe Exhibit A-16, Schedule F3?

A. This exhibit shows the present and proposed rate design and corresponding revenues by rate schedule, based on the billing determinants for the 12 months ending April 30, 2020. The exhibit details the forecasted billing determinants, as well as the resulting present and proposed rates and corresponding revenues. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The forecasted billing determinants were developed based on historical data and relationships, as well as known and measurable changes, and are consistent with Company Witness Mr. Leuker's sales forecast. The existing rates, as approved by the MPSC's Order issued in Case No. U-18255 on April 27, 2018, are in column (c), and are used to calculate the present revenues in column (d). The rates proposed in this proceeding are in column (e), with the resulting revenues in column (f).

Q. What is the basis for the Company's proposed commercial secondary rates in this proceeding?

A. The basis for the proposed rate levels are the functionalized power supply and distribution deficiency amounts supported by Company Witness Mr. Lacey as shown in his Exhibit A-16, Schedule F1.1, page 2 (for power supply) and his Exhibit A-16, Schedule F1.2, page 1 (for distribution). The proposed commercial secondary power supply and distribution charges were designed to meet the respective deficiencies shown in these exhibits. The proposed power supply capacity and non-capacity rates were designed to recover the revenues pursuant to Witness Lacey's Exhibit A-16 Schedule F1.5, which shows how much of the power supply revenue requirement for each rate class is capacity and non-capacity related.

Q. How are the power supply revenue targets allocated in your rate design?

A. I followed the same methodology utilized in Case No. U-18255 to allocate both the capacity and non-capacity power supply revenue requirements to the individual tariffs within the secondary class. In his cost of service, Witness Lacey identifies three separate cost classes: one specific to Rate Schedule D3.2, one specific to Rate Schedule D4, and one to capture Rate Schedule D3 and all remaining classes. The revenue requirements for D3.2 and D4 are assigned directly to the respective class. The revenue requirement for the D3 and other subgroup is further allocated based on each tariff's percentage contribution to the total present power supply revenue for that same subgroup.

Applying this methodology consistently ensures that any specific rate schedule is allocated the same share of capacity costs as non-capacity costs.

Q. How were the commercial secondary energy rates determined?

A. With the exception of rate schedule D4, all of the commercial secondary power supply rates are energy based. After allocating the revenue targets to each individual rate schedule as discussed earlier, I divided the capacity and non-capacity targets for each rate schedule by the associated power supply sales to determine the capacity and non-capacity energy rates, respectively. The rate structure for schedule D4 has a capacity power supply demand charge which is set a level to recover the full capacity revenue requirement, consistent with the methodology approved in U-18248 and U-18255. The non-capacity revenue for D4 is collected through a non-capacity demand charge, and two separate energy charges, dependent on the total hours used. I have designed these rates so that the relationship between total demand revenue and energy based revenue is consistent. The existing differential between the D4 energy rates has been maintained.

Q. Are you proposing any new changes related to commercial secondary service charges?

A. Yes, for commercial secondary rate schedules which are not for supplemental electric service: D1.8, D3, D3.2, D3.3, D4, and R8 separately metered, the Company is proposing a service charge of $15 per customer, per month. A $15 service charge better reflects that some costs are incurred regardless of the amount of kilowatt-hours a customer uses. The supporting cost study is sponsored by Witness Lacey on Exhibit A-16, Schedule F1.4, page 1. Witness Lacey's testimony and cost study supports commercial customer-related costs of approximately $175 per customer per month, but the Company is proposing a $15 service charge in this case. By adjusting the service charge to $15 from $11.25 for D1.8, D3, D3.2, D3.3 and R8, and from $13.67 for D4, more of the delivery costs will be recovered through the service charge and less will be recovered through the variable distribution charges when compared to the current state. Even with this revision, the fixed portion of a customer's bill will be less than 10% of the total bill, as demonstrated on the following table for various consumption levels of a D3 bill:

1600 kWh per month customer					3200 kWh per month customer				
	Current		Proposed			Current		Proposed	
Determinant	Rate	Bill	Rate	Bill	Determinant	Rate	Bill	Rate	Bill
Power Supply (total rate)					**Power Supply (total rate)**				
1600	$0.07992	$127.87	$0.08349	$133.59	3200	$0.07992	$255.74	$0.08349	$267.14
Delivery					**Delivery**				
1	$11.25	$11.25	$15.00	$15.00	1	$11.25	$11.25	$15.00	$15.00
1600	$0.03865	$61.84	$0.03815	$62.10	3200	$0.03865	$123.68	$0.03815	$124.21
Total		**$200.96**		**$210.69**	**Total**		**$390.67**		**$406.38**
	Amount on Bill	**% of Bill**	**Amount on Bill**	**% of Bill**		**Amount on Bill**	**% of Bill**	**Amount on Bill**	**% of Bill**
"Fixed"	$11.25	5.6%	$15.00	7.2%	"Fixed"	$11.25	2.9%	$15.00	3.7%
"Variable"	$189.71	94.4%	$195.69	92.8%	"Variable"	$379.42	97.1%	$389.23	96.3%

The table shows that for a 1,600 kWh per month customer, the Company's proposal to adjust the service charge from $11.25 to $15.00 increases the proportion of the bill due to the fixed service charge from 5.6% to 7.2% meaning that variable kWh charges continue to account for more than 90% of the customer's bill. The table shows for a 3,200 kWh per month customer, the Company's proposal to adjust the service charge from $11.25 to $15.00 increases the proportion of the bill due to the fixed service charge from 2.9% to 3.7% meaning that more than 95% of the customer's bill is still driven by variable kWh charges. For larger commercial customers, the impact is even smaller. In summary, the table above shows that while the portion of the bill attributable to fixed charges increases under the Company's proposal, the customer's bill is still significantly driven by variable charges versus fixed charges, even with the proposed $15.00 service charge. When considering whether or not a $15.00 service charge will significantly impact customer behavior and energy efficiency decisions, it is important to consider the relatively small portion of a customer's bill that would be due to fixed charges versus variable charges.

Q. If Witness Lacey is supporting a customer charge for commercial secondary customers in excess of $175, why is the Company only proposing $15?

A. A lower charge is being proposed at this time to reduce the immediate impact on customers, and in the interest of gradualism.

Q. Is the manner in which revenue deficiency/sufficiency for distribution presented on Witness Lacey's Cost of Service exhibits the same in this case as it was in Case No. U-18255?

A. Yes. In this case, as discussed by Witness Lacey, customer classes for distribution are defined, and the associated costs are allocated on the basis of the voltage level under which customers are served. This method of allocating distribution costs was first used in Case No. U-17689, which the Company filed to comply with Public Act 169 of 2014, and has been used consistently since that time. For non-residential customers who are served under secondary voltage, Witness Lacey provides one distribution revenue deficiency target which accounts for all tariffs within this class.

Q. How does Witness Lacey's revenue deficiency/sufficiency for distribution presented in this case impact your rate design?

A. My rate design in this case is consistent with the rate design methodology used by the MPSC Staff to calculate rates which were approved by the Commission in both Case Nos. U-18014 and U-18255. The Company and MPSC Staff have maintained the position in Case Nos. U-17689, U-17767, U-18014 and U-18255 that if the customers are alike enough to be classified together, their distribution rates should also be alike to the extent possible. However, implementing a uniform distribution rate within the commercial secondary class in any specific case would have resulted in an unreasonable increase to some individual rate schedules. In an effort to move toward an equal distribution rate for commercial secondary customers, while recognizing that it needed to be done gradually, in the aforementioned cases the individual distribution rate increases were capped at 20%. In the current proceeding I am proposing to continue the gradual move towards a uniform rate within the class, however I have designed the distribution rates by capping the increase to individual distribution rate schedules at 10%, which is more reasonable than imposing a 20% rate increase on select rate schedules while the overall class is experiencing a moderate distribution increase.

Q. Will you please describe Exhibit A-16, Schedule F4?

A. This exhibit shows a comparison of typical monthly bills by rate schedule based on present and proposed rates. For each rate schedule, the exhibit calculates the amount of a bill under existing rates and proposed rates across a broad range of energy consumption levels. The difference is representative of the impact of my proposed rate changes.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TAMARA D. JOHNSON

DTE ELECTRIC COMPANY
QUALIFICATIONS OF TAMARA D. JOHNSON

Line
No.

Q. Please state your name and business address.

A. My name is Tamara D. Johnson. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy LLC, as Director, Revenue Management and Protection.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (Company or DTE Electric).

Q. What is your educational background?

A. I earned an undergraduate degree in business administration from Detroit College of Business, with focuses on accounting and finance, and a MBA, with a focus on global management, from University Of Phoenix.

Q. What is your previous work experience?

A. I have worked at DTE Energy since 2003, progressing in leadership assignments in Corporate Services, Controllers Organization and Customer Service & Marketing. I have served as Manager of Business Performance for DTE Gas, where my responsibilities included long term planning, various strategic initiatives, regulatory support, and management reporting. I was also the 2011 Continuous Improvement Maturity Model self-assessment lead. I have also held a series of strategic and tactical leadership roles throughout Customer Service & Marketing.

Q. What is your current position and what are your current responsibilities?

A. On October 30, 2017, I became the director of Revenue Management and Protection (RM&P) group for DTE. I am responsible for the overall direction, strategy, leadership and management of collections, theft mitigation and low-income programs for DTE. The RM&P group is responsible for driving reduced uncollectible expense for DTE Electric and DTE Gas as well as optimizing the Energy Assistance funding for the low-income customers. As a member of the Customer Service senior leadership team, I am familiar with and can provide insight to activities within Customer Service outside of RM&P. I am updated weekly on operational performance measures for all of Customer Service along with regular updates on financial performance and strategic plans to improve all areas of the Customer Service business.

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the details of the Company's actual $139.4 million Customer Service Operation and Maintenance (O&M) expenses for the 12-months ended December 31, 2017, and provide explanation and support of the projected $149.0 million O&M expenses for the 12-month projected test period ending April 30, 2020 inclusive of $51.6 million of uncollectible expense. I will provide details for the historical costs, discuss the inflationary impact on forecasted costs, provide an update on our level of uncollectible expense, support proposed changes to merchant fees, discuss Customer Service performance and areas of improvement, discuss the Company's Low Income initiative, Customer 360 (C360) Project costs and propose changes to the DTE Electric Company Rate Book. I also discuss the impacts of restructuring residential rate D1 to a time of use rate.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-13	C5.7	Projected Operation and Maintenance Expenses – Customer Service and Uncollectibles
A-13	C5.12	Customer 360 Project Costs and Post-Implementation Phase

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Line No.

Q. What work does the Customer Service group perform for DTE Electric?

A. Customer Service is responsible for managing the customer support processes for both DTE Electric and DTE Gas. Customer Service is comprised of several organizations responsible for conducting the work associated with billing, customer contact and payment acceptance.

Q. Which organizations comprise Customer Service?

A. The organizations comprising Customer Service are: Customer Care, Customer Billing, Revenue Management and Protection (RM&P), and Customer Experience. The Customer Service organization supports both DTE Electric Full Service and Electric Choice Service customers.

Customer Care manages requests for new service, responds to inquiries regarding account information, schedules work requests from customers, and responds to emergency and trouble calls.

Customer Billing is responsible for meter reading, residential and commercial billing, major accounts billing, bill issue resolution, and account establishment.

RM&P manages credit policies, administers low income programs (including energy assistance education) and oversees accounts receivable collection. RM&P provides customers with bill payment options, conducts service disconnections due to non-payment and provides low income case management assistance. RM&P is also responsible for theft investigation, remediation, and determining accountability for unauthorized usage.

Line No.

Customer Experience is responsible for developing new technologies for customers to interact with the Company through self-service channels such as the Internet and mobile applications. These self-service interactions include electronic billing, payment, outage reporting & status updates and others.

Q. How are costs allocated between DTE Electric and DTE Gas for Customer Service?

A. Customer Service costs are allocated based on utility specific data that is representative of the amount of electric or gas related work conducted within the organization. The allocations for the current year are based on actual activity data from the previous year.

Customer Care allocates costs based on the number of electric and gas customers. For 2017, 66.00% of the Customer Care expense was allocated to DTE Electric. For a customer who is an electric and a gas customer, that customer is counted as one-half electric and one-half gas.

Customer Billing expense is allocated between DTE Electric and DTE Gas via two cost allocation drivers. The number of non-AMI gas and electric meters is used to allocate meter reading costs, and the number of customers determines the allocation of costs for billing. For 2017, 41.13% of the Customer Meter Reading expense was allocated to DTE Electric. In addition, for 2017 66.00% of Customer Billing expense was allocated to DTE Electric.

Expenses for Customer Service and Customer Experience are allocated based on the number of customers. For 2017, 66.00% of expenses related to Customer Service and Customer Experience was allocated to DTE Electric.

RM&P allocates costs based on the number of accounts in arrears. For 2017, 64.17% of RM&P expense was allocated to DTE Electric.

O&M EXPENSES

Historical Test Year

Q. What was the total O&M cost related to Customer Service for the 2017 historical test year?

A. The total Operating and Maintenance cost related to Customer Service for the 2017 historical test year was $139.4 million. A detailed breakdown of the 2017 historical test year actual O&M expense adjusted by rate case eliminations, normalization adjustments, inflation and other known and measurable adjustments is provided in Exhibit A-13, Schedule C 5.7.

Q. What expenses are included in the $139.4 million 2017 total O&M costs?

A. There are three major components that make up the $139.4 million O&M expense:

- Customer Accounts Expenses ($69.6 million)
- Customer Service and Informational Expenses ($24.5 million)
- Uncollectible Expenses ($51.6 million)

My exhibit also reflects the Marketing Reclassification ($6.2 million).

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Q. What is the $6.2 million in Marketing Reclassification?

A. The $6.2 million represents Regulated Marketing O&M expense reflected in Accounts 907 and 908 on Exhibit A-13, Schedule C5.8 and supported by Company Witness Mr. Clinton.

Customer Accounts Expenses

Q. What are the primary costs included in the Customer Accounts Expenses category totaling $69.5 million?

A. The Customer Accounts Expenses category is primarily driven by costs associated with Customer Records and Collection Expenses ($55.5 million), Customer Records and Collection - Merchant Fees ($8.1 million), and Meter Reading Expenses ($3.4 million).

Q. Which activities comprise the $3.4 million in Meter Reading Expenses?

A. In 2017, the Company used external vendors to manually read meters that were not converted to AMI meters and AMI opt out meters. Other activities include billing operations pertaining to major accounts, metering operations, consecutive estimate team and special reading expenses.

Q. Which types of expense are included in the $55.5 million in Customer Records and Collection Expenses?

A. There are four major components that make up the $55.5 million:

- Customer Care ($25.2 million)
- Revenue Management & Protection (RM&P) ($15.4 million)
- Metering and Billing ($12.4 million)

Line
No.

- Customer Experience ($2.5 million)

Q. What costs comprise the $25.2 million in the Customer Care organization?

A. 80% of the costs within the Customer Care organization are related to handling phone calls by internal call representatives and their direct floor support and the Company's external vendor. In 2017, the Customer Care organization handled just under six million customer phone calls. The Company utilizes internal call representatives, contracted call representatives and external vendors to handle these phone calls. The Company handled three million calls internally, costing the Company $14.2 million. The external vendor handled approximately three million calls, costing the Company $5.9 million. The remaining costs are made up of support staff within the Customer Care organization that handle call routing for both internal and external calls, call quality analysis for external vendor and the telecom costs associated with the Company's toll free number.

Q. Why is the Company's cost of handling three million calls more than twice the expense of the external vendor handling approximately three million calls?

A. The Company's Contact Center handles complex calls that require in depth analysis and resources that are not available at the external vendor. The external vender handles the less complex calls.

Q. What makes up the $15.4 million RM&P Customer Records and Collection Expenses?

A. There are five major components that make up the $15.4 million:

- Internal & External Collections $3.0 million

- Field Operations $4.2 million
- Exceptions $3.7 million
- Advocacy & Customer Offices $3.3 million
- Strategy & Reporting and RM&P Staff $1.2 million

Q. Which activities make up the $3.0 million Internal and External Collections expense?

A. Internal and External Collections group uses external collection agencies to perform collection on outstanding arrears to reduce uncollectible expense. Effective use of this partnership allows us to mitigate the impact of uncollectible expense related to customers who have been disconnected.

Q. What makes up the $4.2 million expense within RM&P's Field Operations group?

A. Field Operations spends $3.1 million in labor to perform theft investigations and non-pay manual disconnects and $0.5 million in outside services primarily for pole cut disconnects, manual disconnects and theft detection completed by external vendors. Effective management of energy theft improves community safety and minimizes revenue loss. The remainder of the $0.6 million in costs include pole cuts and theft detection software costs.

Q. What costs are included in the $3.7 million RM&P Exceptions expense?

A. In 2017, the RM&P Exceptions group worked to identify and resolve fraud cases, work bankruptcy cases and billed unauthorized usage of over $2.7 million to parties responsible for energy theft. Fraud Prevention services are used to verify customer identity information and research perpetrators of fraud. Preventing and resolving theft and identifying fraud helps minimize uncollectible expense and protects the integrity of our customer's data.

Q. What activities comprise the Advocacy and Customer Offices team within the RM&P organization and the associated costs of $3.3 million?

A. The Advocacy team focuses vulnerable customers, including supporting our Low-Income Self-Sufficiency Plan (LSP) customers and working with our partner agencies. The team handled over 100,000 calls, completed just under 50,000 low income validations and approximately 6,000 medical cases. The Advocacy team provided assistance to 40,000 LSP customers.

The Customer Offices cost of $1.0 million is primarily labor costs of nearly $0.6 million for employees staffing the office locations. The remaining costs contained with the Customer Offices were for security and pay agent fees for stores that accept DTE payments. Employees at office locations help customers understand their bills, resolve customer concerns, direct low income customers to energy assistance resources, and the office locations also house payment kiosks to allow customers to pay their bills.

Q. What costs comprise the $12.4 million for bill printing, billing creation and bill mailing?

A. The Company paid $5.9 million for postage costs related to invoices and other customer communications. The total number of customer statements that were generated and mailed in 2017 were 24 million. In 2017, the Company spent $4.9

million on internal and contractor labor costs associated with bill printing, billing major accounts, resolving billing concerns for residential and commercial customers, and resolving meter discrepancies. The remaining $1.6 million is primarily vendor related costs for general office supplies and printer maintenance.

Customer Service and Informational Expenses

Q. What are the primary components of the Customer Service and Informational Expenses category totaling $24.5 million?

A. The Customer Service and Informational Expenses category is primarily made up of activities related to Customer Assistance, $14.5 million, and Miscellaneous Customer Service and Informational Expenses of $8.9 million. The remaining $1.0 million is related to staff group costs.

Q. What are the primary activities that comprise the $14.5 million in Customer Assistance Expenses?

A. There are three major components that make up the $14.5 million:

- Customer Service Groups $6.2 million
- Distribution Operations $0.7 million
- Public Affairs $0.6 million

The $14.5 million includes Marketing costs before the reclassification of $6.2 million to Exhibit A-13, Schedule C5.8.

Q. What activities comprise the $6.2 million Customer Service Group costs within Customer Assistance Expenses?

A. The $6.2 million is made up of costs for the Company's portion of the Customer

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Service organization that drives strategy and continuous improvement including system enhancements and process improvements to improve the customer experience.

Q. What activities comprise the $0.7 million Distribution Operations costs within Customer Assistance Expenses?

A. The $0.7 million is made up of costs associated with the Electric Choice customer support team. The team is comprised of a contact center and billing analysts.

Q. What activities comprise the $0.6 million Public Affairs costs within Customer Assistance Expenses?

A. Public Affairs provides low income customers in the community a forum to learn more about and/or receive various types of energy assistance offered through DTE Energy. Participants may sign up for Home Energy Consultations and Energy Waste Reduction assistance. They may also join the Low Income Self Sufficiency Program or receive emergency relief assistance. Our community partners provide facilities, volunteers, transportation, and other resources to achieve this outreach to customers living in challenged circumstances.

Q. What costs are included in Uncollectible accounts?

A. The account reflects the uncollectible expense the Company incurs. I will discuss uncollectible expense in more detail below.

Q. Were any adjustments made to the historical test period amount?

A. Yes. In column (f), an adjustment was made for C360 Post-Implementation Costs

Line No.

for $11.0 million and a normalization adjustment was made to actual uncollectible expense for $759,000. The C360 Post-Implementation Costs adjustment is calculated on pages 1 and 2 of Exhibit A-13, Schedule C5.12. The 2017 uncollectible expense normalizing adjustment is calculated on page 2 of Exhibit A-13, Schedule C5.7. Both are discussed in more detail below.

Projected Test Period

Q. What is the total amount of Customer Service O&M that DTE Electric is asking to recover in rates for the projected test period?

A. DTE Electric is asking to recover $149.0 million in Customer Service O&M inclusive of uncollectible expense in the projected test year. Exhibit A-13 Schedule C5.7 provides a detailed breakdown of the projected test year O&M expenses that the Company is requesting in this case.

Q. What costs are included in the $149.0 million of O&M expense?

A. In addition to including the 2017 costs described in my testimony above, the Company has included the following changes: 1) inflation adjustments in 2018 for $2.35 million, 2019 for $2.34 million and January 2020 through April 2020 for $830,000 totaling $5.5 million, 2) C360 Regulatory Asset Amortization of $1.4 million and 3) a known and measurable adjustment for merchant fees of $2.6 million.

Q. How did you calculate the $5.5 million for inflation?

A. Projected inflation for 2018, 2019 and 2020 O&M expenses was derived by applying the inflation factors to the adjusted historical test period amounts (column (g)) The assumptions used for the calculating the effect of inflation on labor and services (columns (h) through (j)) were the labor and material inflation adjustment factors of 3.0% for 2018, 2.9% for 2019, and 1.0% for the first 4 months of 2020 as supported by Witness Uzenski.

Q. What is the projected adjustment increase of $1.4 million for C360?

A. This amount represents the increase in C360 regulatory asset amortization from $1.4 million historical expense to $2.8 million projected expense sponsored by Witness Uzenski on Exhibit A-13, Schedule C5.13.

Q. Which activities comprise the 2017 C360 Post-Implementation Project Costs?

A. As shown on Exhibit A-13, Schedule C5.12, a total of $16.6 million was spent in 2017 on post go-live efforts. DTE Electric was charged 66% of the total cost ($11.0 million). The post-implementation costs included additional staffing to handle increased call volumes, system defect remediation, and addressing billing exceptions. More specifically, the Company partnered with Accenture and established a Command Center to:

- Help manage stabilization activities in the post go live period
- Increase the number of Call Center Contractors
- Establish resolution to customer issues through an enhanced exception management process

Q. What were the results of call volume after the C360 Post-Implementation activities were established?

A. During the timeframe of April 1, 2017 through September 30, 2017, the call volume was 3.2 million calls. From the timeframe of October 1, 2017 through March 31, 2018, the call volume was 2.7 million calls. Call volume decreased by 500,000. Therefore, the post go-live costs of $11 million have been removed to normalize 2017 expense.

Q. Why are you proposing a $2.6 million increase for O&M related to merchant fees?

A. The Company has been seeing a steady increase in fees paid to process credit card payments ("merchant fees") over the past five years. Merchant fees on consumer credit cards have grown by a compound annual growth rate of approximately 10% over the one, three and five year historical periods. The Company is therefore proposing a $0.9 million known and measurable increase in residential merchant fees. As far as the non-residential customers the number of non-residential customers using credit cards, and the cost per transaction have grown exponentially over the past five years. Aggressive marketing campaigns and incentive programs by banks and credit card companies have targeted non-residential customers by incentivizing them with cash back rewards when using credit cards. Thus, the Company has experienced a year-over-year increase of 90% and a five-year compound annual growth rate of 60% in merchant fees for corporate credit cards. The Company is therefore proposing a $1.8 million increase in non-residential merchant fees and proposing changing who can pay by credit card.

Q. Under the Company's proposal who will be able to pay by credit card?

A. Residential customers on residential rates, such as D1, D1.1-1.2, D1.6-1.9, D2 and D5, and smaller Commercial and Industrial customers such as, all D3 including choice, D4 and D5 will be able to pay by credit card. Larger Commercial and

Industrial customers on rate schedules D6.2, D8, D11, and Secondary choice customers will not be able to pay by credit card.

Q. Is the Company proposing any changes for non-residential customers who make payments through methods other than credit card?

A. No. Non-residential customers will still be able to make payments directly to DTE Electric via check, ACH debit, wire transfer and debit card. The costs for processing customer payments through these methods will continue to be included in the Company's O&M expense.

Q. How much is included in the Projected Test Period for merchant fees?

A. The expenses for merchant fees for residential ($5.8 million) and non-residential ($5.0 million) customers in the Projected Test Period equals $10.8 million. The separate amounts are shown on Exhibit A-13, Schedule C5.7 in column (m), lines 6 and 7.

<u>Uncollectible Expense</u>

Q. What is Uncollectible Expense?

A. Uncollectible expense is the income statement impact of the portion of accounts receivable that is considered uncollectible.

Q. How is uncollectible expense determined for each utility?

A. Uncollectible expense is determined by a review of individual arrearage accounts for each utility and recorded separately based on actual uncollectible performance.

Q. How does DTE Electric determine the accounts receivable (AR) reserve for uncollectible accounts?

A. DTE Electric's AR reserve is calculated by applying reserve factors to aged receivables. Customer accounts receivable are classified in 30-day increments (arrears buckets) and a reserve factor is applied to each 30-day increment. The sum of these reserve values represents the total AR reserve.

The reserve factors are recalculated monthly using a rolling average of the ratio of historical write-offs to historical arrears within each arrears bucket (30, 60, 90, etc.). A 12-month rolling average is utilized for residential and small commercial accounts and a 60-month rolling average is utilized for large commercial and industrial accounts.

Q. How does the Company account for uncollectible expense?

A. Uncollectible expense is recorded in the income statement to reflect the change in the AR reserve. This is calculated as the increase/decrease in the AR reserve, plus accounts that were written-off that month, minus accounts that were recovered (on previously written off accounts) that month, plus any DTE Electric matches of low-income funding received.

Q. What are the Company's write-off procedures?

A. Routine customer accounts are generally written off once they age to 150 days past the final bill due date, which is issued after service is disconnected. Often, however, there are circumstances that warrant keeping the account on the books until a resolution is obtained – for example, customers with payment arrangements, disputes, etc. Once an account is written off, any payments received on that account are recognized as a recovery. The write-off period of 150 days past the final billing is generally defined as the latest of either the last effective closed agreement date or the last bill due date.

Q. How is uncollectible expense calculated in this case?

A. In this case the Company is utilizing a three-year average based on actual uncollectible expense for 2015 through 2017 resulting in $51.6 million of uncollectible expense. This amount is calculated on page 2 of Exhibit A-13, Schedule C5.7 and shown on line 22 of page 1 of that same exhibit. The $51.6 million projected amount reflects our planned efforts to sustain our results despite continuing economic challenges for many of our customers.

Q. What factors have impacted uncollectible expense for the historic three-year average period ended 2017?

A. DTE Electric uncollectible expenses are driven by economic challenges throughout the service territory, weather conditions, and changes in federal funding which includes the Low Income Home Energy Assistance Program funding (LIHEAP). The uncollectible expense as a percentage of revenue average for 2015- 2017 is 1%.

Q. What has DTE Electric done to maintain control of its uncollectible expense?

A. The Company has taken several proactive steps to control the level of uncollectible expense. DTE Electric continues to diligently ensure adherence to the MPSC Billing Practice Rules with respect to payment arrangements and deposits. Recently, community outreach has increased- significantly providing further energy assistance program support and awareness to customers unable to pay their energy bills. For those customers that do not pay, collection action up to and including disconnect, is conducted in accordance with the Billing Practice rules.

This year, the Company will invest almost a million dollars to enhance the ability to detect fraud for a service turn-on request. Currently, TransUnion provides financial questions to prevent service from being turned on fraudulently. Correctly answering the financial questions is not foolproof. The customer validation enhancements will provide additional measures to detect fraud and reduce uncollectible expense. The results from this new process will be realized in 2019.

DTE Electric reduced the amount of time between when a customer falls into arrears and the issuance of a shut-off notice, in compliance with the MPSC Billing Practice Rules; thereby reducing the customer's balance at the time of noticing. A shut-off notice is often the first time many customers look for assistance. Also, prior to the 2014 fiscal year, many agencies required a shut-off notice before they provided assistance. The earlier a customer seeks assistance, the lower the balance of arrears and the greater likelihood the customer will be able to meet an energy assistance provider's (i.e. The Heating And Warmth Fund (THAW), Department of Health and Human Services (DHHS), Salvation Army, etc.) cap limit. This will result in the customer being more likely to be approved for funding and as a result, the customer avoids disconnection of service.

The Company has also initiated several efforts to improve collection effectiveness. These efforts include:

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- Seeking out proactive ways to help customers meet their utility needs through innovations like the Low-Income Self-Sufficiency Plan (LSP) program
- Improving customer payment behavior through adherence to the MPSC billing practice rules as it relates to turn-ons
- Refine use of specialty collection agencies
- Enhance the use of data and predictive analytics as part of our collections strategy
- Development of a prepay program
- Working at the State and Federal levels for increased low-income funding and to promote improved efficiency of the distribution of low-income funds
- Working with State and community agencies to promote energy efficiency and conservation with its customers, focusing primarily on low income customers.

Q. Does the Company have an uncollectible expense initiative that would require changes to the DTE Electric Company Rate Book?

A. Yes. The initiative will focus on customers who pay with insufficient funds which add to uncollectible expense.

Q. Specifically, what is the Company proposing relative to customers that pay with insufficient funds?

A. The Company is proposing to use third-party vendors who can recover insufficient fund payments. The Company is also requesting an increase in the returned check charge to the maximum amount allowed by the State of Michigan.

Line No.

Q. How would the third-party vendor recover insufficient fund payments?

A. The third-party vendor will re-present the payment to the financial institution and remit the payment to the Company if successful.

Q. What does re-present mean?

A. To re-present means the vendor will utilize a proprietary algorithm to determine when to re-submit the payment to the subject financial institution. The vendor will attempt to re-present the payment for 7 days before the check is returned to the customer for insufficient funds.

Q. Why does the Company want to work with a third-party vendor to recover insufficient fund payments?

A. Currently, the Company's treasury department does not re-run a customer payment after the payment is returned for insufficient funds. The Company does not have technology to anticipate when to re-run the customer payment successfully. The third-party vendor has propriety technology that will provide an optimal time to re-present the customer payment. This effort will help to reduce uncollectible expense.

Q. How does the third-party vendor's propriety technology work?

A. The third-party vendor has an algorithm that re-runs declined payments at the most optimal time for collection.

Q. What is the third-party vendor's insufficient fund payment recovery success rate?

A. The third-party vendor states that their insufficient funds payment recovery success rate is 70- 85%

Q. How much does the Company estimate will be saved in uncollectible expense by using a third-party vendor to recover insufficient fund payments?

A. The Company estimates that this initiative could save approximately $350,000 in uncollectible expense.

Q. How will the third-party vendor be paid for their services?

A. The third-party vendor will be paid by the Company from the returned check charge assessed to customers who make a payment returned for insufficient funds.

Q. What is the current returned check charge assessed to a customer by the Company?

A. The Company assesses a $15.00 charge.

Q. Is DTE Electric proposing to increase the returned check charge?

A. Yes. The Company is proposing to increase the returned check charge to the maximum amount allowed by the State of Michigan.

Q. What is the current maximum amount returned check charge allowed by the State of Michigan?

A. According to the State of Michigan, Department of Insurance and Financial Services, Bulletin 2016-06-CF dated February 18, 2016, the current maximum amount for a returned check charge is $28.66. This has been included as work-paper, TDJ-1.

Q. Is the Company's request to increase the returned check charge related to the partnership with the third-party vendor?

A. No, it is not. The Company's current returned check charge is below the maximum authorized by the State of Michigan. The Company anticipates that charging the maximum allowed rate will deter customers from repeatedly making payments that are returned for insufficient funds.

Q. Will the proposed third-party vendor change affect rates?

A. No. The vendor will not be paid through rates. The third-party vendor will be paid by the Company from the returned check charge assessed to customers who make a payment returned for insufficient funds.

Q. Will the request to increase the amount of the returned check charge to the maximum allowed by the State of Michigan affect rates?

A. No. The returned check charge will continue to be assessed to customers who make a payment returned for insufficient funds.

Q. Where will this proposed change be reflected in the Company's current rules?

A. The change will be made to DTE Electric's Rules and Regulations C4 Application of Rates, C4.6 Payment for Service and Insufficient Funds.

Low Income Programs

Q. What low income programs is DTE Electric supporting?

A. DTE Electric has taken a significant role in developing innovative long-term, systematic approaches to help low income customers achieve self-sufficiency, manage their energy consumption, and affordably take control of their energy bills. This began with multiple pilot projects, evolving into the LSP; which currently serves nearly 30,000 customers. The LSP program began in 2012, and was funded during the first year, by the Michigan Department of Human Service (MDHS), and subsequently by an MPSC grant of $16 million in 2013, $20 million in 2014 and $17 million in 2015 and 2016. In 2017, policy decisions by Department of Health and Human Services (DHHS) to exclude affordable payment plans from receiving any Low Income Home Energy Assistance Program (LIHEAP) funding dramatically reduced funding sources for low income payment programs.

The LSP program has proven to be extremely successful. At the end of the 2017 LSP program year:

- Less than 1% of LSP customers were disconnected for non-payment
- 88% of enrollees successfully completed a full year of the program
- Customer satisfaction remains very high at 93%
- 98% of customers remain within the consumption limits of the program

The goal of DTE Electric's energy assistance programs is to gradually bring down arrears owed, while encouraging and supporting good payment habits and reducing consumption. This program structure will lead to participants reducing their arrears over time and adopting a habit of making regular, affordable payments, albeit subsidized in the short term, with the end goal of customers reaching self-sufficiency to afford the actual costs of the energy they consume.

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Q. Is DTE Electric proposing to continue the Residential Service Special Low Income Pilot tariff, D1.6 approved by the Commission on December 11, 2015 in its general rate case U-17767?

A. Yes. DTE Electric is proposing to continue offering the Residential Service Special Low Income Pilot tariff, Rate Schedule D1.6.

Q. What are the key features of the Residential Service Special Low Income Pilot (LIA)?

A. This pilot offers qualifying Low Income electric customers a $40.00 per month credit on their bill. Electric customers who select this rate must qualify for the Residential Service rate D1. To qualify for this rate, an electric customer must also provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the electric customer's total household income does not exceed 150% of the poverty level as published by the United States Department of Health and Human Services. Customers can also qualify for the credit if they receive any of the following: i) assistance from a state emergency relief program; ii) food stamps; or iii) Medicaid. The LIA credit is applied to customers enrolled in the LSP program mentioned above. The application of this LIA credit to LSP customers allows DTE to provide affordable payment plans for more vulnerable customers.

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Q. Is DTE Electric proposing to make any changes to the Residential Service Special Low Income Pilot (LIA) and Residential Income Assistance Service Provision (RIA)?

A. Yes. The LIA pilot exists alongside the existing RIA credit. The LIA pilot provides a special low income discount of $40 per month and the RIA provides a monthly $7.50 credit for qualifying customers.

DTE proposes that any unused credit amounts should accumulate at the program level to be rolled over for future electric LIA or RIA distribution for the next calendar year. This change is recommended to allow for maximum utilization of the low income discount/ credits for the most vulnerable customers.

Q. What is the total dollar amount included in the electric rates for the RIA credit?

A. The RIA credit total amount is $3.15 million.

Q. How many low income customers can receive the RIA credit in a year at $3.15 million?

A. The $3.15 million can be distributed to 35,000 low income customers based on the current customer charge ($7.50 credit x 35,000 customers x 12 months = $3.15M).

Q. Is DTE Electric requesting a rate increase for the RIA credit?

A. Yes. DTE Electric would like to offer this credit to our eligible single commodity electric customers.

Q. In 2017, how many electric single commodity customers were eligible for the RIA credit?

A. In 2017, there were approximately 35,000 electric only customers who qualified to receive the electric RIA credit due to receiving State Emergency Relief (SER) or the Home Heating Credit (HHC). These additional 35,000 customers would qualify for the electric RIA credit.

Q. What amount is DTE Electric proposing to increase the RIA credit to?

A. DTE Electric is proposing to increase the RIA total amount to $7.6 million to include the 35,000 qualifying electric only customers. This would increase the number of low income qualifying customers to 70,000 ($9.00 credit x 70,000 x 12 months= **$7.6M**). The $9.00 credit is based on Company Witness Mr. Dennis' proposal to increase the residential customer charge to $9.00 in order for it to continue to fully offset the D1 service charge for RIA customers.

<u>Rate Schedule D1 Time of Use</u>

Q. Are you familiar with the Commission's Order in U-18255 regarding the change in the residential rate structure for rate schedule D1?

A. Yes I am. The Commission Ordered the Company in its next general rate case to include proposed tariffs for non-capacity charges based on summer on-peak rates. In other words, approximately 1.9 million customers would be defaulted to time based rates.

Q. What is the expected operational implementation costs for the Commission required residential rate structure change?

A. If the Commission adopts the residential rate structure change ordered in U-18255, the Company will incur significant costs which have not been incorporated into this rate filing. The total impact to the Customer Service operations spend is estimated at $12 million during the implementation year, with ongoing annual expenses of roughly $4 million. These numbers do not include the costs of modifying our systems to accommodate this new rate structure.

Q. What is included in the $12 million Customer Service operational implementation costs?

A. The $12 million include costs to the Contact Center ($6 million), Billing ($4 million), and Customer Experience ($1.6 million).

Q. Which activities are comprised in the $6 million costs to the Contact Center?

A. The activities surround an increase in call volume and training to agents. The additional call volume is estimated to be approximately 500,000 based on a 2 million customer call rate of 25% over a three to four month period. Internal training for 840 FTE's would cost $50,000 and our vendor costs for external training will cost $600,000.

Q. Why would the Company expect an additional 500,000 calls to the Contact Center?

A. The Company anticipates that customers will call in to inquire about their bill statement looking different because of the new rate and how the new rate impacts the

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amount they will have to pay. These conversations will increase handle time due to the complexity. The Contact Center will also help to educate and provide instruction to customers on saving money.

Q. Which activities are comprised in the $4 million costs to Billing?

A. Every meter impacted by this rate change will need to be modified. The meter modifications can be handled electronically without site visits, but whenever changes are made to the meters a small portion of those changes do not flow through our systems flawlessly. For cost estimation purposes, we estimated that 2% of the meter changes would result in manual effort needed by the Billing team to get customers' bills to generate accurately. The $4 million in Billing implementation costs include the manual processing of any meter change exceptions as well as manual review and testing of bills during implementation of the new rate to ensure bill accuracy.

Q. What type of costs are included in the ongoing annual Billing expense?

A. The Company anticipates the proposed new rate structure would result in an estimated additional 180,000 billing corrections per year due to the complexities of the rate. These corrections would have to be processed by the Billing team manually resulting in ongoing annual costs of approximately $3 million per year.

Q. What are the costs associated with Customer Experience?

A. There is a $1.6 million cost associated with Customer Experience during the implementation year of the proposed new rate structure and an annual ongoing cost increase of $1 million. To provide the best customer experience and increase customer satisfaction with the new rate structure, Customer Experience would utilize automated notifications to keep customers informed of their usage amounts and when they are entering peak pricing times. This cost for the implementation year include $600,000 in training to all impacted groups and $1 million to send the alerts and notifications. These estimates do not include the technology costs to develop and implement the alerts and notifications. The annual ongoing costs of $1 million are to continue sending the notifications and alerts to customers every year.

Q. How are the costs for training calculated?

A. The Company used the historical training costs for the Contract Center to calculate the training that will be required.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KENNETH D. JOHNSTON

DTE ELECTRIC COMPANY
QUALIFICATIONS OF KENNETH D. JOHNSTON

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Q. What is your name, business address and by whom are you employed?

A. My name is Kenneth D. Johnston. My business address is 8001 Haggerty, Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE Electric or Company) as Manager of Community Lighting.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric.

Q. What is your educational background?

A. I graduated from Lawrence Technological University with a Bachelor of Science Degree in Engineering in 1983. In 1991, I graduated with distinction from the University of Michigan, Dearborn, with the degree of Master of Business Administration in Finance and received the Distinguished Graduate MBA Student Award. In addition, I have completed advanced level mathematics and mechanical engineering courses at Lawrence Technological University.

Q. Have you completed other courses of study or attended any professional seminars?

A. Yes, I have completed a Training Program titled Fundamentals of Energy Management sponsored by the Association of Energy Engineers, completed a training course offered by International Business Communications titled Energy Industry Essentials, attended a workshop on Retail Open Access offered by the Michigan Electric Power Coordination Center, attended the Lighting Upgrade Workshop offered by the US Environmental Protection Agency (EPA), and

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completed the Nuclear Utility Procurement Training sponsored by the Electric Power Research Institute (EPRI). Finally, I have a Six Sigma Green Belt certification.

Q. Do you belong to any professional organizations or hold any certifications?

A. Yes. I have received certifications as an Energy Manager through the Association of Energy Engineers, a Green Lights Surveyor Ally through the US EPA, and as a Nuclear Utility Procurement Instructor through EPRI.

Q. Please provide your employment history with DTE Electric.

A. My first work assignment for Detroit Edison was in May 1983 as a contract engineer in the Applied Mechanics and Metallurgy Group, Power Systems Division, Engineering Research Department. As a vibration engineer, I was responsible for vibration monitoring, evaluation, and analysis of rotating machinery at Detroit Edison Power Plants.

I was formally hired by Detroit Edison in August 1985 as a planning and scheduling engineer at the Fermi 2 Nuclear Power Plant. In this capacity, I developed, programmed, and directed the production of plant outage schedules, including equipment maintenance and testing, plant system restoration, and plant startup.

In March 1989, I was assigned the duties of Preventive Maintenance Specialist, Nuclear Production-Maintenance, and was responsible for evaluation and implementation of the preventive maintenance program.

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In January 1990, I took a position as a materials engineer, Nuclear Materials Management, and progressed to principal (lead) engineer. In this capacity, I was responsible for the work direction of engineers and technicians in the performance of material engineering, parts planning, and receipt inspection activities. I represented the Company as a member of the EPRI Obsolete Items Database Technical Working Group and the General Electric Boiling Water Reactor Pooled Inventory Management Equipment Committees.

In August 1995, I was assigned the position of principal mechanical maintenance engineer, Rotating Equipment, Maintenance Engineering, Nuclear Production. In this capacity, I provided field-engineering support for mechanical maintenance activities, managed the resolution of emerging technical issues, monitored and evaluated the performance of rotating equipment and performed troubleshooting and root cause analysis of equipment failures.

In January 1997, I became a facilitator with the Energy Partnership, Customer Energy Solutions. In this position, I was responsible for the development, implementation, and management of the Energy Conservation Program at the General Motors Proving Ground in Milford, Michigan. Responsibilities in that position included the identification, financial evaluation, and implementation of natural gas and electric energy projects related to boiler and steam systems, lighting systems, air compressors, and HVAC systems.

In June 1999, I became a Principal Supplier Account Manager with the Supplier Transactions Group of the Electric Choice Implementation Team. In this capacity I

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was responsible for the management of relationships with Alternative Electric Suppliers (AES) including supplier education, supplier qualification, supplier billing, customer enrollment, customer billing, and electronic data management.

In January 2003, I transferred to Regulatory Affairs as a Principal Project Manager and in September 2007, I was promoted to Consultant. In February 2011, I was promoted to Manager of the DTE Electric Choice Program. As Manager of the Electric Choice Program, I was responsible for managing the processes that enable customers to seamlessly migrate between DTE Electric Full Service and Electric Choice Service in accordance with Michigan Compiled Laws (MCL), Michigan Public Service Commission (MPSC or Commission) Orders, and DTE Electric's tariffs. In April 2015, I was promoted to Manager of Community Lighting.

Q. What are your duties and responsibilities as Manager of Community Lighting?

A. In this capacity, I am responsible for managing the marketing & sales, planning & construction and asset management of more than 190,000 DTE Electric-owned street lights and outdoor protective lights, the maintenance and provision of energy to municipally owned streetlights and the provision of energy-only service to municipalities, in accordance with DTE Electric's MPSC-approved tariffs. DTE Electric's assets include mercury vapor, metal halide, high pressure sodium, and light-emitting diode (LED) luminaires.

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Q. What has been your involvement in regulatory case activities?

A. I managed the following cases:

U-13738	In the matter of the application of The Detroit Edison Company to recover implementation costs for the period ended December 31, 2002
U-14079	In the matter of the application of The Detroit Edison Company to recover implementation costs for the period ended December 31, 2003
U-13759	Review of Steam Rates
U-13808-R	2004 Power Supply Cost Recovery Reconciliation
U-14474	In the matter of the application of The Detroit Edison Company to implement the Commission's final order in Case No. U-13808 concerning Inter Alia, 2004 Net Stranded Costs
U-14093	In the matter of the complaint of North Star Steel Company against The Detroit Edison Company regarding credits for experimental electric choice service
U-14124	In the matter of complaint of Nordic Marketing, LLC against The Detroit Edison Company for violations of the Code of Conduct, Public Act 141
U-15223	In the matter of the complaint of Commerce Energy Inc. against The Detroit Edison Company
U-16400	In the matter of the application of Michigan Consolidated Gas Company for the authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority.

I was the case manager and/or sponsored testimony in the following cases:

U-14025	In the matter of the complaint of Strategic Energy LLC against The Detroit Edison Company
U-14054	In the matter of the complaint of Quest Energy against The Detroit Edison Company
U-14070	In the matter of the complaint of Constellation NewEnergy, Inc. against The Detroit Edison Company.
U-14275	2005 Power Supply Cost Recovery Plan
U-14275-R	2005 Power Supply Cost Recovery Reconciliation
U-14208	In the matter of the complaint of Nordic Marketing, L.L.C. against The Detroit Edison Company for failure to comply with enrollment processing requirements.
U-14817	2005 Pension Equalization Mechanism Reconciliation
U-14702	2006 Power Supply Cost Recovery Plan
U-14702-R	2006 Power Supply Cost Recovery Reconciliation
U-15259	2006 Pension Equalization Mechanism Reconciliation
U-15002	2007 Power Supply Cost Recovery Plan
U-15002-R	2007 Power Supply Cost Recovery Reconciliation
U-15081	In the matter of the complaint of FirstEnergy Solutions Corp. against The Detroit Edison Company for violation of the Code of Conduct
U-15417	2008 Power Supply Cost Recovery Plan
U-15417-R	2008 Power Supply Cost Recovery Reconciliation
U-15677	2009 Power Supply Cost Recovery Plan
U-15806	Detroit Edison 2008 PA 295 Renewable Energy Plan (RPS)
U-16047	2010 Power Supply Cost Recovery Plan

U-16356	In the matter of the application of The Detroit Edison Company for the authority to reconcile its renewable energy plan costs with the plan approved in Case No. U-15806-RPS
U-16434	2011 Power Supply Cost Recovery Plan
U-17663	In the matter of the complaint of Severstal Dearborn, LLC against DTE Electric Company
U-17680-R	2015 Power Supply Cost Recovery Reconciliation
U-17734	In the matter of the Formal Complaint of AK Steel Corporation (successor to Severstal Dearborn, LLC) against DTE Electric Company for standby service.
U-17767	DTE Electric General Electric Rate Case Proceeding
U-18014	DTE Electric General Electric Rate Case Proceeding
U-18150	In the matter of the Application of DTE Electric Company for approval of depreciation accrual rates and other related matters.
U-18255	DTE Electric General Electric Rate Case Proceeding
U-20105	DTE Electric determination of Credit A as described in Order U-18494

In addition, I have submitted affidavits supporting changes to DTE Electric's Retail Access Service Rider and Outdoor Protective Lighting tariff, as well as the approval of renewable energy, renewable energy engineering, procurement and construction (EPC), and renewable energy credit (REC) contracts before the MPSC. I was also the case manager and submitted several affidavits regarding energy imbalance service and the recalculation of energy imbalance service costs in FERC Docket EL04-31-000,

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"Complaint of Quest Energy, LLC to receive proper compensation for imbalance services."

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Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to:

- Support the energy forecast for the various outdoor lighting rates including automated traffic signal (ATS) rates and metered street lighting rates;
- Support the proposed rate design for the outdoor lighting (municipal and other) and ATS tariff offerings using the lighting model;
- Support and discuss the reasonableness of the Company's actual Community Lighting O&M expenses ended December 31, 2017, and the projected Community Lighting O&M expenses for the 12-month projected test period ending April 30, 2020;
- Support and discuss Community Lighting's capital expenditures for the historical test year ended December 31, 2017, and the projected Community Lighting capital expenditures for the 12-month projected test period ending April 30, 2020;
- Support the establishment of a post charge for underground-fed streetlights and outdoor protective lights.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring in whole, or in part, the following exhibits:

Exhibit	Schedule	Description
A-12	B5.5	Projected Capital Expenditures – Community Lighting
A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-16	F3	Present and Proposed Revenues by Rate Schedule – 12 months ending April 30, 2020
A-16	F10	Proposed Tariff Sheets

A-25	O1	Community Lighting Outdoor Lighting Outage Duration
A-25	O2	Community Lighting Outdoor Lighting Outage Cost

I am sponsoring lines 8 and 22 within Exhibit A-13, Schedule C5.6, page 1 of 3, and the pages specific to the residential and commercial outdoor protective lighting and municipal classes within Exhibit A-16, Schedule F3. This includes pages 41 through 52. On Exhibit A-16, Schedule F10, I am sponsoring the OPL and municipal tariffs while Company Witnesses Mr. Bloch, Ms. Holmes, and Mr. Dennis sponsor the tariffs for the remaining customer classes.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Can you provide an overview of DTE Electric's Community Lighting Municipal Street Lighting Business?

A. Yes. DTE Electric Community Lighting provides MPSC-approved tariff service to approximately 163,000 street lights on its E1 Option I Rate Schedule, 252 municipally-owned street lights on its E1 Option II Rate Schedule, approximately 83,500 municipally-owned street lights on its E1 Option III Rate Schedule, and almost 30,000 OPLs on its D9 Rate Schedule. In addition to the lighting services above, Community Lighting provides MPSC-approved tariff service to municipalities for the operation of ATS lights on its E2 Rate Schedule.

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DTE Electric's proposed E1 Option I Rate Schedule reflects recovery of costs associated with its ownership, maintenance and provision of energy to its portfolio of mercury vapor, high pressure sodium, metal halide (collectively referred to as high intensity discharge (HID)) and LED street lighting. DTE Electric's proposed E1 Option II Rate Schedule (closed to new customers since January 2009) is applicable to street lighting systems owned by municipalities, but maintained by the Company. DTE Electric's proposed E1 Option III Rate Schedule is applicable to street lighting systems which are both owned and maintained by the municipality for which the Company provides only the energy.

Q. Can you provide an overview of the various lighting technologies that DTE Electric's Community Lighting employs in its Municipal Street Lighting Business (Option I)?

A. Yes. The current lighting portfolio for street lighting customers served on DTE Electric's E1 Option I Rate Schedule includes more than 68,000 high pressure sodium luminaires and 66,000 LED luminaires, or 42% and 40% of its total Company-owned street lighting portfolio, respectively. While the quantity of high pressure sodium luminaires has been slowly dropping over the past several years, the total number of LED luminaires is increasing at a rapid pace due to the conversion of HID luminaires, primarily mercury vapor, to LED.

Approximately 17% or just over 27,000 of DTE Electric's street light assets are currently mercury vapor luminaires. The mercury vapor technology became obsolete pursuant to the Energy Policy Act of 2005, and, as result of their obsolescence and inefficient use of energy, the quantity of mercury vapor street lights has been reduced by approximately 66,000 over the past seven years, primarily through their conversion to LED luminaires. DTE Electric no longer performs periodic group re-lamping of the mercury vapor lighting; rather, the lamps continue to be replaced upon lamp failure. When the entire mercury vapor lighting unit (consisting of the luminaire, lamp, and photocell) fails, DTE Electric converts the failed unit to LED lighting due to its continuing obligation to provide service for Municipal Street lighting (MSL) customers taking service under its E1 Option I Rate Schedule. DTE Electric began to convert failed mercury lighting to LED lighting on February 1, 2017 in accordance with the MPSC's January 31, 2017 Order in MPSC Case No. U-18014. Prior to February 1, 2017, all failed mercury vapor lights were converted to high pressure sodium.

Metal halide lighting luminaires represent less than 2 percent or approximately 1,900 of DTE Electric's company owned lighting luminaires. DTE Electric historically re-lamped metal halide luminaires on a 5-year periodicity; however, DTE Electric moved to a 3-year periodicity in 2017 due to actual lamp life and maintenance history.

Q. Can you provide an overview of the various lighting technologies for the street lights that are municipality owned (Option II & III)?

A. Yes. The mix of lighting for DTE Electric's E1 Option II Rate Schedule reflects a mix of 84% high pressure sodium and 16% mercury vapor. As I previously indicated, this service has been closed to new customers since 2009 and existing E1 Option II Rate Schedule customers electing to convert to LED are required to convert to DTE Electric's E1 Option I or Option III Rate Schedules. The mix of lighting for DTE Electric's E1 Option III Rate Schedule includes more than 65,000 LED luminaires or

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78% of the total; another 21% are high pressure sodium, with the balance being a mix of mercury vapor and metal halide. The high concentration of energy efficient LED lighting is a direct result of the City of Detroit's conversion of most of its street lights to LED.

Q. Can you provide an overview of DTE Electric's Community Lighting OPL (D9 Rate Schedule) and ATS Business (E2 Rate Schedule)?

A. Yes. DTE Electric's proposed D9 Rate Schedule reflects recovery of costs associated with its ownership, maintenance and provision of energy to its portfolio of almost 21,000 commercial and more than 9,000 residential outdoor protective lights. DTE Electric's OPLs employ the same lighting technologies as its street lights and, consistent with its conversion of failed mercury vapor street lights to LED lighting, DTE Electric began to convert failed mercury vapor OPLs to LED lighting on February 1, 2017.

DTE Electric's proposed E2 Rate Schedule reflects the recovery of costs for the production and distribution of energy for ATS lights owned and maintained by municipalities and other public authorities. This service is an energy-only service and represents annual load of more than 59 GWh including service to the City of Detroit.

DTE Electric also provides metered municipality-owned streetlight service under the E1.1 Rate Schedule. Total annual load on this service, including service to the City of Detroit, is almost 12 GWh. I support the energy forecast for this Rate Schedule and Witness Holmes supports the proposed rate for this service.

Line No.

Community Lighting Sales Forecast

Q. How did you develop the sales forecast for Lighting?

A. Consistent with the sales forecast prepared for prior rate cases, the sales forecast for the E1 Option I Rate Schedule was developed by first preparing a forecast of light counts for each lighting type (technology and wattage size) for the projected test period based upon: (1) known projects, (2) continued conversions of mercury vapor lighting to LED lighting, and (3) an estimate of increased light counts resulting from sales growth. The system wattage (nominal lamp wattage plus ballast wattage) applicable to each lighting type was applied to the forecasted volume of lights for each lighting type. Annual usage was assumed to be 4,200 hours, to reflect the hours that the lights on the dusk to dawn or standard provision are illuminated. The energy forecast for lights on the dusk to midnight provision was based upon 2,100 hours use and the energy forecast for lights on the de-energized provision is zero.

The sales forecast for the E1 Option II Rate Schedule was developed based upon using the existing light counts for each of the lighting types. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which all the lights are illuminated on an annual basis.

The sales forecast for the E1 Option III Rate Schedule was developed by first preparing a forecast of light counts for each of the lighting types for the projected test period based upon known projects and an estimate of light count changes. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which all the lights are illuminated on an annual basis.

The total sales forecast for the OPL D9 Rate Schedule, like that prepared for the E1 Rate Schedule, was developed by preparing a forecast of light counts for each of the lighting types for the projected test period based upon existing light counts, an estimate of increased light counts resulting from sales growth and continued conversion of mercury vapor lighting to LED lighting. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which the lights are illuminated on an annual basis.

The total sales forecast for the ATS E2 Rate Schedule was determined by using the total connected wattage, as of April 1, 2018, for that rate schedule and determining the annual usage based upon that determinant. In other words, it is simply the product of the total reported wattage and the total number of hours in the projected test period.

The total sales forecast for the E1.1 Rate Schedule was based upon annualized usage data for the 12-month period ended December 2017.

Community Lighting Operations

Q. What is included in the Maintenance of Street Lighting and Signal Systems account on lines 8 and 22 of Exhibit A-13, Schedule C5.6?

A. Lines 8 and 22 on this exhibit show the Projected Operation and Maintenance Expenses that are directly assigned to Operation and Maintenance of Street Lighting and Signal Systems. The total historical period expense of $2.7 million in Account 596 represents preventive maintenance expense, labor expense and outage restoration expense that was not capitalized. The preventive maintenance work included post inspection, post painting and re-lamping of metal halide luminaires. The labor expense primarily reflects the labor of the Community Lighting team including sales, planning, asset maintenance, construction and asset engineering. As reflected on Exhibit A-13, Schedule C5.6, the historical period operation and maintenance (O&M) expense of $2.7 million is adjusted for inflation of 3.0% for 2018, 2.9% for 2019, and 3.0% for the first 4 months of 2020. DTE Electric has more than 60,000 posts, each of which is inspected every three years.

Q. Why does DTE Electric inspect posts every three years?

A. DTE Electric has established detailed post inspection criteria to inspect posts every three years to both identify posts whose structural integrity dictates their replacement (condemnation), and posts that require painting. At the time posts are inspected, minor post maintenance work such as adding or replacing post asset tags, post hand-hole covers, and T-box door covers may also be completed. Over the past eight years, DTE Electric's post inspection process has resulted in the annual replacement of condemned posts at a rate of approximately 3.9% and post painting at a rate of approximately 8.7%. These inspection service results are mutually exclusive meaning that posts which get replacement are not included in those posts which get identified for painting. Although most of the posts that get identified for replacement typically flow into our planned capital post replacement work process, a handful of posts based on their condemnation classification may get replaced on a reactive basis under the outage event process.

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Q. Does your historical O&M expense include any preventive maintenance expense for LED luminaires?

A. No. Prior to 2018, DTE Electric had not performed any preventive maintenance on LED luminaires. However, beginning in 2018, DTE has implemented its LED washing preventive maintenance program. The proposed known and measurable change for Account 596 for the forecast test period of May 2019 through April 2020 reflects the projected expense for washing LED luminaires during that period.

Q. Why has DTE Electric initiated a LED washing preventive maintenance program?

A. DTE Electric currently re-lamps its HID luminaires on a periodic basis to ensure that their performance (light output) is maintained at an appropriate level to provide for the safety and security of its customers. Given the increasing saturation of LED luminaires in its lighting portfolio, DTE Electric was similarly concerned about the lighting performance of LED luminaires over time. Because of this concern, DTE Electric conducted two formal and separate LED light loss factor (LLF) studies, initially in 2015 and again in 2017, to determine how LED lumen output depreciated over time. The results of those studies identified the need to wash LEDs on a periodic basis to ensure that their lumen output remained at or above L70 (70% of the original design lumen output), the level at which the Lighting Industry has defined LED luminaire end of life and no longer provides acceptable light output to meet the lighting safety and security design requirements of its customers.

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Q. How has DTE Electric determined the projected expense for the performance of the LED luminaire washing?

A. DTE Electric developed a LED luminaire washing schedule based upon its LED luminaire portfolio and when the LED luminaires were originally installed. For instance, LED luminaires originally installed from 2009 through 2013 are scheduled to be washed in 2018, LED luminaires originally installed in 2014 will be washed in 2019, LED luminaires installed in 2015 will be washed in 2020, and so on. Based upon the results of LLF studies, a five-year group washing cycle has been established for the early generation (2009 to 2013) and second generation LED luminaires (2014 to 2018). The five-year group washing frequency will remain in place for the remainder of the useful service life of these LED luminaires.

DTE plans to wash more than 8,000 LED luminaires in 2018, almost 9,000 LED luminaires in 2019 and more than 16,000 LED luminaires in 2020. To develop unit pricing for LED luminaire washing, DTE Electric developed a LED luminaire washing procedure, including video, based upon input from its primary roadway lighting manufacturer which it then used to obtain firm unit pricing from the contractors that it employs to construct and maintain its outdoor lighting assets. The projected known and measurable expense reflects the use of an average unit price for the total number of LED luminaires to be washed during the forecast test period.

Q. Does your historical O&M expense include costs for the relamping of HID lighting which will no longer be required?

A. No. The 2017 O&M expense of $2.7 million only reflected approximately $11 thousand for relamping of metal halide luminaires. DTE does not relamp mercury

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vapor luminaires and, as I will discuss later, DTE completed the strategic movement of this preventive maintenance activity for its high pressure sodium luminaires to an 8-year cycle in 2015.

Q. Do you consider the actual and projected expenses for Community Lighting shown in Exhibit A-13, Schedule C5.6 reasonable?

A. Yes, I do. I base this on my analysis of past expenses, projected requirements for labor and material for the safe and reliable distribution of electric power, and plans for maintaining and/or improving customer service. Community Lighting's direct O&M expense, as recorded in Account 596, has been generally decreasing over the past 10 years.

Q. What are the Community Lighting capital expenditures on Exhibit A-12, Schedule B5.5, "Projected Capital Expenditures – Community Lighting"?

A. Capital expenditures for Community Lighting for 2017 were $11.3 million. The 2017 expenditures included approximately $4.1 million for outage restoration, almost $0.9 million for post replacement, approximately $0.1 million for series conversion, and the balance for new business, planned HID to LED conversions, and capital support staff.

The projected capital expenditures for Community Lighting are $13 million for 2018, $2.4 million for 4 months ending April 30, 2019, and $12.8 million for 12 months ending April 30, 2020. Similar to the 2017 actual expenditures, these projections include outage restoration, including conversion of failed mercury vapor luminaires to LED for both street light and OPLs, post replacement, planned HID to LED conversions, new business, and capital support staff. Other work will include targeted infrastructure upgrades such as underground cable replacement.

Q. A significant amount of Community Lighting's annual capital expense is incurred for outage restoration. What is the Community Lighting team's performance with respect to this activity?

A. On an annual basis, DTE Electric's Community Lighting team typically incurs approximately $5 million of outage restoration expense with 85-90% of this cost being capitalized based on material usage, and the balance being recorded as O&M. During 2017, approximately 55% of this total expense resulted from outage events for the repair of overhead fed lights, and the balance is attributable to underground fed lights. DTE Electric places a significant amount of focus on its outage restoration process and employs balanced metrics to ensure that its outage restoration costs and outage duration are optimized. Exhibit A-25, Schedule O2 reflects DTE Electric's performance for outage restoration cost per event. DTE Electric has driven its annual outage restoration costs down through its application of continuous improvement and strategic investment in various planned projects including underground cable replacement. Exhibit A-25 Schedule O2 reflects a favorable downward trend in DTE Electric's annual outage restoration costs from 2009 through 2017.

Q. What was DTE Electric's performance with respect to outage duration for its lighting customers?

A. DTE Electric has several targets for outage performance: outage duration and outage defects. DTE Electric's 2017 outage duration target was 2.9 days and DTE Electric's 2017 actual performance was 3.6 days. These historical metrics are displayed on

Exhibit A-25, Schedule O1. Over the past ten years, DTE Electric had achieved top decile performance, by reducing the average duration of 8.5 days in 2007 to only 2.4 days in 2016. The Company's 2017 actual results of 3.6 days reflect DTE's decision to prioritize the restoration of electric service to its customers over the restoration of lighting. DTE's lighting restoration is performed by contract crews and when power outages occur, those crews are diverted from restoring lights to restoring power to customers. In March the Company experienced the largest storm in its history which severely impacted its performance and the numerous hurricanes in the fall months further exacerbated the 2017 overall outage duration results. These weather events had a similar impact on DTE's 2017 outage defect target of 292. DTE Electric's actual performance during 2017 was 801. The historical metrics for outage defects are also displayed on Exhibit A-25, Schedule O1. An outage defect is a street light outage event that is greater than 10 days in duration.

In addition to weather-related events, other outage duration and outage defects impacts include extended repair time for underground faults as well as repairs resulting from third party damage. The performance metrics only include reactive street light outage repairs; they do not include any outage repair resulting from patrol and fix activities nor any preventative maintenance activities such as group re-lamping. DTE Electric's outage work management system for street lighting uses 24-hour military time protocol and measures duration to the minute degree. Street light outage events reported on weekends and after normal week day business hours are analyzed and dispatched to crews on the following business day. DTE Electric measures both total and crew duration cycle repair periods. Crews authorized by DTE Electric work both day and evening shifts to complete reactive outage repairs of reported street light outage events; and when seasonal work load increases (late August to November and following storms), additional resources are secured and mobilized.

Q. What other measures does DTE Electric have in place to improve its restoration time and maintain a high level of customer service?

A. DTE Electric has established strategic maintenance contracts with the contractors that perform its outage restoration work which include financial penalties for not achieving desired restoration times. Restoration performance, amongst other metrics, is reviewed with the contractors at monthly performance meetings and, to the extent that restoration performance is not meeting expectations, DTE has shifted responsibility for restoration in certain service territories to alternative contractors to achieve the desired restoration performance. Internally, DTE evaluates contractor performance metrics in weekly huddles to identify potential performance issues or needs for problem solving. From a customer service perspective, whenever an outage event becomes a defect, DTE contacts the reporting customer to update them on the status of their outage. In addition to these efforts, DTE is currently evaluating various arrangements for the provision of special order materials on behalf of those municipalities that choose streetlight materials that are not included in DTE's standard streetlight offerings. Currently the municipality is responsible for stocking special order materials and this responsibility often-times significantly extends outage duration due to material availability.

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Q. What other activities does DTE Electric employ to minimize outage restoration expense?

A. On a planned basis, DTE Electric performs periodic group re-lamping of its high pressure sodium and metal halide lighting luminaires on an 8-year and 3-year cycle, respectively. During 2015, DTE Electric completed its strategic movement from 24,000 hour lamps to 40,000 hour lamps for its high pressure sodium luminaires, an activity that began in 2011. The group re-lamping activity not only improves lighting output, but it also reduces the volume of outage events caused by a failed lamp. DTE Electric does not perform group re-lamping of mercury vapor luminaires as this luminaire technology is obsolete and is being converted to LED upon failure.

Q. How does DTE Electric determine how much capital it contributes to projects?

A. DTE Electric's calculation method for Contributions in Aid of Construction (CIAC) varies depending on whether the DTE Electric project cost is for new business or conversion of existing business (i.e. convert mercury vapor to LED). The determination of CIAC for new business is simply the total estimated project cost less three years of expected incremental revenues from the project based upon the Company's MPSC-approved tariffs. The determination of CIAC for conversion of existing business is the total estimated project cost less three years of expected <u>incremental</u> revenues from the project plus a DTE Electric-provided labor credit. The credit for three years of incremental revenue is zero in most cases because the rates for the lighting technology to which customers are converting are typically lower than the rates for their existing lighting technology. DTE Electric provides a labor credit, equal to the contract labor charge for installation, to both incentivize conversions from the obsolete mercury vapor lighting technology to the LED lighting technology, and to realize the economic efficiencies gained from performing planned conversions of mercury vapor lighting versus reactive conversions upon failure. DTE Electric's contract labor costs for planned conversions are approximately 40% below that for reactive conversions. In addition to the incremental revenue and labor credits, the project cost for conversion of existing business may also be eligible for an energy waste reduction (EWR) grant as part of the Company's MPSC-approved EWR program, further offsetting the customer's contribution to the conversion project.

The underlying purpose of reducing the project cost for new business by three years of incremental revenues is to recognize the impact of increased revenues from the project which are ultimately used to offset the revenue requirement from the new assets that DTE Electric records on its books. In the determination of CIAC for planned conversion of existing business, DTE Electric similarly determines total project cost and similarly reduces this amount by 3 years of expected incremental revenues. As I previously stated, because the rates, and associated costs, for LED lighting are lower than those for equivalent HID lighting, no incremental revenue is available to offset the recovery of the additional assets and therefore, no reduction in CIAC is provided. However, because DTE Electric provides both a labor credit to customers requesting planned conversion of obsolete mercury vapor lighting and facilitates the process for receipt of energy waste reduction grants for conversion of existing HID lighting to LED lighting, the CIAC impact is reduced.

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Q. Do DTE Electric's proposed LED rates reflect any capital expense which was offset by CIAC?

A. No. DTE Electric records customer CIAC as a direct offset to actual capital expense for each of its new business and conversion projects. Therefore, DTE Electric's proposed LED rates do not reflect any capital expense which was offset by CIAC. For instance, if a customer provides a CIAC payment of $50,000 and actual capital expense was $80,000, then DTE Electric would record net capital of $30,000 on its books for purposes of ratemaking.

Q. What is DTE Electric's progress to date with respect to conversion of mercury vapor to LED street lighting?

A. As I mentioned previously, DTE Electric currently has a total remaining population of approximately 27,000 mercury vapor street light luminaires. DTE Electric has placed a priority on partnering with its municipal customers in converting these assets to LED lighting. Over the past four years, DTE Electric has converted approximately 53,000 street lights to LED and is in the process of converting another 8,000 street lights in 2018. The implementation of projects to convert mercury vapor to LED for each individual municipality requires evaluation, establishment and execution of contracts, work planning (including the ordering of materials, updating of drawings, receipt of permits, etc.), construction (including field coordination and oversight), and field verification and billing system updates, all of which is labor intensive. At the current pace of conversion for street light mercury vapor luminaires, all mercury vapor street lights could be converted by 2021 assuming customer demand persists at a rate similar to the past several years.

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Community Lighting Rate Design

Q. What does Exhibit A-16, Schedule F3 show?

A. This exhibit shows the present and proposed rate design and corresponding revenues by rate schedule, based on the billing determinants for the 12 months ending April 30, 2020. The exhibit details the forecasted billing determinants as well as the resulting present and proposed rates and revenues. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The forecasted billing determinants were developed based on historical data and relationships, as well as known and measurable changes, and are consistent with the sales forecast as presented on Company Witness Mr. Leuker's Exhibit A-15, Schedule E2, Other class sales. The existing luminaire and energy rates, both non-capacity energy and capacity energy, as approved in the Order dated April 27, 2018 in Case No. U-18255 are in columns (c), (d) and (e), and are used to calculate the present revenues in column (f). The luminaire rates proposed in this proceeding based upon the lighting cost of service (as discussed in detail below) are in column (g), the proposed non-capacity energy rates are in column (h), the proposed capacity energy rates are in column (i) and the resulting revenues from the new lighting cost of service are in column (j).

Q. How were DTE Electric's present Municipal Street Lighting and Outdoor Protective Lighting charges determined?

A. The lighting rates approved in MPSC Case No. U-18255 reflect a monthly energy charge, both non-capacity energy and capacity energy, and a luminaire charge. The monthly energy charge was determined by applying the energy rates, both in cent/kWh, to the calculated consumption values of the various lighting technology

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lamp sizes for both the E1 and D9 Rate Schedules. The luminaire charge (which includes costs related to customer service charges) is a fixed monthly amount applied to each luminaire dependent on the technology utilized, the lamp size or wattage, the lighting provision and whether it is served from underground or overhead. The total (energy and luminaire) monthly lighting charges that were calculated in MPSC Case No. U-18255 do not fully represent true cost of service rates by technology type (within the lighting rate class). In MPSC Case No. U-18255, the lighting rates were gradually moved towards cost of service with the total movement capped to minimize the impact on any individual customer.

Q. Did DTE Electric change the methodology by which it allocated the production and distribution revenue requirements to the various lighting rate schedules that you are supporting in this case?

A. No. Consistent with the methodology employed in the Company's last rate three Cases U-18014, U-18255 and U-20105 (Credit A), the functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Mr. Lacey for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non-capacity) within each of the rates schedules were designed to meet the production and distribution revenue requirement for each rate schedule shown in these exhibits. Mr. Lacey's Exhibit A-16 Schedule F1.5, which shows how much of the production revenue requirement for each rate class is capacity and non-capacity related, was used to allocate the production revenue requirement between the capacity and non-capacity energy charges. Consistent with the methodology employed in Company's last rate three Cases U-18014, U-18255 and Credit A, the E1 and D9 Rate Schedule energy charges, both capacity and non-capacity, were developed based upon the total production revenue requirement prepared by Witness Lacey for the E1 and D9 Rate Schedules.

Rate Schedule E1

Q. How were the proposed E1 Option I Rate Schedule luminaire charges determined?

A. By carefully reviewing and allocating the specific cost of service components to the type of service, underground or overhead, and then further allocating them to the individual lighting technologies, the Company was able to determine the new luminaire service cost structures listed in the E1 Rate Schedule tariff schedules as shown on Exhibit A-16, Schedule F3. There were no changes in the methodology for the allocation of non-production O&M costs or capital-related costs to luminaire charges proposed in this proceeding. The cost allocation methodology for capital-related costs is consistent with the asset allocation proposal for street lighting asset accounts filed in DTE Electric's depreciation case, Case No. U-18150.

Q. How was O&M allocated to the proposed E1 Option I Rate Schedule luminaire charges in the lighting model?

A. Based upon the Company's cost of service model sponsored by Witness Lacey, total Distribution O&M expense reflected in the E1 Option I Rate Schedule luminaire charge is $8.2 million. This distribution O&M expense of $8.2 million is comprised of the direct assignment of $3.1 million recorded in account 596 (Street Lights &

OPL) to lighting, distribution O&M expense of $2.9 million from various distribution operation and distribution maintenance accounts allocated to lighting, $0.3 million from various customer service/sales accounts allocated to E1 Rate Schedule lighting and $1.8 million of total A&G expense. Based upon the underlying labor costs within account 596 and the various distribution operation, distribution maintenance and customer service accounts allocated to E1 Rate Schedule lighting, approximately 47%, or $0.9 million, of A&G expense was directly allocated to E1 Option I Rate Schedule lighting and the balance was allocated to the various distribution O&M accounts allocated to E1 Rate Schedule lighting.

The total customer service and distribution O&M expense allocated to lighting, including A&G allocated to these accounts, was further allocated to the various E1 Rate Schedule luminaire/distribution charges based upon the system wattage of the luminaires and lamps. All O&M ($3.1 million) and A&G ($0.9 million) directly assigned to lighting was, with the exception of outage restoration, group re-lamping, LED washing, post inspection and post painting, spread equally across all luminaires. O&M associated with LED washing was allocated to LED luminaires, both overhead-fed and underground-fed, based upon the underlying LED saturation and contract cost, O&M associated with post inspection and post painting was spread equally to all underground fed luminaires and O&M for group re-lamping was allocated to metal halide luminaires only. O&M associated with outage restoration was allocated separately to underground and overhead fed lighting based upon historical outage costs.

Q. Can you provide an overview of the Company's street lighting asset allocation proposal in its November 1, 2016 Depreciation filing in MPSC Case No. U-18150?

A. Yes. The Company currently has two asset accounts for street lighting, one each for overhead and underground fed lights. The proposal filed in the depreciation case reflected the redistribution of the existing overhead and underground assets in the two existing FERC subaccounts to a total of eight FERC subaccounts (creation of 6 new accounts) to more accurately record the various street lighting assets to support the rate design process. The proposed subaccounts for overhead-fed lights are as follows:

Subaccount 373010, Street Lighting Infrastructure
Subaccount 373030, Street Lighting Wire
Subaccount 373070, Street Lighting Luminaires – HID
Subaccount 373080, Street Lighting Luminaires – LED

The proposed subaccounts for underground fed lights are as follows:

Subaccount 373020, Street Lighting Infrastructure
Subaccount 373040, Street Lighting Wire/Cable
Subaccount 373050, Street Lighting Luminaires – HID
Subaccount 373060, Street Lighting Luminaires – LED

The subaccount balances proposed in the depreciation case for year-end 2015 were used as a basis to add the street lighting capital spent in 2016 & 2017 and the projected capital to be spent in 2018, 2019 and the first four months of 2020. These account balances were then used to allocate capital related costs to the various lighting technologies. While the proposed street light asset allocation from the depreciation case is being used for rate design, the currently approved depreciation rates are the basis of street light asset depreciation expense.

Q. How was depreciation expense allocated to the proposed E1 Option I Rate Schedule luminaire charges in the lighting model?

A. The total depreciation expense reflected in the E1 Option I Rate Schedule luminaire charges, as established in the Company's cost of service model supported by Witness Lacey, is $15.6 million. This total depreciation expense reflects depreciation for the directly assigned lighting asset accounts of $10.9 million, the distribution asset accounts allocated to lighting of $1.7 million and the balance associated with general and intangible plant accounts allocated to lighting.

Consistent with the allocation performed in the previous rate cases, the depreciation expense for the directly assigned lighting asset accounts followed the asset allocation for each of the FERC subaccounts in the depreciation case. The depreciation expense for overhead subaccount 373010 (street lighting infrastructure) was allocated equally to both overhead and underground fed luminaires. The depreciation expense for overhead subaccount 373030 (Street Lighting wire) was allocated to all overhead luminaires equally. The depreciation expense for underground subaccounts 373020 (Street Lighting Infrastructure) and 373040 (Street Lighting Wire/Cable) was allocated to all underground-fed luminaires equally.

The depreciation expense for both the overhead and underground luminaire subaccounts (both LED and HID) was allocated to the respective overhead and underground luminaires based upon lighting technology, wattage and underlying original investment. For instance, all underground-fed mercury vapor luminaires received an allocation of depreciation expense from subaccount 373050 (underground street lighting luminaires – HID) based upon the luminaire type's investment and underlying mercury vapor luminaire useful life utilized to establish rates in MPSC Case Nos. U-18014, U-18255 and Credit A.

The depreciation expense that was allocated to lighting from distribution was allocated to all underground and overhead lighting based upon each luminaire type's system wattage, the best representation of each lighting type's usage of the distribution system.

Q. How was the revenue requirement for other taxes, return on investment and income tax allocated to the proposed E1 Option I Rate Schedule luminaire charges?

A. Consistent with the allocation performed in the prior two rate cases, all other capital-related components were allocated to the various luminaire types in a manner similar to that employed for the underlying depreciation expense for the luminaire types. For the directly assigned street lighting asset subaccounts, other taxes, return on investment and income tax basically followed the allocation of net plant to each of the lighting types. The net plant in subaccount 373010 was allocated equally to all luminaires, both overhead and underground, the net plant in the remaining non-luminaire overhead accounts was allocated equally to all the overhead luminaires, and the net plant in the remaining non-luminaire underground accounts was allocated equally to all of the underground luminaires. For the luminaire accounts, the net plant was first allocated to either overhead or underground based upon subaccount, next to

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the lighting technology (HID or LED) based upon subaccount, and then to the various wattage sizes based upon initial luminaire investment.

For the distribution subaccounts that were allocated (versus directly assigned) to street lighting, the allocation of all other capital-related components such as return on investment, other taxes and income taxes was performed based upon each luminaire type's system wattage, the best representation of each lighting type's usage of the distribution system.

Q. Have you proposed any new surcharge mechanisms for the E1 Option I Rate Schedule?

A. Yes. I have proposed the creation of a "post" charge for underground-fed lighting, both the E1 Rate Schedule Option I and the D9 Rate Schedule. I have reviewed the lighting tariffs of other electric utilities that provide outdoor lighting services and many of them have both a luminaire charge and a post or pole charge in lieu of an up-front customer contribution or CIAC. DTE is proposing to create the post charge as an alternative to CIAC for newly installed underground-fed lighting. The post charge would recover the revenue requirement associated with the DTE capital expense not covered by the 3-year revenue credit currently provided to new lighting customers. Specifically, the charge would recover the return on and of the additional capital expense including depreciation, income tax, return, and property taxes. O&M expense associated with ongoing maintenance of the light would continue to be recovered through the luminaire charge.

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Q. How was the post charge determined?

A. The proposed monthly post charge of $6.93 was developed by calculating the net present value of the revenue requirement for the life of the assets. The life of the assets or depreciable life was established as the existing group depreciation rate of 2.93% for underground-fed assets. The property tax rate was set to that of the average property tax rate for lighting assets, the income tax rate was set to 27%, the after-tax WACC was set to 5.76% as proposed in this proceeding and it is assumed that the NPV of the revenue requirement would be recovered through monthly charges over 20 years. The initial investment was set to $1,000 and the proposed post charge would be applied to each increment of initial investment. For example, if the incremental capital contribution for a new lighting installation totaled $4,000, DTE would invoice the customer for 4 post charges.

Q. Are you proposing any changes to the contract length for underground-fed customers that avail themselves of the post charge?

A. Yes. I am proposing to extend the minimum contract length to 10 years and also restricting the availability of this option to new underground installations for a minimum of 5 lights or more. Establishing these contract requirements will provide high likelihood that DTE's capital investment in these assets will be recovered from the contracting party.

Q. Do you believe the proposed allocation of costs reflected in the various E1 Option I Rate Schedule luminaire charges is reasonable?

A. Yes. The methodology utilized in the lighting model to allocate each of the individual cost of service components discretely, rather than in total, more accurately reflects the cost to provide lighting service to underground and overhead assets as well as the various lighting technologies. This general methodology was used by the Company in its previous general rate cases (U-18014, U-18255 & Credit A) and the usage of the eight separate asset subaccounts for allocation of the capital-related costs results in more accurate rate setting based upon both how the lights are fed as well as the lighting technology, wattage and luminaire investment.

Q. How were the E1 Option II Rate Schedule charges developed?

A. The E1 Option II Rate Schedule charges were developed based upon a share of the production revenue requirement allocated by Witness Lacey in the Company's cost of service model to the E1 Rate Schedule, a share of the distribution and customer service revenue requirements allocated by Witness Lacey in the Company's cost of service model to the E1 Rate Schedule and a small allocation of the O&M expense directly assigned to the E1 Rate Schedule from Account 596. The allocations of revenue requirement from production, distribution and customer service to the E1 Option II Rate Schedule were accomplished on a per kWh basis across all E1 Option II rates. The proposed rates for the E1 Option II Rate Schedule are displayed in a luminaire charge, similar to that for Rate Schedule E1 Option I, and energy charges, both capacity and non-capacity, in a cent/kWh format.

Q. Have you eliminated any pricing from your presentation of charges for E1 Option II Rate Schedule?

A. Yes. I have eliminated the proposed pricing for all metal halide lighting from this rate schedule. This rate schedule is not open to new customers, there are no existing customers with metal halide luminaires and all existing customer lighting must be

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converted to either the E1 Option I or Option Rate Schedules upon conversion. Therefore, there is no need for the presentation of E1 Option II Rate Schedule metal halide charges.

Q. How were the E1 Option III Rate Schedule charges developed?

A. The E1 Option III Rate Schedule charges were developed based upon a share of the total production revenue requirement allocated by Witness Lacey in the Company's cost of service model to the E1 Rate Schedule, a share of the total distribution revenue requirement allocated by Witness Lacey in the Company's cost of service model to the E1 Rate Schedule and a share of the customer service revenue requirement allocated by Witness Lacey in the Company's cost of service model to the E1 Rate Schedule. The allocations of revenue requirement from production, distribution and customer service to the E1 Option III Rate Schedule were performed on an equal energy basis across all E1 Option III rates. The proposed E1 Option III Rate Schedule distribution and energy charges, both capacity and non-capacity, are displayed in a cent per kWh format, allowing for a transparent comparison of lighting costs for the various luminaire system wattages and the various lighting technologies.

Q. How has your proposed cost allocation methodology impacted the present rates for the E1 Rate Schedule?

A. The cost allocation methodology described above and employed in the lighting model reflects a revenue deficiency for all three E1 Rate Schedule options. Based upon using the same cost allocations in the lighting rate model that were utilized in the Company's last three rate cases, all Rate Schedule E1 Option I lighting rates proposed in this proceeding are below their cost of service, regardless of their technology or how they were fed, overhead or underground. In general, the revenue deficiency for underground-fed lighting is lower than that for over-head-fed lighting and the revenue deficiency for lower wattage luminaires is lower than that for higher wattage luminaires.

Q. What is your proposal regarding rate design in this proceeding for Rate Schedule E1 Option I rates?

A. Consistent with the final rate design in MPSC Cases U-18014 and U-18255 and the proposed rate design in the Credit A rate case, I have proposed a continuation of the gradual move towards rates which are entirely based upon cost of service for the lighting class. Consensus on this methodology was reached in the lighting collaborative ordered in case No. U-17767 and beginning with rate Case No. U-18014, the Rate Schedule E1 Option I lighting rates are being gradually moved to rates which are entirely based upon cost of service. The rates recently approved in Case No. U-18255 (limiting the increase to 15% for any individual municipality) and proposed in the Credit A rate case (capping all rates below their cost of service to the rate approved in U-18255) made significant progress toward rates which are entirely based upon cost of service.

Q. How were the Rate Schedule E1 Option I proposed rates developed in this proceeding?

A. The proposed Rate Schedule E1 Option I lighting rates were designed with two goals in mind; (1) continue the gradual move to rates which are entirely cost based and (2) minimize the impact of the proposed lighting rates on the monthly lighting bill for any municipality. Using the lighting rate model, the first step towards achievement of these goals was to limit the overall increase on any municipality and/or total lighting rate to twice the proposed increase in revenue requirement versus that proposed in the recently filed Credit A rate case. The second step of the process was to allocate the remaining revenue deficiency for the Rate Schedule E1 Option I class, on a percentage basis, to all the remaining lights. This methodology resulted in increasing the rates based upon the lighting model cost of service in this proceeding by 0.58% of the total proposed Credit A luminaire rate. For example, the proposed rate in the Credit A rate case for a 175-watt metal halide luminaire fed from overhead service was $22.07/month, the rate from the lighting model based upon cost of service in this proceeding is $25.80/month and the proposed rate in this proceeding is therefore $25.93/month ($25.80 + (0.0058*$22.07)).

Rate Schedule D9

Q. How were the proposed rates for the D9 Rate Schedule determined?

A. The proposed luminaire rates for the D9 Rate Schedule for both commercial and residential OPL service were developed based upon the allocated and directly assigned distribution costs supported by Witness Lacey in the Company's cost of service model. The luminaire rate design methodology employed in the lighting model for the D9 Rate Schedule mirrors the methodology employed for the E1 Rate Schedule with all allocated distribution costs assigned to luminaire charges based upon energy consumption and the directly assigned costs allocated based upon the underlying individual cost of service components. As I discussed earlier, the proposed energy charges, both capacity and non-capacity, for the D9 Rate Schedule for both commercial and residential OPL service were developed collectively with the E1 Rate Schedule energy charges.

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Q. Are all of the proposed luminaire rates for the D9 Rate Schedule entirely cost-based?

A. No. The proposed rates for Rate Schedule D9 required the use of the same methodology that was employed for the E1 Option I Rate Schedule. For the OPL rate design, this methodology resulted in increasing the rate based upon the lighting model cost of service by 0.62% of the total proposed Credit A luminaire rate to arrive at the proposed OPL rates. The proposed rates for Rate Schedule E1 Option II & III (both municipality-owned) and Rate Schedule E2 continue to be entirely based upon their cost of service.

Rate Schedule E2

Q. How were the proposed Rate Schedule E2 charges determined?

A. The Rate Schedule E2 charges were developed based upon the production, both capacity and non-capacity, and distribution revenue requirements allocated to Rate Schedule E2 customers by Witness Lacey in the Company's cost of service model. Each of the revenue requirement amounts were divided by the total forecasted energy for the projected test period to arrive at a distribution rate, a non-capacity energy rate and a capacity energy rate in cents/kWh. The total rate approved in MPSC Case No. U-18255 was 7.70 cents/kWh. The total rate proposed in this proceeding is 8.41 cents per kWh which includes a distribution charge of 1.91 cents per kWh, a capacity energy charge of 2.85 cents per kWh and a non-capacity energy charge of 3.65 cents per kWh.

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Q. How has Witness Lacey's presentation of the revenue deficiency/sufficiency for production presented in this case impacted your rate design?

A. To allocate the targets to the lighting tariff energy charges, both capacity and non-capacity, in the cost of service based rate presentation, I have allocated the revenue sufficiency for Rate Schedule E2 to the E2 rate directly and I have allocated the total sufficiency for the D9 and E1 Rate Schedules to those energy rates in total.

Q. Will you please describe Exhibit A-16 Schedule F10?

A. This exhibit contains the proposed tariff sheet changes which result from the pricing changes described above.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THOMAS W. LACEY

DTE ELECTRIC COMPANY
QUALIFICATIONS OF THOMAS W. LACEY

Line
No.

Q. What is your name, business address and by whom are you employed?

A. My name is Thomas W. Lacey. My business address is One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC (DTE Energy or DTE) as a Principal Financial Analyst in the Revenue Requirements Department of the Regulatory Affairs Organization.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q. What is your educational background and business experience?

A. I received a Bachelor of Science Degree in Accounting from Michigan State University in 1981 and a Master's in Business Administration from Wayne State University in 1992. From 1982 until 2001, I was employed by ANR Pipeline Company (ANR) in the Rates and Regulatory Affairs department. I had several positions of increasing responsibilities within the Rates area, ultimately rising to the position of Senior Rates Analyst. During my nineteen years with ANR, I worked on numerous rate proceedings and filings before the Federal Energy Regulatory Commission (FERC) including rate cases (FERC Docket Nos. RP82-80, RP83-79, RP86-169, RP89-161, RS92-1 and RP94-43). My work was primarily in the areas of cost-of-service and rate design. In 2002, I joined DTE as a Financial Analyst in the Load Research department of Regulatory Affairs. I worked in Load Research until December 2005. My responsibilities within Load Research included extensive work on the 2003 Michigan Consolidated Gas Company (MichCon) rate case (U-13898) and The Detroit Edison Company (Detroit Edison) rate filings. In

December 2005, I accepted my current position.

Q. What are your responsibilities as a Principal Financial Analyst for both DTE Electric and DTE Gas?

A. As a Principal Financial Analyst, my responsibilities include the preparation of revenue requirements, cost of service and rate design, testimony, exhibits and workpapers, in cases for both DTE Gas and DTE Electric. I am also responsible for managing certain MPSC filings such as DTE Electric's Renewable Energy Plan (REP) Plan case and DTE Electric's most recent depreciation cases.

Q. Have you previously sponsored testimony in cases before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes, I have. I have sponsored testimony in the following cases:

U-13898	MichCon 2006 Uncollectible Expense True-up Mechanism and Safety and Training Related Expenditure Report
U-15985	MichCon 2009 General Rate Case Proceeding
U-16290	Reconciliation of MichCon's 2010 Energy Optimization (EO) Program
U-16730	MichCon 2011 Updated Energy Optimization Plan
U-16730	MichCon 2011 Updated Energy Optimization Plan
U-16751	Reconciliation of the MichCon 2011 EO Program
U-16999	MichCon 2011 General Rate Case Proceeding
U-17288	Reconciliation of the DTE Gas 2012 EO Program
U-17602	Reconciliation of the DTE Electric 2013 EO Program
U-17608	Reconciliation of the DTE Gas 2013 EO Program

U-17632	Reconciliation of the DTE Electric 2013 REP Program
U-17762	DTE Electric 2016/2017 Energy Optimization Plan
U-17763	DTE Gas 2016/2017 Energy Optimization Plan
U-17832	Reconciliation of the DTE Electric 2014 EO Program
U-17841	Reconciliation of the DTE Gas 2014 EO Program
U-18014	DTE Electric General Rate Case Proceeding
U-18111	DTE Electric REP Plan Proceeding
U-18232	DTE Electric REP Plan Proceeding
U-18248	DTE Electric Capacity Charge
U-18255	DTE Electric General Rate Case Proceeding
U-20029	Reconciliation of the DTE Electric 2017 EWR Program
U-20035	Reconciliation of the DTE Gas 2017 EWR Program
U-20105	DTE Electric Tax Credit A Proceeding
U-20172	Reconciliation of the DTE Electric 2017 REP Program

Q. Have you previously testified or submitted testimony in any other regulatory proceedings?

A. Yes. I sponsored testimony in ANR's general rate case in Docket No. RP94-43. I testified at a hearing before the FERC in Docket No. RP94-43.

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Unbundled Cost of Service (UCOS) Studies for DTE Electric's projected test year ending April 30, 2020. I also support revenue requirement calculations for: (1) customer related costs, (2) capacity charge by rate class, and (3) Infrastructure Recovery Mechanism (IRM) by rate class.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am sponsoring the following exhibits:

Section B - Projected Test Year Exhibits

Exhibit	Schedule	Description
A-16	F1.1	UCOS 4CP 75-0-25 Production, 12CP 100-0-0 Transmission, 12 Months Ending October 31, 2018
A-16	F1.2	UCOS Distribution by Voltage
A-16	F1.3	Functionalization Overview
A-16	F1.4	Customer Charges by Voltage for Residential and Commercial Secondary
A-16	F1.5	Capacity Charge Revenue Requirement
A-30	T8	IRM Production Revenue Requirement
A-30	T9	IRM Distribution Revenue Requirement

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Line No.

Q. Can you provide an overview of your testimony and recommendations in this proceeding?

A. Yes, below is a summary of my testimony and recommendations.

- I performed forecast test year UCOS studies that apply the allocation methodologies summarized in the table below:

Cost Type	**Proposed Method**
Production	4CP 75-0-25
Transmission	12CP 100-0-0
Distribution	Various (by voltage class)
Customer-related	Various; uncollectibles by historic incurrence

CP = Coincident Peak, 12 represents average of twelve months and 4 represents average of the four summer months, June through September.

- The proposed allocation method for production (i.e. generation), transmission and distribution reflects the methods approved in Case No. U-18255.
- The proposed allocation of customer-related cost is consistent with past practice. Uncollectibles are allocated to classes based on their historic contribution to net write-offs as approved by the Commission in Case U-18255.
- Customer related distribution costs are calculated using all distribution costs for residential secondary and commercial secondary.
- Capacity related Power Supply Costs are calculated by reducing total Production Cost of Service for fuel costs, variable O&M and non-capacity power supply costs.

Q. How is your testimony organized?

A. My testimony consists of the following five parts:

Part I – Forecast Unbundled Cost of Service Studies

Part II – Cost Allocation Methods

Line No.

Part III – Customer Charge Costs

Part IV – Capacity Charge Revenue Requirement

Part V – IRM Revenue Requirement

Part I: Forecast Unbundled Cost of Service Studies

Q. What is a fully allocated embedded UCOS?

A. A UCOS allocates all items of utility property and cost to determine the fully allocated embedded cost of service for each consolidated customer class of service and shows each customer class' share of costs by major function (Power Supply and Distribution).

Q. What is the objective of a UCOS?

A. The objective of a UCOS is to apportion all costs required to serve customers among each customer class in a fair and equitable manner. This is defined to be that allocation of costs which best reflects the engineering and operating characteristics of the electric utility system and generally results in the costs of the system being allocated to those who caused the costs to be incurred.

Q. What process steps are typically performed in developing a UCOS?

A. The typical process to develop a UCOS consists of three steps: functionalization, classification, and allocation. Functionalization assigns all costs to the major functions, i.e. Power Supply and Distribution. Classification divides these costs into customer-related costs, demand-related costs, and energy-related costs. The sum of these three types of costs within a given class is the cost to serve that class. The last step, allocation, apportions the cost classifications to the respective customer classes based upon each class' responsibility for the incurrence of these costs.

Q. What functions did you use in the cost studies?

A. The major utility functions used in the cost studies are Power Supply (Generation and Transmission) and Distribution. Power Supply includes costs associated with the Company's generating plants, fuel, purchased power and the expense associated with transmission services provided to DTE Electric by the Midcontinent Independent System Operator (MISO) and the International Transmission Company (ITC). Distribution includes the costs associated with the Company's distribution system that generally operates at voltages of 40 kV and below and includes customer service expenses.

Q. How does the UCOS functionalize DTE Electric's costs?

A. On Exhibit A-16, Schedule F1.3 titled "Functionalization Overview," I present the approach I used to functionalize the Company's costs. The MPSC Uniform System of Accounts (USofA) governs utility accounting for ratemaking purposes and serves as the basis for functionalizing direct costs. For example, the USofA requires utilities to record generating plant costs in accounts 310 through 359 and the associated operation and maintenance (O&M) expense in accounts 500 through 557. These costs are directly assigned to the power supply function. Similarly, the USofA requires utilities to record distribution plant costs in accounts 360 through 373 and O&M costs in accounts 580 through 598 that are directly assigned to the distribution function.

The O&M cost in accounts associated with providing customer service are directly assigned to distribution because they apply whether a customer receives power supply from DTE Electric or an alternative electric supplier (AES). Because DTE Electric has divested its transmission plant, all that remains in the USofA's accounts designated for transmission are the plant costs associated with generator step-up transformers. These costs are directly assigned to power supply. In addition, power supply includes the expense charged to account 565, "Transmission of Electricity by Others" including MISO charges. The property tax associated with production plant is directly assigned to power supply based on tax information provided by the Company's Property Tax Department. A share of the property tax associated with general and software plant is allocated to power supply in proportion to the power supply-related general and software plant and the remaining balance is assigned to distribution. Indirect costs are comprised of general and intangible (software) plant costs recorded in accounts 303 and 389 through 399, Administrative and General (A&G) expense in accounts 920 through 935, taxes, and working capital. The cost study also includes a credit for miscellaneous revenue, which is applied to the appropriate functional component based on a combination of direct assignment and allocation.

Q. How was General and Intangible (G&I) plant functionalized in the Forecast UCOS?

A. The Forecast UCOS relied on the G&I direct assignment study performed by the Company in compliance with the December 23, 2008 Order in Case No. U-15244, as modified to separate out intangible plant.

Line No.

Q. How are the remaining indirect costs and miscellaneous revenues functionalized in the Forecast UCOS?

A. A&G expense is functionalized using the direct labor cost. Working capital is functionalized using allocators appropriate to each of the asset and liability line items. For example, fuel inventory is directly assigned to power supply and accounts receivable is functionalized based on net plant. Miscellaneous revenue is functionalized using a combination of direct assignment and allocation.

Q. How does the Forecast UCOS allocate costs to the various customer classes?

A. In general, the allocation schedules used for each function are intended to reflect the load that utilizes the infrastructure associated with that function.

Q. What method was used to allocate production-related and transmission costs in the Forecast UCOS?

A. The Forecast UCOS used the 4CP 75-0-25 method of cost allocation for production-related and 12CP 100-0-0 for transmission costs. For production, the first component is the average of the 4 monthly coincident peaks weighted 75%, the second component is energy use coincident to the MISO on-peak period weighted 0%, and the third component is total energy use weighted 25%, i.e., 4CP 75-0-25. For transmission, the first component is the average of the 12 monthly coincident peaks weighted 100%, the second component is energy use coincident to the MISO on-peak period weighted 0%, and the third component is total energy use weighted 0%, i.e., 12CP 100-0-0.

Q. Does the UCOS develop costs for each individual rate schedule?

A. No, it does not. The allocation process apportions costs to major classes of service that are comprised of one or more individual rate schedules.

Q. How are the allocation schedules used in the UCOS developed?

A. The allocation schedules in the UCOS are either developed external to the UCOS model or internally generated by the UCOS model. The externally developed allocation schedules are based on customer class parameters, such as the number of customers, customer energy use and customer demand, and serve as inputs to the UCOS. The internally generated allocation schedules are calculated within the UCOS model and are based on previously allocated plant investment and/or O&M expense. An example of an internal allocation schedule is schedule 521, "Distribution Plant-In-Service." This schedule reflects the sum of the class allocations of distribution plant in service from each USofA account, some of which are further subdivided by voltage level.

Q. Is Company Witness Mr. Farrell the source of all the externally developed allocation schedules used in the UCOS?

A. No, he is not. The UCOS contains 16 basic externally developed allocation schedules. Of these 16 schedules, 11 are developed and supplied by Witness Farrell and are described in his testimony. I develop the other five schedules. 1) Schedule 800 is based on the number of customers in each class using data from the Company's billing system. 2) Schedules 370T and 370A are based on the number of meters (traditional and automated meter infrastructure (AMI), respectively) associated with each class and the approximate average cost of the metering equipment associated with each class. 3) Schedule 370C is used to allocate meter related costs, this is a combination of Schedules 370T and 370A. 4) Schedule 807, net write-offs by major customer class, is based on data from the Company's billing system, which I use to allocate uncollectible expense.

Q. How are Distribution System costs allocated within the UCOS?

A. The direct distribution costs are allocated based on Schedules 201-205, and 300. The plant-related costs are allocated on the schedule appropriate to the voltage level at which the equipment operates. Distribution O&M expense is allocated based on the corresponding plant-related cost. For example, overhead lines maintenance expense (account 593) is allocated based on the sum of plant-in-service for poles and fixtures (account 364A), overhead conductors (account 365A), and overhead services (account 369A). The cost of some components within distribution, such as those associated with single customer substations, is directly assigned.

Q. How are the indirect costs allocated within the UCOS?

A. As stated in my discussion of functionalization, indirect costs are comprised of general and software plant costs recorded in accounts 303 and 389 through 399, A&G expense in accounts 920 through 935, taxes, and working capital. The functionalized general and software plant costs are allocated based on the corresponding functional plant in service. In other words, the general and software plant costs associated with power supply are allocated based on production plant in service and the general and software costs associated with distribution are allocated based on distribution plant in service. Property taxes are allocated based on the corresponding functional plant in service. The functionalized A&G and payroll

Line No.

taxes are allocated based on the corresponding functional labor ratios. The working capital allocations are driven by the numerous allocators associated with each of the line items that comprise working capital, many of which are the sum of several other lines.

Q. How are you reflecting customers formerly served by Public Lighting of Detroit (PLD) in this case?

A. The customers formerly served by PLD are now retail customers of DTE Electric. Consistent with the Company's Transitional Cost Recovery Plan approved by the Commission in its order dated May 13, 2014 in MPSC Case No. U-17437 and as further explained by Company Witness Ms. Uzenski, the costs associated with building out DTE Electric's distribution system to provide retail service to former customers of PLD are eliminated from this filing.

Q. What forecast test year was used for the forecast UCOS?

A. The forecast test year is the 12 months ending April 30, 2020.

Q. What is the source of the financial information used to produce the forecast UCOS?

A. I used the financial information supplied by Witness Uzenski.

Q. Do the levels of investment for each of the distribution accounts within the Cost of Service match the figures as they are typically presented in the Company's financial records and Form P-521?

A. Not entirely. Although the total distribution investment matches the Company's financial records, the levels of investment for some distribution accounts within the Cost of Service do not match. These accounts do not match because I break out separately the cost of equipment that operates at sub-transmission voltage (24/40 kV) and apply allocation methods that reflect the engineering and operating characteristics of the associated equipment and expense. This redistribution of investment to the accounts in which it was classified prior to the Company's reclassification of 24/40 kV from 350 series accounts (Transmission) to 360 accounts (Distribution) is necessary to properly allocate the associated costs. A reclassification for accounting purposes does not change the engineering and operating characteristics of the associated equipment and expense.

Q. Why did the Company reclassify the 24/40 kV investment in the first place?

A. This reclassification was the result of the Order in MPSC Case No. U-11337 and was pursued to comply with the Company's interpretation of FERC Order 888.

Q. What method have you proposed in this case to allocate production-related and transmission costs?

A. For production-related costs, I have used the 4CP 75-0-25. For transmission costs, I have used the 12CP 100% demand method (12CP 100-0-0). I discuss my reasoning for these methods in Part II of my testimony, "Cost Allocation Methods."

Q. What does Exhibit A-16, Schedules F1.1 and F1.2 show?

A. Schedule F1.1, "Unbundled Cost of Service 4CP 75-0-25 Production, 12CP 100-0-0 Transmission, TME April 30, 2020" summarizes the results of the Year Ended April 30, 2020 UCOS for Production. It shows the production related revenue

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(sufficiency)/deficiency associated with each consolidated rate class. This exhibit shows the Company experienced a total production revenue deficiency of $212.8 million. Schedule F1.2, "Unbundled Cost of Service Distribution by Voltage TME April 30, 2020" summarizes the results of the year ending April 30, 2020 UCOS for Distribution by voltage level. It shows the distribution related revenue (sufficiency)/deficiency by voltage level, a total of $115.7 million. In total the Company experienced a total revenue deficiency of $328.4 million (production and distribution), which matches the revenue deficiency on Exhibit A-11, Schedule A-1, supported by Company Witness Mr. Slater.

Q. What does the distribution COSS (Exhibit A-16, Schedule F1.2) reflect?

A. Schedule F1.2, reflects a revenue deficiency of $108.6 million on line 24 and $115.7 million on line 28. The $108.6 million is distribution's share of the $321.4 million revenue deficiency reflected on line 8 of Exhibit A-11, Schedule A-1. The $115.7 million on line 28 includes the additional $7.1 million revenue deficiency related to the Tree Trim Surge reflected on line 9 of Exhibit A-11, The revenue deficiency related to the Tree Trimming Surge is calculated by Witness Slater on Exhibit A-22, Schedule L2. I have functionalized the Tree Trimming Surge as distribution because it consists of costs included in O&M account 593 (Maintenance of Overhand Lines). I allocated the Tree Trimming Surge to various voltage level using the same allocator used to allocate account 593. Company Witnesses Bloch, Dennis, Holmes and Johnston use lines 28 and 29 of Schedule F1.2 to calculate rates.

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Part II: Cost Allocation Methods

Q. Are the cost allocation methods used to produce the forecast UCOS consistent with the ones approved by the Commission in Case No. U-18255?

A. Yes.

Q. What allocation methods did you use for the forecast UCOS this proceeding?

A. I performed UCOS Studies for the forecast test year based on the proposed allocation methods summarized in the following table and are the same as approved in Case U-18255:

Cost Type	**U-18255 Method**	**Proposed Method**
Production	4CP 75-0-25	4CP 75-0-25
Transmission	12CP 100-0-0	12CP 100-0-0
Distribution	Various (by voltage class)	Various (by voltage class)
Customer-related	Various; uncollectibles by historic incurrence	Various; uncollectibles by historic incurrence

CP = Coincident Peak, 12 represents average of twelve months and 4 represents average of the four summer months, June through September.

Q. What allocation method are you proposing for Transmission?

A. The transmission system that serves DTE Electric's service territory is owned by ITC. DTE Electric's share of the cost of providing transmission service to its customers is determined based upon a 12CP load ratio share. Therefore, an allocation basis that relies on the 12CP 100% demand is reflective of cost causation and was approved in the Commission's April 18, 2018 order in Case U-18255.

Q. What allocation method are you proposing for Production?

A. I propose to continue using the 4CP 75-0-25 method approved in the

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Commission's April 18, 2018 order in Case U-18255. The use of 4CP 75-0-25 is a good initial step in appropriately aligning cost allocation and cost causation.

Q. What is DTE Electric's allocation methodology for distribution?

A. The Company uses three allocation bases for distribution: demand, customer, and those based on special studies. Demand based allocators are used for poles, wires, conduit, substations, transformers and other equipment that comprise the distribution system. Customer based allocators are used for service drops and billing. Special studies were performed to develop the basis for allocating meters and uncollectible expense. The proposed allocation method selected for distribution allocates distribution by voltage level class. Specifically, distribution is broken into residential secondary, commercial secondary, primary, sub-transmission, transmission, and lighting (E-1 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals). This allocation method was approved by the Commission's April 18, 2018 order in Case U-18255.

Q. Why is lighting maintained as a separate class as opposed to being grouped by voltage?

A. Unlike the distribution service for other classes, the lighting class has a significant amount of dedicated infrastructure costs that are required to be directly assigned.

Q. What determines cost causation for distribution?

A. For distribution, the parameters used to design and build the system determines cost causation. The principle system design parameters are the geographic area to be covered and the maximum demand placed on the system at a given voltage level. Because rebuilding a circuit is expensive, distribution planning must consider future load growth and reliability. Also, many of the components of the distribution system are standardized to achieve efficiencies. Consequently, circuits initially have extra capacity but once demand reaches a certain threshold, either the circuit configuration must be changed or the components replaced with components with greater capacity. To meet reliability criteria, distribution planning engineers sometimes add alternate lines and transformers. This redundancy maximizes, to the degree practical, the Company's ability to maintain service in the face of storms. Because of the need to consider future growth, reliability, and standardized components, the capacity of the system will generally support loads greater than those initially experienced. Therefore, once installed, distribution system costs are generally not affected by increases or decreases in either demand or energy until the circuit limit (demand threshold) is approached. However, when viewed prospectively, distribution system design cost is caused (driven) by the number of customers served and the maximum demand placed on the system at a given voltage level.

Q. How did you produce the UCOS by voltage level?

A. I used the allocation schedules developed by Witness Farrell and delivery-related revenues by voltage for customers served at voltage levels primary and above developed by Company Witness Mr. Bloch. In addition, I performed calculations to break out the UCOS inputs that I prepare by voltage level. I used these inputs to produce the proposed UCOS that allocates and displays costs by voltage level.

Q. How are you proposing to allocate costs associated with uncollectible

expense?

A. The costs associated with uncollectible expense are assigned based on net write-offs. This method accurately reflects cost causation by measuring write offs net of recoveries caused by each major class and assigning the uncollectible expense on that basis. I use net write-offs as the basis for allocating uncollectible expense because uncollectibles are not recorded by customer class. This allocation method was approved by the Commission's April 18, 2018 order in Case U-18255.

Part III: Customer Charge Costs

Q. What type of costs are included within distribution?

A. The Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners (NARUC) classifies both distribution plant and expenses as being either demand-related, customer-related, or a combination of the two (Electric Utility Cost Allocation Manual, NARUC, January, 1992). Chapter 6 of the manual titled "Classification and Allocation of Distribution Plant" includes Table 6-1 "Classification of Distribution Plant" and Table 6-2 "Classification of Distribution Expenses". Within both tables and Chapter 6, the only cost classification types identified are demand and customer; energy is not listed as a basis for classifying any portion of distribution-related cost. The only energy-related costs identified are production related.

Q. What is the most appropriate method to recover distribution costs?

A. Demand-related costs should be recovered through a demand charge and customer-related through a monthly customer charge. This will properly match cost recovery

Line
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to cost causation.

Q. Currently, how does the Company recover its demand-related distribution costs for the residential and commercial secondary rate classes?

A. Except for the commercial Large General Service Rate D4 which uses a distribution demand charge, the Company currently recovers its demand-related costs through a variable energy charge, because the Company only has two-part rates: customer and energy charges. This matches the way in which most other electric utilities recovery their costs from residential and commercial customers. However, the industry trend is moving toward the use of three-part rates; adding a demand charge for the recovery of costs from residential and commercial customers. This trend is driven by the availability of demand data for customers served at secondary voltage, the desire to more closely match cost recovery with the underlying nature of the costs, and that it is a mismatch to recover non-variable demand costs through a variable energy charge.

Q. How do you propose the Company collect its non-variable distribution demand costs?

A. The Company should recover its non-variable demand costs through its customer charge, since the Company is not yet ready to implement a demand rate for residential and small commercial customers. Currently these demand costs are collected through an energy charge. This causes a significant variation in monthly bills for the collection of costs that are not variable. By collecting non-variable demand costs through a non-variable monthly charge, rates are better aligned with costs. The only non-variable charge available to collect the demand-related costs is

Line No.

currently the customer charge. Cost causation should match cost recovery as much as possible; therefore, all distribution costs, demand and customer related, should be collected through the customer charge.

Q. Do any other utilities support collecting demand costs through customer charges?

A. Yes. Gulf Power Company has proposed collecting demand costs through customer charges in its filing with the Florida Public Service Commission at Docket No. 160186-EI.

Q. What does Exhibit A-16, Schedule F1.4 "Customer Charge Costs by Rate Class" show?

A. Exhibit A-16, Schedule F1.4 details the results of the customer charge calculations. The resulting customer-related costs per month are $45.53 for residential, and $178.88 for commercial secondary. These customer charge costs are determined by calculating customer charges using all distribution costs (demand plus customer). Column (a) of Page 1 lists total distribution costs by cost type and ties to Exhibit A-16, Schedule F1.2. Column (b) of page 1 details the distribution costs for the residential class and column (c) for the commercial secondary

Part IV: Capacity Charge Revenue Requirement

Q. What costs have you included in your calculation of capacity revenue requirement reflected on Exhibit A-16, Schedule F1.5?

A. As directed by Company Witness Mr. Stanczak, I included all Production related costs per Exhibit A-16, Schedule F1.1, except fuel, variable O&M and certain purchase power costs explained later in my testimony. This is the same methodology I supported in Case No. U-18255, the Company's last rate case filing. Generally, the Commission's April 18, 2018 Order in Case U-18255 supported this approach, only differing on the amounts to be subtracted and the calculation of 2018 energy sales net of fuel on line 2 of Exhibit A-16, Schedule F1.5.

Q. How is the calculation of energy sales net of fuel different from that adopted by the Commission in Case No. U-18255?

A. I used the calculation of energy sales net of fuel supported by Company Witness Mr. Arnold on his Exhibit A-29, Schedule S3. The Commission reflected a $584 million reduction for energy sales net of fuel in Case U-18255, based on a calculation originally adopted in Case No. U-18248.

Q. Can you describe in more detail the costs reflected on Exhibit A-16, Schedule F1.5?

A. Line 1 of Exhibit A-16, Schedule F1.5 exactly matches line 27 from Exhibit A-16, Schedule F1.1 (COSS for Production). Line 2 is a reduction in revenue requirement for projected energy sales revenue net of projected fuel costs, calculated by Witness Arnold on Exhibit A-29, Schedule S3. Line 3 is a reduction to the revenue requirement for fuel included in the Production COSS. Lines 4 and 5 are a reduction to the revenue requirement for Non-capacity related purchased power. Line 6 is a reduction to the revenue requirement for variable O&M. Line 7 is the total capacity cost revenue requirement that I supply to Witnesses Bloch, Holmes, Dennis, and Johnston.

Q. Did you reduce the capacity charge revenue requirement for any non-capacity related purchased power?

A. Yes. On lines 4 and 5 of Exhibit A-16 Schedule F1.5, I reduced the capacity charge revenue requirement for non-capacity related purchased power. The reason for this adjustment is that these costs are not capacity-related, these purchase power costs are for energy charges purchased from MISO for Rider 3 and Rider 10 (line 4) and other energy related purchased power (line 5). For this reason, the $299.6 million purchased power expense identified on line 5 of Exhibit A-16, Schedule F1.1 is considered to be all capacity except for the $47.2 million directly assigned to Rider 10 and $0.2 million assigned to Rider 3 (which is included with D11) and $156.5 million of other energy-related costs. The $47.4 million of non-capacity cost is equal to the sum of the R10 MISO pricing Option costs listed on line 20 of Exhibit A-13, Schedule C4 and Voltage Level adder costs listed on line 21 of Exhibit A-13, Schedule C4. The $156.5 million of other energy-related purchased power is the difference between the capacity related purchased power costs of $95.7 million calculated by Witness Arnold on Exhibit A-29, Schedule S3 line 7 and the total remaining purchased power costs of $252.2 million ($299.6 million less $47.4 million directly assigned to D11 and Rider 3).

Q. Did you make any other adjustments?

A. I also adjusted for variable O&M on line 6 of Exhibit A-16, Schedule F1.5.

Q. What costs did you include on line 6 of Exhibit A-16, Schedule F1.5 for variable O&M?

A., I calculated variable O&M on Exhibit A-16, Schedule F1.5, page 5. I only included the non-labor portions of Accounts 501 (Fuel Handling), 502 (Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants and Water), 520 (Steam Expenses), 538 (Electric Maintenance Expenses) and 548 (Peaker Expenses).

Q. Why did you only include the non-labor portion in variable O&M?

A. The NARUC Electric Utility Cost Allocation Manual (Manual) describes the classification of production plant in Chapter 4 of the manual. Chapter 4 describes that accounts 502, 505, 519 and 538 should be: Classified between demand and energy based on labor expenses and materials expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related. Therefore, I determined only the material related costs are variable, and that account 501 and 548 should be handled in the same manner. In Chapter 4, the Manual states:

> Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy-related.

Q. Why did you only include the above accounts in variable O&M?

A. Based on my review of the descriptions of the various production O&M accounts in the Code of Federal Regulations, only these accounts appear to be variable. The descriptions for these accounts includes variable material costs such as lubricants, chemicals and water.

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Q. How did you allocate the Capacity Charge revenue requirement to the various rate classes on Exhibit A-16 Schedule F1.5?

A. I allocate the Capacity Charge revenue requirement to the various rate classes using the 200B (4CP) allocator excluding Rider 10, which is the methodology approved in Case No. U-18255. The values for this allocation schedule are listed on Line 8 of pages 1-4 of Exhibit A-16 Schedule F1.5. Line 9 of Schedule F1.5 reflects the amounts allocated to rate class and is calculated by multiplying line 8 by the total Capacity Charge revenue requirement of $1,947.7 million on line 7, divided by 100. Line 10 is the Non-Capacity revenue requirement and is the difference between line 9 and the total production revenue requirement on line 11. Line 11, total production revenue requirement, is equal to line 27 of Exhibit A-16, Schedule F1.1.

<u>Part V: IRM Revenue Requirement</u>

Q. What is reflected on Exhibit A-30, Schedules T8 and T9?

A. Exhibit A-30, Schedule T8, is a four-page exhibit and reflects the allocation of the production related IRM revenue requirement to the various rate classes. Exhibit A-30, Schedule T9, is a one page exhibit and reflects the allocation of the distribution related IRM revenue requirement to the various voltages.

Q. How did you allocate the production related IRM revenue requirement to the various rate classes on Exhibit A-30, Schedules T8?

A. I allocated production related IRM revenue requirement to the various rate classes using allocation schedule 520, which is calculated in the UCOS, described in Part I above, and is equal to each rate classes' share of production related plant. I used this allocator because the components of the IRM revenue requirement are all plant

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or plant related. The value of the allocator is listed on line 1 of Schedule T8. Each rate classes' share is calculated by multiplying the total production related IRM revenue requirement listed on column (a), lines 2, 3 and 4 on page 1 of Schedule T8 by line 1. The IRM revenue requirements listed in column (a) of schedule T8 are calculated on Exhibit A-30, Schedules T6 and T7 by Witness Slater.

Q. How did you allocate the distribution related IRM revenue requirement to the various rate classes on Exhibit A-30, Schedules T9?

A. I allocated distribution related IRM revenue requirement to the various voltage classes using allocation schedule 521, which is calculated in the UCOS, described in Part I above, and is equal to each voltage classes' share of distribution related plant. I used this allocator because the components of the IRM revenue requirement are all plant or plant related. The value of the allocator is listed on line 1 of Schedule T9. Each rate classes' share is calculated by multiplying the total distribution related IRM revenue requirement listed on column (a), lines 2, 3 and 4 on page 1 of Schedule T9 by line 1. The IRM revenue requirements listed in column (a) of schedule T9 are calculated on Exhibit A-30, Schedules T5 by Witness Slater.

Q. How would you propose to allocate any revised IRM revenue requirements resulting from an IRM reconciliation filing?

A. I would allocate any revised, distribution related or production related, IRM revenue requirement to the various rate and voltage classes using the same allocation schedules described above. In the reconciliation example described by Witness Slater in Exhibit A-30, Schedule T13, I would allocate the revised

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distribution revenue requirement of $77.7 million using allocation factor 521.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARKUS B. LEUKER

THE DTE ELECTRIC COMPANY
QUALIFICATIONS OF MARKUS B. LEUKER

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Q. What is your name, business address and on whose behalf are you testifying?

A. My name is Markus B. Leuker. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q. What is your present position with the Company?

A. I am the Manager of Corporate Energy Forecasting.

Q. What is your educational background?

A. I received a Bachelor of Science in Business Administration from Xavier University in Cincinnati, Ohio with a concentration in Marketing and Management in 1991. I received a Master of Business Administration from Xavier University in Cincinnati, Ohio in 1998. I have also completed several Company sponsored courses and attended various seminars to further my professional development.

Q. What is your work experience?

A. I joined the Company in November, 2010 as Manager, Corporate Energy Forecasting. Prior to DTE Electric, I worked for IHS/CSM Worldwide as a Sr. Manager, North American Advisory Services where I led the pursuit, development, execution and delivery of key client projects. Some of my experiences at IHS/CSM Worldwide included: Market Research & Analysis, Market Opportunity Analysis, Business Modeling and Strategic Analysis, Regulatory Market Assessment, and Financial and Scenario Analysis. In addition to my experience with DTE Electric and IHS, I worked as North American Manager, Market Research & Analysis for Visteon Corporation where I managed global coordination of the research function and led a team of

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researchers in various studies including customer and competitor research, new product creation, and customer satisfaction. I have also had prior experience in the utility industry working as a Senior Analyst at Cinergy Corporation (currently Duke Energy). While at Cinergy, I worked on various non-regulated activities and regulated marketing activities.

Q. What are your duties as Manager, Corporate Energy Forecasting?

A. I am responsible for the development of the economic and electric sales forecasting activities for DTE Electric. These activities include data collection, statistical analysis of data, forecast model building and interaction with other departments on forecast-related activities. My role also includes the preparation of long-term (one year or greater) sales forecasts, short-term (monthly) forecasts, next day forecasts, and the economic forecast that supports the sales forecast.

Q. Do you belong to any professional organizations?

A. I am a member of Edison Electric Institute's (EEI) Load Forecasting Group (LFG). The LFG's purpose is to enhance load forecasting capabilities by exchanging information among the group's base of experienced and knowledgeable load forecasters. I am also a member of the Detroit Association for Business Economics (DABE). DABE discusses economic issues affecting Southeastern Michigan.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I sponsored testimony in the following cases:

U-17049 2012 Energy Optimization Plan

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1	U-17097	2013 PSCR Plan
2	U-17302	2013 Renewable Energy Plan Update
3	U-17319	2014 PSCR Plan
4	U-17680	2015 PSCR Plan
5	U-17762	2016-17 Energy Optimization Plan
6	U-17767	DTE Electric General Rate Case
7	U-17793	2015 Renewable Energy Plan
8	U-17920	2016 PSCR Plan
9	U-18014	DTE Electric General Rate Case
10	U-18111	2016 Amended Renewable Energy Plan
11	U-18143	2017 PSCR Plan
12	U-18255	DTE Electric General Rate Case
13	U-18262	2018-19 Energy Waste Reduction Plan
14	U-18403	2018 PSCR Plan
15	U-18419	2017 Certificate of Necessity

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Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide the Company's current electric sales, maximum demand and system output forecast for the period 2018-2028, including the projected 12-month test period May 2019 through April 2020. I will discuss the outlook for the national and local economy which is the basis of the forecast. I will describe how the forecast of electric sales, maximum demand and system output is developed. My testimony will support the reasonableness of the electric sales forecast used by DTE Electric in this proceeding.

Q. Are you supporting any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-5	E1	Annual Sales by Major Customer Classes and System Output 2013-2017 Historical
A-15	E1	Annual Sales by Major Customer Classes and System Output 2018-2028 Forecast
A-15	E2	Annual System Output, Maximum Demand and Load Factor
A-15	E3	Projected Period Known and Measurable Changes to Sales
A-15	E4	Summary of Economic Outlook
A-15	E5	Variance of Temperature-Normalized Electric Sales and Peak and ITRON's Benchmarking Survey Results

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Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How is your testimony organized?

A. My testimony consists of the following parts:

Part I: Current Electric Load Forecast

Part II: Economic Outlook

Part III: Forecast Development

Part I: Current Electric Load Forecast

Q. Can you explain the Company's current electric load forecast?

A. The current forecast of annual sales and system output for DTE Electric's service area for the years 2018 through 2028 is reflected on Exhibit A-15, Schedule E1, page 1 of 3. The current forecast of DTE Electric's full service, also described as "bundled," sales and output is shown on Exhibit A-15, Schedule E1, page 2 of 3, and the current forecast of Electric Choice sales is reflected on Exhibit A-15, Schedule E1, page 3 of 3.

Q. Can you explain Exhibit A-15, Schedule E1?

A. Exhibit A-15, Schedule E1, shows annual sales from 2018 through 2028 for the four major customer classifications: Residential, Commercial, Industrial, and Other. Sales to former PLD customers that are now on DTE Electric retail rates are excluded from sales for 2018 through 2028 because they are included in a separate program – the Transitional Reconciliation Mechanism (TRM), as described by Company Witness Mr. Stanczak. Sales for the projected test period, May 2019 through April 2020, are also

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shown. Additionally, Exhibit A-15, Schedule E1 displays total sales and net system output. Service area sales are presented on page 1 and are further broken down into DTE Electric bundled and DTE Electric Choice sales on pages 2 and 3, respectively. DTE Electric's bundled sales are determined by subtracting Electric Choice sales from DTE Electric's service area sales.

Q. Can you explain Exhibit A-15, Schedule E2?

A. Exhibit A-15, Schedule E2, shows annual net system output, annual peak demand and annual load factor for both DTE Electric's service area and DTE Electric's bundled sales levels. Net system output and peak demand excluding wholesale PLD and former PLD customers that are now on DTE Electric retail rates for historical periods (2014 through 2017) are not available.

System output, annual peak demand and annual load factor for the projected test period ending April 30, 2020 are also shown. A 10% and 90% confidence band on forecasted summer peak demand is provided for DTE Electric's service area and DTE Electric's bundled sales levels. Finally, the Electric Choice impact on peak demand is shown.

Q. Can you explain Exhibit A-15, Schedule E3?

A. Exhibit A-15, Schedule E3, provides the changes between the historical period calendar year 2017 actual sales and the projected test period May 2019 through April 2020 forecasted sales, both excluding sales to former PLD customers that are now on DTE Electric retail rates, for both DTE Electric bundled sales and Electric Choice sales. The change in sales by class from the historical period to the projected test period is provided, as well as the sources of change for each class.

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Q. Can you explain Exhibit A-15, Schedule E4?

A. Exhibit A-15, Schedule E4, shows the major economic parameters used in the forecast models. The years 2013 through 2017 are historical. The years 2018 through 2028 are the Company's forecast.

Q. Can you explain Exhibit A-15, Schedule E5?

A. Exhibit A-15, Schedule E5, shows historical temperature-normalized service area annual sales for three major customer classes: Residential, Commercial and Industrial on page 1. Total sales, which includes Other Class sales, is also shown. Historical and forecasted peak demands are also shown. The year 2013 includes wholesale sales to PLD and years 2014 through 2017 include sales to former PLD customers. Historical temperature-normalized peak demand is also shown.

The sales and peak demand forecasted for 2013 through 2017 is shown. A comparison of temperature-normalized sales and peak demand to the forecast for each year yields an absolute percent variance. The average absolute percent variance is also shown.

The results of ITRON's benchmarking survey of utilities for absolute percent variance is provided on page 2 for Residential, Commercial and Industrial Class sales and for Total Sales. The absolute percent variance for peak demand is also shown.

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Q. What is the compound annual growth rate (CAGR) of the DTE Electric service area electric sales over the forecast period?

A. DTE Electric temperature-normalized service area sales in 2017 were 46,810 GWh excluding PLD sales as shown in Exhibit A-5, Schedule E1, page 1, line 6, column (f). Service area sales are expected to decrease from 46,810 GWh to 46,327 GWh for the projected test period in this case as shown in Exhibit A-15, Schedule E1, page 1, line 2, column (f). This represents a 1.0% decrease. Service area sales excluding the Other class are not expected to return to the pre-recession sales level of 2009 through 2028.

Service area sales are expected to be 46,177 GWh in 2028 as shown in Exhibit A-15, Schedule E1, page 1, line 12, column (f). This represents a 0.1% average annual decrease in sales from 2017 with PLD sales excluded.

Q. What has been the compound annual growth rate of DTE Electric service area sales over the last five years?

A. On a temperature-normalized basis, service area sales decreased from 48,379 GWh in 2013 (as shown in Exhibit A-5, Schedule E1, page 4, line 2, column (f)) to 46,810 GWh in 2017 with PLD sales excluded. This represents a 0.8% average annual decrease in sales. The decline is mainly due to the expiration of the Thumb Electric Cooperative contract at the end of 2013 and the termination of the wholesale contract with Public Lighting Department (PLD) on June 30, 2014.

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Q. What is the compound annual growth rate of DTE Electric bundled electric sales over the forecast period?

A. DTE Electric temperature-normalized bundled sales in 2017 were 42,002 GWh excluding PLD sales as shown in Exhibit A-5, Schedule E1, page 2, line 6, column (f). Bundled sales are expected to decrease from 42,002 GWh to 41,427 GWh for the projected test period in this case as shown in Exhibit A-15, Schedule E1, page 2, line 2, column (f). This represents a 1.4% decrease. Bundled sales excluding the Other class are not expected to return to the pre-recession sales level of 2009 through 2028.

Bundled sales are expected to be 41,277 GWh in 2028 as shown in Exhibit A-15, Schedule E1, page 2, line 12, column (f). This represents a 0.2% average annual decrease in sales from 2017 when PLD sales are excluded. The long-term growth rate for DTE Electric bundled sales is comparable to the growth rate for service area sales due to steady Electric Choice sales.

Q. What is the general approach used in developing this forecast of DTE Electric's service area electric sales and system output?

A. The general approach reflects widely accepted industry standards for electricity forecasting. It has also provided reasonable forecasts for DTE Electric service area electric sales with, on average, small variances from actual historical annual sales.

For most sectors of the forecast, electric sales levels are related to the various economic, technological, regulatory, and demographic factors that have affected them in the past. The procedure begins with the assembly of historical data relating to the various sectors of the forecast. These data are examined and the factors that are statistically significant

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in explaining electric sales are identified using regression techniques. Forecast models are developed employing the appropriate regression equations.

The Company receives economic forecasts from various sources that are then entered into the forecast models to calculate projected future sales levels. Economic driving variables (explanatory factors), include motor vehicle production, steel production, employment, and others.

Part II: Economic Outlook

Q. What is the condition of the national economy just prior to the forecast period?

A. Gross domestic product, the comprehensive measure of goods and services produced in the United States, grew by 2.3% in 2017, disposable personal income rose by 1.2%, and personal consumption expenditures rose by 2.8%. These measures from the national income and product accounts are in real terms, meaning that inflation has been removed from them. The Consumer Price Index for All Urban Consumers rose by 2.1%. Housing starts, including single and multi-family dwellings, rose by 2.5%. Light vehicle unit production in the United States contracted by 7.9% in 2017, and light vehicle sales declined 1.7%.

Q. What is the outlook for the national economy in 2018 and 2019?

A. Gross domestic product is forecast to increase by 2.7% in 2018 and 2.3% in 2019. Correspondingly, disposable personal income is expected to increase by 3.7% in 2018 and 3.1% in 2019. Personal consumption expenditures are expected to grow by 3.1% in 2018 and 3.0% in 2019. These measures from the national income and product accounts are in real terms, meaning that inflation has been removed from

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them. The Consumer Price Index for All Urban Consumers (CPI-U) is forecast to increase by 2.3% in 2018 and 1.7% in 2019. Total light vehicle production in the United States is forecast to reach 11.28 million units in 2018 and inch up to 11.35 million in 2019.

Q. What is the outlook for Southeast Michigan's economy in 2018 and 2019?

A. Total non-farm employment is forecast to increase by 0.7% in 2018 and 0.7% in 2019. Natural resources, mining, and construction employment is expected to rise 3.5% in 2018 and 3.0% in 2019. Total private non-manufacturing employment is forecast to rise by 1.1% in 2018 and 0.7% in 2019. In the government sector, employment is expected to decline by 0.4% in 2018 and by 0.1% in 2019. Manufacturing employment is forecast to decline by 0.3% in 2018 and rise by 1.9% in 2019. Manufacturing jobs appear headed for smaller increases than in the years immediately following the Great Recession because recessionary pent-up demand for vehicles has been met. Southeast Michigan auto production is expected to be 1.44 million vehicles in 2018 and 1.39 million in 2019, well below 2013's post-recession peak of 1.91 million. Local raw steel production is forecast to rise by 1.7% in 2018 and by 1.3% in 2019. Building permits, which rose to 11,196 in 2017, are forecast to decline by 35.7%, settling to a more typical level, in 2018 and to rise by 1.5% in 2019. Population is forecast to rise by 0.1% in 2018 and again in 2019.

Q. What is the economic outlook beyond 2019 for Southeast Michigan?

A. Following several up-and-down years, regional automotive output is expected to expand gradually after 2024. However, it must be noted that the changing domestic and international political environment introduces substantial uncertainty to the location of automotive manufacturing plants. For example, Ford Motor had intended to move production of its Focus compact car from Wayne, Michigan, to Mexico in mid-2018 but in 2017 unexpectedly announced that the new site would be in China. Steel production will likely continue to decline as automakers gradually adopt alternative materials. Based on the outlook for population and housing stock, residential construction permits are expected to decline over the longer term. Total employment should continue growing if the economy expands as anticipated, but technological advances will almost certainly restrain growth of manufacturing jobs.

Part III: Forecast Development

Q. How was the Residential Class forecast developed?

A. Electricity sales in the Residential Class were forecasted using an end-use method including 39 different appliances or appliance groups. For each forecast year, three separate items were forecast: (1) number of residential customers, (2) saturations of major appliances, and (3) average electricity use per appliance. For each appliance, the product of these three forecast values yields the annual electricity sales. The total for all appliances is the total annual Residential Class electricity sales.

The number of residential customers were forecasted using the annual percentage change in forecasted households. This percentage change each year is applied to the prior year's customer count to obtain the forecast of customers for that year.

The Company conducts an appliance saturation survey, usually every other year. The survey is sent to a representative sample of DTE Electric's Residential customers. Among the questions asked are ones related to whether the customer has certain

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appliances and if the appliances were replaced in the last two years. The responses determine the saturation rates and life expectancy of the appliances in the Residential model.

The Federal Government has enacted energy efficiency standards for many appliances. The end-use approach incorporates projected increases in energy efficiency of the various appliances into the total Residential Class electricity sales. The Company uses federal efficiency standards to determine the decrease in use per appliance. As most customers do not buy a new appliance just because a more energy efficient one becomes available, the Company phases in the decrease in energy usage which over time drives down Residential customer electric usage.

The Residential distributed generation forecast is obtained by first reviewing the historical annual adoption of distributed generation resources, which is continually tracked by DTE Electric. Then, a logistic forecasting function, also referred to as an S-curve, is fit to these historical data to estimate future growth. Following the characteristic logistic pattern, sales approach an asymptote in the outgoing years.

Q. What is the outlook for Residential Class Sales?

A. DTE Electric's service area Residential Class Sales are forecast to decline 0.5% between 2017 and the projected test period in this case. The service area Residential Class Sales will decrease 0.2% annually, on average, through 2028. This growth rate utilizes 2017 temperature-normalized sales excluding sales to former PLD customers as the base year in its computation. This approach is used on all class growth rate calculations in my testimony.

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Modest average annual growth of 0.4% in residential customer count is expected through 2028 due to a moderating housing market. However, use-per-customer through 2028 is expected to decrease by 0.4% annually on average. This is due to the long-term trend of increases in the saturation of appliances being offset by more efficient electric appliances and the adoption of energy efficient lighting.

Based on historical behavior, Electric Choice is not expected to have a significant effect on residential customers. DTE Electric bundled Residential Class sales equal service area Residential Class sales in the forecast.

Q. How was the Commercial Class forecast developed?

A. Sales for most sectors of the Commercial Class were forecast using regression models. Explanatory variables included county level employment, real personal income, local automotive production and population.

Other non-manufacturing markets, such as agricultural supply, farming and apartments, were forecasted with time trend models and were combined with the previous regression models to obtain total Commercial sales.

Commercial Secondary and Primary rate class sales were obtained using historical allocations for each market, which were then summed to get total Commercial Secondary and Primary sales.

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Q. What is the outlook for Commercial Class sales?

A. DTE Electric's service area Commercial Class sales are forecast to increase 0.6% between 2017 and the projected test period in this case. The Commercial Class is expected to rise 0.1% annually, on average, through 2028.

Annually, on average through 2028, the Other Medical sector increases 0.3% due to the increasing age of the population. Offices increase 0.5% annually, on average through 2028 because of an increasing demand for office space. The Other Schools sector decreases 1.1% annually, on average, through 2028 due to a decrease in school employment. In addition, a few universities are planning to build co-generation facilities which by 2020 will reduce sales by 268 GWh annually, on average through 2028.

DTE Electric temperature-normalized bundled Commercial Class sales will decrease 0.1% annually, on average, through 2028.

Q. How was the Industrial Class forecast developed?

A. For the development of the Industrial Class forecast, the automotive sector was disaggregated into seven groups of automotive facilities (i.e., assembly plants, stamping plants, powertrain/drivetrain plants, research and administrative facilities, other parts plants and parts suppliers, foundries, and other automotive plants). Electricity sales for the groups identified above were forecast using regression-based models with automotive production as the primary explanatory variable. Additional effects from announced plant closings or expansions and plant specific information were also factored into these models. The non-automotive sector was disaggregated

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into eleven markets and submarkets (i.e., chemicals, petroleum, rubber and plastics, mining, non-metal processing, metal fabrication, manufacturing equipment, other manufacturing, Big 3 rubber and plastics, Big 3 manufacturing equipment and primary metals). Electricity sales for these markets were also forecast using regression-based models with automotive production, manufacturing employment and other economic indicators.

Q. What is the outlook for Industrial Class Sales?

A. DTE Electric's service area Industrial Class sales are expected to decrease by 4.1% from 2017 to the projected test period in this case. The Industrial Class sales are expected to decrease 0.3% annually, on average, through 2028. Because Industrial Class sales move so robustly with conditions of the local economy it is necessary to understand the differences in near term and long term growth rates.

Foreseeable events that result in a more pronounced decline within the short term include the retooling of several local assembly plants, as well as slowed production volumes in response to declining national automotive sales. The shifts in economic activity are expected to return to more stable levels in the mid to long term, which based on historical trends, would cause Industrial Class sales to stabilize as well. Industrial Class sales are comprised of three large subclasses: automotive, primary metals (steel) and other manufacturing sales. It is necessary to examine each subclass separately.

First, DTE Electric's service area automotive sales will decrease 0.2% annually, on average, through 2028. Most of the decrease in sales occurs in 2018 as local assembly plants go down for changeover to new products. Production ramps up slowly in the following years. In addition, sales growth is constrained by efficiency measures at automotive facilities.

Second, DTE Electric's service area steel sales will decrease 0.6% annually, on average, through 2028. Global over-capacity continues to put downward pressure on local steel facilities. Additionally, increased use of alternative materials in automotive manufacturing lowers the forecast for steel.

Third, DTE Electric's service area other manufacturing sales will increase 0.3% annually, on average, through 2028. The growth in sales will be mainly due to 1) increased operations at four auto supplier facilities in rubber & plastics and 2) an expansion at one facility and a new facility in non-metal fabrication.

DTE Electric's temperature-normalized bundled Industrial sales will decline from 9,904 GWh in 2017 as shown in Exhibit A-5, Schedule E1, page 2, line 6, column (d) to 9,657 GWh in 2028 as shown in Exhibit A-15, Schedule E1, page 2, line 12, column (d), which is a 0.2% decrease annually on average. Since temperature-normalized Electric Choice sales in this class decrease only slightly from 2,123 GWh in 2017 as shown in Exhibit A-5, Schedule E1, page 3, line 6, column (d) to 1,940 GWh in 2028 as shown in Exhibit A-15, Schedule E1, page 3, line 12, column (d), the growth rate for DTE Electric bundled sales is comparable to service area sales.

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Q. What is the outlook for Other Class Sales?

A. DTE Electric's service area Other Class sales are expected to decrease by 35 GWh from 2017 to the projected test period in this case and to decrease 1.7% annually, on average, through 2028. The Other class consists of Street Lighting and Traffic Signals. The forecast of Other Class sales is sponsored by Company witness Mr. Johnston.

Q. Is Energy Waste Reduction (EWR) captured in the forecast?

A. Yes, EWR is implicitly captured in the forecast. The Company analyzes forecast results compared with historical performance to ensure consistency and assure historical trends and future EWR programs are implicitly included.

As can be seen from the data below, the incremental EWR program implemented in 2017 which increases the targeted level of savings from 1.15% to 1.5% is implicitly captured in the use per customer growth rates. For instance, in the residential model, the historical growth (CAGR) on a use per customer basis fell 0.3% between the years 2009 through 2016. The forecast use per customer growth rates are as follows:

Actual-Temp Normalized UPC CAGR (w/1.15% EWR program)

2009-2016	-0.28%

Forecasted Residential UPC CAGR (w/1.5% EWR program beginning in 2017)

2017-2028	-0.64%

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Q. How were the sales forecast methodologies validated?

A. DTE Electric's sales forecasts are tracked annually. The Company checks the accuracy of the sales forecast models. For example, the DTE Electric Total service area forecast in 2016 was 47,373 GWh as shown in Exhibit A-15, Schedule E5, page 1, line 11, column (e). Temperature-normalized Total service area sales in 2016 were 47,551 GWh excluding PLD sales as shown in Exhibit A-15, Schedule E5, page 1, line 5, column (e). This represents a 99.6% accuracy of the Totals sales 2016 forecast. On average, for historical years 2013 through 2017, the absolute percent variance for the Total sales forecast is 1.04% using the Company's forecasting methods, as shown in Exhibit A-15, Schedule E5, page 1, line 19, column (e). The forecast accuracy achieved validates DTE's forecast methodology.

Q. Does the Company perform any benchmarking on forecast accuracy?

A. Yes. The Company conducts benchmarking activity by researching forecast accuracy studies. A study[1], conducted by ITRON in 2017, found the average absolute percent variance among peer utilities for the Residential class for years 2012 through 2016 is 1.65%, as shown in Exhibit A-15, Schedule E5, page 2, line 6, column (b). DTE Electric performs on a better accuracy than peer utilities across the nation in forecasting residential, commercial, industrial, total sales and peak demand, as shown in Figure 1 below.

[1] ITRON's 2017 Forecasting Benchmark Survey is available at http://capabilities.itron.com/efg/Reports/ItronForecastingBenchmarkSurvey2017.pdf

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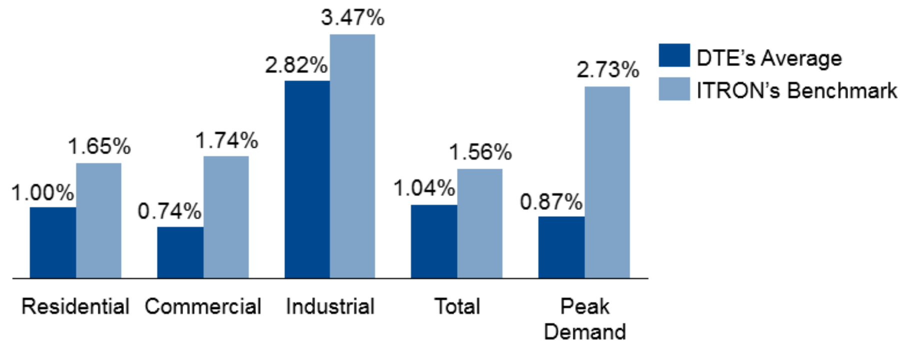
Figure 1: DTE Electric vs. ITRON Forecast Accuracy Benchmark



Q. What were Electric Choice sales for 2017?

A. Electric Choice sales in 2017 were 4,820 GWh as shown in Exhibit A-5, Schedule E1, page 3 of 4, line 5, column (f). On a temperature-normalized basis, Electric Choice sales for 2017 were 4,809 GWh as shown in Exhibit A-5, Schedule E1, page 3 of 4, line 6, column (f).

Q. What is the forecast for Electric Choice sales for 2018 through 2028?

A. The forecast for Electric Choice sales by rate classification is shown on Exhibit A-15, Schedule E1, page 3 of 3.

Q. How was the Electric Choice sales forecast developed?

A. The Electric Choice sales forecast was based on temperature-normalized sales expected for 2017 of approximately 4,900 GWh. The forecast remains consistent for Electric Choice sales, since sales have been stable for several years; therefore, no other changes in Electric Choice sales are forecasted.

Q. How was the DTE Electric system peak demand forecast made?

A. The Hourly Electric Load Model (HELM) was used to forecast annual DTE Electric service area and DTE Electric bundled peak demand. HELM was also utilized to determine monthly peak demands in the forecast period.

Q. Can you explain HELM?

A. HELM was developed by EPRI and aggregates hourly demand profiles from various sales categories or end-uses into a system annual load shape. The annual sales and hourly demand profiles for each sales category or end-use are key inputs to this model. HELM also provides monthly and annual net system output.

Q. What temperature assumptions were made regarding the DTE Electric service area and the DTE Electric bundled peak demand forecast?

A. Normal temperature on the day of the annual peak is assumed to be 83.0°F, which is the mean temperature from Detroit Metropolitan Airport. This value is based upon an average peak-day mean temperature for a 30-year period (1981 through 2010). The peak day is assumed to occur on a weekday in July or August. In addition, normal temperature conditions were utilized for the projection of weather-sensitive sales.

Q. What is the compound annual growth rate of the DTE Electric service area system peak demand over the forecast period?

A. Peak demand excluding wholesale PLD and former PLD customers that are now on DTE Electric retail rates for historical periods (i.e., 2014 through 2017) are not available. Therefore, peak demand for 2018, which excludes the peak demand for former PLD customers, as do all forecast years, is used as the base in the calculation of the average compound annual growth rates for DTE Electric's service area system peak demand and DTE Electric's bundled peak demand.

DTE Electric's service area system peak demand in 2018 is expected to be 11,169 MW as shown in Exhibit A-15, Schedule E2, page 1 of 2, line 7, column (c). Based on this peak and a forecast service area peak demand of 10,934 MW in 2028, as shown in Exhibit A-15, Schedule E2, page 1 of 2, line 18, column (c), an average compound annual growth rate of -0.3% is expected. The decline in peak demand is mainly due to a decline in residential air-conditioning sales. The decline in residential air-conditioning sales, which is 0.3% on average annually, is mainly due to energy efficiency improvements because of federally mandated energy efficiency standards.

Q. Are Demand Response programs included in the Company's peak forecast?

A. No. Demand Response programs are not explicitly included in the peak forecast. However, Demand Response programs are included in determining the Company's required amount of unforced capacity needed to meet the MISO Adequacy requirements for the forecast MISO coincident peak demand for the DTE Electric bundled load.

Q. What is the compound annual growth rate of the DTE Electric bundled peak demand over the forecast period?

A. DTE Electric's bundled peak demand in 2018 is expected to be 10,308 MW as shown in Exhibit A-15, Schedule E2, page 2 of 2, line 7, column (c). Based on this peak

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and a forecast DTE Electric bundled peak demand of 10,074 MW in 2028, as shown in Exhibit A-15, Schedule E2, page 2 of 2, line 18, column (c), an average compound annual peak growth rate of -0.5% is expected.

Q. How are the confidence bands developed for the bundled peak forecast?

A. An autoregressive integrated moving average (ARIMA) based model is used to determine bandwidths around the forecasted bundled peak load. The model captures variances due to loss factor uncertainty, weather/load factor uncertainty and Electric Choice sales uncertainty. This method was used by the North American Electric Reliability Corporation's Load Forecasting Working Group to determine bandwidths for their Reliability Assessments.

Q. What is the 90% confidence band for DTE Electric's bundled peak demand for the projected test period?

A. Based on a standard deviation of 941 MW, the DTE Electric bundled peak demand for the projected test period, using the 90% confidence band, would be 11,486 MW.

Q. Can you please summarize how the bundled retail sales forecast and the Electric Choice sales forecast for the projected test period May 2019 through April 2020 compare to the historical period?

A. Yes, based upon the reasonable and prudent methodologies and analyses I describe above, temperature-normalized bundled retail sales are forecasted to decrease from 42,002 GWh in 2017 to 41,427 GWh in the projected test period. Electric Choice sales are forecasted to increase from 4,809 GWh to 4,900 GWh over the same period.

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Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DAVID C. MILO

DTE ELECTRIC COMPANY
QUALIFICATIONS OF DAVID C. MILO

Line No.

Q. Would you please state your name and position?

A. My name is David C. Milo. My position is that of Fuel Resources Specialist, in the Operations and Logistics group of the Fuel Supply department.

Q. What is your business address and on whose behalf are you testifying?

A. My business address is One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of DTE Electric Company (Company or DTE Electric).

Q. What is your educational background?

A. I have a Bachelor of Arts Degree in Accounting and a Master of Business Administration Degree, in Finance, from Michigan State University, East Lansing, Michigan.

Q. Please summarize your professional experience.

A. In 2004 I joined DTE Energy in the Property Tax department as a Senior Tax Advisor. In this capacity, I was responsible for property tax compliance for Michigan Consolidated Gas Company and various other subsidiaries of DTE Energy.

In 2008 I transferred to the Budget, Forecast and Reporting group as a Principal Analyst. In this capacity, my responsibility was to assist in the preparation of corporate budgets and forecasts and prepare reports for management on various financial performance measures.

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In 2010 I transferred to the Asset Management group where I prepared reports on capital asset expenditures for DTE Energy. In November of that same year, I transferred to the Gross Margin group as the fuel accountant. In this capacity, my responsibilities were to prepare the accounting for the purchase and expense of all fuels used in the production of electricity for DTE Electric and preparation of internal and regulatory reports thereon.

In 2013 I transferred to the Fuel Supply department of DTE Electric as a Fuel Resources Specialist in the Planning and Procurement group. My responsibilities included preparation of the budget and forecasts regarding all fossil fuels (i.e., coal, natural gas & oil) used by DTE Electric for electric generation and preparing management reports on DTE Electric's fossil fuels and assisting in various accounting activities.

In 2016, I moved to the Operations and Logistics group of Fuel Supply where I assist in administering and managing the company's railcar fleet.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony in the following cases:

U-17097-R	2013 Power Supply Cost Recovery (PSCR) Reconciliation
U-17319	2014 PSCR Plan
U-17319-R	2014 PSCR Reconciliation
U-17680	2015 PSCR Plan
U-18014	2016 DTE Electric Rate Case

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1	U-18255	2017 DTE Electric Rate Case

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Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss and support the reasonableness of DTE Electric Fuel Supply's (Fuel Supply) and Midwest Energy Resources Company's Fuel Handling (MERC) actual $8.1 million O&M expenses ended December 31, 2017, and the projected $8.7 million O&M expenses for the 12-month projected test period ending April 30, 2020. I will also discuss $5.7 million of capital expenditures for the historical test year ended December 31, 2017 and projected capital of $7.9 million expenditures from January 1, 2018 through the projected test period ending April 30, 2020.

Q. Can you please explain the nature of Fuel Supply expenditures?

A. Fuel Supply's expenditures are primarily for the maintenance of the Company's railcar fleet and the planning, procurement and agreement administration of the fossil fuel commodities and associated transportation. The MERC expenditures are primarily for the operation of the coal terminal that processes rail shipments of western coal for vessel delivery to DTE Electric's power generation plants in southern Michigan.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.2	Projected Capital Expenditures – Midwest Energy Resources Company (MERC) and Fuel Supply
A-13	C5.2	Test Period Operation and Maintenance Expenses –Fuel Supply and Midwest Energy Resources Company (MERC)

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. What is MERC?

A. MERC is a wholly-owned subsidiary of DTE Electric, which provides advantaged coal transportation services to DTE Electric and coal transportation services to third-party utility and industrial customers through its Superior, WI, Midwest Energy Terminal.

Q. Why is MERC included in this rate case filing?

A. As a wholly-owned subsidiary of DTE Electric, MERC is fully consolidated into DTE Electric. The accounting and ratemaking treatment of MERC's revenues and costs are specified by MPSC orders in Case No. U-5041, dated September 17, 1976, and Case No. U-5108, dated May 27, 1977.

Q. What does Exhibit A-12, Schedule B5.2 show?

A. Exhibit A-12, Schedule B5.2 shows capital expenditures for MERC and Fuel Supply for the historical test year 2017, as well as projected capital expenditures for the interim forecast period and the 12-month projected test period ending April 30, 2020.

Q. What is the rationale for MERC and Fuel Supply capital expenditures shown on Exhibit A-12, Schedule B5.2?

A. All the expenditures described below for the period of January 2017 through April 2020 are related to improving safety, meeting environmental requirements, upgrades to increase efficiency and reliability, and/or replacement of end of life equipment. These expenditures are reasonable and prudent and necessary to maintain and/or improve Fuel Supply operations and MERC's coal transshipment capabilities.

Q. What are the capital expenditures for MERC and Fuel Supply for the historical test year 2017 included on Exhibit A-12, Schedule B5.2, column (b), lines 19 and 23, respectively?

A. The total capital expenditures in 2017 for both entities were $5.7 million. The MERC expenditures on line 19 of $4.4 million were for the Caterpillar D11 Dozer; programmable logic controller (PLC) controls and motor control center (MCC) system upgrades; mobile equipment; plow feeder hydraulics, controls and gearboxes; conveyor drives and motors; conveyor belts and scrapers; terminal roadways; train indexing equipment; LED lighting; dock pile jacketing; building and structural improvements; environmental and safety; and a few capital projects that are less than $100,000 each.

Fuel Supply has a project to rebuild railcar trucks on 1997-1999 vintage cars. The railcar truck rebuilds extend the trucks' useful life and mitigate future potential railcar repair costs. The costs for these rebuilds during the January 2017 through December 2017 period were $1.3 million as shown on Exhibit A-12, Schedule B5.2, line 21, column (b).

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Q. What are the projected capital expenditures for MERC and Fuel Supply for January 2018 through April 2019 as reflected on Exhibit A-12, Schedule B5.2, column (e)?

A. The total capital expenditures for January 2018 through April 2019 are estimated to be $5.0 million for both entities. MERC total capital expenditures for this period are projected at $3.7 million. Capital projects at MERC for 16 months ending April 2019 include $0.2 million on the Caterpillar D11 dozer; $0.3 million for PLC controls and MCC upgrades; $0.1 million for mobile equipment; $0.2 million for plow feeder hydraulics, controls and gearbox replacement; $0.2 million for conveyor drives and motors replacement; $0.2 million for conveyor belts and scrapers replacement; $1.5 million for dock pile jacket installations; $0.3 million for building and structural improvements; and $0.7 million for capital projects that are less than $100,000 each.

Fuel Supply continues the project to rebuild railcar trucks on 1997-1999 vintage cars. The railcar truck rebuilds extend the trucks useful life and mitigate future potential railcar repair costs. Fuel Supply is expected to spend $1.3 million on this truck rebuilding project in January 2018 through April 2019.

Q. What are the projected capital expenditures for MERC and Fuel Supply for projected test period, May 2019 through April 2020, as reflected on Exhibit A-12, Schedule B5.2, column (f)?

A. The total capital expenditures for May 2019 through April 2020 for both entities are estimated to be $2.9 million. MERC total capital expenditures for this period are projected at $1.9 million. Capital projects currently planned at MERC in projected test period include $0.3 million for a Caterpillar D11 Dozer; $0.1 million for PLC controls

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and MCC upgrades; $0.4 million for conveyor belts and scraper replacement; $0.3 million for reclaim tunnel structural improvements; and $0.8 million for capital projects that are less than $100,000 each.

Fuel Supply expects to spend $1.0 million in projected test period to continue the railcar truck rebuild project on the 1997-1999 vintage railcars. Fuel Supply capital expenditures consist of railcar truck rebuilds. The railcar truck rebuilds extend the trucks useful life and mitigate future potential railcar repair costs.

Q. What does Exhibit A-13, Schedule C5.2, show?

A. Exhibit A-13, Schedule C5.2, shows historical and projected operation and maintenance (O&M) expenses associated with the Fuel Supply department on lines 1 through 7 and MERC Fuel Handling on lines 8 through 15.

Q. What were Fuel Supply and MERC's adjusted historical O&M expenses for 2017 as shown on Exhibit A-13, Schedule C5.2?

Fuel Supply and MERC historical O&M expenses for 2017 totaled $8.1 million as shown in column (f), line 16. This is comprised of $4.2 million for Fuel Supply in column (f), line 7, and $3.9 million for MERC in column (f), line 15.

Fuel Supply O&M expenses include $0.9 million for operation supervision and engineering; $0.3 million for maintenance supervision and engineering; $0.9 million for maintenance of miscellaneous steam plant in column (f), as well as a reclassification of $2.1 million in column (d) for Fuel Supply department's portion of Fuel Handling O&M expense recorded in Fuel Account 501.

MERC's fuel handling expenses charged to Fuel Account 501 are shown on lines 9 through 15, column (d), which reflect the components of fuel handling costs that are reclassified to other expense categories on DTE Electric's adjusted historical financial statements (see Exhibit A-3 C.16). Therefore, an adjustment is made in column (e) to remove these cost items from O&M. The remaining amount in column (f), line 15 is the total MERC fuel handling expenses included in O&M.

Q. What are Fuel Supply and MERC's projected O&M expenses for the 12 months ending April 2020, as shown on Exhibit A-13, Schedule C5.2?

A. The projected test period O&M expense is $8.7 million, comprised of $4.5 million for DTE Electric Fuel Supply in column (l), line 7, and $4.1 million for MERC in column (l), line 15. These amounts were based on the adjusted historical 2017 expenses adjusted for inflation. The labor and material inflation adjustment factors of 3.0% for 2018, 2.9% for 2019, and 1.0% for four months from January 2020 through April 2020 are supported by Company Witness Ms. Uzenski.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

BRIAN V. MOCCIA

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is Brian V Moccia. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company), as Manager of the Advanced Metering Infrastructure (AMI) Engineering group in Electric Distribution Operations.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric.

Q. What is your educational background?

A. I graduated from the University of Michigan Dearborn in 1982 with a Bachelor of Science in Electrical Engineering. In addition, I received a Master of Business Administration degree from the Wayne State University in 1987.

Q. What work experience do you have?

A. In 1982, I joined The Detroit Edison Company as an electrical engineer in the Electrical Systems, Relay Engineering organization. During my early career, I held positions in Electrical Systems Engineering, Customer Service, Business Development and Marketing, Information Technology, Major Enterprise Projects and Electric Distribution Advanced Meter Engineering. In 1989, I was appointed Supervisor in Electrical Systems Relay organization, responsible for all power plant and electrical system relay protection and Substation Supervisory Control and Data Acquisition systems. In 1991, I transitioned to Customer Service as the Director of Customer Service Technology, I was responsible for all technology for the customer call centers, customer offices and customer billing systems. In 1998 I moved to Marketing and Business Development as the Director of Engineering and Marketing on the Intelligent Link Program. I was responsible for technology strategy and integrating new customer technologies and platforms. I transitioned from Marketing to Information Technology Systems in 2001 and managed the customer systems technology transition as Detroit Edison merged with MichCon. In 2004, I moved responsibilities within Information Technology Systems organization, responsible for all real-time data management systems for Electrical Systems Operations and Merchant Operations. In 2010, I transitioned to the Advanced Metering Infrastructure (AMI) Program in Major Enterprise Projects. I was responsible for AMI engineering and technology strategy for the program. I remained in this capacity through the end of the Program in 2016. In 2017, I transitioned to Electric Distribution Operations, Advanced Metering Infrastructure.

Q. What are your responsibilities in your current position?

A. I am the Manager of Advanced Meter Engineering and Infrastructure in Electric Distribution Operations. I am responsible for maintaining the existing AMI infrastructure, future technology strategy and AMI asset life cycle management. I am responsible for development, administration and reporting of the AMI project for DTE Electric, including the negotiation and execution of the contract with the main project vendor Itron, Inc. (Itron).

Q. What is the purpose of your testimony in this proceeding?

A. I am providing testimony to discuss and support the reasonableness of DTE Electric's AMI project from a benefit perspective. I will provide a brief background on the progress made with AMI, and current status of completion. I will also provide testimony to discuss and support AMI 3G to 4G communication upgrade, AMI Industrial 4G communication upgrade, and AMI leveraged tools (PI, Analytics). I will also provide an update on the Company's AMI meter opt out program.

Are you sponsoring any exhibits in this proceeding?

A. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures, Distribution Plant – Technology and Automation (page 9), lines 6 - 9
A-19	I1	AMI Detailed Benefit Analysis
A-23	M4	Distribution Plant Capital Project Detail – Technology and Automation (pages 11 – 18)

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

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AMI Background

Q. What has DTE Electric's progress been related to the AMI program?

A. The AMI pilot installation began in the fall of 2008. DTE Electric has been using AMI reads in its billing system since about February 2009. Since the completion of the pilot installation in 2008, the Company has been steadily installing meters and modules. As of June 1, 2018, DTE Energy has installed over 2.6 million electric meters, 632,000 AMI gas modules and nearly 464,000 Advanced Meter Reading (AMR) gas only modules for a total of nearly 3.6 million endpoints. This represents 99.96% of our planned electric meters.

Due to numerous customer related issues, included but not limited to, Can't-Get-In's (CGI's), vacant properties, locked gates, lack of customer response, etc., we are still working to complete the remaining 1,077 installments of AMI electric meters in 2018.

Q. Can you summarize the overall experience with AMI from the pilot period to current date?

A. Yes. The Company has integrated all of the basic functions of AMI from meter reading, reconnects, disconnects, and outage notifications to theft/tampering investigation. Manual meter reading routes have been dramatically reduced. Prior to AMI, DTE had 3,205,238 meters manually read through 6,029 routes with an average of 532 meters per route. Now DTE is managing 1,238 routes with an average of 72 meters per route. Monthly and daily reads are being obtained at the 98.5% plus rate, enhancing customer service operations with the read timeliness and accuracy. Reconnects and disconnects are being completed over the air and

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within minutes as opposed to the former manual and field visit requirement. The Company continues to work to further integrate the meter functionality into our outage systems, and to work with our theft group on analytics to enhance the theft/tamper event resolution.

Q. Has the Company encountered any problems with completing the remaining installations?

A. The Company has been experiencing three types of problems with the remaining installations (1) meter replacements that require more experienced technicians due to difficult electrical hook ups; (2) customer locations where we have not been able to reach the customer via phone or field visit and cannot gain access to our meters, such as locations with locked gates or dogs in the yard; and (3) customers who have placed locks on their existing meters. Given the large service area of the meters still needing to be replaced, as well as some of the steps the Company must take to elicit customer actions for meter replacement, the process will take the remainder of the year to complete.

AMI Benefits

Q. What are the major benefits DTE Electric customers enjoy with the AMI technology?

A. The major benefits are as follows:

(1) Meter Reading – automation of meter reading provides daily and on demand, accurate meter reads of each customer meter regardless of energy type. DTE Electric has some 2.6 million electric meters to read every month of which about 10% are located inside of facilities or homes. AMI eliminates the need

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to gain access for inside meter reads, thereby reducing meter reading costs (see Exhibit A-19, Schedule I1, Page 1, Line 5 for meter reading savings). AMI provides customers with daily reads that will further enhance the customer experience by eliminating miscellaneous and off-cycle reading of customer meters. AMI provides customers with actual reads every month. As meters are automated, customers with multiple homes will be able to combine sites onto one bill with the readings on the same day. These reads can be used to readily start and stop billing services with the actual reads and without the need for costly and appointment only field visits.

(2) Bill Accuracy – customers benefit with a near elimination of estimated customer bills. Additionally, AMI eliminates both the transposition of numbers that could occur with manual entry of meter data and eliminates simple read errors that can occur with the existing meter read methodology.

(3) Theft and tampering notice – the system notes tampering at the meter any time it occurs. As a result, we receive tamper events at any time on any day. This is a significant advantage over our current monthly meter reader site review. DTE Electric tracks energy theft occurring in its service territory by number of sites and dollar value, not specifically by the change in theft resulting from AMI. Changes in levels of theft occurring from time to time is a result of many factors, including the economy, law enforcement engagement, etc. However, the installation of AMI meters gave DTE a fresh start on methods for identifying theft. AMI technology enables DTE to reduce the timeframe to identify possible theft from months to days. Leveraging AMI device events and smart algorithms, the Company identified 10,281 potential theft incidences in 2017.

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(4) OSHA recordable injury rate – at both utilities, we are always considering the safety of our employees and customers. Winter conditions create an increased risk of slips and falls for our meter readers. Dog bites, or as often happens, injuries due to trying to avoid dogs, are among the highest contributors to OSHA events for our meter readers. AMI essentially negates these issues.

(5) Turn on / Turn off / Restore – this functionality allows DTE Electric to reconnect customers remotely, speeding reconnections, which is a significant improvement in customer service. Disconnections in accordance with billing rules can be impacted equally. The capability to affect the remote disconnects and reconnect over the airwaves in minutes provides efficiencies to all involved.

(6) Outage Efficiency – with the systems' ability to report customer outages and restorations, the overall outage operation is enhanced tremendously. Although the system will not replace or fix customer outages, the ability to receive timely information aids the process. The outage efficiency feature is most important at the end of a storm. We often complete a circuit problem and sometimes do not restore every customer on the circuit due to trouble behind trouble. With AMI, the Company is able to "ping" the meters to determine their power condition. During a storm event crews perform this ping from their truck and staff support personnel can ping remotely as well. I want to emphasize that AMI does not replace the customer call, but it will enhance the operation. At present, AMI is only able to tell us the condition at the meter and not the source of the outage. For example, AMI cannot determine if an energized wire is down in the area, it can only tell us that the meter is not energized for the customer. For this reason, customers will still

need to report downed wires for effective storm operations. As more enhanced functionality is deployed within the AMI network overtime, new features and enhanced analytics will reduce the need for customer calls.

Q. What new ideas leveraging the AMI technology are being worked at DTE that will provide future benefits to DTE customers?

A. New ideas enhancing existing customer benefits and future improvements in Electric customer quality of service include the following:

(1) Power Quality – AMI records instances of voltage problems at customer locations. The ability to have this data available to DTE Electric enhances the engineering design process of the electric infrastructure as well as a program to interact proactively to resolve disturbances before they become a customer issue or complaint.

(2) Daily storm and non-storm outage statistics – AMI data is currently used to create all daily outage statistics such as CAIDI, SAIFI, and SAIDI. This improves the accuracy of the outage data based on the outage experience at the customer site. The quantity and quality of the AMI data improves the overall storm modeling and restoration process.

(3) Tree trim program enhancement – AMI is indirectly used to enhance the trim maintenance program by including the frequency of momentary outage interruption data experienced at the customer meter, into the tree trim program. In the future, this data combined with other data such as tree species data, will be used to create predictive maintenance algorithms.

(4) Enhanced automated storm job closures – AMI is used to automate single customer outages that are auto closed as electrical power is restored in an area. The auto close algorithms are currently implemented for daily and storm day outages and are avoiding numerous "ok on arrival" truck rolls. This feature also shortens the follow-up truck rolls required after an outage and allows the crews to have a higher percentage work time on confirmed outages. If a customer calls back to DTE after an AMI auto-close function and DTE remotely reads 240 volts at the meter, instead of sending an overhead or underground line crew, Electric Field Operations (EFO) is sent to resolve the issue at far less cost as these remaining issues tend to be associated with a meter block or trouble inside the customer premise.

(5) Enhanced storm information – during large storms experiencing over 100,000 customer outages, the AMI system is repurposed to perform similar to an electric distribution management system, rather than a meter reading system. In this mode, all 2.6 million meters are polled every four hours for a voltage response at the customer. Those areas responding with below normal voltage are updated in the storm tracking system for problems such as one leg dead, possible open neutral, or low voltage in an area. Meters responding with normal voltage, follow an automated process to assist in closing outages. This has become an important feature for optimizing crew logistics and defining trouble-behind-trouble work.

(6) Electric grid phase modeling – DTE is currently collecting five-minute average voltage samples from 2.6 million meters, over 3.7 billion voltage samples per day, and creating voltage signatures of the quality of electric service delivered at the customer site. Using the voltage signatures and high

volume computing, DTE is exploring the use of the data to improve the accuracy of the electric network and which customers are fed from which transformers as well as predictive maintenance algorithms. Previously, this type of customer mapping was only possible through manual field audits every few years and never with this volume data provided by AMI. Leveraging of the AMI data, the intention is that customer to transformer phasing can be done electronically using remote AMI data for enhanced future grid management.

Q. Can you explain Exhibit A-19, Schedule I1?

A. Yes. This Exhibit, which reflects AMI benefits by year through 2030, is similar to exhibits the Company has provided in the past, except this exhibit does not include future costs or a net present value revenue requirement.

Q. Why didn't the Company provide a cost / benefit analysis like in prior general rate cases?

A. In DTE Electric's previous general rate case (Case No. U-18255), the Commission stated, A full cost/benefit analysis is no longer necessary. Given the other reporting requirements noted by the utility, the provision of an annualized benefit analysis in a general rate case should be easily accommodated by DTE Electric, and will provide the Commission with important evidence on the record regarding the ongoing and long-term benefits of AMI. (Pg 84 U-18255 Order). Therefore, pursuant to this directive, the Company has provided the requested information in Exhibit A-19, Schedule I1.

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Q. Can you provide a few other examples of benefits that you can assimilate to AMI?

A. Yes. The Company used the disconnect functionality to assist customers affected by the flooding in July 2014. There were 17 customers that called and asked us to disconnect their power while their basement was flooded. The Company completed this over the air and nearly immediately. In the past, this would have required a crew visit.

Another more recent example of the benefit of AMI occurred January, 2016. As a result of the Commission's Order in Case No. U-17767 (DTE Electric's General Rate Case), Residential Rate Schedule D1.7 (Geothermal rate) on-peak hours were moved from 10:00 a.m. – 7:00 p.m. to 11:00 a.m. – 7:00 p.m. We were able to remotely adjust the on-peak hours for approximately 3,000 customers. This over-the-air update took only about 24 hours to complete. In the past this would have been a field visit for the 3,000 customers requiring multiple man-days of effort. Unfortunately, since we were not at full deployment of AMI, the remaining D1.7 customers who did not have an AMI meter, required a field visit.

Also, along with obtaining daily reads, the Company has been able to enhance our sales and forecasting systems. In prior years, at month-end we would have actual reads for only 1/30th of our customers due to reading meters manually over each of the 30 days of the month. Now, the Company can effectively obtain a read at the end of each month for more customers, enabling increased accuracy and timeliness in the process. In addition, with the implementation of AMI, the Company is now

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able to facilitate the data needed for our DTE Energy Insight application (iPhone or Android).

Even more recently, the company has leveraged AMI within the storm process in several new and improved processes. During the March, 2017 catastrophic storm, the AMI system was used to poll voltage data from 2.6 million meters every 4 hours. The meter data response was used to update the number of customers restored and restored with normal voltage, to identify trouble behind trouble and to identify customer secondary services still outaged. Also, this data, was cross checked with senior customer account status, and used to proactively contact senior customers to ensure they had access to other facilities for heat and warmth during the outage period. Although this feature is very much in development, it provides a great example of innovative customer features that can be leveraged through access and use of remote AMI data.

Other new applications being developed into sustainable programs are using AMI momentary outage data, voltage power quality data and outage data greater than 10 minutes in duration, to prioritize poor performing circuits and increase field crew efficiencies. Back office data analysis assists in early detection of customer issues, shortens the time required for repair and reduces the number of crew attempts for transient or momentary circuit problems.

Q. Can you describe your approach to security of the AMI system?

A. Security is always at the forefront of the project. Security assessments must be continual and in depth, not one-time reviews. IT professionals continually review, test, and assess the system security. Itron is equally dedicated to maintaining the most secure system relative to our current system and environment knowledge. The Company has engaged with third party vendors to assess the Itron product as well as our own procedures. Assessments are continual and are part of our testing before any new software is installed. The Company has also participated with the MPSC and other utilities as ordered by the Commission regarding data privacy issues in Case No. U-17102.

Capital Investments - Technology Enhancements

Q. Can you elaborate on the AMI Technology Enhancement programs?

A. I am supporting the AMI technology enhancements on lines 6 through 9 of Exhibit A-12, Schedule B5.4, page 9. Line items 6 and 7 forecast the capital spend required in new AMI infrastructure due to public cellular wireless carriers phasing out 3G cellular by year 2020. Line 8 forecasts the capital spend required to complete the AMI first time installations requiring special skills, appointments, or hard to access customers. As of January, 2018, Line 8 specifies that there were approximately 5,200 meters remaining. As of June 1, 2018, 1,077 customers on an active account were still pending an AMI meter installation. Line 9, provides the detailed 2017 actual capital spend on analytics infrastructure required to store, analyze and generate new benefits using existing AMI data. Additional detailed project information is included in Exhibit A-23, Schedule M4, pages 11-18.

Q. What is the driving force of the AMI 3G to 4G communication upgrade program?

A. The Company has installed advanced metering technology and systems within the AMI program, across the DTE Electric serving area. A Cell Relay (CR) is an 'aggregator' or "gateway" within a service area for AMI. CR's are deployed at a ratio of one CR per 750-1,000 meters within a geographic area. Cell Relays communicate with meters using an unlicensed spread spectrum frequency within the 902-929 MHz band and communicate out of the serving area to DTE Energy data centers via 3G cellular using traditional public cellular telecommunications carriers.

The CR's deployed using third party public cellular carriers for backhaul to DTE, will periodically go through a period of capital planned obsolescence, approximately every seven years to ten years, as the public cellular providers migrate technology. The cellular industry is currently migrating from 3G to 4G technology and is phasing out 3G cellular in Michigan by late 2020. This cellular industry transition forces DTE Electric and most other utilities that have deployed similar AMI solutions over the past decade, to upgrade the components of their systems that are dependent on cellular technology, such as the AMI CR. The transition will be managed over multiple years to provide the least possible interruption to customer services, customer energy billing data or to back office leveraged customer services using AMI data. Without this technology upgrade, more than one million meters will no longer function for remote read, customer outage reporting, and remote disconnect/reconnect capabilities after 2020 as well as negating the benefits discussed as derived from the AMI program.

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Q. What is the scope of the AMI 3G-4G communications network upgrade program?

A. DTE has approximately 3,300 cellular 3G CR's integrated within its AMI system and 6,000 3G cellular industrial customer meters. As the Michigan telecommunication carriers phase out 3G cellular, these devices will require replacement with a 4G cellular device or where it better aligns with SmartGrid strategy, another compatible network device other than cellular, possibly DTE's own private infrastructure. All 3,300 Cell Relays and 6,000 industrial meters must be replaced prior to Q4, 2020. Without this upgrade, DTE Electric will lose daily communication with approximately 1 million of the 2.6 million DTE Electric residential electric meters and communication to approximately 6,000 industrial meters. These meters will not be remotely accessible which will have a significant negative impact on our ability to bill customers, eliminate our ability to obtain critical power quality and outage data; and remove our ability to remotely connect/disconnect meters after the cellular carriers transition to 4G cellular.

Q. How is the 3G to 4G communications network program being prioritized to best support the Company's customers?

A. DTE and its equipment vendors have focused on the replacement strategy for the 3G cellular CR's and industrial cellular meters since 2016. At that time, AMI equipment vendors had yet to transition factory production to 4G compatible devices. The plan to replace 3G cellular AMI equipment with 4G equipment includes the following scope and strategic efforts:

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2016 -- DTE established a utility forum creating critical mass within the electric utilities, focused on leveraging lessons learned with the 3G CR devices to provide input to equipment vendors on strategic customer functionality required in the next vintage CR product. Also, transitioning the existing direction away from the CR being focused as an advanced metering data collector, to a more strategic platform supporting AMI and alignment with future SmartGrid functionality.

2017 -- Conducted early beta testing with five utilities to leverage joint testing efforts on new 4G devices and to coordinate and consolidate commentary to strategic equipment vendors

2017 -- Conducted focused working groups to align vendor product roadmaps ahead of the telecommunication carriers 3G cellular phase out plan.

2017 -- Conducted a high level geographic analysis of advanced metering network assets and surrounding infrastructure impacted by the telecommunication carriers 3G cellular phase out plan.

2018 -- Implementing product testing on vendor production versions of 4G LTE cellular and private network products.

2018, Q4 -- Expecting to begin installation of 4G cellular replacement assets phasing out 3G cellular CR's within targeted advanced metering network geographies while positioning DTE with a further expansion of its hybrid mixed use SmartGrid network. Deployment scope of approximately 100 of 3300 CR assets.

2019 -- Continue planned 3G CR replacement and upgrade of DTE's hybrid 4G cellular and private mesh advanced metering and SmartGrid network infrastructure.

2020 -- Complete planned replacement and upgrade optimization of DTE's hybrid 4G cellular and private mesh advanced metering and SmartGrid network infrastructure. DTE is determining the feasibility of pulling forward some of the 2020 work into 2019 where DTE has already noted areas experiencing 3G cellular connectivity problems.

Q. Why has DTE not transitioned to 4G cellular earlier?

A. As of May, 2018, AMI systems vendors still had only released beta products for utility testing. FCC approved commercially available AMI 4G CR's have yet to be released. Various product solutions from multiple vendor factories in production volumes will not be available until late Q3 and early Q4 of this year. Although DTE and other major utilities started this process in 2016, product engineering, prototyping, testing and FCC approval, have delivered a product schedule to the industry where products will not be commercially available until late 2018. DTE's parallel quality control process is targeted to minimize wasted investment and problematic services to our customers while successfully transitioning to 4G infrastructure.

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Q. Why has DTE continued to install 3G cellular AMI infrastructure?

A. Where feasible, DTE began transitioning to 4G LTE AMI individual meter devices as early as 2016. However, more complicated CR and network router devices were on a longer development timeline from multiple product vendors. Replacement 4G LTE CR devices are only available as beta units until full FCC approval expected early Q3, 2018. DTE's project planning process has optimized which existing CR's will be removed and retired, which will be replaced with 4G devices and what other assets may be installed to support a smarter grid in preparation for DTE's advanced distribution management system within the next few years.

Q. Why not go directly from 3G to 5G infrastructure?

A. DTE has planned the 3G transition, with engineering input from cellular carriers and AMI equipment vendors. With the information provided, all parties are expecting 4G devices to coexist within 4G and 5G infrastructure. At present, manufacturers of AMI equipment are not designing 5G products and 5G infrastructure is not readily available. DTE has however, worked with multiple manufacturers of AMI equipment to minimize the impact as the cellular industry upgrades technology beyond 4G cellular. For instance, the cellular component of the existing CR is an integrated component of the CR. Where the replacement device, the new design is such that the cellular card is designed as removable from the device, establishing the possibility of upgrading the cellular card while the rest of the device remains for an extended service life. This feature and many others minimizing future costs, were driven by electric utility participation in product redesign.

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Q. How will the Cell Relay enhancement provide customer benefit?

A. Without the cellular 3G to 4G upgrade, by year-end 2020 DTE Electric will lose daily communication with approximately 1 million of the 2.6 million DTE Electric residential electric meters and communication to approximately 6,000 industrial electric meters. These meters will not be remotely accessible which will have a significant negative impact on our ability to bill customers; eliminate our ability to obtain critical power quality and outage data; and remove our ability to remotely connect/disconnect meters.

Most new 4G data routing CR devices are sited to be installed on poles within the targeted geography and not on the customer premise. This design enhancement, over the previous design, reduces the need to be on the customer premise for telecommunication network issues and provides a design that has the new data routing CR devices 30 to 35 feet on poles. Also, cellular 4G technology has significantly better RF signal propagation than 3G cellular. These features will provide better connectivity to meters and faster data rates, enabling DTE to improve on its current 98.5% AMI read rate and help to eliminate hard to reach customer meters within the AMI network.

Q. How do these enhancements align with the SmartGrid strategy?

A Network devices mounted at a 30-35 feet on a utility pole instead of at a customer premise blocked by the structure will provide better frequency propagation, more reliable and resilient meter mesh communications, and enable clearer communication with future SmartGrid network devices such as intelligent switches, capacitor banks, reclosers and sectionalizers.

Q. What is the Company's current status of customers opting out?

A. As of June 1, 2018, we have approximately 7,600 customer sites and approximately 9,399 customer meters that have opted-out.

Q. How does the number of customers opting out of the AMI program compare to expectations?

A. The anticipated volume of opt-out customers in Case No. U-17053 was 15,500, at full installation. Thus, our current rate of customers taking the opt-out option now is considerably lower than expected even though we have not completed installations.

Q. Based on this current data, what is your estimate of customers opting out of the AMI program?

A. Based on the current pattern of opt-outs and 1,077 hard to reach non-AMI customers remaining to be converted to AMI, I would estimate that the residential customers opting out once the full installation is complete, would be less than 8,300 customer sites.

Q. Is DTE Electric proposing any changes to the opt-out charges at this time?

A. No. Pursuant to the Commission's Order in Case No. U-18014 (page 129), six months following completion of AMI installations, the Company shall file, in a separate docket, an application for review of its opt-out charges. As stated above, DTE Electric will not be at 100% completion of its electric meters until year end 2018. Therefore, a filing to address the opt-out charge will be made consistent with the Commission's Order in U-18014.

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Q. Does this complete your direct testimony?

A. Yes, it does

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MATTHEW T. PAUL

DTE ELECTRIC COMPANY
QUALIFICATIONS OF MATTHEW T. PAUL

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Q. What is your name, business address and by whom are you employed?

A. My name is Matthew T. Paul. My business address is One Energy Plaza Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. My formal education consists of a Bachelor of Science degree in Mechanical Engineering from Michigan State University and a Masters of Business Administration degree from the University of Chicago. I have also completed several Company sponsored courses and have attended various seminars to further my professional development with DTE Electric.

Q. Please summarize your professional experience.

A. From 1991 through mid-2000, I worked for Koch Industries in various engineering, trading, and leadership positions.

In June of 2000, I joined DTE's non-regulated coal company, DTE Coal Services, Inc. (DTECS) as Director, Trading. In this capacity, I was responsible for building and running DTECS' coal and emissions trading group. From 2000 through late 2012, I held various positions of increasing leadership at DTECS, eventually holding the position of President, DTECS from mid-2006 through late 2012. As President, DTECS, I was responsible for all aspects of the business.

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In November of 2012, I accepted the position of Director, Generation Optimization. In this position, I was responsible for all aspects of the Generation Optimization group including the Merchant Operations Center, Merchant Analytics Team, Wholesale Power, and Settlements.

In December 2014, I was appointed Executive Director - Generation Optimization and Corporate Fuel Supply. In this position, I was responsible for the dispatch of DTE Electric's generation assets into the MISO marketplace, the fossil fuel supply and transportation requirements for DTE Electric's fossil fuel electric generating assets, as well as the Company's coal transshipment facility, Midwest Energy Resources Company (MERC), located in Superior, Wisconsin. I also acted as DTE Electric's North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Senior Manager with responsibility for DTE Electric's NERC compliance organization and processes.

Q. What is your current position with the Company and what are your current responsibilities?

A. In October 2016, I was appointed Vice President Fossil Generation Plant Operations for DTE Electric. In this capacity, I am responsible for all phases of operations, maintenance, engineering, planning and expenditures associated with DTE's fossil fueled power plants, including our 84 peaking units, and our interest in the Ludington Pumped Storage facility with Consumers Energy.

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Q. Are you a member of any trade associations or participate on any Boards or Committees?

A. Yes, I am currently a member of the board of directors of the Reliability First Corporation. Reliability First is a regional entity reporting to NERC with a footprint spanning 13 states and the District of Columbia whose mission is to ensure the reliability and security of the Bulk Power System. I am also a member of the board of directors of the Michigan Manufacturing Association (MMA), a leading advocate for Michigan manufacturers.

Q. Have you previously provided testimony before the Michigan Public Service Commission (Commission)?

A. Yes. I provided testimony in the Company's 2016 Power Supply Cost Recovery Plan case, Case No. U-17920.

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the reasonableness and prudency of the operations and maintenance (O&M) and capital expenditures for steam power generation, hydraulic power generation (Ludington) and other power generation (peaking units) for the historical test year ending December 31, 2017, and the projected test period ending April 30, 2020. I will also address the following additional topics in my testimony:

1) I will explain forecasted changes in power plant capacity ratings on a yearly basis for 10 years looking forward (2018 through 2027). The capacity changes are associated with forecasted retirements of current generating assets, the addition of new generation assets, as well as changes in capacity ratings.

2) I will provide a review of Fossil Generation coal unit availability performance for five years prior and five years following the historic test year in this case. In addition to discussing availability, I will also discuss the planned and unplanned outage performance for these same timeframes. This data will show that the Fossil Generation coal unit Random Outage Factor (ROF), Planned Outage Factor (POF) and Equivalent Availability (EA) are forecasted to improve in the 2018-2022 timeframe compared to the 2012-2017 actual performance realized.

3) For capital expenditures, I will provide details of the historical 2017 level of expenditures on a plant level basis and provide forecasts of expenditures to be incurred from January 1, 2018 through April 30, 2020. This data will show the levels of expenditures related to routine maintenance, new environmental compliance requirements as well as expenditures related to safety and general reliability that have been, and will be made. I will also provide additional details on the portion of the Fossil Generation capital expenditures that are focused on

the Tier 1 coal-fired plants (Belle River and Monroe) and compare that with the far lower expenditures that are focused on the Tier 2 coal plants (St Clair, River Rouge and Trenton Channel).

4) I will provide a synopsis of the O&M and capital expenditures made to repair the damage caused by the 2016 St. Clair Power Plant fire and the actual and pending insurance recovery for this event.

5) I will discuss the Tier 2 coal units and specifically the logic of retiring the units over the 2020 to 2023 timeframe. The discussion focuses on the need to phase out the retirements between 2020 and 2023 due to environmental regulations, workforce planning concerns, the impact on the communities where the units are located and potential grid reliability concerns. I will show that the level of continuing capital expenditures forecasted in this case are reasonable and prudent in that they are limited to expenditures required to sustain safe and environmentally compliant operations of the Tier 2 plants.

6) I will support the multiple known and measurable changes in Fossil Generation O&M expenses that will span the timeframe from the 2017 historic test year in this case to the projected test year, ending April 30, 2020. These known and measurable changes include:

- St Clair Power Plant fire event recovery cost and insurance proceeds
- St Clair Power Plant normal operations adder
- St. Clair Power Plant Unit 4 retirement
- Fly ash settlement

7) I will describe the new combined heat and power (CHP) facility being built at the Ford Motor Company Research and Engineering Center in Dearborn, Michigan. Included will be a description of the major equipment being installed and planned

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plant operations. Company Witness Mr. Feldmann will provide additional details for this project.

8) I support 2020-2022 Fossil Generation capital expense forecasts that are being introduced as part of a proposed infrastructure recovery mechanism (IRM). The Fossil Generation capital spend included in the proposed IRM are related to planned outage work of Tier 1 steam generating units including Monroe, Belle River, and Greenwood power plants, scheduled capital equipment replacements on these Tier 1 units, planned outage work on large natural gas fired peaking units, and the construction costs of the new combined cycle gas turbine (CCGT) generating plant expected to come online in 2022.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-6	F1	Planned Long Range Fossil Generation Changes
A-6	F2	Fossil Generation Coal Unit Performance
A-12	B5.1	Projected Capital Expenditures – Steam, Hydraulic, and Other Power Generation
A-13	C5.1	O&M Expenses – Steam Power Generation
A-13	C5.4	O&M Expenses – Hydraulic Power Generation
A-13	C5.5	O&M Expenses – Other Power Generation
A-30	T3	Infrastructure Recovery Mechanism Capital – Fossil Generation Expenditures 2020-2022

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Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How is your testimony organized?

A. My testimony consists of the following four (4) parts:

Part I	Fossil Generation Plant Capacity and Availability
Part II	Fossil Generation Capital Expenditures
Part III	Fossil Generation Operating and Maintenance Expenses
Part IV	Infrastructure Recovery Mechanism (IRM)

Part I - Fossil Generation Plant Capacity and Availability

Fossil Generation Net Summer Installed Capacity

Q. Can you provide an overview of DTE Electric's Fossil Generation assets?

A. As of January 1, 2017, Fossil Generation's owned generation based on installed summer capacity ratings equaled 10,037 MW and was comprised of:

Rated Capacity (Summer) as of 1/1/2017

Fossil Steam	7,019 MW
Peaking Plant	2,033 MW
Pumped Storage	985 MW
Total Fossil/Hydraulic System	10,037 MW

The Company's 7,019 MW's of fossil steam plant contains coal-fired units that provided 6,234 MW of capacity and a natural gas-fired unit that provided an additional 785 MW of capacity as shown below:

Rated Capacity as of 1/1/2017

Coal Steam Plants	Net Summer Capability	No. Units
Belle River (DTE ownership)	1,034 MW	2
Monroe	3,066 MW	4
River Rouge	272 MW	1
St. Clair	1,367 MW	6
Trenton Channel	495 MW	1
Total Coal Capacity (steam)	6,234 MW	14

Gas Steam Plants	Net Sumer Capability	No. Units
Greenwood	785 MW	1
Total Natural Gas (steam)	785 MW	1

The Michigan Public Power Agency (MPPA) is joint owner of Belle River Power Plant and its ownership entitlement is 18.61% (234 MW) of the plant. The MPPA ownership of Belle River is not included in the 1,034 MW Belle River Plant's capability shown above.

DTE Electric's peaking plants, along with DTE Electric's ownership share of the Ludington Pumped Storage facility, jointly owned with Consumers Energy, are shown below:

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Rated Capacity as of 1/1/2017

Pumped Storage and Peaking	Net Summer Capability	No. Units
Gas/Oil Combustion Turbines (10 locations)	1,905 MW	38
Diesel Generators (10 locations)	128 MW	46
Total Peaking Capacity	2,033 MW	84
Ludington Pumped Storage	985 MW	6
Total Pumped Storage/Peaking Capacity	3,018 MW	90

As evidenced by the data provided, DTE Electric's fossil generating system is diverse both with regards to size and fuel type. This diversity gives DTE Electric important flexibility in meeting the energy needs of its electric customers in a cost-effective and reliable manner.

Q. What standard or test is used to verify the capacity numbers stated above?

A. The Company's unit capacity testing protocols are defined in Power Plant Order (PPO) No. 302 titled "Generation Verification Test Capacity (GVTC)". This PPO requires that the capacities of all Fossil Generation units be verified in the manner specified by MISO. The PPO details requirements that must be followed across Fossil Generation, is approved by Fossil Generation management and is routinely updated to ensure it remains current.

Q. Did Fossil Generation retire or rerate any generating units in 2017?

A. Yes. St Clair Unit 4, rated at 151 MW, was retired in November 2017. In addition, the capacity of Ludington Unit 5 was increased by 34 MW after completion of its upgrade overhaul in May 2017.

Q. Can you provide a summary of DTE Electric's Fossil Generation assets incorporating the 2017 Fossil Generation retirements and unit rerates as of December 31, 2017?

A. As of December 31, 2017, Fossil Generation's owned generation based on summer capacity ratings equaled 9,920 MW and was comprised of:

Rated Capacity (Summer) as of 12/31/2017

Type	Net Summer Capability	No. Units
Fossil Steam	6,868 MW	14
Peaking Plant	2,033 MW	84
Pumped Storage	1,019 MW	6
Total Fossil/Hydraulic System	9,920 MW	

Q. Can you provide a summary of Exhibit A-6, Schedule F1 titled "Planned Long Range Fossil Generation Changes Years 2017 through 2027"?

A. Exhibit A-6, Schedule F1 provides the 2017 actual generation rating changes and a 10-year projection of the forecasted changes in Fossil Generation unit capacity ratings for 2018 through 2027. Changes are based on the forecasted timing of upcoming unit retirements, development of new generation assets and minor changes to existing assets.

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Q. Can you please explain the yearly changes in generation capacity shown on Exhibit A-6, Schedule F1 for 2017-2027?

A. As discussed previously, St. Clair Unit 4 was retired in November 2017 for a reduction of 151 MW of summer rated capacity and the capacity of Ludington Unit 5 was increased by 34 MW after completion of its upgrade overhaul.

In 2018, the Ludington Unit 6 upgrade will be completed for an additional 34 MW and DTE Electric’s share of Belle River will increase by 8 MW due to replacement of the Unit 2 high-pressure turbine with a more efficient design.

In 2019, the Ludington Unit 3 upgrade will be completed for an additional 34 MW and DTE Electric’s share of Belle River will increase by 8 MW due to replacement of the Unit 1 high-pressure turbine with a more efficient design.

In 2020, the Ludington Unit 1 upgrade will be completed for an additional 34 MW. Also in 2020, Fossil Generation is forecasting the retirement of River Rouge Unit 3, a 272 MW (summer rating) coal-fired unit. Finally, DTE Electric will be adding a 34 MW Combined Heat and Power facility to its generating fleet in 2020.

No changes are currently forecasted in the capacity ratings of the Fossil Generation fleet in 2021.

In 2022, Fossil Generation forecasts the retirement of St. Clair Units 1, 2, 3 and 6, representing a combined 776 MW of coal-fired summer rated capacity. Also in 2022, Fossil Generation will be adding a 1,100 MW CCGT plant to its portfolio.

In 2023, the Company forecasts the retirement of Trenton Channel Unit 9, a coal-fired unit with a summer capacity rating of 495 MW, and St. Clair Unit 7, representing 440 MW of coal-fired summer rated capacity.

No changes are currently forecasted in the capacity ratings of the Fossil Generation fleet in 2024 through 2027.

Q. Why is DTE forecasting retirements of River Rouge, St. Clair, and Trenton Channel coal-fired generating units to occur between 2020 and 2023?

A. To comply with the 2023 implementation deadline for certain environmental regulations, significant capital investments would need to be made at the River Rouge, St. Clair, and Trenton Channel generating units, collectively referred to as the "Tier 2" units. As described in detail in Case U-18419, DTE concluded in the spring of 2016 that it would not be economically beneficial for DTE's customers to spend the money to comply with these regulations to keep the units running beyond 2023. Based on this conclusion and for other reasons explained further below, the Company made the decision to retire its Tier 2 plants prior to the implementation deadline and backfill that capacity with a combination of renewables, energy efficiency, demand response, and the recently approved Blue Water Energy Center, an 1,100 MW CCGT plant. However, given that these Tier 2 units comprise nearly 2,000 MW of net summer capability, it is reasonable and prudent to facilitate a phased transition between now and 2023 to maintain a safe and reliable supply of energy for our customers.

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Q. What factors other than environmental regulations are considered by the Company when making the determination to retire a generating unit and the associated timing of that retirement?

A. There are several factors to consider when determining whether a generating unit should be retired and the associated timing of that retirement. Among these factors include the age and condition of the generating unit, resource adequacy, grid reliability concerns, local community impacts, and workforce planning. Additionally, when considered along with the factors I mentioned above, an economic cost and benefit analysis can provide a general guideline for the reasonableness and prudency of continued operations of a particular generating unit.

Q. Why should resource adequacy be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. Because DTE Electric has the obligation to provide safe, reliable and affordable electricity to its customers, decisions around the addition of new capacity and/or the retirement of existing facilities must be carefully considered to ensure that the Company has sufficient resources to meet this obligation. DTE Electric cannot foresee or control other entities' various assumptions, projections and sometimes-changing decisions regarding plant retirements. There is also no guarantee that the Company's Tier 2 power plants will continue operations through their planned retirement dates. As a recent example, the Company had planned to retire St. Clair Unit 4 in 2022, but in 2017 decided to retire it due to the discovery of the degraded condition of an important piece of equipment. Because of these variables, it is important that the Company carefully consider its resource position relative to its MISO-imposed planning reserve margin requirement when considering the timing of its Tier 2 unit retirements. The retirement of a generating unit is likely a permanent decision with long-term consequences since the unit cannot simply be "un-retired" if underlying assumptions around resource needs were to unexpectedly change. Attempting to bring a unit back online once it has been retired would require the cleaning, inspecting and potential repairing of major equipment that has likely laid dormant since its retirement date, re-staffing of plant employees, undergoing a lengthy generator interconnection agreement process with MISO, and renewal of required permits.

Q. Why should grid reliability be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. Retirement of a generating unit has the potential to impact grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff[1] states that an owner of a generation resource that is planning to retire or suspend operations of all or any portion of that resource must notify MISO by submitting an Attachment Y Notification of Generator Change of Status form. The Attachment Y Notification must be submitted to MISO at least twenty-six (26) weeks prior to the requested status change unless the generation resource is inoperable due to a forced outage, in which case the Attachment Y Notification must be submitted at least thirty (30) days prior to the requested status change. In collaboration with the affected transmission owners, MISO will then perform a reliability study to determine whether the generation resource is necessary for the reliability of the transmission system based on the analyses described in Section 38.2.7 of MISO's tariff and the criteria set forth in the MISO Business Practices Manual. If, after completing a reliability study, MISO determines that a reliability concern exists, MISO may deem the generating unit to be a

[1] https://cdn.misoenergy.org/Tariff%20-%20As%20Filed%20Version72596.pdf

System Support Resource (SSR), meaning that continued operation of that generating unit is required to maintain system reliability. MISO would require that a solution, such as transmission system upgrades or the installation of a new generating resource, be implemented before the generation resource is authorized to be retired or suspended. Even if a generating unit is not given an SSR designation, the MISO reliability study may identify unfavorable system conditions that could require mitigation solutions that have adverse impacts to our customers such as the need for firm load interruptions. Therefore, given that retirement of a generating unit has the potential to negatively affect the electrical grid and with it our customers, it is critically important to take grid reliability into consideration when making the determination to retire a generating unit and the associated timing of that retirement.

Q. Has DTE Electric filed any Attachment Y Notifications with MISO related to the Tier 2 units forecasted to retire between 2020 and 2023?

A. Yes. In January 2018, the Company filed confidential Attachment Y Suspension requests for its Tier 2 generating units to prompt MISO to study the impact of plant suspension on the transmission system. The decision to initiate the reliability study process with MISO was based on the Company's forecasted retirement of nearly 2,000 MW of generation between 2020 and 2023, coupled with the addition of the 1,100 MW combined cycle gas plant expected to come online in 2022.

Filing of the Attachment Y Suspension requests this year does not change the Company's need to file Attachment Y Retirement requests 26 weeks prior to the expected retirement dates for each unit. As mentioned earlier in my testimony and shown on Exhibit A-6 Schedule F1, the forecasted retirement dates for our Tier 2 generating units are:

- River Rouge Unit 3 2020
- St. Clair Units 1, 2, 3, 6 2022
- St. Clair Unit 7 2023
- Trenton Channel Unit 9 2023

Q. Has the Company received the final study reports from MISO for the Attachment Y Notifications it submitted for the Tier 2 Units?

A. Yes. The Company has received the final study reports for the River Rouge and St. Clair Attachment Y Suspension requests. These studies conclude that there are no reliability issues identified related to the suspension of the River Rouge and St. Clair units that would require the units to be designated as SSR units. However, the reports do indicate that retirement or suspension of these units may create thermal and voltage issues that could require the Company to shed firm load to ensure grid reliability. Although firm load shed is utilized as a countermeasure within MISO's planning criteria, the Company has significant concerns about implementing electrical service interruptions to our customers as a means of addressing known grid reliability issues. Maintaining and operating River Rouge and St. Clair power plants until their planned retirement dates will provide additional time to identify and implement alternative solutions that can ensure continued reliable electric service for its customers.

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Q. Has MISO indicated that any of the Tier 2 units could be deemed a System Support Resource (SSR)?

A. The confidential study that is currently in progress indicates that Trenton Channel Unit 9 provides critical reliability support to the grid. MISO could potentially deem Trenton Channel Unit 9 as a system support resource (SSR), meaning that MISO will not authorize DTE to retire the unit without proper measures and solutions in place to mitigate the identified grid reliability issues. DTE Electric will work closely with stakeholders in this process to evaluate solutions to mitigate the reliability concerns.

Q. How should local community impacts be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. The property tax assessments for DTE Electric's Tier 2 generating units make up a significant portion of the operating budgets for the city of River Rouge, the city of Trenton, and East China Township. Although the Tier 2 unit retirements planned over the next two to five years will lead to the loss of much of the tax revenue these communities depend on, announcing the retirements years in advance allows these communities time to complete needed planning activities and realize a smoother fiscal transition than would otherwise occur. Executing an immediate and unexpected unit shutdown of some or all the Tier 2 units would leave these communities with a large sudden shortfall in revenue. As a matter of fact, the Company received a letter, dated April 25, 2018, from the mayor of the City of River Rouge, expressing grave concerns over the potential early retirement of River Rouge Unit 3. In this letter, Mayor Bowdler stated, "The loss in this revenue would also make it difficult to continue to maintain the existing services provided by the City and would probably result in much of the City

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being shut down and only functioning on a part-time basis... the immediate closing of the plant would cripple the City of River Rouge and significantly impact the current residents and businesses way of life – from police and fire protection, library services, and rubbish collections everything will be affected." It is in the best interest of the communities in which our generating units operate, for the Company to thoughtfully develop and deliberately execute the retirement plan of our Tier 2 units and to communicate that plan well in advance to all affected parties. This allows the communities as much time as possible to prepare for the unavoidable loss of property tax revenue.

Q. Why should workforce planning be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. The employees stationed at our Tier 2 plants represent a significant percentage of the Fossil Generation workforce. The retirement of all these units at the same time would create a significant challenge in finding vacancies that match the specialized skill set that these transitioning employees have acquired at the Company over a period of years in operating and maintaining Company generation units. Phasing the Tier 2 retirements out over the next two to five years allows a systematic reduction in the number of employees at the Tier 2 plants by moving employees to the Tier 1 units where they can fill critical vacancies that require their unique skills. Therefore, it is in the Company's, our employees', and our customers' best interest to phase the retirement of the Tier 2 generating units between 2020 and 2023.

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Q. Has the Commission given guidance on how and when to properly analyze generating unit retirements?

A. Yes. On pages 48-49 of the MPSC Case No. U-18419 Order dated April 27, 2018, the Commission states, "The Commission agrees with DTE Electric that, although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the company's 2019 IRP analysis and the results of MISO's Attachment Y reliability study. Other matters such as workforce and local government tax impacts may also be considered in a decision of this magnitude." The Company plans on filing an IRP analysis with the Commission in March 2019.

Q. Can you summarize Fossil Generation's plan for retirement of its Tier 2 coal-fired generating units?

A. Yes. Consistent with the aforementioned guidance given by the Commission in the MPSC Case No. U-18419 Order dated April 27, 2018, Fossil Generation considers factors such as resource adequacy, grid reliability, local community impacts, and workforce planning when making the determination to retire a generating unit and the associated timing of that retirement. The need to comply with the implementation deadline for applicable environmental regulations is driving a need to retire the Tier 2 units no later than the end of 2023. However, rather than planning to retire all the Tier 2 units in 2023, DTE Electric took into consideration the various factors mentioned above and believes staggering the unit retirements between 2020 and 2023 is the most reasonable overall approach. Despite the impending near-term retirements, Fossil Generation is committed to maintaining the units for continued safe and environmentally compliant operation.

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<u>Fossil Generation Plant Performance</u>

Q. How is Fossil Generation Plant performance monitored and calculated?

A. Fossil Generation utilizes equivalent availability factor (EAF), random outage factor (ROF) and planned outage factor (POF) to monitor overall unit performance. EAF is equal to 100 minus the ROF minus POF. Equivalent availability is equal to total possible megawatt-weeks minus planned outage megawatt-weeks minus random outage megawatt-weeks (full and partial derates) divided by total possible megawatt-weeks. Total possible megawatt-weeks are calculated by multiplying the net demonstrated capability of the unit by the weeks in the time-period (52 weeks per year). Planned outage megawatt-weeks refers to the equivalent number of weeks in the time-period that the unit is not available due to scheduled maintenance multiplied by the capacity that is out of service. Random outage megawatt-weeks is the number of weeks of unit unavailability caused by an outage or derate that is not planned or scheduled, multiplied by the capacity that is out of service.

Q. What are the major drivers of unit unavailability?

A. There are three major drivers of unit unavailability: (1) planned full unit or periodic maintenance outages, (2) unplanned or random unit outages, and (3) derates or partial unit outages which can be planned or unplanned.

Planned full outages and planned derates are those outages for which the Company has developed long range maintenance plans designed to sustain unit performance and proactively address emerging reliability issues. Unplanned unit outages and unplanned derates are those that occur due to either reliability issues common across

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the industry or unusual events which are unique to a specific DTE Electric Fossil Generation plant or unit.

Q. Can you explain Fossil Generation's 2017 total fossil fleet plant availability performance?

A. The EAF for Fossil Generation was 69.8% for the 2017 historic period. The 69.8% equivalent availability was the result of a 12.8% ROF and a 17.4 % POF. In 2017, total Fossil Generation assets included Greenwood, Belle River, St Clair, River Rouge, Trenton Channel, Monroe, peakers and Ludington power generation facilities. Fossil fleet availability for 2017 was reduced by multiple planned major overhaul maintenance outages completed on Belle River Unit 2, Greenwood Unit 1, St. Clair Units 4 and 7, Monroe Unit 2, Trenton Channel Unit 9, multiple large peaker units and Ludington Units. Less comprehensive planned outages were completed on many units to prepare for or recover from high peak load summer operations. The major items impacting the 2017 ROF were the fire damage to St Clair Unit 7 and the retirement of St Clair Unit 4.

Q. Why did the retirement of St Clair Unit 4 contribute to the ROF of the fossil generation fleet in 2017?

A. The North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) reporting requirements dictated that the unit be placed into forced outage as soon as it is determined that repair of the unit was not going to be completed. The unit was placed into forced outage on June 21, 2017 and remained in this state until its official MISO retirement on November 13, 2017. This nearly 5-months of outage time on St Clair Unit 4 was coded as a forced outage, thus negatively impacting 2017 ROF.

Q. What was the equivalent availability of the coal units within the Fossil Generation fleet in 2017?

A. As shown on line 6 of Exhibit A-6 Schedule F2, coal plants had an equivalent availability of 69.2% in 2017. The 69.2% equivalent availability for coal plants in 2017 was the result of a 14.0% ROF and a 16.8% POF for those units. Coal plants include Belle River, St Clair, River Rouge Unit 3, Trenton Channel Unit 9, and Monroe power generation facilities.

Q. How did the performance of the Fossil Generation coal units in 2017 compare to the performance of the total Fossil Generation fleet?

A. The EAF of the Fossil Generation coal units performed on par with the total Fossil Generation fleet in 2017 and the year-over-year EAF of the coal generating units improved by 4.5% (64.7% in 2016 versus 69.2% in 2017).

Q. How has the year-over-year ROF performance of the Fossil Generation coal units changed?

A. Most coal units showed improved (lower) ROF in 2017 compare to 2016. Table 1 below summarizes those results. Large improvements can be seen on Monroe Unit 2, and St. Clair Units 1, 2, 3 and 6. Belle River Units 1 and 2, Monroe Units 1, 3 and 4, and Trenton Channel Unit 9 remained relatively flat, while St. Clair Units 4 and 7 and River Rouge Unit 3 showed a deterioration in ROF performance from 2016 to 2017.

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Table 1
Coal Unit ROF Performance

	2016	2017	Delta
Belle River 1	4.84	4.47	-0.37
Belle River 2	4.19	6.13	1.94
Monroe 1	7.13	3.56	-3.57
Monroe 2	40.94	7.54	-33.40
Monroe 3	6.37	7.22	0.85
Monroe 4	8.15	7.60	-0.55
River Rouge 3	19.35	30.96	11.61
St. Clair 1	19.21	5.56	-13.65
St. Clair 2	31.02	16.57	-14.45
St. Clair 3	27.74	8.56	-19.18
St. Clair 4 (retired 11/2017)	24.93	42.4	14.47
St. Clair 6	53.52	28.89	-24.63
St. Clair 7	49.15	78.14	29.04
Trenton Channel 9	16.21	12.28	-3.93

Q. Can you provide additional details on the contributing factors on the units showing lower performance in 2017 compared to 2016?

A. During the planned St. Clair Unit 4 turbine inspection outage in late 2016 and early 2017, it was determined that the LP turbine discs and blades needed to be repaired or replaced. The cost of this repair proved to be financially unfavorable and the Company made the decision to retire the unit in June of 2017. The unit was placed into forced outage on June 21, 2017 per NERC GADS reporting requirements as soon as it was determined that repair of the unit was not going to be completed. It remained in this state until MISO granted its official retirement effective November 13, 2017. St. Clair Unit 7 was in forced outage from August 11, 2016 until August 31, 2017 to complete repairs required to return the unit to service following the August 2016 fire event and turbine failure. River Rouge Unit 3 experienced an extended unit derate

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followed by a maintenance outage to repair and replace degraded furnace rear wall refractory and insulation that was causing excessive furnace gas temperatures. These two events resulted in the ROF performance experienced at River Rouge Unit 3 in 2017.

Q. What are the projections for Fossil Generation coal unit availability for 2018 through 2022?

A. The coal unit equivalent availability is forecasted to be 73.4%, 74.4%, 77.0%, 78.1% and 79.0% for the years 2018-2022 respectively. Coal unit EAF, POF and ROF performance is shown in Exhibit A-6, Schedule F2 for the years 2012 through 2022. Actual data is provided for the years 2012-2017 while forecasted data is provided for 2018-2022.

Q. How does the forecasted coal unit availability compare to the actual historical coal unit availability?

A. As shown in Exhibit A-6 Schedule F-2, the average coal unit availability for 2012-2017 was 74.4% while the forecast of average coal unit availability for 2018-2022 is 76.4%.

Q. On what basis did you make your forecast of plant availability for 2018 and beyond?

A. The Fossil Generation forecasted plant availability projections are based on input from plant staff, plant reliability engineers, engineering subject matter experts (SMEs), historical unit performance, the known maintenance and operational status of each unit, and future planned outage schedules and work scope.

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Q. What is DTE Electric doing to maintain the overall availability of Fossil Generation coal units?

A. Company efforts to maintain overall Fossil Generation availability are based on placing priority on maintenance expenditures in the Tier 1 coal plants (Monroe and Belle River) to sustain high levels of performance, while minimizing long-term expenditures in the Tier 2 coal-fired units at Trenton Channel, River Rouge and St. Clair Power Plants. Although expenditures are being minimized at these three Tier 2 plant sites, all necessary work to safely operate the units and to comply with legal and regulatory requirements will be completed.

<u>Unplanned Outage Frequency Reduction</u> – Historically, boiler tube failures have been the largest factor contributing to unit random outages. These outages are typically relatively short in duration, normally lasting less than seven days each. However, each seven-day outage is the equivalent of approximately two percentage points of ROF. A formal Boiler Tube Failure Reduction (BTFR) team addresses all unplanned outages related to boiler tubes within the fossil fleet, utilizing industry data and experience as input to supplement their own expertise. This team utilizes all available outage opportunities to identify, prioritize, and recommend the most critical areas for boiler tube replacement based on equipment history, equipment inspection and data collection. They also consider recommendations of industry best practice groups such as the Electric Power Research Institute (EPRI) and OEMs. The conclusions drawn from these efforts drive project planning for O&M and capital expenditures as well as operational changes in order to improve reliability performance.

While turbine component failures on operating units are infrequent events, when they do occur, they can result in long duration outages that require months to complete the required repairs. Knowing that low-probability, high-impact events can have a significant effect on reliability, the Company established a rotor reliability team more than 10 years ago. The rotor reliability team is comprised of turbine, generator, vibration, fracture mechanics, nondestructive examination (NDE), metallurgy and chemistry experts. This team makes inspection and repair recommendations for Fossil Generation turbines, generators and boiler feed pump turbines that form the basis for planned outage work scope. These recommendations are based on EPRI and OEM recommendations, and experience gained from component failures in DTE equipment as well as failures in the utility industry.

<u>Planned Outage Improvement</u> – Fossil Generation continues its process of reviewing completed planned outages to ensure that future outages are completed with the goal of decreasing the overall cost without impacting the scope of work performed.

<u>Vendor Contracts and Workmanship</u> – Fossil Generation utilizes both Supplier Performance Management (SPM) and Quality Assurance (QA) initiatives to monitor and improve the performance of its major suppliers and contractors. SPM ensures that suppliers live up to their contract terms and are expeditious in resolution of disputes. The QA focus includes surveillances to ensure that suppliers have quality programs in place, that these programs are followed and that any non-conformances identified are both documented and corrected. The QA function ensures that corrective actions are put in place to proactively address issues before they occur and to ensure that items identified are addressed at the root cause level to prevent

reoccurrence. Both SPM and QA provide positive impacts to the organization and its performance.

Part II - Fossil Generation Capital Expenditures

Q. Can you please provide an overview of your Part II discussion?

A. Yes. In this section of my testimony, I will discuss the following:

- Capital Planning Process
- 2017-2020 Capital Projects Summary
- Non-Routine Capital Expenditures
- Routine Capital Expenditures
- Summary of Tier 1 and Tier 2 Coal-Fired Generation Capital
- 2017-2020 AFUDC Estimate

Capital Planning Process

Q. Can you explain the Fossil Generation capital planning process?

A Yes. Capital projects are initiated to support safety, regulatory requirements, environmental compliance, plant-level reliability plans, OEM recommendations or the engineering recommendations of Fossil Generation's equipment and system experts. Capital expenditure requests require the initiation of an approved project form that includes a detailed explanation of the project and an initial estimate of the costs and benefits associated with the project. Projects are then further developed including work scope identification and ranking based on customer-centric economic metrics and other important drivers such as safety requirements, environmental regulations, and outage timing opportunities. The planned outage schedule heavily influences capital project timing since many capital projects are implemented during longer

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duration planned outages to minimize implementation impact on plant availability. During these planned outages, inspections are completed on critical systems to ensure that the outage being executed addresses the work needed to sustain future unit reliability. These inspections often reveal unanticipated damage because many of these systems cannot be thoroughly inspected or evaluated until they are disassembled during the outage.

Once capital project requests are fully developed, they are prioritized and presented for management review and approval. The review process focuses on ensuring that the projects represent the best solution to address the issue at hand and represent the least cost method for accomplishing the proposed work. Projects are approved if they are justified by an economic evaluation or required to meet safety and/or environmental regulations.

In summary, the capital spending and approval process is designed to identify the optimal allocation of capital resources to meet safety and environmental regulations while maintaining overall Fossil Generation reliability performance and minimizing costs.

Q. What do you mean by projects being justified by economic evaluation?

A. The prioritization of economic projects is based on an internal rate of return (IRR) analysis performed comparing the costs of implementing the new project to its customer benefits. Included in the analysis are projected capital expenditures, future avoided outages, as well as changes to unit capacity ratings, heat rate (efficiency) and fuel blending capabilities. Future avoided outage impacts include the value of

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avoiding events such as boiler tube failures, condenser or feedwater heater leaks and turbine blade failures. The IRR of the project is based on the O&M, capital expenditures and MISO market impacts of the unit's operations with and without the project being implemented over its useful life.

Q. What would be the consequences of not completing the capital projects approved by the process you just described?

A. Failure to complete the approved capital projects described in this case could negatively affect plant reliability, potentially leading to unit derates, unplanned outages, or even the premature forced retirement of a unit. This would result in increased Power Supply Cost Recovery (PSCR) costs, due to additional capacity and energy purchases, lost energy sales, and/or additional ancillary services costs.

Q. Can you explain the governance process for approval of Fossil Generation capital projects?

A. The capital governance process includes the documentation of project assumptions, calculation of costs and benefits, and a rigorous internal review. Projects costing less than $250,000 are approved by plant management, utilizing a project appropriation form, within a budget established based on historic plant spend. These projects generally do not require engineering and often reflect replacement-in-kind.

Projects that cost greater than $250,000 but less than $10 million and/or projects that require engineering are approved on an individual project basis by the Capital Governance Board (CGB) which consists of plant directors, the Director of Engineering and me.

Projects greater than $10 million require senior executive approval, while projects greater than $50 million require approval by the Finance Committee of DTE's Board of Directors.

<u>2017-2020 Capital Projects Summary</u>

Q. Can you provide a high-level discussion of the routine and non-routine capital expenditures being made by Fossil Generation during the historical year 2017 and the 28-month projected period ending April 30, 2020?

A. Yes. Fossil Generation completes routine ongoing expenditures across its existing generation fleet (steam power, hydraulic and peakers) to maintain safe, environmentally compliant, reliable, and efficient operations. The majority of these expenditures involve our Tier 1 plants.

Non-routine capital project expenditures are driven by steam power generation upgrades with a heavy focus on environmentally mandated work at our Tier 1 coal plants, restoration work required by the August 2016 St. Clair Power Plant fire event, decommissioning and environmental remediation projects at steam power generation plants, upgrades at the Ludington Pumped Storage Plant, and construction costs for the new CCGT and CHP plants.

Q. Can you explain Exhibit A-12, Schedule B5.1 entitled, "Projected Capital Expenditures Steam, Hydraulic and Other Power Generation" in more detail?

A. Exhibit A-12, Schedule B5.1 is a 9-page exhibit. Page 1 summarizes both "routine" and "non-routine" capital expenditures for 2017 (actual) through April 30, 2020 (forecasted) for Steam Power Generation, Hydraulic Power Generation (Ludington Pumped Storage) and Other Power Generation (Peaking Units, CCGT plant, and

CHP plant). Page 2 provides additional detail for major non-routine capital expenditures for Steam, Hydraulic, and Other Power Generation. Page 3 provides detail on line item 10 from page 2, the restoration projects associated with the August 11, 2016, St Clair Power Plant outage event. Page 4 summarizes routine Steam, Hydraulic and Other Power Generation capital expenditures by plant site and major category. Pages 5 through 8 provide additional detail for routine maintenance projects with a spend of greater than $1 million for 2017 through April 30, 2020. Finally, page 9 summarizes Allowance for Funds Used During Construction (AFUDC) included in the routine and non-routine capital expenditures.

Q. Can you provide additional details concerning Exhibit A-12, Schedule B5.1, page 1 of 9 entitled, "Projected Capital Expenditures Steam, Hydraulic and Other Power Generation"?

A. Yes. Line 2, Routine Steam Power Generation, includes capital expenditures necessary to operate and maintain DTE Electric's fossil steam power plant sites. Included are projects related to safety, boiler and turbine work, cables and controls, balance of plant projects and maintenance of environmental control systems. Safety expenditures includes the capital necessary to maintain a safe work environment and meet applicable safety regulations and standards. Boiler and turbine work includes the capital expenditures intended to maintain boiler or turbine operations, replace unreliable systems or equipment, maintain or improve heat rate (efficiency) and/or address operating and maintenance problems related to the boiler and turbine systems. Examples of these projects include replacement of worn or damaged turbine blades, air heater baskets, and boiler tube sections such as waterwalls, reheaters, superheaters and economizers. Cables and controls expenditures includes the capital

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intended to replace or improve distributed control systems, large power cables, main unit transformers, and electrical switchgear. The balance of plant area expenditures includes the capital associated with mobile equipment, station air compressors, general service water systems, fuel handling equipment and systems, and plant vehicles and computers. Routine environmental expenditures include the capital necessary to maintain operations of existing environmental control and monitoring equipment. An example of routine environmental expenditures is the ongoing replacement of the Selective Catalytic Reduction (SCR) catalyst beds previously installed at Monroe Power Plant to comply with nitrogen oxides (NO_x) emissions limits. These routine environmental capital expenditures to existing environmental systems differ from the non-routine environmental capital expenditures required to install any future new environmental systems.

Line 3, Non-Routine Steam Power, includes capital expenditures related to environmental compliance projects, site decommissioning, environmental remediation and required equipment modifications related to retired power generation assets, as well as other plant level projects such as physical and cyber security at generation sites.

Line 6, Routine Hydraulic Power Generation, includes the routine capital expenditures necessary to operate and maintain the Ludington Pumped Storage facility of which DTE Electric has a 49 percent ownership interest.

Line 7, Non-Routine Hydraulic Production Plant, includes the capital expenditures related to the efficiency upgrade project currently underway at the Ludington Pumped Storage facility of which DTE Electric has a 49 percent ownership interest. This multi-year project includes installation of new higher efficiency hydraulic turbines, main unit transformers and upgraded generators.

Line 10, Routine Other Power Generation, includes capital expenditures related to maintaining peaker site operations and peaker control system upgrades to meet the requirements of the MISO ancillary services market.

Line 11, Non-Routine Other Power Generation, includes those capital expenditures related to augmenting certain peaker units to provide black start capability to restart the electric power grid in the event of a major blackout like the one that occurred in 2003. This augmentation is needed because some of the coal units that are currently providing black start capability are slated for retirement by 2023. This line also includes capital expenditures related to the development and construction of a 1,100 MW CCGT plant and a 34 MW CHP plant.

<u>Non-Routine Capital Expenditures</u>

Q. Can you summarize Exhibit A-12, Schedule B5.1, page 2 of 9 entitled, "Projected Capital Expenditures Steam, Hydraulic and Other Power Generation – Non-Routine"?

A. Page 2 of Exhibit A-12, Schedule B5.1 provides project level detail for non-routine capital expenditures completed and planned for Steam Production, Hydraulic, and Other Power Generation from 2017 through April 30, 2020.

Q. Can you explain line 2 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 2 (Monroe Dry Fly Ash Basin) represents a project required to maintain the exterior slope of the onsite fly ash landfill berm. This work is necessary to restore embankment degradation resulting from the natural freeze thaw cycles that occur in Michigan.

Q. Can you explain line 3 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 3 (Monroe Fly Ash Basin Vertical Extension) represents a project to expand the storage capabilities at the existing fly ash basin to begin storing dry fly ash while meeting the coal combustion residuals (CCR) requirements.

Q. Can you explain line 4 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 4 (Monroe Coal Combustible Residuals Transfer Pad) represents a project needed to build a new concrete storage containment pad that allows for storage of fly ash until it can be transported to a landfill. This pad accommodates fly ash removed during normal plant cleaning activities and meets the EPA CCR rule requiring that temporary storage of fly ash be executed in a manner that does not allow it to contact the ground or ground water.

Q. Can you explain line 5 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 5 (Monroe ELG Fly Ash Dry Conversion) represents a project required to convert the existing wet fly ash transport system at Monroe Power Plant to a dry fly ash transport system in accordance with EPA's fly ash Effluent Limitation Guidelines (ELG) rule promulgated in 2015 requiring all fly ash transport systems be dry by 2023. Conversion to a dry fly ash transport system will require installation of new

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piping to pneumatically transport ash from each generating unit's precipitator to new storage silos.

Q. Can you explain line 6 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 6 (Monroe Dry Fly Ash Processing) represents a project intended to reduce the amount of fly ash that will need to be transported from Monroe Power Plant to the onsite landfill. Ash processing will allow for fly ash with high carbon content to be treated and turned into an acceptable product for use in concrete manufacturing. Reducing the amount of fly ash placed in the landfill will minimize cost increases related to the new environmental requirements.

Q. Can you explain line 7 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 7 (Monroe Site Security) represents a project intended to improve Monroe Power Plant Site Security. General site access security improvements as well as specific security enhancements for critical equipment are being implemented to mitigate design basis security threats. In addition to physical security, NERC CIP compliance requires the Company to protect its cyber assets to minimize the risk to the electrical grid. These details on these cyber related security initiatives are confidential and are therefore not being provided in order to maintain the integrity of these measures.

Q. Can you explain line 8 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 8 (DSI/ACI Control Projects) represents a project required to finalize improvements to the DSI/ACI control system for St Clair Unit 7.

Q. Can you explain line 9 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 9 (316b) includes costs to complete studies for meeting EPA 316(b) rules on cooling water intake structures at existing power plants. Under their authority to administer the National Pollutant Discharge Elimination system (NPDES), the Michigan Department of Environmental Quality (MDEQ) has asked that additional biological baseline sampling be completed at Monroe and Belle River Power Plants. It is expected that the reports for each power plant will be filed as part of the NPDES reapplication process with MDEQ in 2020.

Q. Can you explain line 10 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 10 (St. Clair Fire Restoration) details the actual expenses required to finish restoring the St. Clair Power Plant and its generating units to full service following the August 2016 outage event.

Q. Can you explain in more detail the work and expenses required to restore plant infrastructure and unit operations following the August 2016 outage event at St. Clair Power Plant shown in line 10?

A. As previously discussed in Case No. U-18255, St. Clair Unit 7 experienced a turbine blade failure on August 11, 2016. As a result of the Unit 7 blade failure and ensuing fire, the turbine house roof as well as several plant common and other unit specific equipment areas were also damaged. Please see Exhibit A-12, Schedule B5.1, page 3 of 9 for a detailed listing of the equipment replaced in 2017.

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Q. Can you explain line 11 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 11 (St. Clair Fire Insurance Recovery) details insurance recovery proceeds, all of which received will be credited to capital accounts for fire restoration work performed at St. Clair Power Plant.

Q. Can you explain line 12 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 12 (Trenton Channel Aux Boiler & Main Steam Reducing Station) details the actual spend that occurred in 2017 to finalize the installation of auxiliary steam boilers and supporting equipment that became necessary after the retirement of Trenton Channel Units 7A and 8 in 2016.

Q. Can you explain line 13 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 13 (Trenton Channel Ash Handling & Sibley Quarry Landfill) summarizes the expenditures planned to meet the CCR regulations for Trenton Channel Power Plant and the Sibley Quarry Landfill. At Trenton Channel Power Plant, a new concrete storage containment pad was required to permit storage of fly ash removed during normal cleaning activities until it can be transported to a landfill. This project meets the EPA CCR rule requiring that temporary storage of fly ash be completed in a manner that prevents it from coming into contact with the ground or ground water. Sibley Quarry work activities include the installation of groundwater monitoring equipment and a workplan study in preparation for eventual termination of landfill activities.

Q. Can you explain lines 16-18 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Lines 16-18 details non-routine capital projects associated with environmental remediation projects at River Rouge, St. Clair and Monroe power plant sites.

Q. Can you explain line 16 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 16 (River Rouge Bottom Ash Remediation) represents a project that is required to comply with the EPA CCR rule and ensure groundwater adjacent to the River Rouge bottom ash basin is collected and monitored per the plant's NPDES permit. The groundwater is collected through a series of wells and monitored prior to discharge.

Q. Can you explain line 17 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 17 (St. Clair Scrubber Basin Remediation) represents a project that is required to permanently close the St. Clair scrubber basin by removing the existing scrubber sludge and transporting it to a landfill. The scrubber sludge was a by-product of a pilot plant scrubber that was installed and operated on St. Clair Unit 6 in the late 1970s.

Q. Can you explain line 18 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 18 (Monroe Inactive Impoundment Remediation) represents a project that is required to segregate coal pile run off and other non-bottom ash discharges from the existing inactive bottom ash basin in association with EPA 40 CFR Part 257. Additionally, monitoring equipment will be installed to ensure that the outfall from the coal pile runoff basin meets all MDEQ and EPA requirements.

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Q. Can you explain lines 19-22 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Lines 19-22 detail steam plant removal costs associated with the retirement and decommissioning of power generation assets at Harbor Beach and Conners Creek power plants, and selected equipment removal work associated with River Rouge Unit 2, and Trenton Channel Units 7A and 8. Removing retired steam generating units involves three primary activities: decommissioning, decontamination, and demolition. Decommissioning activities include the cost to isolate all unit systems and equipment to prepare them for removal from the site. This includes electrical, mechanical, plant controls, water and gas service shutdown and disconnection from the transmission system. Decontamination includes disposing of hazardous materials (including draining oils, chemicals and other fluids), cleaning tanks and pipelines, and removing batteries. Demolition includes tearing down buildings, removing and remediating the coal pile, asbestos abatement, and remediating (fill and cap) ash basins and ponds.

Q. Can you explain line 26 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 26 (Ludington Upgrades) provides yearly detailed costs for the efficiency upgrade project being completed at the Ludington Pumped Storage Facility that is being managed by CMS Energy, Ludington's majority owner. The projected spend represents DTE Electric's 49% share of project costs during the projected period. The unit upgrades are scheduled to be completed between 2015 and 2020.

Q. Can you explain line 27 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 27 (Ludington Transformers) represents a project that is needed to replace the existing main unit transformers at the Ludington Pumped Storage facility. The new larger transformers are required to support the additional capabilities gained from the generator upgrades being executed as part of the efficiency upgrade projects. The forecasted spend represents DTE Electric's 49% ownership interest in the facility.

Q. Can you explain lines 30-32 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 30-32 details non-routine capital projects associated with construction of new CCGT and CHP plants as well as improvements to the security and blackstart capabilities of peaker sites.

Q. Can you explain line 30 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 30 (Combined Cycle – 2022) represents a project to build a nominal 1,100 MW combined cycle gas turbine (CCGT) generating plant on 40 acres adjacent to the existing Belle River Power Plant. This location was strategically selected due to its proximity to transmission lines and high-pressure gas pipeline infrastructure. Engineering and development of this project is currently underway, groundbreaking is scheduled for late 2018, and the plant is expected to be commercially operational by May of 2022.

On April 27, 2018, the MPSC issued an Order in Case No. U-18419 approving DTE's application for three certificates of necessity (CON) for this plant. In approving the CONs, the commission determined through an open hearing process that the energy to be supplied by the project is needed, a natural gas fired CCGT plant was the most reasonable and prudent means of meeting DTE Electric's future energy needs, and that the Company can recover up to $951.8 million in costs for the plant through future rates. Per the requirements of MCL 460.6s (7), DTE Electric will provide an annual update to the Commission on the status of project costs and schedule.

Q. Can you explain line 31 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 31 (Peaker Site Security & Black start) represents a project to augment certain peaker units to provide black start capability to restart the electric power grid in the event of a major blackout like the one that occurred in 2003. This augmentation is needed because some of the coal units that are currently providing black start capability are slated for retirement by 2023. Because black start capabilities are critical to grid reliability, the specific capabilities and units designed as black start assets are kept confidential.

Q. Can you explain line 32 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 32 (Ford CHP Unit) is a project to build a 34 MW combined heat and power (CHP) pilot facility. As indicated by Witness Feldmann, Ford Motor Company has determined that the infrastructure supporting their Dearborn Research and Engineering campus in Dearborn Michigan required significant upgrades and replacements to meet the needs of its employees with highly efficient and environmentally compliant systems. The upgrade planned by Ford included replacement of the complex's Central Energy Plant which includes chilled and hot water systems, on site energy storage, steam generation and distribution, geothermal energy and electrical energy. As part of that larger project, DTE Electric will develop a new 34 MW CHP plant to be located on Ford property. The CHP plant will provide electrical energy to serve Ford and other DTE Electric customers along with process steam to support the needs of the Ford Motor Company Research and Engineering

Center complex. The project is expected to be completed by December 31, 2019 for $62.3 million.

Q. What major equipment is included in the CHP project?

A. The CHP project consists of two 14.5 MW gas turbine generators and two heat recovery steam generators (HRSG). The steam produced by the HRSG's feed a common 5 MW condensing steam turbine generator and provides the process steam demands of the Ford Research and Engineering Center complex in Dearborn Michigan. Also included in the plant design are gas compressors, boiler feed pumps, deaerators, reverse osmosis water treatment systems, cooling towers, plant control systems and a myriad of other smaller components and system needs to operate a fully functional and independent electrical generating plant.

Q. Can you provide more details on the anticipated plant operations, efficiency and environmental controls associated with this CHP project?

A. The two gas turbine generators will operate on natural gas and utilize dry low-NOx combustors for NOx emissions reduction. The HRSGs will be provided with economizers to maximize unit efficiency. The plant will be highly flexible and capable of functioning at various output levels to meet varying demands for steam and electricity production.

Q. What impact will the Ford CHP have on Fossil Generation O&M requirements for the tenure of this case?

A. The new CHP plant will be operational by the end of 2019. Per the O&M agreement between DTE Electric (Owner) and DTE Energy Services (Operator), all major and day-to-day operations and maintenance expenses will be borne by the Operator. Accordingly, there are no O&M expenses related to the Ford CHP project in this case.

Q. Are there circumstances where DTE Electric would bear some O&M expenses associated with the long-term operations of the new CHP plant?

A. Yes, it is possible that that the Company could incur some O&M costs during the life of this asset. The Owner and Operator have agreed to operations and maintenance activities that will be provided by the Operator to the Owner at no cost. However, there are certain items that fall outside of this scope of Operator-provided work. Examples of these items include control systems upgrades or variable frequency drive replacements more than two times during the life of the asset, changes in applicable law leading to increased Operator's costs, and modifications to the facility specifically required by the Owner.

<u>Routine Capital Expenditures</u>

Q. What information is provided on page 4 of Exhibit A-12, Schedule B5.1?

A. Page 4 provides a summary of the routine capital expenditures for steam power, hydraulic power (Ludington) and other power generation (peakers) facilities from 2017 through April 30, 2020 broken down by site and by major spending category.

Q. What were Fossil Generation's routine capital expenditures in 2017 for Steam Power Generation?

A. During 2017, Fossil Generation routine capital expenditures related to steam power generation were $216.2 million as shown on Exhibit A-12, Schedule B5.1, page 4 of

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9, line 8. These expenditures included the following projects that individually exceeded $1 million as detailed on page 5 of Exhibit A-12, Schedule B5.1:

- Expenditures on Belle River Unit 2 included $1.3 million for replacing four economizer outlet, primary air fan outlet and precipitator inlet expansion joints to reduce failures that cause unit derates or outages. In addition, $1.4 million was spent on the installation of a wet dust collector. The new wet dust collector replaced two dry dust collectors and improved combustible dust control following National Fire Protection Association (NFPA) guidelines. Four Intermediate Pressure (IP) turbine stop valves and IP turbine control valves were rebuilt at a cost of $2.3 million to ensure the continued reliable operation of these critical safety systems. The High Pressure (HP) turbine replacement project was completed at a cost of $4.4 million to resolve reliability issues. These reliability issues were related to loose stationary and rotating blades and continued cracking of the outer casing of the HP turbine. Boiler waterwall panels and front lower slope tubes were also replaced on Unit 2 to mitigate quench cracking damage and deformation from fallen slag. These tube replacements totaled $7.4 million.
- Common projects at Belle River included $1.4 million to cap and close a section of the Range Road Landfill as required by the landfill operating license. To satisfy the landfill license requirements, it is necessary to cover the closed sections with two feet of clay cover and six inches of top soil and to ensure soil stabilization by planting native grasses on the site. $2.1 million was spent to replace the existing Bradford breaker style coal crusher with a new hammer mill style coal crusher. As part of this same project, a tramp iron detection system and coal sizing grid bypass chute was installed around the crusher. Coal crushers are

an integral part of the coal processing system to ensure coal mill reliability required for maximizing boiler combustion performance.

- $2.3 million was spent on Greenwood Unit 1 to rebuild the internal steam path components of 11 different turbine valves including the turbine stop valves, control valves, equalizing valve, and ventilator valve. The frequent start/stop cycles and large load swings experienced by this turbine make these valves prone to high levels of wear.
- For Monroe Unit 1, $1.0 million was spent to engineer and procure 4,300 square feet of waterwall tubes due to deterioration from corrosion fatigue combined with fireside corrosion, creep damage, and tube thinning. $1.4 million was spent on replacing two SCR Catalyst layers to comply with air permit emissions limits for NO_x and ammonia slip guidelines. $2.0 million was spent to engineer and procure materials for the Secondary Superheater (SSH) inlet pendant replacement project. This project replaced the 53 SSH inlet pendant assemblies that were 46 years old. These original equipment SSH inlet pendants are at end of useful metallurgical life and experiencing failures due to graphitization, thermal fatigue and wall loss in multiple areas impacting boiler reliability. $2.5 million was spent to rebuild coal mill silos 1-2, 1-4, and 1-5 due to the corrosive and abrasive properties of coal. $2.7 million was spent on the North and South Boiler Feed Pump Turbine Blade projects. Blade rows 4, 5, 6A and 6B were replaced due to damage found during internal inspections and similar damage found on other Monroe boiler feed pump turbines.
- Monroe Unit 2 had several projects executed during the periodic outage in 2017. Two hundred fourteen (214) economizer tube assemblies were replaced for $1.8 million due to washout and thinning of the tube walls caused by soot blower

erosion. Sections of the reheat outlet pendants were replaced for $2.1 million due to failures related to localized stress induced precipitation hardening (SIPH). $2.6 million was spent on installing SCR catalyst on layer 2 which was vacant and replacing layer 4 to comply with air permit emissions limits for NO_x and ammonia slip guidelines. The horizontal reheater tubes were replaced for $2.7 million due to ID oxygen pitting, fly ash erosion, and abrasive wear between the horizontal reheater and primary superheater tubes. The Unit 2 generator had developed multiple shorted turns and needed to be rewound to ensure unit reliability at a cost of $4.0 million. Like other Monroe units, Unit 2 had dynamic rotating classifiers installed on the coal mills. Replacing the static classifiers to improve combustion and reduce the slagging and fouling inherent with varying fuel blends for $6.8 million will help reduce PSCR costs. For similar reasons as Unit 1, the Secondary Superheat Inlet Pendants on Unit 2 were replaced for $11.2 million. Lastly, $15.5 million was spent on Unit 2 to replace waterwall tubes that exhibited fireside corrosion due in part to the low NO_x reducing atmosphere found in the combustion zone of the Monroe boilers.

- On Monroe Unit 3, $1.2 million was spent to rebuild coal mill 3-4 due to service hours and lube oil analysis indications of deteriorating internal components. $1.8 million was spent to engineer and procure tubes for the west half of the main unit condenser which are 44 years old and had deteriorated due to ammonia grooving, general erosion, and stress corrosion cracking.
- $1.2 million was spent on Monroe Unit 4 to procure a replacement SCR catalyst to comply with air permit emissions limits for NO_x and ammonia slip guidelines. In addition, $1.2 million was spent to engineer, procure and install blade rows 4, 5, 6A and 6B for the North Boiler Feed Pump Turbine.

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- Common projects at Monroe include $1.2 million to replace all five canal gates that were original plant equipment and had deteriorated due to corrosion. The canal gates need to be operable in the winter to allow condenser cooling water temperature to be controlled which prevents freezing of the intake screens avoiding plant outages. 100 pole mounted lights were replaced for $1.2 million to improve visibility of pedestrian traffic, road hazards, and general driving conditions during non-daylight hours. The old Bradford breaker style coal crusher was replaced with a new hammer mill style coal crusher. As part of this project a metal detection system and coal sizing grid bypass chute was installed for $1.5 million. This new coal crusher improves coal quality being processed by the coal mills improving combustion and reducing boiler and coal mill maintenance. $1.6 million was spent to rebuild the Unit 1 and 2 cascade counterweight room walls to contain coal fines and prevent leakage of these highly combustible fines into other areas of the plant. $1.8 million was used to engineer, procure, and install an upgrade to the makeup water system used to make ultrahigh purity boiler feedwater. The upgrade allowed use of less expensive general service water (river water) as its supply source rather than city (potable) water that has traditionally been used at Monroe. Two Caterpillar D10 dozers were purchased for $2.8 million to replace mobile equipment that had exceeded their economically maintainable service lives. $3.3 million was spent to replace a dust collector with a wet scrubber, including additions of explosion ventilation doors and ductwork meeting NFPA guidelines. $3.6 million was spent for engineering the fuel supply control system replacement like one recently completed at Belle River Power Plant. Lastly, $4.2 million was spent to engineer, procure, and install a new soot blowing air compressor to ensure sufficient high

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pressure air is available to meet plant demands and eliminate the need for rental compressors.

- St. Clair Unit 6 spent $2.3 million to engineer and procure two rows of L-0 blades for both low-pressure turbines, due to erosion damage on the blade tips.
- St. Clair Unit 7 had several projects completed during the 2017 periodic outage. $1.0 million was spent to rebuild Coal Mill D due to service hours and lube oil analysis indications of deteriorating internal components. Corroded coal bunker walls were replaced to eliminate coal spillage into the boiler house at a cost of $1.1 million. The cold end baskets of the north and south air preheater were replaced for $1.1 million based on inspections which revealed corrosion and erosion impacting 50-80% of the heating element material. $1.1 million was spent on replacing the Unit 7 stack liner insulation due to degradation and safety concerns with falling insulation. The reheat pendants were replaced for $2.9 million to maintain unit reliability. These pendants were 47 years old and had experienced increasing frequency of leaks due to thinning from scale exfoliation, oxygen pitting, soot blower erosion and thermal fatigue. $3.4 million was spent on replacing waterwall tubes experiencing fireside corrosion and quench cracking thermal fatigue damage. Quench cracking results when waterwall surfaces are cleaned to remove ash accumulations that form during combustion of low sulfur western coal. Lastly, $5.3 million was spent on replacing both rows of the L-1 blades in Low Pressure Turbine 1 and both rows of the L-0 blades in Low Pressure Turbine 2.
- A common project at St. Clair included a Caterpillar D10 dozer purchased for $1.5 million to replace equipment that was beyond its economically maintainable service life.

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Q. What are the routine projects with projected capital expenditures greater than $1 million in 2018 for Steam Power Generation?

A. Planned 2018 maintenance projects greater than $1 million are detailed on page 6 of Exhibit A-12, Schedule B5.1 and discussed below.

- $3.7 million will be spent to engineer and procure the Belle River Uni1 1 HP Turbine replacement. The HP turbine is being replaced because of the risk of blade failures from loose stationary and rotating blades. The blades have been retightened twice and based on OEM recommendations the blades cannot be tightened again and must be replaced.
- Expenditures on Monroe Unit 1 during the periodic outage will include $1.0 million to re-tube the north boiler feed pump turbine condenser which is original plant equipment and shows deterioration due to ammonia grooving, general erosion and stress corrosion cracking. $1.2 million will be spent to overhaul the steam path components of the turbine valves to ensure the continued reliable operation of this critical safety system. Feedwater Heater No. 3 will be replaced for $2.1 million due to an internal malfunction leading to damage to upstream heaters. Installation of the Flue Gas Desulfurization (FGD) booster fans made the ID fan discharge dampers redundant and they will be removed for $2.6 million. Removal of ID fan dampers will eliminate the risk of flue gas leaking from duct work. Two hundred fourteen (214) economizer tube assemblies will be replaced for $2.9 million due to sootblower erosion which causes washout and thinning of the tube walls. ID oxygen pitting, fly ash erosion, and abrasion between the horizontal reheater and primary superheater, requires the horizontal reheater tubes to be replaced for $2.9 million. Boiler combustion control and unit reliability require that various expansion joints be replaced for $3.3 million. The

boiler flue gas system has over 100 expansion joints on each unit and these expansion joints have a finite life requiring Monroe to engage in a continuing replacement program. These replacements are part of that continuing program. Coal mill silos will be rebuilt due to deterioration caused by the corrosive and abrasive properties of coal. Three silos are scheduled for replacement to restore their structural integrity for $3.3 million. To ensure continuing compliance with air permit emissions limits for NO_x and ammonia slip guidelines two SCR catalyst layers will be replaced for $3.8 million. The Secondary Superheat Inlet Pendants will have the 48-year old inlet pendant assemblies replaced. These original equipment SSH Inlet Pendants are at end of useful metallurgical life and experiencing failures due to graphitization and significant wall loss in multiple areas impacting boiler reliability and will be replaced for $11.9 million. Approximately 5,000 sq. ft. of boiler waterwall tubes will be replaced for $11.9 million. These tubes are exhibiting corrosion fatigue failures that are occurring due in part to the low NO_x reducing atmosphere found in the Monroe boilers combustion zone. Boiler tubes sections will be replaced with material that includes an Inconel weld overlay protective coating that is resistant to the harsh boiler combustion zone conditions. Inconel protective coatings have been utilized for over 10 years and have proven well suited for this application.

- In 2018, Monroe Unit 3 will replace blade rows 4, 5, 6A and 6B on the south boiler feed pump turbine as has been done on other Monroe units in 2016 and 2017 for a cost of $1.3 million. Secondary superheater inlet pendants will be procured to allow their replacement because the pendants have reached the end of their useful metallurgical life due to graphitization and significant wall loss for $1.8 million. Replacement of the SSH inlet pendants which are 44 years old will

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restore reliability of this component. Two coal silos are scheduled for replacement to restore structural integrity for $2.2 million. The coal mill silos will be rebuilt to restore deterioration caused by the corrosive and abrasive properties of coal. Two SCR catalyst layers will be procured for $2.2 million to ensure continued compliance with air permit emissions limits for NO_x and ammonia slip guidelines. One layer will be installed in 2018 and the other in 2019 during the periodic outage. SCR catalysts lose activity with use as they are exposed to boiler flue gas and ash. Periodic replacement with new or regenerated catalyst is required approximately every two years to maintain NO_x removal performance.

- Monroe Unit 4 secondary superheater inlet pendants will be procured to allow their replacement due to graphitization and significant wall loss in various areas for $1.1 million. Replacement of the SSH inlet pendants which are 44 years old will restore the reliability of this component. $1.8 million will be spent to rebuild coal mill 4-5 silo to restore structural integrity. Engineering and procurement of materials to replace one depleted SCR layer to comply with the air permit NO_x limits and ammonia slip guidelines will be completed for $2.3 million.
- A major fuel supply project is being undertaken at Monroe to replace the 40-year old fuel supply control system for $8.3 million. The availability of replacement equipment and vendor support is inadequate which puts the ability to fuel the plant at risk while also creating safety concerns. The system is very complex with 10 transfer houses, 26 conveyors, 9 miles of belts, 51 diverting gates, 12 feeders, 6 rotary plow feeders, 2 tripper cars, 2 crushers and 28 coal storage silos located throughout the coal yard and inside the plant requiring a very extensive control system to manage and deliver coal to the plant. The fuel supply system

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can deliver various blends of Low Sulfur Western coal (LSW), High Sulfur Eastern coal (HSE) and Pet Coke to the plant. The work scope of this project includes updating all as-built drawings showing I/O terminations, installing a new DCS control/annunciation system, replacing all relay logic panels, augmenting the existing fiber optic network, updating the Fuel Supply control room to include new operator interface equipment and upgrading the 4160V breaker and starter controls to Intelligent Electronic Devices (IED). A similar fuel supply controls project upgrade was completed at Belle River Power Plant in 2016.

- Other Monroe fuel supply common equipment projects include $1.7 million to be spent for the coal crusher CR-01 sizing grid and bypass chute to assist with crushing low-sulfur western coal and coal fines separation. $2.1 million will go towards upgrading the 45-year old medium voltage switchgear that needs to be replaced to ensure the continued reliable operation of these safety systems. Dust collectors will be replaced on conveyors for Units 1 and 2 to mitigate combustible dust for $5.3 million and an additional $2.2 million will be spent on upgrading the train unloading conveyor chute to comply with the NFPA combustible dust guidelines.
- Monroe plant common equipment projects include precipitator SIR lifting rails and trollies for $1.0 million to assist with replacing failed parts and reducing safety risk. $1.4 million will also be spent to install an upgrade to the makeup water system which previously used city water to supplement the boiler rather than general service water. Monroe will also have its plant air and soot blowing air supply augmented by installing new compressors at a cost of $4.1 million. Additional soot blowing high pressure air supply is required to adequately clean boiler waterwalls, superheaters, reheaters, economizers and air heaters of ash

Line No.

accumulations. If the ash removal is inadequate, tube passages plug and air flow is restricted though the boiler. Pluggage can cause overheating and hard ash accumulations which require extended duration forced outages to remove.

- River Rouge Unit 3 will rebuild the steam path components of the Reheat and Intercept Stop Valves for $1.6 million. This is mandatory work required to ensure the continued reliable operation of these critical safety systems. Failure of these valves to perform a safe shutdown of the turbine upon a generator trip can cause a turbine over speed event leading to catastrophic failure, potentially resulting in large components becoming ejected from the turbine casing creating an unacceptable personnel safety risk.
- St. Clair Unit 6 will rebuild the steam path components of the turbine valves for $1.5 million to ensure continued reliable operation of these critical safety systems. Also, $4.1 million will be spent to install the L-0 blade rows on low pressure turbines, LP1 and LP2 due to erosion damage on the blade tips.
- Trenton Unit 9 will replace the main steam piping tee due to an internal inspection that revealed evidence of two separate cracks in the shoulder areas on the north and south sides of the tee. The tee is seam welded and predisposed to creep fatigue cracking. This safety driven project will be completed for $1.6 million. In addition, $1.7 million will be spent to engineer and procure blade rows 4, 5 and 6 on the south boiler feed pump turbine due to industry wide known blade failures.

Line No.

Q. What are the routine projects with projected capital expenditures greater than $1 million in 2019 for Steam Power Generation?

A. Planned 2019 maintenance projects greater than $1 million are detailed on page 7 of Exhibit A-12, Schedule B5.1 and discussed below.

- Expenditures on Belle River Unit 1 will include $2.2 million to replace four economizer outlet, primary air fan outlet and precipitator inlet expansion joints to reduce failures that cause unit derates or outages. Four Intermediate Pressure (IP) turbine stop valves and four IP turbine control valves will be rebuilt at a cost of $3.0 million to ensure the continued reliable operation of these critical safety systems. Approximately 2,500 square feet of boiler waterwall panels will be replaced on Unit 1 to mitigate quench cracking damage on the tubes. The tube replacements total $5.7 million. The HP turbine will be replaced at a cost of $8.8 million to resolve reliability issues related to blade failures caused by loose stationary and rotating blades. The blades have been tightened twice and based on OEM recommendations the blades cannot be retightened again and must be replaced. For Belle River Unit 2 $1.0 million will be spent to engineer and procure blades for the LP turbine due to blade erosion on the L-0, L-1, L-2, and L-3 blade rows. $1.1 million will also be spent to engineer and procure approximately 2,500 square feet of waterwall tubes for the 2020 periodic outage. Failure mechanisms being mitigated include fireside corrosion and quench cracking.
- Common projects at Belle River include $1.5 million to replace dust collector 109/110 with a wet type dust collector including explosion ventilation doors and ductwork that meet the NFPA guidelines.

- For Monroe Unit 2, the 2-6 coal mill silo will be rebuilt to restore structural integrity for $1.4 million. A replacement SCR catalyst layer will be installed to ensure compliance with the air permit NOx limits and ammonia slip guidelines for $2.0 million.
- During the Monroe Unit 3 periodic outage many projects will be executed. One coal silo is scheduled for replacement to restore structural integrity for $1.0 million. $1.2 million will be spent to overhaul the steam path components of the turbine valves to ensure the continued reliable operation of this critical safety system. For $1.3 million, the reheat stop valves will be upgraded to achieve 4-5 years of service life. The north and south FGD booster fan hub and blades are part of the original 2009 installation. The fans require new internal components to restore design capabilities and will be replaced for a cost of $1.4 million. $1.5 million will be spent to improve the overall integrity of the ID Fan discharge ductwork and eliminate the safety hazard associated with leaking flue gas. $2.0 million will be spent to replace the expansion joints on Low Pressure Turbines A and B. $2.0 million will be spent to install tubes in the west half of the main unit condenser which are 44 years old and deteriorated due to ammonia grooving, general erosion, and stress corrosion cracking. ID oxygen pitting, fly ash erosion, and abrasion between the horizontal reheater and primary superheater, require the horizontal reheater tubes be replaced for $2.9 million. Boiler combustion control and unit reliability require that various expansion joints be replaced for $3.5 million. The boiler flue gas system has over 100 expansion joints on each unit and these expansion joints have a finite life requiring Monroe to engage in a continuing replacement program. These replacements are part of that continuing program. $5.5 million will be spent on replacing SCR Catalyst layers 2, 3 and 4

to comply with air permit emissions limits for NOx and ammonia slip guidelines. $10.9 million will be spent to replace the 53 Secondary Superheater (SSH) inlet pendants. These original equipment SSH Inlet Pendants are at end of useful metallurgical life and experiencing failures due to graphitization, thermal fatigue and significant wall loss in multiple areas impacting boiler reliability. Lastly, $14.0 million will be spent to install approximately 4,000 square feet of waterwall tubes due to deterioration from corrosion fatigue combined, fireside corrosion, creep damage, and tube thinning.

- For Monroe Unit 4, $1.0 million will be spent to engineer hot end air heater baskets that have degraded due to corrosion of the basket elements. The replacements will restore physical integrity and heat transfer to improve boiler efficiency. $1.0 million will be spent to install tubes in the east half of the main unit condenser which are 45 years old and deteriorated due to ammonia grooving, general erosion, and stress corrosion cracking. $1.1 million is planned for the secondary superheat inlet pendants which replaces the 53 SSH inlet pendant assemblies that are 46 years old. $1.5 million will also be spent to engineer and procure approximately 4,000 square feet of waterwall tubes that will be replaced due to deterioration from corrosion fatigue combined with fireside corrosion, creep damage, and tube thinning. The generator stator which is approaching 45 years of age will need a rewind for $2.9 million due to deterioration of the brazed joints which causes stator coil leaks and deterioration of the stator slots allowing stator coil movement.
- Fuel supply common projects at Monroe include $1.5 million to install a new main transfer tower coal chute from CVC-6 to CVC-7 and CVC-8 to reduce combustible dust and $1.8 million to rebuild the Unit 3 and 4 cascade

counterweight room to mitigate coal fine that contaminate other areas of the plant. Dust collectors will be replaced on conveyors for Units 3 and 4 to mitigate combustible dust for $7.0 million. Combustible dust control is required to mitigate the risk of explosions and fires that can otherwise occur. Lastly, $7.9 million will be spent on the fuel supply controls replacement project.

- Monroe plant common projects include $1.0 million to support NERC CIP medium to low impact migration throughout the fleet.
- For St. Clair Unit 7, plans are to rebuild the steam path components of the turbine valves for $1.5 million to ensure continued reliable operation of these critical safety systems.
- St. Clair common projects include replacement of a coal conveyor belt for $1.0 million, installation of a 3TH3 dust collector with a wet dust collector meeting NFPA safety guidelines for $2.0 million.
- For Trenton Unit 9, $1.5 million will be spent to install blade rows 4, 5 and 6 on the north boiler feed pump turbine due to industry wide known blade failures. The steam path components of the turbine valves will be rebuilt for $1.5 million to ensure continued reliable operation of the critical safety systems.

Q. What are the routine projects with projected capital expenditures greater than $1 million to be executed in the first four months of 2020 for Steam Power Generation?

A. Planned 2020 maintenance projects greater than $1 million are detailed on page 8 of Exhibit A-12, Schedule B5.1 and discussed below.

- Expenditures on Belle River Unit 2 will include approximately 2,500 square feet of boiler waterwall panels to be replaced to mitigate quench cracking and fireside corrosion damage on the tubes. The tube replacements total $2.0 million. The LP turbine blades will be replaced due to blade erosion on the L-0, L-1, L-2, and L-3 blades for $3.0 million.

- Monroe Unit 4 periodic outage expenditures include $1.0 million for the air heater hot-end basket replacements to restore physical integrity and heat transfer to improve boiler efficiency. In addition, $1.2 million will be spent for expansion joints replacements for boiler combustion control and unit reliability. The coal mill 4-1 silo will be rebuilt to restore structural integrity for $1.4 million. The generator stator is approaching 45 years of age and needs to be rewound for $3.7 million. The generator's brazed joints have deteriorated resulting in stator cooling water leaks, stator slot damage and stator coil movement. $4.0 million will be spent to replace approximately 4,000 square feet of waterwall tubes damaged from fireside corrosion. Lastly $4.7 million is planned for the secondary superheat inlet pendant project which replaces the 53 SSH inlet pendant assemblies that are 45 years old.
- Monroe common projects include $1.4 million to replace three coal mill silos to restore structural integrity.

Q. What were Fossil Generation's routine capital expenditures in 2017 for Hydraulic Power generation (Ludington)?

A. During 2017, Fossil Generation routine capital expenditures for the Ludington Pumped Storage facility were $2.5 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 9. Expenditures were related to unit maintenance and auxiliary equipment upgrades and switchgear replacements.

Q. What will be Fossil Generation's routine capital expenditures for Hydraulic Power Generation (Ludington) in the 16 months ending April 30, 2019?

A. During the 16 months ending April 30, 2019, Fossil Generation routine capital expenditures for the Ludington Pumped Storage facility are projected to be $5.5 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 9. Investments will be related to unit maintenance and auxiliary equipment upgrades.

Q. What will be Fossil Generation's routine capital expenditures for Hydraulic Power Generation (Ludington) in the projected test year, the 12 months ending April 30, 2020?

A. During the 12 months ending April 30, 2020, Fossil Generation routine capital expenditures for the Ludington Pumped Storage facility are projected to be $5.4 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 9. Investments will be related to unit maintenance and auxiliary equipment upgrades.

Q. What were Fossil Generation's routine capital expenditures in 2017 for Other Power Generation (Peakers)?

A. During 2017, Fossil Generation routine capital expenditures for peaking units were $26.5 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 10. This included $1.8 million for a control system upgrade due to obsolescence on the Belle River diesel peakers, and $2.4 million for combustion cans overhaul at Renaissance. $4.0 million was spent for a hot gas path overhaul on Delray 11-1, and $5.8 million for a generator field rewind and hot gas path overhaul on Delray 12-1. Northeast 12-1 and Superior 11-4 had combustion can and hot gas path overhauls completed for $6.5 million

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Q. What will be Fossil Generation's routine capital expenditures for Other Power Generation (Peakers) in the 16 months ending April 30, 2019?

A. During the 16 months ending April 30, 2019, Fossil Generation routine capital expenditures for peaking units is expected to be approximately $32.4 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 10. This includes $1.0 million for a generator field replacement on Hancock 11-3. $2.0 million will be spent to engineer a new Continuous Emissions Monitoring Systems (CEMS) for the Belle River Peakers and to replace the CEMS controls at the Renaissance peakers. $2.4 million will be spent for a hot gas path component overhaul on Delray 12-1, $3.1 million for insulator replacements at the Renaissance Peakers, $4.4 million for combustion can overhauls on Greenwood 11-1 and Renaissance Unit 4, and $9.4 million for control system upgrades due to obsolescence at sites placed into service between 1966 and 1999.

Q. What will be Fossil Generation's routine capital expenditures for Other Power Generation (Peakers) be in the projected test year, the 12 months ending April 30, 2020?

A. During the 12 months ending April 30, 2020, Fossil Generation routine capital expenditures for peaking units is expected to be approximately $20.0 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 10. This includes $1.3 million to install CEMS on the Belle River Peakers, $3.8 million for hot gas path component overhauls on two Fermi Peaking units, $2.5 million for a spare Renaissance transformer, $4.1 million for combustion can overhauls on Renaissance Units 2 and 3, and $1.2 million for a new control system and motor control center on Fermi 11-1.

Line No.

<u>Summary of Tier 1 and Tier 2 Coal-Fired Generation Capital</u>

Q. Please explain the tiered maintenance strategy Fossil Generation employs for its generating units.

A. In anticipation that certain coal-fired generating units would be retired many years before others, a tiered maintenance and capital expenditure strategy was developed. The Tier 1 long-term coal-fired units are identified as Belle River and Monroe while the remainder of the coal-fired units are classified as Tier 2 units. Fossil Generation operates its coal fleet with two distinct strategies that drive both the O&M and capital expenditure plans for the different tiers. Investments in Tier 1 coal units are designed to achieve 1st quartile reliability performance as measured by ROF, while investments in Tier 2 units are being limited to those required to maintain safe and environmentally compliant operations until the units are retired over the next five years.

Q. Can you explain how the tiered maintenance expenditure strategy is translating into different capital expenditure levels at the Tier 1 coal units compared to the Tier 2 coal units?

A. Yes. I have prepared two tables with data extracted from the Exhibit A-12 Schedule B5.1 pages 2 and 4 in this proceeding that clearly shows that expenditures are being minimized at the Tier 2 coal units as they are moving towards retirement. The expenditure levels are shown in Table 2 while Table 3 shows that data as percentages. During the 2017-April 30, 2020 timeframe of this proceeding, Fossil Generation is expending a combined $660 million in routine capitalized maintenance and non-routine capital additions for its Tier 1 and Tier 2 coal-fired units. The six Tier 1 coal units (Belle River 1-2 and Monroe 1-4) are receiving 69% of this total capital for routine capitalized maintenance while 16% is going towards the Tier 1 non-routine capital additions, primarily for environmental related projects. The seven Tier 2 coal units (St Clair 1-3, 6-7, River Rouge 3 and Trenton Channel 9) are receiving just 14% of the total expenditures for their capitalized maintenance and just 1% for their non-routine capital additions. It should be noted that maintenance must continue to be performed on the Tier 2 plants to ensure that they operate safely and are environmentally compliant until their retirements. Some of that maintenance is categorized as capitalized maintenance as opposed to O&M expense per the accounting rules with which the Company must comply.

Table 2 – Capital Expenditures 2017-April 30, 2020

Tier 1 vs Tier 2 Coal Plants
Dollars (000's)

		2017-April 30, 2020	Exh. A-12, Sch. B5.1
Tier 1	Routine (Capitalized Maintenance)	455,184	Page 4, lines 3 & 7 (b,e,f)
	Non-Routine Additions	107,394	Page 2, lines 2-7 & 9 (b,e,f)
	Total Tier 1	**562,578**	
Tier 2	Routine (Capitalized Maintenance)	93,862	Page 4, lines 4-6 (b,e,f)
	Non-Routine Additions	4,011	Page 2, lines 8, 12 & 13 (b,e,f)
	Total Tier 2	**97,873**	

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Table 3 – Capital Expenditure 2017-April 30, 2020

Tier 1 vs Tier 2 Coal Plants

Percentage Expenditure by Category

	Routine Maintenance	Non-Routine Additions	Total
Tier 1 Coal Units	69%	16%	85%
Tier 2 Coal Units	14%	1%	15%

Q. Can you explain in more detail the continuing routine capital expenditures at River Rouge Power Plant?

A. River Rouge Unit 3 is scheduled to operate until its currently planned retirement in May of 2020. From now until the plant's retirement, it is necessary to operate the plant in a safe and environmentally compliant manner. River Rouge Power Plant spent $5.4 million in 2017 and plans to expend $4.9 million in the 28-month period including 2018, 2019 and the first 4 months of 2020 for routine capitalized maintenance. These expenditures are mainly related to the replacement of pumps, motors, valves, instruments and control system components to maintain continued operations in a safe and environmentally compliant manner.

Q. Does the Company provide additional support for the ongoing capital expenditures to allow the safe and environmental compliant operations of River Rouge Unit 3?

A. Yes. Witness Dimitry presents the results of an economic analysis that compares operating and maintaining River Rouge Unit 3 until its planned retirement date in 2020 to retiring that unit at the end of 2018. Three sensitivities were conducted using different capacity price assumptions, and resulted in economic outcomes that showed the 2020 retirement scenario as economically favorable, essentially neutral, or unfavorable depending on which capacity price assumption is used.

Q. Can you provide justification for performing the analysis with various capacity pricing assumptions?

A. Yes. As described by Witness Dimitry, the Company considered multiple capacity pricing alternatives for this analysis, ranging from a low forecast based on modeling conducted by PACE Global, an energy industry consulting firm, to the MISO Zone 7 Cost of New Entry (CONE) at $90.70 / kW-year. The Company feels that it is important to consider a wide range of capacity pricing scenarios when performing an economic analysis, given the nature of capacity pricing. While the most recent auction clearing price for MISO Zone 7 capacity was $10.00 / MW-day, prices would go to CONE if unforeseen circumstances led to a situation where total MISO planning resources did not meet the system-wide planning reserve margin requirement or if resources identified in the MISO Planning Resource Auction didn't meet Zone 7's local clearing requirement. While there is no way of knowing if such unforeseen circumstances would arise, it is prudent to include these sensitivities in an economic analysis given the reliability impact such an event would have on the electrical grid, thus negatively impacting our customers.

Q. What is your conclusion regarding the planned retirement of River Rouge Unit 3?

A. Given the range of economic outcomes showing the 2020 retirement scenario as economically favorable, essentially neutral, or unfavorable as compared to the 2018 retirement scenario, coupled with the other factors explained in my testimony on pages 13-20, continued operations of River Rouge Unit 3 until the planned retirement date of May 2020 is in the best interest of our customers and needed to support grid reliability, resource adequacy and workforce planning while minimizing the negative impacts to our local communities. Further justification for continued operations of River Rouge Unit 3 until its planned retirement date of May 2020 is provided by the MISO Attachment Y reliability study report for River Rouge Unit 3. The report specifically indicates that retirement or suspension of River Rouge Unit 3 may create thermal and voltage issues that could require the Company to shed firm load to ensure grid reliability. Although firm load shed is utilized as a countermeasure within MISO's planning criteria, the Company has significant concerns about implementing electrical service interruptions to our customers as a means of addressing known grid reliability issues. Maintaining and operating River Rouge Unit 3 until its planned retirement date of May 2020 will provide additional time to identify and implement alternative solutions that can ensure continued reliable electric service for its customers.

<u>2017-2020 AFUDC Estimate</u>

Q. Do the capital expenditures you are supporting include an allowance for funds used during construction (AFUDC)?

A. Yes, capital expenditures include an allowance for funds used during construction (AFUDC) for eligible projects that are in Construction Work in Progress (CWIP). At the direction of Company Witness Ms. Uzenski, AFUDC is applied to projects greater than $50,000 and lasting more than six months, except for large environmental projects which are exempt from AFUDC treatment.

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Q. How much AFUDC is assumed in the projected test period for Fossil Generation?

A. AFUDC for Fossil Generation is included on Exhibit A-12, Schedule B5.1, page 9 of 9. As shown, the Fossil Generation AFUDC is projected to be $4.1 million for the 12-month period ending April 30, 2020. This amount includes $1.9 million for routine expenditures and $2.2 million for project specific expenditures. A historical trend is used to estimate AFUDC on routine capital since the mix of eligible projects is consistent year to year, while the AFUDC is calculated specifically on a project by project basis for eligible non-routine projects. The authorized cost of capital rate used is 5.34% per the U-18255 rate order. For additional details on AFUDC refer to Witness Uzenski.

Part III - Fossil Generation Operating and Maintenance Expenses

Q. What is the process used to prepare the Fossil Generation Operating and Maintenance (O&M) projected level of expense?

A. Projected O&M expense is developed by taking historical O&M expenditure data and adjusting for any known projected period changes. Plant level changes include labor and material cost increases, year-over-year variations in periodic outage work, cost variations related to environmental equipment operation, non-periodic maintenance cost variations driven by predictive maintenance programs and other known changes.

The overall Fossil Generation O&M projection is developed by adjusting the actual historic test year (2017) results for rate case adjustments between witnesses, normalization adjustments to the 2017 data and known and measurable adjustments

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to handle O&M changes (up or down) due to changes that are anticipated to occur by the end of the forecasted test year.

Fossil Generation operations expenses are those associated with day-to-day operation of the Company's generating units, including certain Account 501 fuel handling expenses. Fossil Generation maintenance expenses are associated with periodic outage, non-periodic outage, and other maintenance activities. Other maintenance activities include standard day-to-day work to maintain plant equipment, such as inspections, servicing, and minor maintenance that does not require the unit to be taken offline to complete.

Fossil Generation O&M is presented in three major cost categories as shown below:

- Steam Power Generation
- Hydraulic Power Generation
- Other Power Generation

Q. What were Fossil Generation's historical O&M Expenditures for 2017 for Steam Power Generation?

A. During 2017, Steam Power Generation adjusted O&M expenses totaled $274.1 million as shown on Exhibit A-13 Schedule C5.1, line 19, column (g). This was comprised of $134.4 million in operations costs and $139.7 million in maintenance costs. The $8.1 million of Steam Power Generation O&M that relates to Fuel Supply and MERC Fuel Handling is sponsored by Company Witness Mr. Milo on Exhibit A-13, Schedule C5.2 and is subtracted on line 20 (Note 1), resulting in remaining Steam Power Generation adjusted O&M in the amount of $266.0 million.

Line No.

Q. Can you provide an overview of Exhibit A-13, Schedule C5.1?

A. Exhibit A-13, Schedule C5.1 is a two-page exhibit. Page 1 of Schedule C5.1 shows total test period O&M for Steam Power Generation by starting with the 2017 actual O&M expenses and adjusting for rate case eliminations, normalization adjustments, and inflation adjustments. The normalization adjustments are required to determine the portion of the 2017 O&M expenses that will reoccur in the 12-month period ending April 30, 2020. Those normalization adjustments are shown in note 4 on page 1. There are no additional known and measurable adjustments required in column k to determine the O&M required in the 12-month forecasted test period ending April 30, 2020. Page 2 provides additional detail of the $23.1 million of 2017 costs experienced due to the St. Clair August 2016 Outage Event equipment repair/restoration shown in Note 4 on Page 1. The two pages of Exhibit A-13, Schedule C5.1 are discussed in more detail in testimony that follows.

Q. What are the major O&M expense categories found in Exhibit A-13, Schedule C5.1?

A. The expenses shown in Exhibit A-13, Schedule C5.1 are categorized into the major categories of operations and maintenance consistent with FERC accounting guidelines.

Operations account 500 includes the cost of plant management for the individual plant sites, their supporting staffs and the Fossil Generation Engineering Support Organization. Plant management includes plant site director, area managers and administrative support. The major supporting staffs in this area are the technical and engineering personnel associated with problem solving daily plant operating issues, obtaining and interpreting test data and developing long term operating and maintenance plans to maintain plant availability and efficiency.

Operations account 501 “Fuel Handling” includes expenses incurred for coal train and vessel unloading, ash disposal, coal pile management and mobile equipment operations. Depending on plant site and delivery options, plants maintain and manage a coal pile inventory that can vary over many months. Larger coal pile inventories are required at Belle River and St. Clair power plants at the end of December to ensure adequate coal supplies when vessel deliveries cannot be obtained due to winter ice on the Great Lakes.

Accounts 502 and 505 represent operations personnel and materials expenses associated with direct operating supervision and control of boiler, turbine, generator, water and environmental control systems. Shift supervisor and control room supervising operators are key to the successful steam power generation unit operations that are required to ensure adequate and cost efficient production of electrical energy for our customers. Their labor expenses are captured in these accounts.

Account 506 “Misc. Steam Power Expenses” includes Instrument and Controls personnel to troubleshoot and calibrate the vast array of complex instruments and controls found on steam generating units. Also included in this account are operations of all common equipment such as water, air and cooling equipment systems. Plant buildings and grounds cleaning, landscaping, snow removal and maintenance are also captured in this account.

Maintenance accounts 510 through 514 capture expenses associated with planned and unplanned maintenance activities. These expenses mostly consist of the planned maintenance activities that generally occur on a two to five-year interval on all boiler systems and on a six to ten-year interval on turbine systems. Account 510 captures management of the plant maintenance area including area managers and general foremen. Account 511 covers maintenance of common infrastructure areas such as roofs, windows and roads. The major area of expense captured in account 512 "Maintenance of Boilers" includes maintenance expenses for internal and external labor and all materials associated with planned and unplanned outage work on the boilers. The boiler maintenance scope of work includes the boilers, air and flue gas systems, ash handling and fuel burning equipment. The major area of expense captured in account 513 "Maintenance of Electric Plant" includes internal and external labor and materials expenses associated with work on turbines. The major area of expense captured in account 514 "Maintenance of Misc Steam Plant" includes internal and external labor and materials expenses for maintenance of all common equipment such as water, air and cooling equipment systems.

Q. Can you provide additional detail on the O&M expenses incurred by the Company's Steam Power Generation during 2017?

A. In the historic period of 2017, the Company spent $266.0 million in Steam Power Generation O&M expenses after adjustments and reclassifications. Planned major periodic maintenance outages were executed in 2017 on Belle River Unit 2, Greenwood Unit 1, St Clair Unit 4, St Clair Unit 7, Monroe Unit 2 and Trenton Channel Unit 9. Also completed during 2017 were multiple short duration unit tune-up outages on the Belle River, St Clair, River Rouge, Trenton Channel and Monroe

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units to allow their continued efficient operation burning high percentages of lower sulfur content western coals. Costs for the portions of outages that occur in 2017 and 2018 will be captured in those respective years.

The other category of maintenance expenses incurred during the historic period were associated with regular plant maintenance while units were in operation or expenses to repair or replace equipment during a forced or unplanned unit outage. These short duration unplanned maintenance outages can generally be completed in three to seven days and will be experienced at varying intervals on all steam power generating units depending on the severity of their service cycles and the time elapsed since their last planned maintenance outage.

During the projected 12-month period ending April 30, 2020, the Company will execute four periodic maintenance outages on Belle River Unit 2 and Monroe Units 1, 2 and 3. As in the historic period, short duration unit tune-up outages will also be completed on the St Clair, Belle River, River Rouge, Greenwood, Trenton Channel and Monroe Units to optimize continuing performance.

Q. What adjustments were made to the historical test period amounts?

A. First, Fuel Handling O&M expenses recorded in Fuel Account 501 are added to Steam Power O&M in column (d). This amount includes Fuel Supply and MERC Fuel Handling for which an adjustment is made in column (e) to reclassify non-O&M fuel handling sponsored by Witness Milo (Note 3). In column (f), five (5) normalizing adjustments, netting to $1.9 million, were made to eliminate non-recurring expenses. These five items are identified in Note 4. The forecasts for these expenses through the projected test period are based on the historic labor and materials expenses as adjusted for escalation. The labor and material inflation adjustment factor of 3.0% for 2018, 2.9% for 2019 and 1.0% for the first four months of 2020 is supported by Witness Uzenski.

Q. Can you provide a further explanation of the net $1.9 million normalizing adjustment shown on note 4 of Exhibit A-13, Schedule C 5.1, page 1 of 2?

A. Yes. The $1.9 million of normalizing adjustments shown in this exhibit is made up of 5 line-item adjustments.

Line 1 shows $23.1 million of O&M expense associated with the August 2016 St. Clair outage event caused by a turbine blade failure on Unit 7 that was incurred in 2017. This amount is being eliminated because it is considered a one-time occurrence and not representative of future plant operations.

Line 2 shows $3.6 million added in as a normalization change to reflect normal 2017 plant operations that were interrupted by continuing work to restore plant equipment and systems after the August 2016 St. Clair Power Plant outage event. Had the Company not been expensing $23.1 million to restore the plant and plant equipment damaged in the August 2016 outage event, normal plant operations would have required funding of $3.6 million.

Line 3 shows a reduction of $1.4 million for operations and maintenance expenses associated with St. Clair Unit 4 that will no longer be incurred because of the unit's retirement.

Line 4 shows the $21.2 million of insurance proceeds (credit) received in 2017 associated with the St. Clair fire event O&M expenses. Since this credit does not repeat in the projected test year ending April 30, 2020, this amount is added back as an increase to future O&M.

Line 5 shows an increase of $1.6 million needed to offset a credit booked in 2017 for ash sales that occurred in 2016. The credit was not booked in 2016 due to a pending legal settlement. After finalization of the legal settlement, the 2016 ash sale credit was booked in 2017 along with the normal 2017 ash sale credit creating a higher than normal credit in the historic test period of this case. The $1.6 million adjusts the 2017 expenses to normalize for this timing issue of accounting entries.

Q. Can you explain Exhibit A-13, Schedule C 5.1, page 2 of 2?

A. Yes. Page 2 of Exhibit A-13 Schedule C 5.1 provides further details of the $23.1 million credit being applied to the 2017 actual O&M expenses by showing the specific units or common systems that these charges are attributable to.

Q. Can you summarize Exhibit A-13, Schedule C5.4, entitled "Operations and Maintenance Expenses - Hydraulic Power Generation"?

A. Exhibit A-13, Schedule C5.4 represents DTE Electric's share of the continuing operation and maintenance expense of the Ludington Pumped Storage facility. As a 49 percent owner of this facility, the Company incurs expenses for operating and maintaining the facility. The forecasts for these expenses through the projected test period are based on the historic labor and materials expenses as adjusted for escalation. The labor and material inflation adjustment factor of 3.0% for 2018, 2.9%

for 2019 and 1.0% for the first four months of 2020 is supported by Witness Uzenski. No other historical or projected adjustments were made to Hydraulic Power Generation Projected Operation and Maintenance expenses.

Q. Can you summarize Exhibit A-13, Schedule C5.5, entitled "Operations and Maintenance Expenses - Other Power Generation?

A. Exhibit A-13, Schedule C5.5 represents DTE Electric's peaker fleet O&M costs. DTE Electric owns and operates a quantity of peaking units ranging from 2.5 MW diesel fueled engines to newer 165 MW natural gas fired combustion turbines. The main driver of projections for these expenses through the projected test period is the labor and material required to support these peaker assets. Included in this category will also be the labor expenses for the Generation Optimization and Integrated Resource Planning teams. The forecasts for these expenses through the projected test period are based on the historic labor and materials expenses as adjusted for escalation. The labor and material inflation adjustment factor of 3.0% for 2018, 2.9% for 2019 and 1.0% for the first four months of 2020 is supported by Witness Uzenski.

Q. Did you make any adjustments to the historical test period operations and maintenance expenses for other power generation?

A. Yes, I eliminated $17.7 million of expenses related to the renewable energy program in column (d) because they are handled by a separate surcharge not associated with this proceeding.

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Q. What are your thoughts concerning the level of DTE Electric's historical and projected capital and O&M expenses contained in your testimony?

A. DTE Electric has been reasonable and prudent in past capital and O&M expenditures and I anticipate this to continue through the projected test period and beyond. During this same time frame, generation unit availability is managed through a rigorous process that continues to be focused on prudent capital and O&M expenditures. I believe that DTE Electric has fully justified its request for recovery of the Fossil Generation plant expenses that are set forth in my testimony and associated exhibits.

<u>Part IV - Fossil Generation Infrastructure Recovery Mechanism (IRM)</u>

Q. What is Fossil Generation proposing in support of an Infrastructure Recovery Mechanism (IRM) for capital expenditures?

A. As part of the IRM process being introduced by Company Witness Stanczak, a portion of Fossil Generation's future capital expenditures will be included in an IRM. The Fossil Generation capital expenditures proposed to be included in this IRM are related to planned and scheduled work needed to ensure continued safe and reliable operations of our Tier 1 steam generating units (Monroe, Belle River and Greenwood) and peaker generating units, along with capital expenditures related to the construction of an 1,100 MW CCGT plant.

Q. What categories of projects are being proposed as part of the IRM in Exhibit A-30 Schedule T3 for 2020-2022?

A. Fossil Generation is proposing that a portion of expenditures related to the following categories be included in the recovery mechanism:

- Planned outage work on Tier 1 steam generating units

- Scheduled capital equipment replacements on Tier 1 steam generating units
- Planned outage work on large gas fired peakers
- Costs to build a new gas fired combined cycle generating unit

Q. Can you provide examples and justification for completing the Monroe/Belle River/Greenwood Planned Outages work shown on line 1 of Exhibit A-30 Schedule T3?

A. The planned outage work for Monroe, Belle River, and Greenwood as part of the IRM timeframe of 2020-2022 is similar to the work included in my earlier testimony for the same units in the years 2017 through the first four months of 2020. Monroe, Belle River, and Greenwood steam generating units receive periodic outage maintenance on a two to four-year cycle. During these periodic outages, boilers, turbines, generators, electrical systems, environmental equipment and safety systems are inspected, repaired and have components replaced to allow the units to sustain safe, reliable and environmentally compliant operations. For example, the selective catalytic reduction (SCR) system installed at Monroe Power Plant to control boiler NOx emissions requires that its catalyst beds be replaced on a routine basis to sustain required performance levels. Additionally, critical safety systems such as turbine stop valves are overhauled during these major periodic outages to ensure their proper operation if events require their activation.

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Q. Can you provide examples and justification for completing the Monroe/Belle River/Greenwood Scheduled Work shown on line 2 of Exhibit A-30 Schedule T3?

A. The scheduled work for Monroe, Belle River, and Greenwood steam generating units includes work on the plant common systems, environmental projects and site security work that can typically be completed without the units in planned outage. Plant common systems work includes projects on fuel supply control systems, plant switch gear, combustible dust management, coal silo restorations, water treatment equipment, air compressors and auxiliary boiler tube replacement projects. Environmental work includes ground water monitoring, NPDES environmental monitoring and reporting systems, and maintenance of environmental basins, liners and other waste segregation systems. Site security work includes projects that control access to facilities and critical equipment with the intent of protecting the integrity of the bulk electrical system. Performing these projects is required to sustain continued safe, reliable and environmentally compliant operations of the Tier 1 steam generating units.

Q. Can you provide examples and justification for completing the Peaker Planned Outage work shown on line 3 of Exhibit A-30 Schedule T3, for large gas fired peakers?

A. The planned outage work for the large gas fired peakers (Belle River, Dean, Delray, Greenwood and Renaissance) as part of the IRM timeframe of 2020-2022 is similar to the work included in my earlier testimony for the same units in the years 2017 through the first four months of 2020. Planned outage scope for large gas fired peakers includes combustion zone overhauls and replacements of control and electrical systems. The need for combustion zone overhauls on large gas fired peakers is based on well-defined requirements that are triggered by a combination of run hours and the number of startup events. Control system replacement projects are based on parts and technology obsolescence and compatibility with other new systems. Electrical system projects include main unit transformers and generator rewinds. The work performed during these periodic outages allows the unit to continue to provide safe and reliable service.

Q. Can you describe line 4 of Exhibit A-30 Schedule T3, labelled New 1,100 MW Combined Cycle Generation?

A. The expenditures shown on line 4 are the remaining costs to complete the construction of an 1,100 MW combined cycle gas turbine plant. On April 27, 2018, the MPSC issued an Order in Case No. U-18419 approving DTE's application for three certificates of necessity (CON) for this plant. In approving the CONs, the commission determined through an open hearing process that the energy to be supplied by the project is needed, a natural gas fired CCGT plant was the most reasonable and prudent means of meeting DTE Electric's future energy needs, and that the Company can recover up to $951.8 million in costs for the plant through future rates. Per the requirements of MCL 460.6s (7), DTE Electric will provide an annual update to the Commission on the status of project costs and schedule.

Q. Will the Company provide additional information around the scope of the projects supporting the categories shown on Exhibit A-30 Schedule T3?

A. Yes. As described by Company Witness Stanczak, in the fall of the year preceding the upcoming IRM year, the Commission will be provided a report detailing the

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Company's IRM plan for the next year. In that report, Fossil Generation will list specific projects and the associated capital expenditures related to the four line items shown on Exhibit A-30 Schedule T3 for the upcoming IRM year.

Q. What information will the Company provide to reconcile the projected capital expenditures shown in Exhibit A-30 Schedule T3 to the actual capital expenditures for each IRM year?

A. After completion of the most recent IRM year, the Company will provide to the Commission Staff a report on the actual work completed in the same form as that provided in the previous fall for work related to the four line items shown on Exhibit A-30 Schedule T3. Company Witness Stanczak discusses the reconciliation process in additional detail in his testimony.

Q. Is the Company proposing any program metrics related to the Fossil Generation capital expenditures proposed within the IRM?

A. Yes. The Company is proposing metrics for each category of Fossil Generation capital expenditures proposed within the IRM on Exhibit A-30 Schedule T3. Company Witness Stanczak describes the proposed reporting process for the program metrics in his testimony.

For line 1, Monroe/Belle River/Greenwood Planned Outages, the program metrics may include number of boiler overhauls, number of turbine overhauls, number of SCR layers replaced and number of electrical system replacements versus targets provided in the prior year.

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For line 2, Monroe/Belle River/Greenwood Scheduled Work, the program metrics may include the number of fuel supply overhauls, number of infrastructure overhauls and number of site security initiatives completed versus targets provided in the prior year.

For line 3, Peaker Planned Outages, the program metrics may include the number of combustion path overhauls completed versus targets provided in the prior year.

For line 4, New 1,100 MW Combined Cycle Generation, we will provide an annual update to the Commission on the status of project costs and schedule, per the requirements of MCL 460.6s (7).

Q. Are there any additional performance indicators the Company will report to allow the MPSC Staff to assess the benefits of the projects contained in the IRM?

A. Yes. Fossil Generation will provide a report to the Commission Staff on unplanned unit outages that have occurred due to failures on components replaced within IRM projects completed in the preceding year.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

HEATHER D. RIVARD

DTE ELECTRIC COMPANY
QUALIFICATIONS OF HEATHER D. RIVARD

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Q. What is your name, business address and by whom are you employed?

A. Heather D. Rivard, Senior Vice President of Distribution Operations, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I graduated from the University of Michigan with a Bachelor of Science in Engineering in 1992. I also earned a Master's Degree in Business Administration from the University of Michigan in 2004.

Q. What is your work experience?

A. I began my career with ANSER Corporation and worked there from 1992-1993. I have been employed by DTE Electric since 1993 and was first assigned to the Customer Information Technology group where I worked on the prioritization and review processes for information technology projects. Over the years, I held a number of positions with increasing leadership responsibilities in areas that include: Customer Marketing, a DTE Energy start-up subsidiary, Customer Service, DTE Electric President's Staff organization, DTE Electric's Lapeer and Pontiac Service Centers, Customer Billing, and Enterprise Performance Management.

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In 2006, I was promoted to Director – Electric Service Operations where I was responsible for the operation of thirteen service centers leading over 1,000 employees performing maintenance, operations, and construction on DTE Electric's electrical distribution system.

In 2011, I began working for DTE Energy's Corporate Services organization as the Executive Director, and was promoted to Vice President of Corporate Services in 2014. In these roles, I was responsible for DTE Energy's procurement, warehousing, fleet, facilities, and real estate operations.

Prior to my current position, I served as the Vice President of Electric Distribution from 2015 to 2016. In this role, I was responsible for overseeing the Company's electrical system construction, including new customer connections, distribution reliability planning and construction, distribution contract management, tree trimming, and emergency responsiveness.

Q. What are your current job responsibilities?

A. Currently, I am the Senior Vice President of Electric Distribution. In this role, I am responsible for the delivery of electricity to the homes and businesses of DTE Electric's customers. This includes tree trimming, engineering, system planning, construction, system operations, substation operations, outage restoration, field and meter services, and system maintenance activities.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony in the following cases:

U-16246	DTE Electric’s 2009 Restoration Expense Tracking Mechanism
U-16578	DTE Electric’s 2010 Restoration Expense Tracking Mechanism and Line Clearance Expense Report

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Discuss the importance of DTE Electric's vegetation management ("Tree Trimming") program;
- Support the historical Operations and Maintenance (O&M) expenses related to tree trimming efforts for 2017 and the projected O&M expenses for May 1, 2019 to April 30, 2020;
- Provide details related to the Company's development of a Tree Trimming program structure that will deliver on the reliability goals established in the Company's Five-Year Investment and Maintenance Plan ("Five-Year Plan");
- Describe the customer benefits of the proposed expansion in the Company's Tree Trimming Program

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-22	L1	Projected Value of Tree Trimming Surge Program

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

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Outline of Testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Recent progress of the Company's Tree Trim program
- Vision for Tree Trimming
- Surge proposal description
- Benefits of the Surge proposal
- Funding required
- Funding mechanics
- Resourcing the Surge
- Herbicide program
- Measuring progress
- Conclusion

Recent Progress of the Company's Tree Trim program

Q. What is the Company's Tree Trimming program?

A. The Company has an ongoing Tree Trimming program to address interference between vegetation and overhead electric distribution facilities. The objectives of the program are to reduce tree-related safety hazards and to reduce the volume of tree-related trouble cases. The Company's Tree Trimming program, which is based on industry best practices and the Company's experience, is known as the Enhanced Tree Trimming Program ("ETTP"). The ETTP was described in detail in testimony in the Company's last two rate cases: Case No. U-18014 and Case No. U-18255.

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Q. How does the ETTP define tree work to be performed based on circuit zones?

A. In the right-of-way of all Zones, the Company attempts to remove all small trees and larger trees that pose an unacceptable risk to the electrical system. Additionally, the Company attempts to mitigate all hazard trees (trees outside the right of way that are dead, diseased, or dying and threaten to interrupt service to customers).

Specifically, in Zone 1, the portion of the circuit from the substation to the first protective device or drop down, the Company removes all branches overhanging the conductors. In Zone 2, the portion of the circuit from the first protective device or drop down to the fused lateral, the Company removes all softwood branches overhanging the conductors and hardwood branches overhanging the conductors at less than a forty-five-degree angle. In Zone 3, the fused laterals, the Company removes all softwood and hardwood branches overhanging the conductors at less than a forty-five-degree angle.

Q. What were the results of the Tree Trimming program in 2017?

A. The 2017 results will be described in terms of miles trimmed, cost to achieve, reliability impact, and customer satisfaction.

(i) Annual Plan Miles Completed: The Company trimmed 3,601 line miles on 305 separate circuits in 2017 compared to a plan of 3,618 miles.

(ii) Costs to Achieve: DTE Electric spent $84.3 million on the tree trimming program in 2017. This equates to $9.1 million more than the $75.2 million of funding approved in MPSC Case No. U-18014, which was the Company's rate case with a projected test year of August 1, 2016 through July 31, 2017.

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(iii) Reliability Impact: Circuits trimmed as part of the ETTP had an average annual reduction of approximately 50 percent in the number of tree-related customer interruptions and an average annual reduction of approximately 80 percent in the number of customer minutes of interruption in the year following trimming.

(iv) Customer Satisfaction: According to J.D. Power, Power Quality and Reliability (PQR) is the highest driver in affecting overall customer satisfaction. Both the Residential Electric and Business Electric PQR scores for the Company improved from 2016 to 2017 by approximately 3%-4%. The tree trimming program is the program with the biggest impact on system reliability. Another important measure of customer satisfaction is the number of MPSC complaints filed each year related to the Company's tree trimming work. Although the complaints for tree-related service issues increased slightly in 2017 (35 complaints vs. a prior five-year average of 31), approximately 70% of the complaints were driven by customers asking for tree trimming, with the next highest complaint pertaining to debris removal. The complaints have not been driven by customer concerns regarding the tree trimming work conducted on their properties; rather, they demonstrate customers' support for tree trimming and its positive impacts on reliability and costs.

Q. How many miles does the Company anticipate trimming in 2018?

A. The Company plans to trim 3,978 miles in 2018. This is 377 more miles than the 3,601 that were trimmed in 2017.

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	Annual Plan Miles Completed / Planned	Percent of Distribution System
2017 Actual	3,601	12%
2018 Plan	3,978	13%

TABLE 1 – Tree Trimming Mileage

Q. Does the Company expect to achieve the 2018 target?

A. Yes. The Company has prioritized a mix of circuits that will encompass the 3,978-mile target.

Q. How are circuits prioritized for trimming?

A. The Company prioritizes circuits for trimming based on reliability impacts, wire down reductions, and the number of years that have passed since the last trim. Resource balancing across the service territory is also considered to ensure resources are available to respond to unplanned events in a timely manner.

Q. What has been the reduction in events on circuits trimmed to the ETTP?

A. The actual reduction compared to the three-year average preceding trimming, and excluding the historically unprecedented March 8, 2017 wind storm, is approximately 47%, as depicted in Table 2.

Line
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	Number of Circuits Trimmed	% Event Reduction in Year after Trimming
ETTP	322	47%
Clearance Circle	2,444	13%

TABLE 2 – Post-Trim Tree-Related Outage Event Reduction

Q. How does this reduction compare to results under the prior trimming practice?

A. The past practice of trimming a “clearance circle” around conductors provided only a 13% reduction in tree-related events in the year following trimming as compared to the average number of events in the three-years preceding trimming

Q. How did the circuits trimmed as part of the ETTP perform in comparison to the system during the March 8, 2017 wind storm?

A. The circuits trimmed as part of the ETTP performed much better than the remainder of the system as shown in Table 3.

Line
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	Non-ETTP Circuits	ETTP Circuits	ETTP Improvement
Outages/circuit	4.2	1.9	54%
Outages/Customer	0.0062	0.0037	41%
Minutes of Interruption/Customer	1,591	864	46%

TABLE 3 – Circuit Performance during March 8, 2017 Wind Storm

Q. What has been the reduction in wire down events post-ETTP trimming?

A. Wire downs on the circuits that have been trimmed as part of the ETTP have been reduced by 28% in the year after trimming in comparison to the three-year average preceding trimming.

Q. Please describe some of the productivity initiatives the Company has undertaken to improve the cost-effectiveness of the ETTP and ensure the authorized spend is executed efficiently?

A. The Company has adopted several productivity and process improvement initiatives which have led to significant cost efficiencies, including:

(1) The utilization of GPS technology and the Clearion work management system have provided increased visibility into our contractors' work, allowing us to partner with them in making process improvements in both work planning and execution.

(2) The implementation of weekly huddles with scorecards for each of our contractors has allowed for improved communications and the ability to eliminate roadblocks before becoming a detriment to productivity.

Line
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(3) The optimization of pull-out locations, which allowed tree trimmers to reduce drive time to the worksite.

(4) An updated wood haul process whereby the Company would leave wood that could be used by customers. This process was also intended to mitigate the spread of tree diseases and invasive species.

(5) The use of fuel trucks at the contractor pull-out locations which made it possible for the tree trimmers to be on the jobsite for longer periods of time by not having to take time in the beginning or end of the day to fuel their own vehicles.

(6) The hiring of chip tippers allowing for the extension of the workday by eliminating the need for tree trimmers to dump chips at the end of the day.

(7) The continued utilization of specialty equipment to improve efficiency and reduce manual work such as: mowers, side trimmers, backyard buckets, off-road buckets (70’ and 55’), and mini-skid steer.

Q. What are the savings from these initiatives?

A. The initiatives in 2017 provided a 7.5% average annual improvement in productivity as measured by earned hours.

Q. What are earned hours?

A. Earned hours is a metric created by the Company to track contractor productivity. The Company has 50 units to represent all the types of work executed in the field. Each unit has a standard time associated, which is the expected amount of time required to complete that unit. Every week, contractors submit the number of units completed, by day of week, by circuit, and the hours it took to complete the units.

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The expected value of time it would take to complete the units is compared to the actual hours it took to complete the units determining the Earned Hours.

Q. Are the improvements in productivity sustainable?

A. Yes. The improvements are sustainable and have been implemented by the Company's contractors to ensure they achieve the expected levels of productivity while executing contracts.

Q. Are there additional improvements the Company would like to make related to its tree trim program?

A. Yes. Further improvements are needed to achieve the Company goals related to safety, reliability, and cost reduction. Currently, the Company continues to evaluate a series of initiatives. The value in the shift in contracting structures from time and equipment to fixed-bid will continue to be assessed as the Company develops the contracts for the 2019 Plan in the third quarter of the year. Other initiatives include expanding the use of herbicides to control undesirable vegetation in the right-of-way, which I will discuss later in my testimony. Additionally, we are increasing our efforts in partnering with local communities to clear alleys to improve bucket truck accessibility and lower costs, as was conducted with the City of Highland Park in early 2018. We are also testing the effectiveness of circuit shutdowns to reduce the risk of working near energized lines and increase the pace at which tree trimmers work. This initiative will improve efficiency of trimming; however, it will result in customer outages during the time of trimming which could lead to increased customer complaints.

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Vision for Tree Trimming

Q. How does the Company benchmark in reliability?

A. As discussed by Witness Bruzzano in his testimony, the Company is in the fourth (bottom) quartile of the industry based upon customer minutes of interruption, System Average Interruption Duration Index – excluding Major Event Days (SAIDI – excluding MEDs).

Q. What is the biggest root cause of outages?

A. As discussed in the Company's Five-year Plan, tree interference is the leading driver of customer outages. Tree-caused outages account for two-thirds of the time that customers spend without power; thus, the successful execution of the tree trimming program will allow the Company to significantly improve the overall reliability of electric service.

Q. What is the best way to reduce tree related outages?

A. A robust tree trimming program is needed to address system reliability including customer minutes of interruption and the number of customer interruptions. The program must be funded to maintain a tree trim cycle that permits the subsequent trimming of a circuit before the trimmed trees grow into the Company's wires and become hazards.

Q. What is the Company's vision for its Tree Trimming program?

A. The Company remains firmly committed to achieving a five-year cycle. This will be accomplished by continuing to improve the efficiency with which trimming work is

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executed and by working through the regulatory process to obtain the funding to support the program. As stated by Company Witness Bruzzano in his testimony regarding the Company's Global Prioritization Model, tree trimming is the highest priority investment. No other program in the Company's portfolio of distribution projects will have a greater impact on mitigating risks, improving system and customer reliability, and managing the costs of operating the Company's electric distribution system.

Q. How many miles need to be trimmed annually to achieve a five-year cycle?

A. DTE Electric currently needs to trim approximately 6,538 miles per year to achieve the optimal five-year cycle for distribution circuits.

	Overhead Miles	Cycle Length (years)	Cycle Mileage (miles / year)
Distribution Circuits	28,459	5	5,692
Subtransmission Circuits	2,539	3	846
Total	30,998	4.75	6,538

TABLE 4 – Tree Trimming Cycle Length

Q. What is the Company's current trimming cycle?

A. In 2017, the Company cleared 3,601 miles which equates to an effective eight and a half-year cycle. Based on funding and miles trimmed in 2015-2017 the system is on an effective nine-year cycle.

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Q. Why is the Company proposing to move to a five-year cycle?

A. The Company typically performs trimming within 15 feet of either side of the distribution pole centerline, or approximately 10 feet from the conductors. The Company's target of a five-year cycle is based on the following facts:

(1) As discussed later in my testimony, trees near the Company's distribution equipment grow approximately 10 feet on average in five years.

(2) The five year-cycle provides a reasonable and acceptable level of tree-to-conductor contact comparable to the industry standard of 10% - 15%. Tree-to-conductor contact represents the likelihood of any portion of the tree touching the conductor. A tree-to-conductor contact level of 10% - 15% denotes the estimated average percentage of trees in contact with the overhead electrical facilities across the entire distribution system when the recommended cycle length and clearance standards are reached.

Q. How does the Company's targeted cycle length compare to the industry benchmarks?

A. The Company's targeted five-year cycle on distribution circuits is comparable to the actual industry average of 4.9 years, per the report published by CN Utility Consulting, Inc. (CNUC) - Distribution Utility Vegetation Management Benchmark Survey Results 2016 - as shown in Chart 1. Furthermore, all but six of the participating companies target a cycle of five years or less. Furthermore, the Company's own benchmarking efforts indicated an average actual cycle length of 5.2 years.

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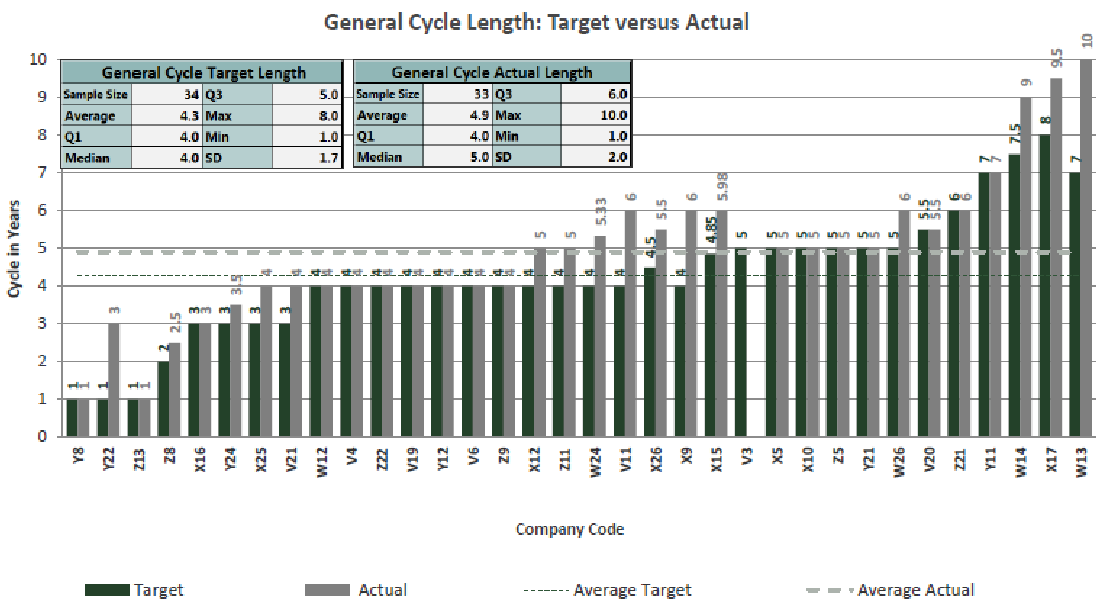

CHART 1 – CNUC Benchmark Study – General Cycle Length

<u>**Surge Proposal Description**</u>

Q. When does the Company propose to achieve a five-year cycle?

A. The Company is proposing a seven-year surge in the tree trimming program to achieve a five-year cycle and eliminate the backlog of miles yet to be trimmed as part of the Enhanced Tree Trimming Program (ETTP) by 2026.

Q. What is meant by "backlog" and "on-cycle"?

A. Backlog refers to the circuit miles that have yet to be trimmed as part of the ETTP. On-cycle means that the circuit miles have been trimmed within the last five years.

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Q. Why will it take a seven-year surge to achieve a five-year trimming cycle?

A. The number of years it will take to complete the Surge is primarily driven by three factors:

(1) The funding level provided to the program

(2) The resources available to trim nearly 31,000 miles of overhead circuits

(3) Ensuring that any mile previously trimmed as part of the ETTP will remain on a five-year cycle.

Q. Will the Company prioritize circuits already trimmed as part of the ETTP before the circuits on the backlog?

A. Yes. Circuits already trimmed as part of the ETTP will be maintained on a five-year cycle, while also addressing the backlog of circuits that have yet to be trimmed as part of the Company's ETTP.

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Q. How many miles will be addressed annually on the backlog compared to those on-cycle during the Surge?

A. Chart 2 shows the miles the Company intends to trim from the backlog of circuit miles that have yet to be trimmed as part of the ETTP and the miles that are on-cycle and have been trimmed as part of the ETTP.

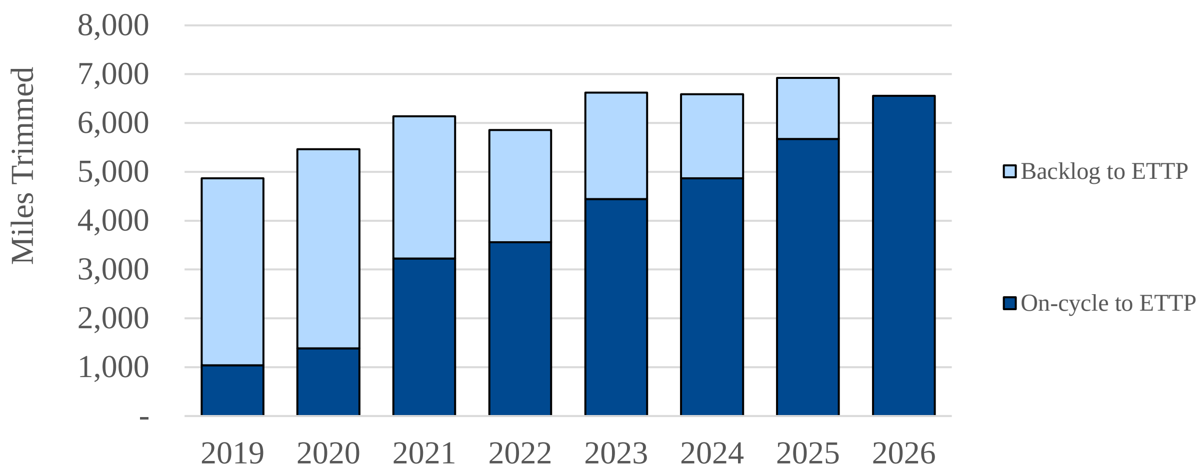

CHART 2 – Miles Trimmed During Surge and First Year of Post-Surge

Q. Are the specifications applied consistently throughout the Surge?

A. Yes. Tree trimming specifications are applied consistently throughout the Company's service territory. The Company trims circuits to maintain clearance for one five-year cycle worth of growth which, on average, necessitates ten feet of clearance to the outermost conductor. The required clearance is species-specific.

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Q. How was the average tree regrowth rate determined?

A. The regrowth rate is based on the Company's historical experience and was reaffirmed during a regrowth study performed by ECI, a nationally recognized expert in utility vegetation management, during the first quarter of 2017. The rate accounts for the physical orientation of specific trees and the corresponding types of trimming performed as shown in Chart 3. This average growth is a function of the tree species mix in the Company's service area. The inventory of common species was developed by ECI through a visual sampling of the vegetation surrounding the Company's overhead lines. On average, in a five-year period, a tree in the Company's service territory will grow ten feet upwards and approximately seven feet outwards. The average growth rate of the common tree species in the Company's service territory is provided in Table 5.

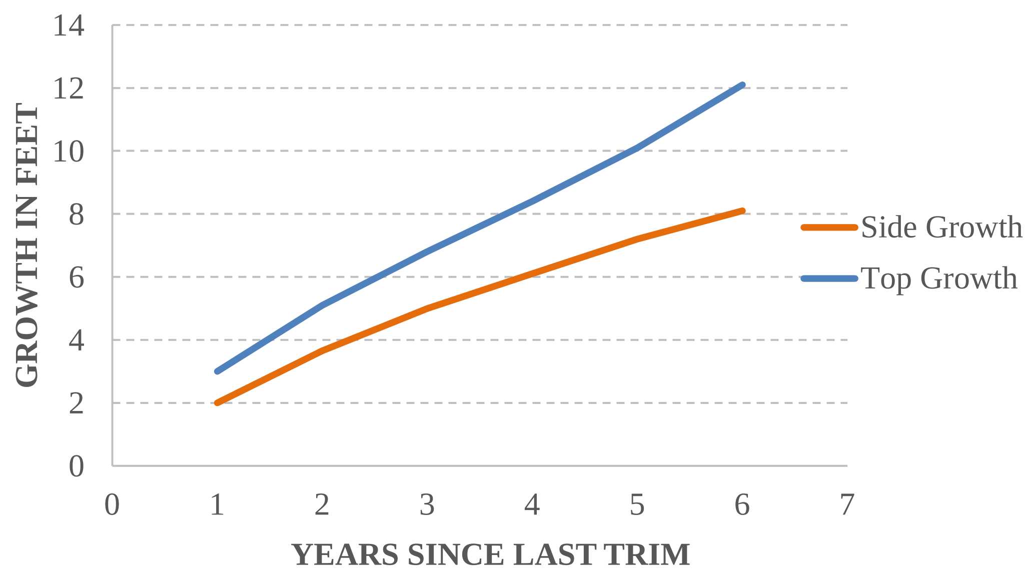

CHART 3 – Average Tree Regrowth Rate on the Electric Distribution System per ECI

Tree Species	Pruning Type	Inches of Regrowth by Age of Sprout 1 Year	2 Years	3 Years	4 Years	5 Years	6 Years
Box-elder	Side	30	53	78	97	117	136
	Top	53	91	124	157	185	213
Maple, Norway	Side	21	37	51	67	79	90
	Top	33	59	85	112	134	153
Maple, red	Side	17	33	50	65	81	95
	Top	27	52	80	106	126	142
Maple, silver	Side	37	60	89	109	129	144
	Top	41	72	105	140	170	194
Maple, sugar	Side	19	36	55	72	87	100
	Top	30	51	74	97	115	132
Tree-of-heaven	Side	18	35	53	71	89	103
	Top	40	68	92	113	135	157
Elms	Side	37	61	81	99	115	134
	Top	54	97	132	168	200	240
Honeylocust	Side	20	37	51	66	82	96
	Top	31	54	77	95	111	125
Walnut, black	Side	23	45	63	78	91	103
	Top	72	106	134	154	174	191
Mulberry	Side	36	64	83	104	121	141
	Top	46	82	107	129	154	174
Spruce, Norway	Side	16	26	37	44	50	57
	Top	15	28	44	56	71	86
Spruce, blue	Side	16	26	37	44	50	57
	Top	8	16	24	32	39	48
Pine, red	Side	11	20	28	36	44	55
	Top	12	22	34	46	61	74
Pine, eastern white	Side	9	19	29	40	47	56
	Top	18	35	53	69	85	102
Cottonwood, eastern	Side	28	51	78	99	115	129
	Top	49	78	110	133	150	165
Pear, Bradford	Side	12	26	40	53	63	75
	Top	23	44	66	89	106	120
Oak, white	Side	15	29	38	47	58	67
	Top	17	31	42	55	66	76
Oak, red	Side	20	38	54	70	84	99
	Top	23	46	65	81	98	117

TABLE 5 – Average Regrowth Rate for Common Tree Species on the Company's Electric Distribution System per ECI

Line
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Q. Can you provide additional information on ECI and how their work relates to this testimony?

A. ECI was founded in 1972 and is a leading provider of vegetation management consulting and field services to electric and gas utilities, actively consulting and partnering with over 40 utilities nationwide, including Consumers Energy. The Company contracted ECI's consulting services in 2015 to improve the management of right-of-way vegetation by applying industry best practices to increase service reliability, reduce risks, and lower the costs associated with managing the vegetation around the Company's lines.

Q. Why is a three-year cycle needed on subtransmission circuits?

A. The three-year cycle is maintained because of the high customer impact of subtransmission lines. A trouble event on a subtransmission circuit can potentially cause an entire substation to lose power, which would affect, on average, over 3,600 customers, while a trouble event on a distribution circuit would affect, on average, approximately 700 customers. Therefore, outage events on subtransmission lines have a severity effect five times greater than a similar outage event on a distribution circuit.

<u>Benefits of the Surge Proposal</u>

Q. How will customers benefit from reducing the tree trimming cycle length to the industry benchmark of a five-year cycle?

A. Reducing the tree trimming cycle length to five years will provide tree-related benefits and savings in multiple ways:

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(1) Lower customer complaints. The Company recognizes and acknowledges that tree-related outage and non-outage events are a major issue for our customers that can be rectified through the tree trim program and requested funding.

(2) Fewer wire down events, resulting in improved safety

(3) Fewer outage and non-outage events, leading to a positive impact on reactive O&M and capital costs. This will also allow for the re-allocation of resources to other necessary work across the Company's distribution system.

(4) Lower future trimming costs as the number of trees growing within the right-of-way are trimmed or removed more frequently, resulting in the need to remove less wood from the trees near the Company's lines.

(5) Lower customer costs as tree-related outages are reduced. The improved reliability will reduce downtime for customers' manufacturing processes, allow commercial businesses to remain open, and reduce the inconveniences that residential customers experience.

Q. How much value does the program provide to customers?

A. The net present value ("NPV") analysis as shown in Exhibit A-22 Schedule L1, which compares the NPV of continuing the current tree trimming practices and investing in the Surge program, indicates the program is $46 million favorable to customers.

Q. Was the economic value to customers of the improved reliability from the Tree Trimming Surge taken into consideration when determining the NPV?

A. No. The value of the program was based upon the forecasted reduction in revenue requirement that customers would receive through 2040 due to the investment in the

Tree Trimming Surge program. The analysis did not take into consideration the additional economic benefits that derive from improved reliability as could be calculated utilizing the Interruption Cost Estimation (ICE) Calculator developed by Nexant and the Lawrence Berkeley National Lab (Lawrence Berkeley Study) as described by Company Witness Bruzzano.

Q. How much does the Company expect to reduce costs per line mile trimmed upon achieving a five-year trimming cycle?

A. Based on the work study completed by ECI, the Company expects its cost per line mile to decrease, on average, by 40% compared to the initial trimming conducted as part of the ETTP.

Q. How many tree-related trouble events does the Company expect to reduce upon achieving a five-year cycle through the investment surge?

A. Based upon details from the Company's outage and dispatch management systems, the Company typically attributes approximately 56,900 outage and non-outage events to trees, or 25% of its roughly 225,000 average annual outage and non-outage events the Company experiences. Upon completion of the Surge, the Company expects the tree-related events to be reduced by approximately 40%.

Outage and Non-Outage Events	Pre-Surge 2012-2016 Average	Post-Surge 2026	% Reduction
Tree-Related	56,913	33,649	40.9%

TABLE 6 – Average Annual Outage and Non-outage Events

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Q. What reliability improvements will be provided through the Surge program?

A. The Company expects a 40% reduction in tree-related All-Weather SAIDI. This reduction is driven by fewer tree-related events.

Q. How did the Company determine the percentage reduction in events upon completion of the Surge?

A. The Company based the 40% reduction upon:

(1) The circuits that have been trimmed as part of the ETTP have shown a 47% reduction in events in the year after trimming as compared to the three years prior to trimming the circuit.

(2) A study ECI conducted on behalf of the Company indicated a reduction in the cycle length from an effective eight and a half-year cycle to a five-year cycle would reduce events by 35%.

(3) Benchmarking of peer utilities suggests an improvement in event reductions in excess of 50%.

Q. What cost savings will be provided through the Surge program?

A. At the completion of the Surge, tree-related O&M and capital costs for reactive maintenance and storm will be lower. With fewer tree-related events, the need for tree crews and Service Operations' overhead crews will be reduced. There will be less of a need to repair and replace assets on the system that have failed because of tree interference. Table 7 shows current O&M and capital cost compared to the projected costs upon completion of the Surge, excluding inflation.

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<table>
<tr><th colspan="4">Estimated Tree-related Annual Cost Savings
($ millions, excluding inflation)</th></tr>
<tr><th colspan="2">Cost Category</th><th>Current Cost</th><th>Post-Surge 2026</th></tr>
<tr><td rowspan="3">Tree-Related O&M</td><td>Tree Trim Reactive</td><td>$11.4</td><td>$6.7</td></tr>
<tr><td>Tree Trim Storm</td><td>$10.5</td><td>$6.2</td></tr>
<tr><td>Other DO – Service Operations Storm and Trouble</td><td>$11.6</td><td>$6.9</td></tr>
<tr><td rowspan="3">Tree-Related Capital</td><td>Tree Trim Reactive</td><td>$4.6</td><td>$2.7</td></tr>
<tr><td>Tree Trim Storm</td><td>$18.5</td><td>$10.9</td></tr>
<tr><td>Other DO - Service Operations Storm and Trouble</td><td>$34.6</td><td>$20.4</td></tr>
</table>

TABLE 7 – Tree Trimming Surge Cost Savings

Q. What will reliability performance be if the Surge program is not funded?

A. Without an increase in funding, the backlog of circuits in need of trimming as part of the ETTP will not be addressed. In 2026, there will be nearly a 10,000-mile backlog of distribution circuit miles that have yet to be trimmed as part of the ETTP.

The proposed funding level, absent the Surge, would allow the Company to maintain an effective 11-year cycle. If the Surge funding is not approved and an 11-year cycle becomes the standard for the Company, outage and non-outage events, including wire downs, will continue to grow, customer satisfaction will erode, and complaints to the

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MPSC will increase. Ultimately, tree-related reactive and storm costs will increase by approximately 45%, excluding inflation, taking away from the funds that were to be allocated to planned investment and maintenance activities.

Q. Does it cost more to trim a circuit if it is not trimmed on-cycle?

A. Yes. As referenced by the MPSC Staff in 2013 Ice Storm Report, Case No. U-17452, deferring maintenance results in cost escalation as described in the May 1997 study funded by International Society of Arboriculture ("ISA") and conducted by ECI, LLC – The Economic Impacts of Deferring Electric Utility Tree Maintenance. Table 8 shows the relative cost, excluding inflation, of deferring maintenance beyond the optimum time – five years after the previous trim for the Company. By deferring maintenance, the Company will need to allocate more funds to trimming the deferred work in a subsequent year.

Timing of Trimming	Years since last trim	Relative Cost
Optimum	5	$1
1-year past optimum	6	$1.16 to $1.23
2-years past optimum	7	$1.30 to $1.43
3-years past optimum	8	$1.40 to $1.59
4-years past optimum	9	$1.47 to $1.69

TABLE 8 – Projected Impact on Cost of Deferring Maintenance

Q. Will it take more resources to trim a circuit if it is not trimmed on-cycle?

A. Yes. Longer tree trimming intervals result in higher tree trimming cost over time, as also described in the May 1997 ISA study. As illustrated in Diagram 1, as the time since last trim continues to grow, the work becomes more complex as trees begin to interfere with the conductors.

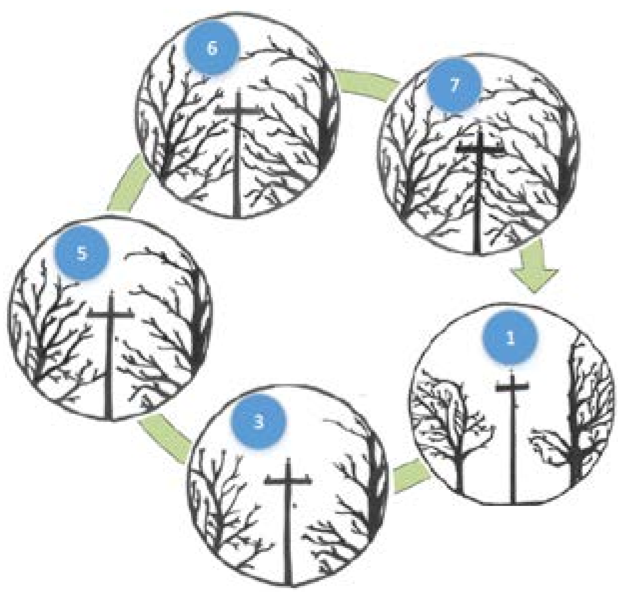

DIAGRAM 1 – Illustrative Tree Growth Impact on Complexity

(Years since Last Trim)

Q. Was a longer cycle considered?

A. Yes. A longer cycle was considered. However, lengthening the overall cycle beyond five years increases the level of tree-to-conductor contact. Excessive tree contact will result in a significant increase in tree-related events and customer minutes of interruptions. The five year-cycle provides a reasonable and acceptable level of tree-to-conductor contact, as shown in Table 9. The Company targeted the industry

Line
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standard of 10% - 15% tree-to-conductor contact level as stated in the May 1997 ISA study.

Clearance (in feet)	**Est. %Tree Contact Avg. All Circuits by Cycle Length**					
	1 Year	**2 Year**	**3 Year**	**4 Year**	**5 Year**	**6 Year**
1	100.0	100.0	100.0	100.0	100.0	100.0
2	77.3	86.8	90.8	92.9	94.3	95.1
3	50.0	66.1	75.1	80.6	84.0	86.5
4	27.0	44.7	56.9	65.6	71.5	75.7
5	13.5	27.9	41.2	51.1	58.8	64.5
6	5.2	16.3	28.2	38.4	46.8	53.6
7	2.3	9.8	18.9	27.4	35.8	42.8
8	0.7	5.1	11.5	18.4	25.8	32.6
9	0.3	2.5	7.3	12.7	18.5	24.8
10	0.1	1.3	4.4	8.2	12.7	17.8
11	0.1	0.7	2.6	5.3	8.7	12.9
12		0.3	1.4	3.2	5.8	9.1
13		0.2	0.7	2.0	4.0	6.6
14		0.1	0.5	1.4	2.8	4.6
15		0.1	0.4	0.9	1.9	3.3

Greater than 15% Contact

DTE target 5-year cycle

Effective 7-yr cycle

TABLE 9 – Likelihood of Tree-to-Conductor Contact

Q. What would be the expected tree-to-conductor contact on a seven-year cycle?

A. Understanding that average tree regrowth is two feet per year, the Company would expect a seven-year cycle to have an equivalent clearance of a five-year cycle with six feet of clearance. This would equate to the likelihood of tree-to-conductor contact in excess of the industry standard at 46.8%. Upon achieving a seven-year cycle in 20 years, system performance would only be improved by 15%.

Line
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Q. Was a larger tree-to-conductor clearance considered?

A. Yes. A larger clearance to the conductor was considered as a method for extending the cycle beyond five years; however, costs and customers complaints would increase with the increased removal of vegetation from customers' properties. The Company expects that the cost to trim an additional two feet of clearance would be similar to the added cost of deferring maintenance a year beyond the optimum time of trimming, resulting in an increase in cost per mile by 16% - 23% as depicted in Table 8.

Funding Required

Q. Can you please describe Exhibit A-13, Schedule C5.6, page 3, "Tree Trim Expenses"?

A. This page shows the details of the calculation supporting Tree Trimming expenses for the projected test period. The amount is broken down into three categories: maintenance and staff, herbicide, and reactive maintenance. Column (c) shows the actual expenses for 2017, and inflation is applied to this expense in columns (d) to (f). The inflation rates are supported by Company Witness Uzenski. The O&M adjustments for the trimming of miles approved in Case No. U-18255 and the implementation of an herbicide program are included in Lines (2) to (3) column (g). Column (h) shows the result of all the adjustments applied to the historic period, which is used to forecast the 12-month period ended April 30, 2020. The total amount requested for the projected period is $95.1 million. These amounts are included in Exhibit A-13, Schedule C5.6 on Line (18) as a part of total distribution O&M. The amount requested in Exhibit A-13, Schedule C5.6 does not include the total funding needed to achieve a five-year cycle which will be discussed later in my testimony.

Line
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Q. How much funding was included in Case No. U-18014 to trim trees in 2017?

A. In Case No. U-18014, the tree trimming program was funded to $75.2 million. The projected test year in that rate case was August 1, 2016 through July 31, 2017.

Q. How much funding was included in Case No. U-18255 to trim trees in 2018?

A. In Case No. U-18255, the tree trimming program was funded to $83.8 million for a total increase of $8.6 million above the funding level approved in the 2017 order with the goal of increasing the number of miles trimmed year-over-year. For reference, the projected test year in Case No. U-18255 was November 1, 2017 through October 31, 2018.

Q. How much funding was included in Case No. U-18014 for reactive maintenance 2017?

A. In Case No. U-18014, the tree trimming program included $6.0 million for reactive maintenance in 2017.

Q. How much funding was included in Case No. U-18255 for reactive maintenance?

A. In Case No. U-18255, the authorized tree trimming amount included $6.3 million for reactive maintenance.

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Case No.	Year	Program Funding excluding Reactive Maintenance	Reactive Maintenance	Total Program Funding
U-18014	2017	$69.2	$6.0	$75.2
U-18255	2018	$77.5	$6.3	$83.8
Funding Increase		$8.3	$0.3	$8.6

TABLE 10 – Tree Trimming Spend ($ million)

Q. How much did the Company spend on Reactive Maintenance in 2017?

A. In 2017, the Company spent $11.4 million on reactive maintenance, or $5.4 million more than the amount included in Case No. U-18014 for 2017, and $5.1 million more than the 2018 forecasted spending in Case No. U-18255.

Q. How much funding is the Company requesting for Tree Trimming Maintenance and Staff (Program Funding excluding Reactive Maintenance and Herbicides)?

A. The Company is requesting inflation adjusted funding on $77.5 million, equating to a projected test year spend of $80.9 million on the Tree Trim Program's Maintenance and Staff. This amount includes the cost of trimming circuit miles and approximately $6.3 million for staffing, auditing, planning, and meeting customer requests. This amount does not include the total needed to trim the circuit miles needed to achieve a five-year cycle which will be discussed later in my testimony.

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Q. How much funding is the Company requesting for Reactive Maintenance?

A. The Company is requesting inflation adjusted funding based on the 2017 historical spend of $11.4 million. The Company expects to spend $12.2 million on reactive maintenance in the projected test year.

Q. How much funding is the Company requesting for Herbicides?

A. The Company is requesting $2 million for the Herbicide program in the projected test year. This program will be discussed in more detail later in my testimony.

Q. Do these requests include the Surge funding?

A. No. The amounts requested in the Exhibit A-13, Schedule C5.6 do not include the total amount needed to fund the tree trimming program to achieve a five-year cycle.

Q. Including the Surge, what is the total requested funding in 2019 and 2020?

A. In 2019 and 2020, the Company is requesting a $137.5 million and $171.1 million as depicted in Exhibit A-22, Schedule L1, Line (5), columns (c) and (d), respectively.

Q. What is the requested funding amount for the Surge in 2019 and 2020?

A. Of the $137.5 million in 2019 and the $171.1 million in 2020, the Company is requesting the deferral of $43.3 million and $74.1 million in Surge funding as depicted in Exhibit A-22, Schedule L1, Line (11), columns (c) and (d), respectively.

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Q. What is driving the increase in Reactive Maintenance expense beyond what was included in Case No. U-18255?

A. Tree Trimming reactive maintenance expense has been escalating as a result of increased requests as shown in Chart 5. Reactive maintenance, which is primarily driven by increased customer-initiated requests for tree-related work, has increased 62% over the past three years. As shown in Chart 6, the number of years that have passed since the last trim is indicative of the number of customer initiated requests.

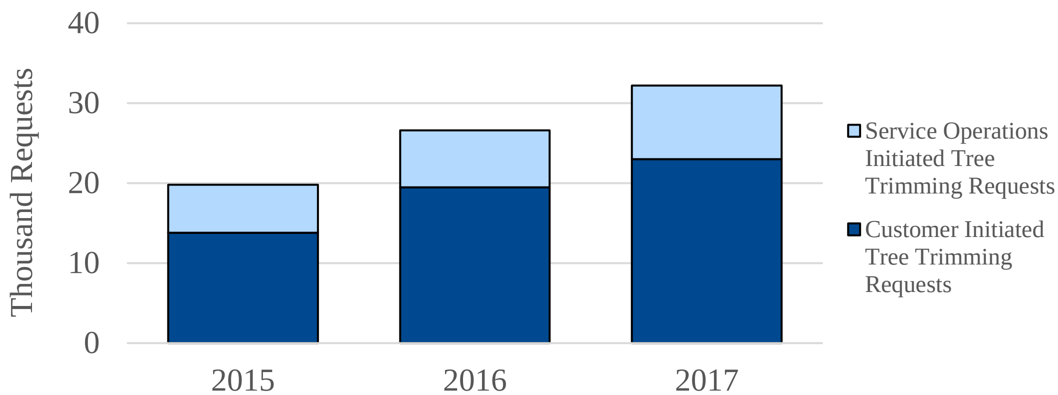

CHART 5 – Reactive Maintenance Tree Trimming Requests

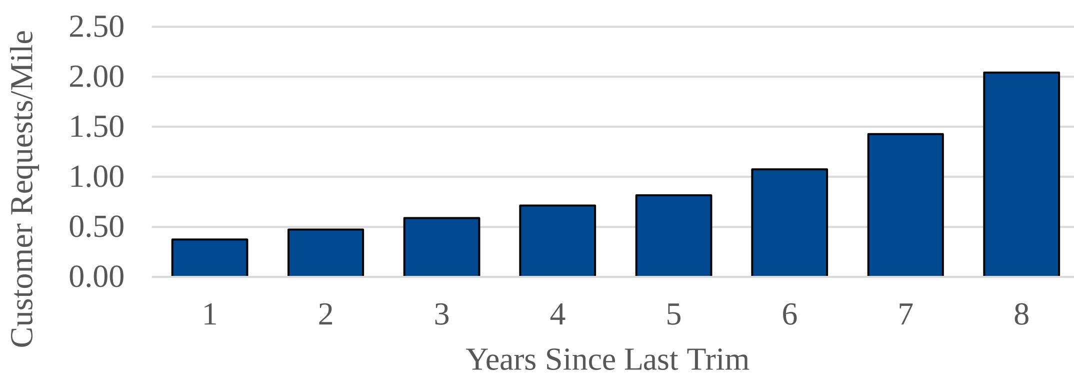

CHART 6 – Customer Initiated Requests per Mile by Years since Last Trim

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Q. What is the Company's estimated cost per mile for Surge tree trimming?

A. The Company expects the average cost to trim a distribution circuit that is part of the ETTP backlog to be approximately $20,160/mile, excluding staffing, auditing, planning, meeting customer requests, and inflation. The circuits that are "on-cycle" and have already been trimmed as part of the Company's ETTP are expected to cost 40% less.

Q. How does this estimated cost compare to the Company's historical ETTP cost per mile for distribution circuits?

A. Excluding staffing, auditing, planning, and meeting customer requests, the forecasted cost per mile to trim the backlog is higher than historical average as shown in Table 11. The backlog cost is expected to increase as a result of the time that has passed since last trim and the mix of resources.

	2016 Actual	2017 Actual	2018 Forecast	Historical Average	Backlog
Cost per Mile ($ k/mile)	$18.9	$18.6	$18.7	$18.7	$20.2

TABLE 11 – Distribution Circuit Cost per Mile to Trim

Q. How did the Company develop this cost estimate?

A. The Company hired ECI to conduct a density study on the circuits that have not yet been trimmed as part of the ETTP. Using this data, the average cost was obtained by aligning the average density in trees per mile with the average historical cost to trim a tree in each service center area. As demonstrated in Chart 7, density is a significant driver of the cost to trim.

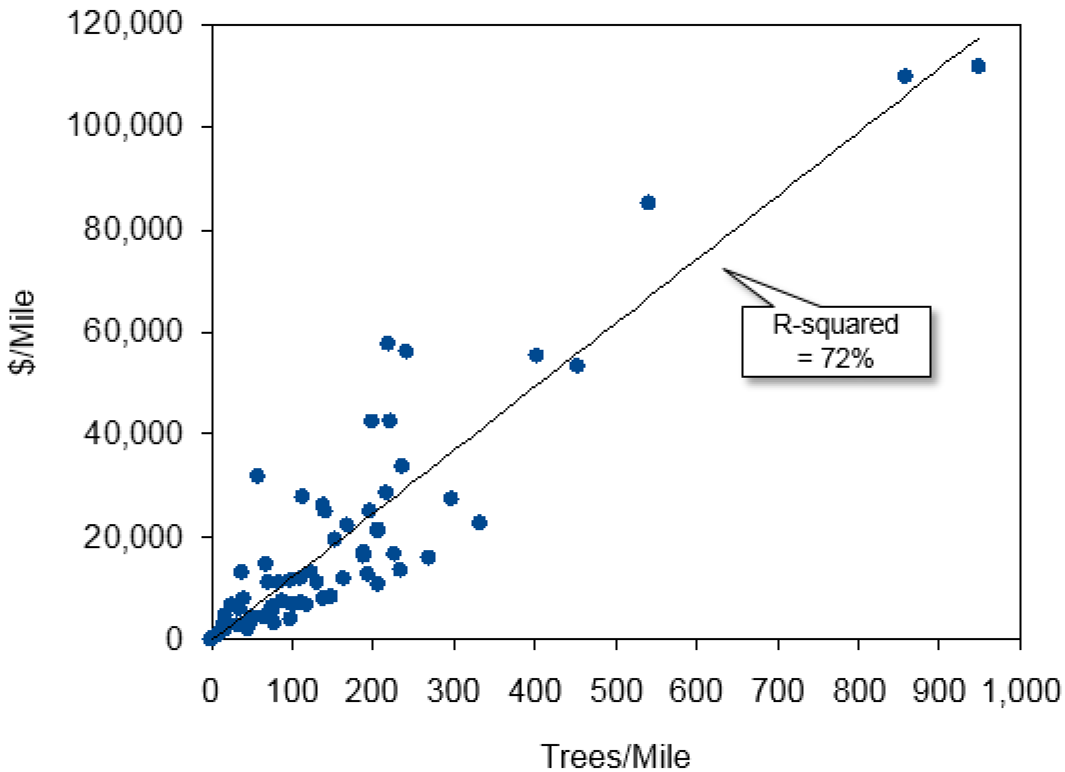
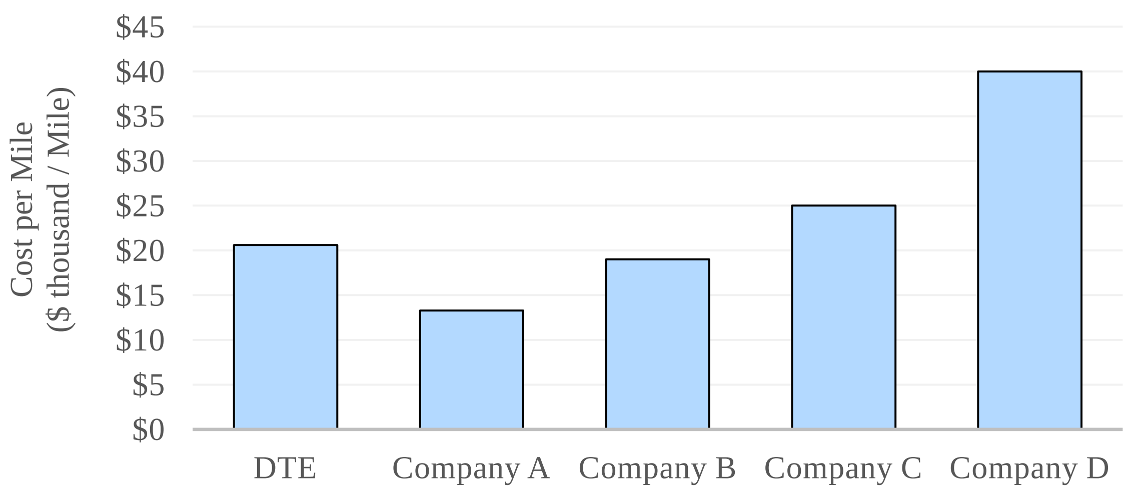


CHART 7 – Density as a Driver of Cost

Q. How does this estimate compare to the Company's benchmarks?

A. The Company has benchmarked with several companies. Some provided the Company with cost per line mile information that ranged from approximately $13,000-$40,000/mile as shown in Chart 8. Other companies stated that they perform the work on capital and do not track it on a per mile basis. In addition to speaking to other utilities, the Company also has been able to confirm the reasonableness of our estimates from consultation with ECI and through earned value calculations on each circuit (earned value was described earlier in the testimony).



	DTE	Company A	Company B	Company C	Company D
Density (trees/mile)	187	110	134	100	169

CHART 8 – Cost to Trim Backlog of Miles to ETTP

Q. Why are the costs forecasted to increase?

A. Cost forecasts are based on tree density, work location, and the type of work to be conducted. The Company expects to sustain the productivity and cost improvements

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that have been made to-date, but the Company expects upward pressure on costs as the circuits to be trimmed have higher tree density, more backlot work, and more climbing required as depicted in Tables 12 and 13.

Service Center	Miles Trimmed to ETTP	Miles of Backlog to ETTP	Avg. Tree Density (trees/mile)	Work Location (% Backlot)	Work Type (% Climbing)
Ann Arbor	787	1,283	212	60%	64%
Caniff	342	1,087	235	79%	69%
Howell	894	1,684	223	58%	64%
Lapeer	1,176	1,443	175	64%	67%
Marysville	1,195	1,609	126	51%	51%
Mt. Clemens	717	1,644	151	67%	66%
North Area	1,258	1,881	92	54%	56%
Newport	778	929	118	60%	66%
Pontiac	688	2,087	256	67%	73%
Redford	678	2,408	284	79%	81%
Shelby	394	861	159	63%	62%
Western Wayne	602	2,066	184	72%	76%
DC System	12,900	15,594	187	64%	66%

TABLE 12 – Miles Trimmed/To be Trimmed and Cost Drivers

	Weighted Avg. Tree Density (trees/mile)	Weighted Avg. Work Location (% Backlot)	Weighted Avg. Work Type (% Climbing)
Miles Trimmed to ETTP	174	62%	65%
Miles of Backlog	195	66%	68%
% Increase in Complexity	21	4%	3%

TABLE 13 – Increased Complexity

Q. Is the Company capable of spending the increased funding?

A. Yes. As shown in Table 14, the Company has spent more than the authorized tree trimming spend since 2016 and will be able to cost effectively complete the tree trimming required at the increased funding level.

Tree Trimming Spend ($ millions)			
	Authorized	Actual	Variance
2016	$65.7	$74.2	13%
2017	$75.2	$84.3	12%

TABLE 14 – Tree Trimming Authorized vs. Actual Spend

Funding Mechanism

Q. Can you please describe Exhibit A-22, Schedule L1, pages 1 and 2, "Projected Value of Tree Trim Program"?

A. These pages show the details of the calculation supporting the Projected Value of the Tree Trim Program through 2040. The page is broken up into four sections: Surge

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Program O&M Costs, Status Quo Program O&M Costs, Surge Program Capital Costs, and Status Quo Program Capital Costs. The first section depicts the tree-related O&M costs for the Surge Program. Line (2) depicts the cost to trim the miles needed to achieve a five-year cycle. Line (3) shows the cost of the continuation of the Herbicide Program and is equal to Line (14) as the Herbicide Program will be continued regardless of an approval of the Surge program. Lines (4), (8), and (9) depict the Tree Trim Reactive Maintenance, Tree Trim Storm, and Other DO Tree-Related O&M Costs, respectively. These costs are dependent upon the projected event reduction resulting from the surge in investment in the Tree Trim Program. Line (6) conveys the Credit to the Regulatory Asset. This is calculated by taking the Total Tree Trimming O&M Spend in Line (5) and subtracting Line (16), which is the inflation adjusted tree trimming spend for the Status Quo Program. The next section demonstrates the tree-related O&M costs for the Status Quo Program, which simply grows at the rate of inflation for Line (16). Lines (15), (17), and (18) are impacted by the Company’s ability to maintain limited overhead circuit miles on a five-year cycle. Because an inflation adjusted program does not provide adequate funding to achieve a five-year cycle on the entire system, the reactive, storm, and trouble costs escalate. Line (20) calculates the respective O&M savings of the Surge program as compared to the Status Quo. The third section conveys the Surge program capital costs. The costs shown in Lines (22), (23), and (24) are driven by events and the respective reduction in events expected upon investing in the tree trimming Surge. The fourth section represents the Status Quo Program capital costs. Line (27) conveys the amount of tree trimming charges when trimming in support of replacing an asset on a Blue Sky day, while Line (28) is for Storm spend only. Line (29) depicts

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the capital spent by the Service Operations organization as a result of tree-related events. Ultimately, the capital savings from investing in the tree trimming Surge program is shown on Line (31).

Q. What is the total forecasted cost of tree trimming from 2019 through 2025?

A. Tree trimming costs are expected to be approximately $1.13 Billion from 2019 to 2025.

Q. How much of the cost will be recovered through base rates?

A. $722 million is expected to be recovered through base rates from 2019 to 2025.

Q. How is the base rate cost recovery calculated?

A. The total amount requested for the projected test period ending on April 30, 2020 of $95.1 million is inflated at 3% per year.

Q. How much cost is the Company expecting to recover outside of base rates?

A. The Company is proposing to recover the surge cost of $410 million above base rates through an alternative mechanism. See Chart 9 for the costs details.

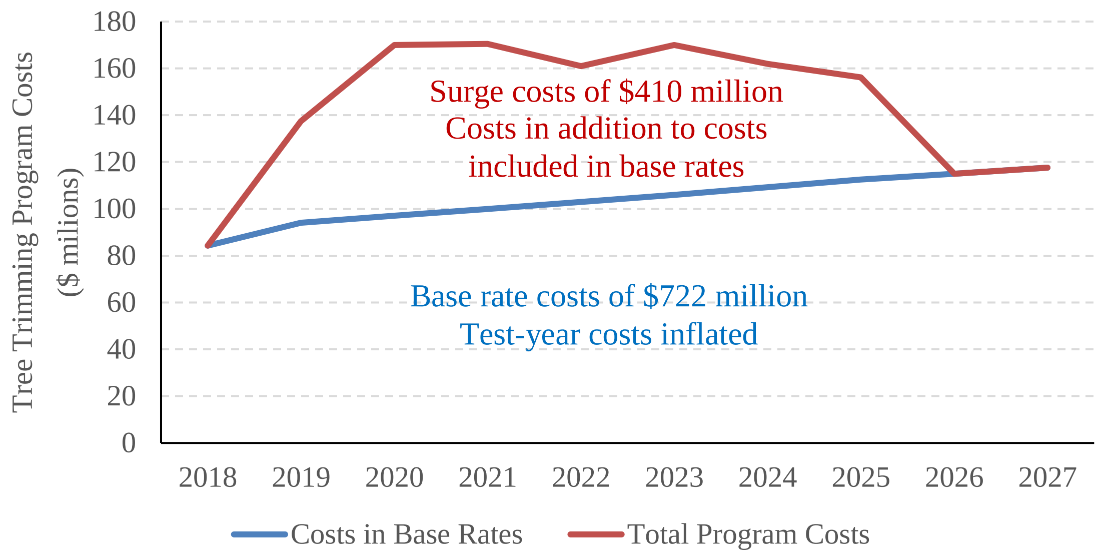

CHART 9 – Tree Trim Program Cost Components

Q. How does the Company expect to recover the program costs above base rates?

A. The Company proposes to defer the incremental cost above base rates of $410 million and amortize it over 14 years as described by Company Witness Uzenski.

Q. Why is the Company proposing to defer and amortize the costs?

A. As previously discussed, the surge investment is intended to lower future reactive costs that would be incurred given the current state of vegetation near or on the distribution system. The deferral recognizes the long-term nature of the program. As the costs are incurred up front and the full savings will not be realized until after the program has matured, the deferral of the incremental costs and subsequent amortization provide a better matching of costs with the anticipated savings, minimizing the cost impact to customers by aligning the increased cost with the

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realization of savings. Assuming securitization of the regulatory asset, amortization of the deferred costs over 14 years provides a larger net present value benefit to customers than shorter amortization periods and is consistent with the recommendation supported by Witness Solomon.

Q. Is the Company seeking to capitalize the Surge costs?

A. No. The Company is not seeking to capitalize the incremental costs of the Surge.

Q. Is the Company seeking the approval of regulatory asset treatment of the incremental tree trimming expense?

A. Yes. Company Witness Uzenski provides testimony regarding regulatory asset treatment.

Q. Will the Company seek to securitize the regulatory asset?

A. Yes. The Company will propose to securitize the regulatory asset in a future proceeding. Company Witness Solomon provides testimony regarding the securitization of the regulatory asset.

Q. How will the value to customers change if the requested regulatory approvals are not granted?

A. The incremental cost of the investment surge would be expensed immediately. This would result in a misalignment of program cost and savings, and a potential sharp increase in rates as program savings would occur after the expense has been incurred

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Resourcing the Surge

Q. Are sufficient resources available to execute the Surge trimming goals?

A. Yes. Approximately 1,300 tree trimmers are needed to execute the annual scope. Today, the Company employs approximately 850 tree trimmers through five tree trimming contract companies. Approximately 450 additional trimmers will be needed by 2022, and the Company has a plan to secure these resources as they are needed.

Q. How will the tree trimming work be resourced?

A. The Company will use a mix of local and non-local crews to conduct the work. The Company will not be able to achieve the plan through the utilization of local trimmers only, and will need to utilize qualified tree trimming crews from outside of our service territory, especially as the program is ramped up and as local recruitment efforts take hold. The primary long-term plan is to achieve an adequate level of qualified local workers.

Q. What is the Company's plan to secure additional local tree trimmers?

A. The Company has partnered with its tree trimming contractors and IBEW Local 17 to develop and implement a training program to satisfy the demand for qualified tree trimmers. First, new recruits must complete a nine-day boot camp. The boot camp gives participants intensive training and hands-on work experience on subjects such as safety, climbing systems, climbing techniques, arborist equipment, arborist tools, commercial vehicle operation, tree species identification, communication with line crews, customer relations, and aerial rescue techniques. Second, boot camp graduates

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enter the Line Clearance Tree Trimming Apprentice Program. The 5,000-hour apprenticeship program, which includes 160 hours of classroom training, is recognized by the Department of Labor as an approved apprenticeship program and is benchmarked throughout the industry. Additionally, continuous education training is required every two years for tree trimmers who have graduated to journeyman status.

Q. What efforts is the Company undertaking to recruit local talent?

A. The Company is partnering with Local 17 and its contractors and reaching out to local high schools such as the Randolph Technical High School to introduce the tree trimming trade to interested candidates. Additionally, the Company recently engaged the Vocational Village at Parnall Correctional Facility in Jackson to develop a pre-apprentice program that will allow returning citizens to enter directly into the apprenticeship program upon leaving the correctional facility.

<u>Herbicide Program</u>

Q. What is the herbicide program?

A. The Company intends to expand the use of EPA-regulated herbicides to replace mechanical removal of vegetation from the right-of-way with a chemical treatment which will only control the tree species with the potential to grow into electrical wires. The Company has based the program off industry best practices that were collected and developed through benchmarking and by working with an outside consultant – ECI.

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Q. Does the Company currently use herbicides?

A. The Company currently uses herbicides to treat the stumps that remain after the trees are removed from the right-of-way to prevent regrowth. Herbicides for the cut stump treatment are applied immediately after cutting the tree, killing the stump and preventing new growth.

Q. How will the Company alter its herbicide program?

A. The Company will expand the use of herbicides by implementing foliar herbicide treatment, basal herbicide treatment, and dormant stem treatment. These treatments target tree species that pose a risk to the electrical equipment.

Q. Please describe foliar treatments?

A. Foliar herbicide treatment is applied on brush. The herbicide is sprayed on the leaves of the brush using manual or mechanical sprayers. Foliar treatment is intended to prevent growth of brush and the regrowth of brush that was mechanically removed or trimmed during a maintenance cycle. A foliar treatment is typically applied one to two years after trimming and the treatment must be repeated every three to four years to remain effective.

Q. Please describe basal treatments?

A. Basal treatment is applied to established trees to avoid having to mechanically remove them. It is applied on small trees in areas where their fall will not present a hazard to the public, customer property, or electrical equipment. The herbicide is sprayed on the trees' bark using manual sprayers. The herbicide is applied one to

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two years before trimming. Consequently, the treated trees will die and will not need to be removed when the area is trimmed. The treatment will be repeated one to two years prior to the next trimming cycle.

Q. Please describe dormant stem treatments?

A. Dormant stem herbicide treatments are similar to foliar herbicide treatment, being applied on brush using manual or mechanical applicators. Unlike the foliar treatment, the targeted vegetation doesn't need to be in an active growing state to be controlled by the applied herbicides. This treatment is suitable to be used in the cold season, from fall to early spring. The targeted vegetation will gradually die and will not have to be removed when the area is trimmed. As with the foliar treatment, dormant stem treatment is typically applied one to two years after trimming and the treatment must be repeated every three to four years to remain effective.

Q. How much will the herbicide program cost?

A. The Company intends to spend $2 million on its herbicide program in the projected test year. The current cost of the cut stump treatment is included within the cost of maintaining circuits as the resources used to remove a tree simply apply the herbicide as part of the current tree removal process.

Q. How many miles will the company treat with herbicide in the projected test year ending April 30, 2020?

A. The Company intends to treat with herbicides a surface equivalent to approximately 200 miles distributed over the approximately 3,300 miles that were trimmed in 2016.

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Q. What are the benefits of the herbicide program?

A. The herbicide treatment will reduce the cost of maintenance trimming in the right-of-way by reducing tree density. Chart 10 shows herbicide effectiveness to decrease brush density – as brush grows into trees, a lower brush density results into a lower tree density, which is the main driver of tree trimming costs. There are other advantages besides realizing cost savings. As tree density and brush height decreases, the electrical system becomes more reliable and the right-of-way becomes more accessible and safer.

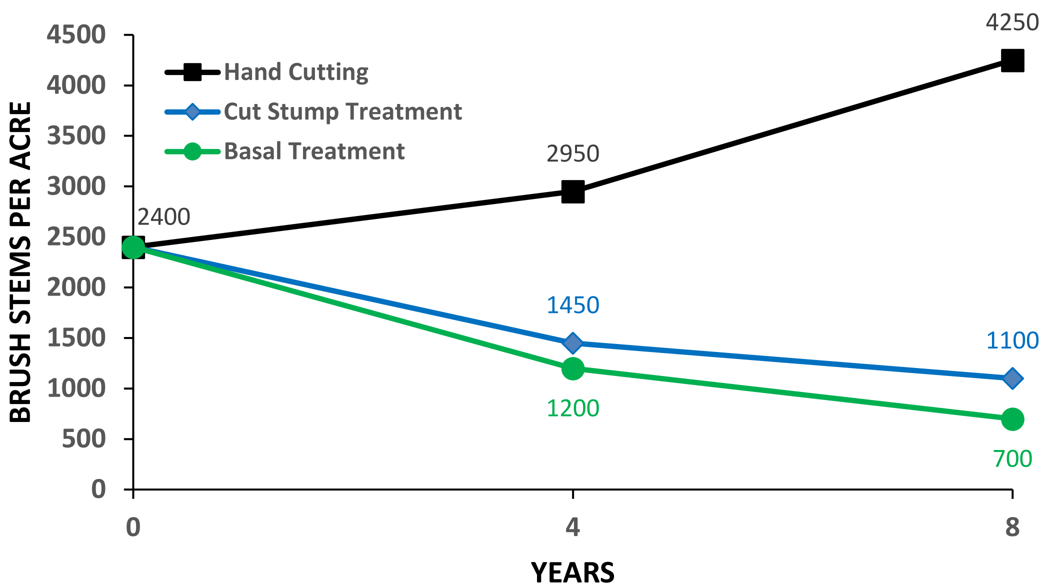

CHART 10 – Effectiveness of Herbicides for Control of Brush Over Time

Q. When does the Company expect to benefit from the herbicide program?

A. The Company expects to realize cost savings on the subsequent cycle of trimming. Foliar treatment benefits are realized three years after application for a five-year trimming cycle. Basal treatment cost benefits are realized two years after application.

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The Company expects the herbicide treatment will reduce the overall trimming costs by 3%, and the Company included those savings in the projected cost of the Surge program.

Q. Are there any additional benefits to treating the right-of-way with herbicides?

A. Yes. Because grasses and shrubs are not affected by the herbicide treatment, the area will become a habitat for pollinators, birds, and small mammals. The treatment will also target invasive plant species, limiting their spread.

Measuring Progress

Q. How will the Company evaluate the results of the tree trimming Surge?

A. The Company will provide an annual report detailing the circuit performance. Additionally, the Company proposes to submit a Tree Trimming Effectiveness Report in 2022 to the Commission.

Q. How will circuit performance be measured in this annual report?

A. The Company will provide an annual report detailing the outage and non-outage events for the average of the three-years prior to the study period compared to the year after trimming for distribution circuits trimmed as part of the ETTP and those not trimmed.

Q. How will the Company evaluate the results of the tree trimming Surge in 2022?

A. The Tree Trimming Effectiveness Report, which will be filed in 2022, will provide an overview of the Surge and the benefits customers have received. This evaluation

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will be based upon data from five years of trimming circuits as part of the ETTP in 2016 through 2020, as shown in Table 15. This will provide five years of historical circuit performance on the ETTP compared to the remainder of the system.

<table>
<tr><th>2013</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th></tr>
<tr><td colspan="3">Three-year Average Pre-trim Performance</td><td>Year of Trim</td><td>Post Trim Year 1</td><td>Post Trim Year 2</td><td>Post Trim Year 3</td><td>Post Trim Year 4</td><td>Post Trim Year 5</td><td rowspan="5">ETTP Effectiveness Report</td></tr>
<tr><td></td><td colspan="3">Three-year Average Pre-trim Performance</td><td>Year of Trim</td><td>Post Trim Year 1</td><td>Post Trim Year 2</td><td>Post Trim Year 3</td><td>Post Trim Year 4</td></tr>
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<tr><td></td><td></td><td></td><td colspan="3">Three-year Average Pre-trim Performance</td><td>Year of Trim</td><td>Post Trim Year 1</td><td>Post Trim Year 2</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="3">Three-year Average Pre-trim Performance</td><td>Year of Trim</td><td>Post Trim Year 1</td></tr>
</table>

TABLE 15 – Illustrative Data Detail for Effectiveness Report

<u>Conclusion</u>

Q. Do you recommend this investment the tree trimming program?

A. Yes. The tree trimming program is the most impactful and important program in the Company's long-term investment strategy. The program will significantly decrease system risk (specifically reduced wire downs), increase reliability (fewer and shorter outages), and decrease reactive trouble costs. The tree trimming program as proposed is required to provide safe, reliable and affordable electricity to the Company's customers. Without the incremental Surge investment, the distribution system will continue to degrade, resulting in higher risks and lower reliability. The

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Company believes this program is right for our customers. The Company is requesting the regulatory asset treatment of the Surge costs with the intention to securitizing the regulatory asset in order to execute the program in a way that makes it affordable for customers.

Q. In your opinion, are these expenses reasonable?

A. Yes, they are. I base my opinion on analysis of past expenses, and the projected requirements for labor and materials to conduct the necessary tree trimming.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

CAMILO SERNA

DTE ELECTRIC COMPANY
QUALIFICATIONS OF CAMILO SERNA

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Q. Please state your name, title, business address, and by whom you are employed.

A. Camilo Serna, Vice President of Corporate Strategy, One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE or the Company).

Q. What is your education background?

A. I received an Industrial Engineering degree from Universidad de Los Andes in Bogotá, Colombia in 1995. In addition, I received a Master of Business Administration from Kellogg School of Management at Northwestern University in 1999.

Q. What work experience do you have?

A. I joined DTE Energy as Vice President of Corporate Strategy in 2016. In this role, I develop and implement key strategic initiatives including the execution of the annual strategic planning process. Prior to joining DTE Energy, I was with Eversource Energy for eight years, most recently as the Vice President of Strategic Planning and Policy. Eversource Energy is the leading utility in New England and services Connecticut, Massachusetts, and New Hampshire. In this role, I led efforts to understand market, technology, customer, and policy trends to identify strategic issues. Prior to joining Eversource in 2008, I was a leader in Oliver Wyman's Energy & Utilities management consulting practice, helping utility and energy companies in Europe, Latin America, and North America with a wide array of strategic and

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operational challenges.

Q. Have you ever previously provided testimony?

A. Yes, I sponsored the following testimony in Connecticut:

- Docket #13-06-02, 2013, Yankee Gas for proposed natural gas expansion plans to comply with Connecticut's comprehensive energy strategy.

I have also sponsored the following testimony in Massachusetts:

- Docket #16-105, 2016, NSTAR Electric Company d/b/a Eversource Energy for approval of a request to own, construct and operate solar facilities.

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Q. What is the purpose of your testimony?

A. My testimony has two components: transportation electrification and distributed generation tariff.

With respect to transportation electrification, the purpose of my testimony is to:

1. Provide an overview of transportation electrification in Michigan;
2. Discuss the importance of the utility's role in transportation electrification;
3. Provide details on the Company's proposed electric vehicle (EV) program (Charging Forward) and its three primary components: (1) Customer Education and Outreach; (2) Residential Smart Charger Support; and (3) Charging Infrastructure Enablement;
4. Discuss Charging Forward's cost estimates and approach for cost recovery;
5. Explain the benefits supporting cost recovery from a utility customer perspective; and
6. Highlight DTE Electric's approach to EV program evaluation moving forward.

With respect to the distributed generation tariff, the purpose of my testimony is to:

1. Describe the statutory and regulatory framework for the Company's new distributed generation tariff under Public Acts 341 and 342;
2. Describe the role of the grid supporting distributed generation customers;
3. Highlight the need to follow cost of service principles for a new distributed generation tariff;
4. Provide details on the overall structure of the filed new distributed generation tariff and the key components of the Company's filed tariff, including:
    a. Overview and structure of the tariff mechanism
    b. Cost-based volumetric inflow pricing

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c. Cost-based System Access Contribution

d. Cost-based outflow credit compensation

e. Technical and administrative implementation

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.9	Charging Forward Cost Details
A-16	F11	Distributed Generation Maximum Hourly Average Peak
A-27	Q1	Letters of Support for the Charging Forward program

Q. Were the exhibits prepared by you or under your direction?

A. Exhibits A-12 and A-16 were prepared under my direction, and Exhibit A-27 are expressions of support from interested stakeholders.

Transportation Electrification

Q. What are the key categories of transportation electrification?

A. The key categories of transportation electrification include on-road transportation (e.g., light-, medium-, and heavy-duty vehicles) and off-road transportation (e.g., forklifts, airport ground support equipment, seaport equipment, etc.). The Charging Forward program focuses on the advancement of on-road transportation electrification.

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Q. What do you define as an EV?

A. For the purposes of this testimony, EVs include all-battery EVs (BEVs)[1] and plug-in hybrid EVs (PHEVs).[2]

Q. What are the dynamics for EVs in today's market?

A. Improvements in lithium-ion battery technology have helped cut production costs and increase the range on EV models. Additionally, in response to global policies regarding internal combustion engine (ICE) vehicles, automakers are investing heavily in the development of new EV models. Examples of recent announcements as of May 2018 according to Bloomberg New Energy Finance (BNEF) include:[3]

- BMW — 47 EV models by 2025
- Daimler — 10 EV models by 2022
- Ford — 28 EV models by 2022
- General Motors — 20 EV models by 2023
- Hyundai-Kia — 23 EV models by 2025
- Renault-Nissan-Mitsubishi — 12 EV models by 2022
- Toyota — 10 EV models by early 2020s
- VW Group — 80 EV models by 2025

Q. What are the national trends in terms of EV adoption?

A. Approximately 800,000 EVs have been sold in the United States (US) and ~200,000 of those were sold last year.[4] 2017 EV sales grew ~23% over 2016 EV sales, despite

[1] Battery Electric Vehicles (BEVs) use only electricity stored in a battery pack to power an electric motor
[2] Plug-in Hybrid Vehicles (PHEVs) are like BEVs but also have an internal combustion engine fueled by gasoline, which can power the vehicle
[3] "Long Term Electric Vehicle Outlook 2018" - Bloomberg New Energy Finance
[4] Bloomberg New Energy Finance, https://insideevs.com/monthly-plug-in-sales-scorecard/

the US auto industry's overall sales dropping by ~2% in the same period.[5] In fact, US EV monthly sales have risen year-over-year for 31 consecutive months,[6] and adoption forecasts continue to be adjusted upwards. Currently, BNEF forecasts EVs to be approximately one-third of new light-duty vehicle sales by 2030 and almost two-thirds of new vehicle sales by 2040 as shown in the table below:[7]

Year	2017	2025	2030	2040
Approximate Percent of New Sales	1%	7%	35%	64%

This rapid adoption is anticipated due to lower EV prices in combination with converging trends of autonomy and shared mobility, which will likely have an electric future. PHEV sales are expected to play an important role in EV adoption from now to 2025, but the engineering complexity and dual powertrains of PHEVs make BEVs likely to be more attractive in the long-run. Therefore, BNEF predicts BEVs will take over and account for most EV sales after 2025.

Q. How many EVs are currently registered in Michigan and the Company's territory?

A. As of February 2018, there were 15,300 EVs sold in Michigan, and DTE estimates that ~70% of them (or ~10,500) are in the Company's electric service territory.[8]

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[5] Bloomberg New Energy Finance, https://www.usatoday.com/story/money/cars/2018/01/03/u-s-auto-sales-record-streak-likely-snapped-2017/999182001/
[6] https://insideevs.com/monthly-plug-in-sales-scorecard/
[7] "Long Term Electric Vehicle Outlook 2018" - Bloomberg New Energy Finance, "Plug-in Electric Vehicle Sales Forecast Through 2025 and the Charging Infrastructure Required" Edison Electric Institute
[8] https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

Q. How does this compare to other states?

A. As of December 2017, Michigan ranked 10th in the nation for EV volume and 16th in the nation for EVs per Capita as shown in the table below:[9]

Geographic Area	2016 Census	EV Volume	Rank - EV Volume	EV per Capita	Rank - EV per Capita
California	39,250,017	369,626	1	0.94%	1
New York	19,745,289	32,082	2	0.16%	15
Washington	7,288,000	29,989	3	0.41%	3
Georgia	10,310,371	28,444	4	0.28%	6
Florida	20,612,439	27,870	5	0.14%	20
Texas	27,862,596	23,781	6	0.09%	28
New Jersey	8,944,469	17,576	7	0.20%	12
Oregon	4,093,465	16,044	8	0.39%	5
Illinois	12,801,539	15,643	9	0.12%	24
Michigan	**9,928,300**	**15,300**	**10**	**0.15%**	**16**
Massachusetts	6,811,779	14,462	11	0.21%	10
Colorado	5,540,545	13,263	12	0.24%	8
Maryland	6,016,447	12,186	14	0.20%	11
Arizona	6,931,071	11,432	15	0.16%	14
Connecticut	3,576,452	7,826	19	0.22%	9
Hawaii	1,428,557	7,560	20	0.53%	2
Vermont	624,594	2,566	28	0.41%	4
New Hampshire	1,334,795	2,353	30	0.18%	13
District of Columbia	681,170	1,660	36	0.24%	7

[9] https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

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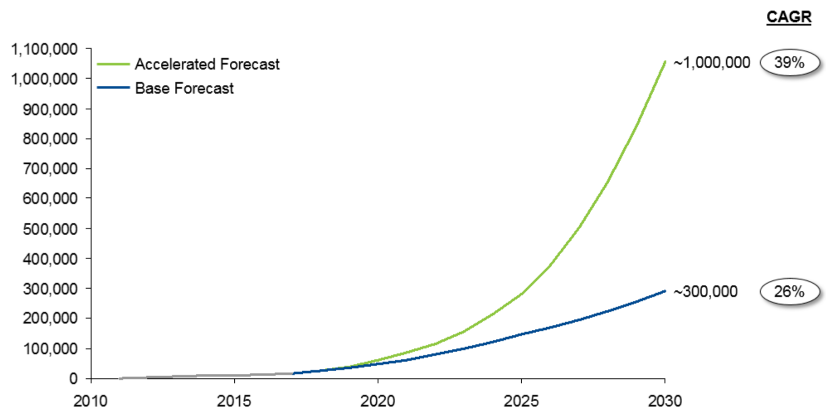
Q. What is the future demand for EVs in Michigan?

A. DTE applied two industry expert national forecasts to Michigan's current EV volume to create two adoption scenarios for the state (Base Forecast and Accelerated Forecast) as shown in the graph below:[10]



Q. What are the key elements that will determine future EV penetration?

A. Key elements impacting EV penetration in the future include:

- The upfront purchase price compared to a similar ICE vehicle. Price parity will help to grow EV adoption;
- The availability and range of EV models. More available EV models and longer electric ranges will help to increase EV penetration;
- Awareness of available EVs, their operation and features, and their lifetime economic and environmental benefits. Greater EV awareness among potential buyers will help to improve EV sales; and
- Availability of public charging infrastructure along corridors and within communities. More public charging infrastructure availability will help to increase EV adoption.

[10] "Long Term Electric Vehicle Outlook 2018" - Bloomberg New Energy Finance, "Plug-in Electric Vehicle Sales Forecast Through 2025 and the Charging Infrastructure Required" Edison Electric Institute

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Q. What trends do you see in terms of reducing the purchase price of an EV?

A. The upfront EV purchase price is largely determined by lithium-ion battery costs, which have fallen ~80% since 2011 and are expected to drop another ~50% by 2025. Because of this, EVs are expected to reach upfront price parity with their traditional gasoline counterparts in the mid-2020s.[11]

Q. What do you see in terms of EV availability and range?

A. As I have already noted, there are numerous new EV models coming to market in the next few years. Due to increased density of lithium-ion batteries, the average range of BEVs is expected to grow from ~150 miles in 2017 to ~200 miles in 2021[12] and available EV model sizes will also increase. Almost 50% of EV model launches are in the sport utility vehicle (SUV) category, significantly increasing the availability of EV models across vehicle segments.[13] In combination with declining costs, DTE believes these factors will likely accelerate demand for EVs in Michigan in the coming years.

Q. What is the customer education and awareness challenge?

A. At the Michigan EV Convening by Michigan Energy Innovation Business Council in March, several EV educational challenges were identified, including lack of familiarity of available EV models, unfounded fears about EV performance, confusion around EV policies and incentives, and misconceptions about operational savings. With the onset of longer-range, more affordable EVs coming to market,

[11] "When Will Electric Vehicles Be Cheaper Than Conventional Vehicles" - Bloomberg New Energy Finance
[12] "What are the most effective incentives / triggers for increasing electric vehicle sales?" - Electric Power Research Institute
[13] "Automotive Manufacturers' Electrification Strategies" - Bloomberg New Energy Finance

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successful adoption of these models will be dependent on awareness of their operation, features, and lifetime benefits. However, per a 2016 survey, ~60% of consumers felt they did not know enough about EVs to be able to purchase one.[14] In addition, per a 2017 survey, ~70% of respondents could not even correctly name an EV model.[15] In-person exposure to EVs is another contributing factor to a consumer's purchasing decision, but in Michigan, only ~15% of residents have ever driven or been in an EV.[16] Because of that, there could be significant latent demand existing in the market today that cannot be realized without a concerted EV education and awareness campaign.

Q. What charging infrastructure exists today in Michigan?

A. Charging infrastructure can be grouped into 3 primary categories:

1) Level 1 (L1) - 120-volt, alternating current (AC) power. Most EVs come equipped with an L1 cord set, and drivers can typically plug into a standard 120-V, 3-prong outlet. L1 chargers provide about 2 to 5 miles of electric range per hour of charging, so they are most useful in long-duration / overnight settings (e.g., single family home, multi-unit dwellings, hotels, and airports). For EVs with longer ranges, L1 is not able to provide a full charge overnight. Given the ubiquitous nature of 120-V, 3 prong outlets, there is currently no publicly available estimate of how many L1 outlets are used by EVs in Michigan.

2) Level 2 (L2) - 240-volt, AC power. L2 chargers are typically mounted on a wall or pedestal and provide about 10 to 20 miles of electric range per hour of charging (depending on the EV charging capability and power supplying the L2).

[14] AltmanVilandrie&Company Connected Cars Survey, 2016, n=2,557
[15] Ken Kurani, UC Davis (via Enervee)
[16] PEV Consumer Survey, Michigan, Navigant 2017

As battery capacity continues to increase, L2s are preferred over L1s to enable faster overnight charging. They are also useful in public, commercial locations for "topping off" (e.g., at restaurants, movie theaters, shopping centers, entertainment venues, etc.), even for the longer-range EVs. L2 chargers can have 2 ports which can be used simultaneously by EV drivers. There are currently ~700 public L2 ports in Michigan.[17]

3) Direct Current Fast Charger (DCFC) – DCFCs convert AC to DC and deliver a charge to the vehicle at higher power. DCFCs provide about 150 to 210 miles of range per hour of charging and can be used with most BEVs but not with most PHEVs. They are most useful along highway corridors and in urban, short-term parking locations. Where available, DCFC stations enable BEVs to be operated more like an ICE vehicle. The current standard for DCFC is 50 kilowatts (kW), but 150 kW charging standards are in progress and near completion. Chargers powered as high as 400 kW are also in development. DCFC ports are either the Society of Automotive Engineers (SAE) standard Combined Charging System (CCS, used by American and European EV models), CHAdeMO (used by Japanese models), or Tesla Superchargers. "Dual-port" DCFC chargers are typically referring to those with both CCS and CHAdeMO ports, but only one of the ports can be used at a time. There are currently 11 public dual-port DCFC chargers in Michigan.[18]

[17] Alternative Fuels Data Center as of 5/24/18 (excluding Tesla and dealerships)
[18] Alternative Fuels Data Center as of 5/24/18

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Q. What is the status of infrastructure deployment in DTE's electric service territory?

A. In the Michigan Public Service Commission (MPSC) Order U-18368 dated October 25, 2017 summarizing the August 2017 technical conference, it is stated that the automotive panel "expressed a need to work together to mitigate range anxiety by constructing additional charging stations […]. The automakers stressed that the lack of charging stations has been an impediment to increased EV adoption and urgently called for a solution. They provided a summary of their fundamental decision that charging infrastructure should not be borne in the cost of the vehicle, but needs to be funded and constructed by other entities." A broad group of stakeholders[19] filed comments U-18368 on November 17, 2017 (joint comments) stating "the private investment committed to deploy charging equipment and services in Michigan is not enough to close the infrastructure gap across the state (especially in underserved markets including multi-unit dwellings), so public and utility investments should be utilized to complement private funding sources to establish a foundational charging infrastructure in Michigan." It is likely too early to define a precise ratio, but Electric Power Research Institute (EPRI) and National Renewable Energy Laboratory (NREL) released reports with recommendations for public charging infrastructure based on volume of EVs. Although the amount of charging infrastructure needed to support EV adoption varies by source, both reports suggest there is still much investment needed, assuming ~10,500 EVs in DTE's electric service territory today as shown in the table below:

[19] Joint Comments of DTE Electric Company, Actia, Advanced Energy Economy, The Alliance for Transportation Electrification, Clean Fuels Michigan, Consumers Energy Company, The Ecology Center, Edison Electric Institute, Ford Motor Company, General Motors, Greenlots, Michigan Electric and Gas

	Public L2 Ports	Public DCFC Chargers
EPRI Recommendation[20]	~3,600	~55
NREL 2016 Recommendation[21]	~2,300	~5
NREL 2017 Recommendation[22]	~800	~45
Actual in DTE Electric Territory[23]	416	11
Average Gap Today	**~1,800**	**~25**

The "actual" stations today are being deployed on an ad-hoc basis without a coordinated effort or agency. In addition, the non-Tesla DCFC stations currently in Michigan offer no redundancy, meaning there is only one charger available at a site. If the charger is already in-use or not functioning properly, then an EV driver will be unable to charge. Not only is this inconvenient, but it leaves the customer with a negative experience and lower confidence in EV technology. Finally, the gap between actual and recommended charging infrastructure will only compound as adoption continues to grow at an increased rate, since the charger recommendations are on a per EV-basis.

Q. Why is a robust charging network needed for increased EV adoption?

A. Consumers need to feel confident that fueling options are available to them to consider purchasing an EV. For example, 27% of survey responders felt they knew enough about EVs, but they still would not buy one, citing a lack of charging stations as the primary factor in their decision.[24] DCFCs are critical to reduce range anxiety

Association, Michigan Energy Innovation Business Council, Michigan Environmental Council, Michigan League of Conservation Voters, Natural Resources Defense Council, Phoenix Contact, Siemens, and Sierra Club

[20] https://www.epri.com/#/pages/product/000000003002004096/
[21] http://www.nrel.gov/docs/fy17osti/66980.pdf
[22] https://www.nrel.gov/docs/fy17osti/69031.pdf
[23] Alternative Fuels Data Center as of 5/24/18 (excluding Tesla and dealerships)
[24] AltmanVilandrie&Company Connected Cars Survey, 2016, n=2,557

and make EVs viable for consumers with long-distance road trips or without access to chargers overnight. 65% of potential EV owners indicated they would be significantly more attracted to a BEV model if they had access to a nationwide network of fast chargers.[25] Similarly, Level 2 charging is important for "topping off" and increasing the electric vehicle miles traveled (eVMT). Therefore, without a robust Level 2 and DCFC network to give consumers the confidence they need, EV adoption could remain low. Low EV adoption discourages charging station deployment due to the capital investment required from EV charging station owner-operators (site hosts), so the problem is perpetuated.

Utility's Role in the Electrification of the Transportation Sector

Q. Why is the overall electrification of the transportation sector beneficial to DTE's customers?

A. The electrification of the transportation sector promises significant benefits to the energy grid, its customers, and the public at large. Individual customers that switch from ICE vehicles can save ~$630 per year on fuel and maintenance.[26] The environment can benefit by reducing carbon emissions by ~45-60% today and ~10% more by 2030 as DTE shifts its generation portfolio toward low and no carbon sources.[27] Transportation electrification can also improve particulate matter air pollution, particularly in Southeast Michigan. For example, the Detroit-Warren-Ann Arbor region is ranked 14th highest in the country for annual particle pollution out of 187 metropolitan areas.[28] EVs also present an important element of economic

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[25] CleanTechnica Survey, 2015, n=1,198
[26] http://www.umich.edu/~umtriswt/PDF/SWT-2018-1_Abstract_English.pdf
[27] https://www.afdc.energy.gov/vehicles/electric_emissions.php; assuming coal retirements and renewables generation are on track, is replaced with gas
[28] http://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/msas/detroit-warren-ann-arbor-mi.html#pmann

development opportunity in Southeast Michigan given the significant presence of automakers and their suppliers. In addition, a transition to electricity as a “fuel” can provide the United States with greater energy independence since an EV displaces ~500 gallons of fossil fuel annually.[29] Finally, the broad utility customer base can benefit from the additional load added to the system if it does not trigger significant utility infrastructure investments. Since EV load is a relatively flexible load, there is an opportunity to implement managed charging programs like demand response (DR) in the future to further balance generation needs during critical peak times. While the load is relatively small, the utility can learn about consumer charging behavior, charging station utilization, and impact on the distribution system to effectively and efficiently integrate the load at greater levels of adoption in a reasonable and efficient manner that benefits the distribution system.

Q. Can you explain, in more detail, how growth in EV sales can help all utility customers?

A. Currently, most EV charging takes place overnight at home, effectively utilizing distribution and generation capacity during low load periods. It is from this improved load factor that utility customers would benefit; increased EV adoption puts downward pressure on rates by spreading utility fixed costs over a greater volume of sales. In an era of flat or declining electric sales growth, this increased load from electric transportation provides affordability benefits to the utility customer base. Details of the expected affordability benefits EV sales provide toward DTE Electric’s generation and distribution system fixed costs are explained further in the “Program Benefits and Evaluation” section below.

[29] Assuming an average gas mileage of ~24 miles per gallon for different car segments

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Another benefit of overnight charging is integration with renewable resources: Pacific Northwest National Laboratory found that EVs charging at night will increase renewable wind use, when average wind generation is highest for those areas with high wind penetration.[30] Lastly, given that EVs are intelligent storage assets, the electrification of transportation will continue to build a significant resource for distribution services over time. For example, in the long-run, EVs may provide additional DR services and assist with the integration of renewable energy resources by optimizing customer charging patterns during periods of low demand or high renewable generation.

Q. What are the key roles for utility involvement?

A. DTE believes there are three key roles for utility involvement in the EV space:

1) Grid integration and interaction: Utilities, like DTE, need to integrate EV infrastructure in a manner that mediates system capabilities, costs, and future growth while maximizing system benefits;
2) Education and awareness: Electric companies can leverage established customer relationships to develop an informed market and grow customer confidence in EV technology; and
3) Charging infrastructure: Accelerating the deployment of infrastructure is necessary to enable increased adoption of EVs and produce system benefits, so it is critical to appropriately leverage multiple funding sources, inclusive of utility investment, in a manner that complements a robust EV charging market.

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[30] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-20501.pdf

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Q. How do EVs interact with the distribution system?

A. EV load today is small compared to overall load, and it is unique in that it can be managed to shift to off-peak periods with minimal impact to the driver. Time-of-use (TOU) rates and DR programs have proven to mitigate EV load during peak demand periods because of the programming capabilities of both EVs and chargers. In California, with more than 200,000 EVs on the road as of December 2016, the costs associated with integrating the EV load have been very low (less than 0.2% of EVs have required a service line and / or distribution system upgrade).[31] However, the immediate demand of a single EV can be comparable to that of an entire home, which can result in distribution system impacts if not properly managed.

Q. What has DTE done to better understand EV load?

A. Based on a study DTE performed in 2011, when EV charging occurs off-peak, it would take ~25% EV penetration before any of DTE's current distribution system would see disturbances. Even then, less than ~5% of transformers would be overloaded. Although this study is outdated since it assumes much lower charging rates than what is currently available today, the Company believes it is still directionally correct. As EV adoption continues to grow, the Company will consider updating this study. Current efforts to better understand EV load include DTE's Energy Forecasting group attending EV industry conferences and meetings in addition to interacting with the Electric Marketing group to understand key market trends and adjust the residential load forecast as applicable. Additionally, the Distribution Operations group is working to develop equipment standards for charging infrastructure to facilitate the process of installation.

[31] From California's Joint IOU Electric Vehicle Load Research Report filed on 12/30/2016

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Q. What has DTE done to manage vehicle charging?

A. DTE has offered an EV TOU rate since 2010, with reduced, off-peak charging rates available between 11 pm and 9 am. The Company's analysis has found that customers on the flat fee option[32] charge during on-peak hours ~75% of the time versus ~30% of the time for those on the TOU option. Thus, the Company has concluded that the optional EV TOU rate properly incentivizes behavior and shifts EV charging to off-peak hours. Because enrollment in the EV TOU rate is hindered by the requirement of a second meter, the Company's Electric Marketing team also promotes the whole-home TOU rate as an EV-friendly option for customers.

Q. What has been DTE's experience with EV charging infrastructure and what does the Company plan to do in the near future?

A. To boost enrollment in the Company's experimental EV TOU rate approved in 2010 and learn more about residential charging behavior, an incentive program of $2,500 was offered to offset the purchase and installation costs of a Level 2 charging station. From 2011 to 2014, DTE received over 2,700 applications and fully subscribed the program by installing over 2,400 Level 2 residential chargers. In addition, the Company has supported the installation of non-residential EV charging infrastructure in DTE's electric service territory to date. Currently, the Company is also in the process of developing and installing three DCFC stations in Southeast Michigan in 2018 to gain expertise and learn more about the market. These three DCFC pilots include an Ann Arbor charging showcase in Kerrytown, a downtown Detroit charging showcase in Capitol Park, and a highway corridor station powered by battery storage.

[32] The monthly flat fee is $46.28 per month regardless of usage and limited to 250 customers

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Q. What technical elements does DTE plan to test / pilot and what are the targeted learnings from its proposed program?

A. The series of pilots that DTE launched in 2018 will be complemented by the proposed program. The combination of the pilots and the program will provide DTE a series of additional technical learnings that will inform future activities. A brief description of the key technical tests and learnings to be gathered from the pilots and program are as follows:

- Extreme fast charging: DTE is supporting Delta Electronics in their DOE grant award to test and develop extreme fast charging up to 400 kW. Being involved in this project provides the opportunity for DTE to evaluate the impact to a distribution circuit when a high-powered charger cycles on and off, including loading, voltage, harmonic, and power quality concerns. It will also allow DTE to evaluate the effect of different charging ramp rates and how these can be adjusted to mitigate power quality metrics. The results from these technical evaluations will ultimately enable the Company to quantify the potential characteristics of a charger installation on various circuits and develop the necessary planning standards to support it;
- DR: DTE is currently discussing possible DR pilot options with Ford to better understand the potential value of delayed and interrupted charging and the most practical applications. More specifically, the Company is looking to test customer interest in DR programs through curtailment of the vehicle and direct acceptance (or override) of a control signal. By messaging directly to customers via the MyFord app in DR events, DTE can get actual consumer level data on load and participation before, during, and after events. Additional insights will be derived from the charging profiles of the participants and their vehicles to

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determine the appropriate rate design and incentive for participation in a long-term program; and

- Battery storage: DTE is planning to install a corridor fast charging station powered by battery storage within the next year. This will allow the company to analyze fast charging discharge and low power recharge to determine long-term impacts on both the battery and chargers. The results of this pilot will enable the Company to discern where it makes economic and technological sense to deploy battery storage versus distribution upgrades to support charging infrastructure deployment. Furthermore, it will give us the analytical capability to determine the battery size required to support a given charging demand.

All of these learnings will directly support the implementation of the larger EV program, Charging Forward, in the following ways:

- It will ultimately supply additional data points to refine and confirm initial engineering standards and circuit impacts; and
- The Company's improved understanding of higher powered EV charging impacts on circuits can then be used by Distribution Operations planning and engineering groups to begin to build-in charging infrastructure impacts into their long-term infrastructure planning.

Q. Why is utility involvement important to increase EV awareness?

A. In a January 2018 survey, 68% of respondents believed utilities should help them understand EV benefits, but only 19% of those polled felt their energy provider is doing enough.[33] Utilities can drive awareness by bringing clarity to the above-mentioned educational gaps, especially around electric pricing plans and operational

[33] https://blog.enervee.com/revving-up-the-ev-market-8c90d21610f0, n=200 from CA, FL, MA, and NY

savings opportunities (i.e., fuel and maintenance savings).

Q. What has DTE been doing on customer education and awareness?

A. DTE has significantly increased its sense of urgency surrounding EV education and awareness, which Company Witness Mr. Clinton explains in more detail in his direct testimony.

Q. What customer behavior elements does DTE plan to test with the Charging Forward EV program and what are the targeted learnings?

A. There are several key customer behavior elements that the Company plans to test throughout the Charging Forward program, including:

- Customer awareness: Though it will primarily be tracked through customer surveys, each campaign's effectiveness will also be measured by appropriate quantitative marketing metrics like "open" rates, "click-through" rates, and time spent on the website. Other qualitative measures might include customer satisfaction verbatims and feedback from EV dealers regarding customer interactions;
- Charging behavior: Site hosts sharing the charging utilization data and the residential rebate program will enable DTE to refine its charging pattern estimates including hour of the day and location of charging. Understanding where and when the load occurs will allow the Company to more effectively manage charging to shift the load to off-peak hours and benefit the distribution system;
- EV purchase funnel: DTE will improve its understanding of the EV purchase decision funnel through continued relationships with dealerships, customer surveys, and focus groups. Using this knowledge will enable the Company to

effectively and efficiently adapt messaging to various customer segments depending on where they are in the purchase funnel; and

- Site host interest: DTE is currently working to understand the existing appetite in the market for commercial customers to add EV charging to their properties, and the EV program will enable the marketing team to convert their learnings into actionable infrastructure deployments. Furthermore, by working with various types of site hosts and their preferred charging equipment – in combination with understanding customer charging behavior as mentioned above – DTE will be able to provide better guidance on the recommended charging equipment power level and mix for each type of site host.

Q. Moving forward, how do you think DTE can efficiently and effectively help advance the adoption of EVs?

A. Utilities can help address two of the primary barriers to EV adoption: lack of EV awareness and ad-hoc and deficient infrastructure deployment. DTE can help raise awareness of available EVs while educating customers on their associated benefits. The Company can also help bridge the gap of deploying charging infrastructure in the near-term to increase EV adoption in the long-term. Finally, DTE can integrate EV load into the grid in an efficient and cost-effective manner to help ensure the benefits of this increased load accrue to the system.

EV Program Overview

Q. Why is DTE proposing the Charging Forward program in this rate case?

A. Michigan is the automotive capital of the world with more than 70% of the country's automotive research and development spending. The state's 91 education and training institutions offer over 650 automotive-based degrees and programs to feed top talent into the automotive industry.[34] DTE has performed an analysis of the EV market in Michigan, and this analysis highlights that EVs can provide the system benefits outlined above. Despite the state's automotive leadership position, adoption of EVs in Michigan lags that of other states, inhibiting the benefits on the DTE electric system. DTE has been a leader in cost-effectively integrating EVs into its system, and this work will continue and be refined over time. To advance the benefits of transportation electrification to the public, DTE believes the Charging Forward program is needed to address the two key challenges identified: (1) lack of EV awareness and (2) ad-hoc and deficient infrastructure deployment. To that end, DTE developed the Charging Forward program under the following four guiding principles:

- Help customers realize the benefits of EVs;
- Efficiently integrate EV load with the DTE Electric distribution system;
- Reduce barriers to adoption; and
- Participate in infrastructure deployment through thoughtful partnerships.

By adhering to these principles in the program design, DTE believes Charging Forward is a sustainable program that is both dynamic and flexible enough to be quickly scaled up or down to react to market developments.

[34] https://www.michiganbusiness.org/cm/files/Auto-Strategic-Plan.pdf

Q. What are the components of the Charging Forward program?

A. The three primary components of the Charging Forward program include:

1. Customer Education and Outreach;
2. Residential Smart Charger Support; and
3. Charging Infrastructure Enablement.

Q. How do the proposed components address the challenges faced by the EV market today?

A. Increasing customer education and outreach will raise awareness of available EV models and their lifetime benefits so customers in the market for a vehicle can make an informed decision. Supporting residential smart chargers will increase enrollment in the optional TOU rates available, helping to ensure charging is primarily accomplished off-peak which produces the system benefits described above. Enabling charging infrastructure will reduce site host capital costs and help bridge the gap in infrastructure in the near-term.

Q. What is the timing for the Charging Forward program implementation?

A. DTE anticipates the program will be implemented over three years, starting shortly after approval of the expenses.

Q. How has the Company gathered and solicited input from EV charging market participants and other stakeholders on the Charging Forward program?

A. DTE's involvement goes back many years to the experimental EV rates and early EV "task force". More recently, DTE engaged multiple stakeholders and conducted ~50 interviews with automakers, charging companies, utilities, regional organizations, environmental groups, governmental organizations, and national organizations. In addition, DTE participated in the MPSC EV technical conferences. Furthermore, DTE was instrumental in the setup of the EV Convening by Michigan Energy Innovation Business Council, which has had three meetings to date and led to the aforementioned joint comments. Finally, as DTE prepared the Charging Forward program, it sought input from many organizations, including the Alliance for Transportation Electrification, Edison Electric Institute, automakers, environmental groups, municipalities, regional organizations, and charging companies. DTE will remain active at both the state and national levels to continue to refine its approach and strategy for its EV program.

Q. Do EV market participants and other stakeholders support Charging Forward?

A. Yes, the Company worked with the above-mentioned groups to solicit feedback, refine the proposal, and build support. Please see Exhibit A-27, Schedule Q1 for Letters of Support for the Charging Forward program.

<u>Component #1: Customer Education and Outreach</u>

Q. What is the Customer Education and Outreach component of the Charging Forward program?

A. DTE's Electric Marketing team has a strategy for customer education and awareness, which Company Witness Mr. Clinton explains in more detail in his direct testimony.

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<u>Component #2: Residential Smart Charger Support</u>

Q. Why does DTE include the Residential Smart Charger Support as part of the Charging Forward program?

A. As discussed above, the clear majority of charging for EVs takes place at home. Therefore, to ensure the benefits of transportation electrification accrue to the system, DTE's objective is to ensure that most of this EV charging load occurs during off-peak hours through enrollment in the Company's optional TOU rates. In addition, based on longer-range EV models coming to market, drivers will need to switch from Level 1 to Level 2 chargers to be able to completely recharge within eight hours. By incentivizing this technology switch, DTE can both engage customers and support the continued development of the EV market.

Q. How would the proposed Residential Smart Charger Support component of Charging Forward be structured?

A. DTE would provide a rebate of up to $500 to ~2,800 residential customers who own an EV and install a qualified "smart" Level 2 charger.[35] The primary qualifications of the charger will be that it is new, 240 volts, and Underwriters Laboratories (UL) or Electrical Testing Laboratories (ETL) certified.[36]

Q. How did you select $500 as the rebate amount?

A. DTE's first residential rebate program was for $2,500 and was meant to cover all costs of Level 2 charger installation for the customer, including the charger itself. Charging equipment prices have significantly decreased over the last five years, and

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[35] "Smart" chargers are able to communicate to the car, host, and/or utility and enable "managed charging" options like TOU charging, demand response events, and/or load curtailment

[36] UL and ETL are nationally recognized testing laboratories (NRTL) that provide independent safety and quality certifications on electric vehicle charging stations

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the intent of the rebate is to cover a portion of the costs for customers. DTE also benchmarked other utilities offering a residential rebate for Level 2 chargers and found that $500 was the most common incentive amount offered.[37]

Q. What are the required customer commitments to qualify for the rebate?

A. The customer must enroll in a year-round TOU rate[38] and commit to enroll in future DR programs offered by the Company. These future DR programs will allow DTE to smartly manage the charging of the vehicles, for example by sending a signal to reduce the level of charging for a specific period of time. Future DR programs will always provide options to customers to override the signals if required/desired to do so.

Q. How would the Residential Smart Charger Support component of Charging Forward be administered?

A. The Company will create a process to validate the customer's proof of EV ownership, Level 2 installation, and TOU rate enrollment. In the application process, the customer will also commit to enroll in future DR programs as explained above. Once verified, the Company will send a check to the customer.

[37] "EV Home Charging Tariffs" - Bloomberg New Energy Finance
[38] Including D1.2 (Residential Time-of-Day Service Rate), D1.8 (Dynamic Peak Pricing Rate), and D1.9 (Experimental Electric Vehicle Rate)

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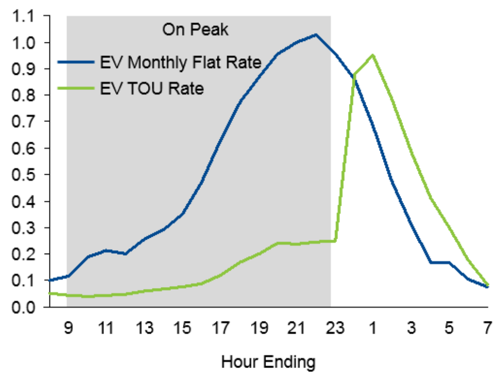
Q. What system benefits does Residential Smart Charger Support provide?

A. Since enrollment in a TOU rate is required, it will ensure most of the EV load for those customers shifts to off-peak hours to more efficiently utilize existing Company generation and distribution resources. As explained before, DTE found that customers on the optional EV TOU rate respond to price signals and shift the majority of their charging to off-peak hours as shown in the chart below:[39]



Requiring smart chargers will also enable DTE to potentially implement DR programs in the future to prevent or delay costly investments in substations reaching critical capacity due to neighborhood “clustering” of EVs.

Q. Have other utilities pursued similar residential charger rebate programs?

A. Yes, in its research, the Company has identified at least 20 other utilities that offer rebates for the installation of a residential Level 2 charger.[40]

<u>Component #3: Charging Infrastructure Enablement</u>

Q. What categories of EV charging will be included in the Company’s proposed Charging Infrastructure Enablement component?

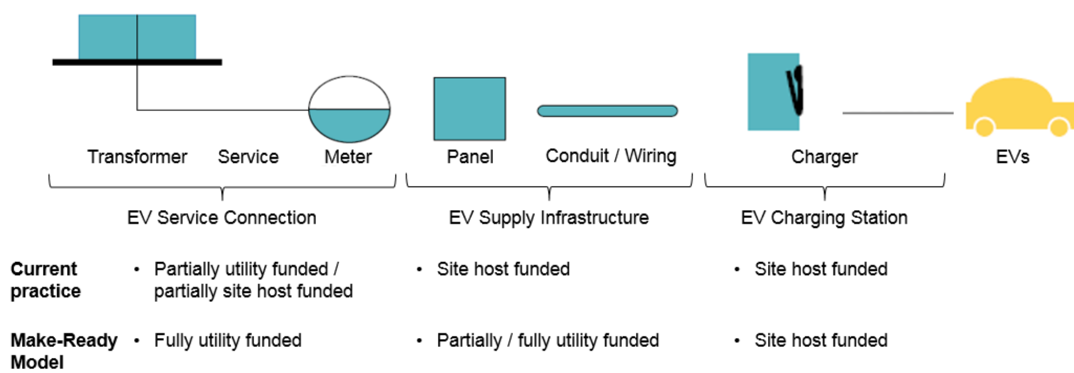
A. The three categories of charging in DTE’s proposal include:

[39] Based on 2017 D1.9 AMI data from an average summer, non-holiday weekday
[40] “EV Home Charging Tariffs” - Bloomberg New Energy Finance

1. DCFC stations;
2. Level 2 stations; and
3. Fleet charging stations.

Q. How would this component work?

A. DTE believes the best way to invest in the EV charging infrastructure is with the "make-ready" model, outlined in the following graphic:



In today's current practice, deployment is on an ad-hoc basis, which can lead to unnecessary distribution system investments. Additionally, today's current practice doesn't address the challenging business model of operating charging stations: significant capital investment is required, but utilization can be low while EV adoption is low. Under a make-ready model, there is potential to minimize distribution system investments, and therefore burden on utility customers, while tying deployment to market demand. Apart from limiting market risk of underutilized stations, a recent report also asserts that the utility make-ready model is the most expedient path to closing the charging infrastructure gap.[41] DTE will seek to implement the make-ready model by contributing the "EV service connection" costs up to the meter in the form of capital. For the "EV supply infrastructure" costs

[41] Rocky Mountain Institute "From Gas to Grid", 2017

(after-the-meter, including panel, conduit, and wiring), DTE will provide a fixed rebate to customers, as further discussed below. In all cases, site hosts will be responsible for the purchase, operation, and maintenance of the EV charging station. As such, they will also choose the charging equipment and vendor that meets their needs.

Q. Have other utilities pursued and received approval for a make-ready model like the one DTE proposes?

A. Yes. American Electric Power Ohio (AEP Ohio), Eversource, Long Island Power Authority, Pacific Gas & Electric Company, Rocky Mountain Power, and Southern California Edison (SCE) have all received approval to offer incentives for charging stations where the customer will own and operate the chargers. Ameren Missouri (Ameren), Bear Valley, Liberty CalPeco, National Grid, and PacifiCorp all have incentive programs for customer-owned and -operated charging stations pending.[42]

Q. Has DTE benchmarked utilities that have or are deploying these "make ready" Charging Infrastructure Enablement activities?

A. Yes, the Company has evaluated the AEP Ohio, Ameren, Eversource, and SCE "make ready" charging infrastructure programs to refine cost estimates, hone charger and site host qualifications, and apply lessons learned where possible.

Q. What type of DCFC segments will DTE support?

A. All DCFC infrastructure should be publicly accessible, and stations will be focused primarily along highway corridors. The Company will also consider DCFC

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[42] Edison Electric Institute

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"showcases" for municipalities interested in offering fast charging in their downtown areas. The Company will prioritize dual-port CCS/CHAdeMO chargers so that the greatest number of EV drivers possible can use them.[43]

Q. What is your rationale and approach to highway corridor stations?

A. An expansive network of highway corridor stations is critical for road trips, longer commutes, and addressing range anxiety. Using EV density, proximity to intersections, and traffic patterns as guidance, DTE identified the gap in DCFC infrastructure which currently exists today within its electric service territory. The company plans to prioritize interested site hosts near these infrastructure gaps to create a foundational backbone of DCFC coverage. The Company also plans to proactively target potential site hosts to enhance coverage in a way that minimizes the required investment in the Company's distribution system. DTE seeks to learn from its corridor charging station pilot to improve the process for site host selection and installation with the Charging Forward program. For example, DTE issued a Request for Information (RFI) for the above-mentioned corridor pilot, which gave the Company good leads on who may be interested in hosting a fast charging station near highway exits.

Q. What is your rationale and approach to downtown showcase stations?

A. Showcase stations are intended to expose broad segments of the population to EVs and charging infrastructure. In addition, they provide a platform for marketing, education, and promotional events. Portland General Electric (PGE) has successfully used their downtown "Electric Avenue" to promote EV adoption among their

[43] Tesla models can use CHAdeMO ports with an adaptor

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customers: there has been a 583% increase in the number of alternative fuel vehicles since 2011 and 68% growth in station usage from 2016-2017.[44] Thus, DTE includes a similar showcase element in the Charging Forward program. The Company will seek partnerships with cities willing to install chargers in high foot-traffic areas of their downtown centers. DTE aims to learn from its Ann Arbor and Detroit showcase pilots to improve its expertise on location selection and showcase format for the Charging Forward program.

Q. What is the after-the-meter rebate for DCFC infrastructure and how did you determine it?

A. DTE is proposing an after-the-meter rebate for DCFC infrastructure of $20,000 per charger. The Company benchmarked cost estimates for DCFC sites from Avista, Duke Energy Florida, National Grid, and PGE. The Company also looked at a sample of station costs across its electric service territory for comparison and solicited input from industry experts. As DTE learns from the Charging Forward program, the Company will adjust the rebate to accurately reflect the average costs of the "supply infrastructure". DTE will work to ensure that in no instance the amount of the rebates is greater than the total installation cost for the customer.

Q. What type of Level 2 segments will DTE support?

A. Level 2 infrastructure will be focused primarily in workplaces and multi-unit dwellings (MUDs), but DTE will also be looking for site hosts interested in providing public Level 2 stations to increase visibility and decrease range anxiety. The

[44] https://www.portlandgeneral.com/residential/electric-vehicles-charging-stations/electric-avenue

Company will prioritize the SAE standard J1772 Level 2 chargers in public places since all EV models can refuel with this port type.

Q. What is the Company's rationale and approach to workplace stations?

A. Workplace charging acts as an EV showcase by grouping all EVs together in a condensed charging area of the employer's parking lot, effectively raising awareness of available EVs and generating meaningful conversations among coworkers. A DOE study showed that employees with access to workplace charging are twenty times more likely to drive an EV.[45] Ford reported that there was a 45% increase in eVMT among employees who regularly used the Campus Charging Network after it was activated, and the network had a positive impact on the purchase decision for 61% of employee EV drivers. DTE plans to issue a market intelligence survey to select commercial customers together with the Major Account Services group to better understand the appetite for those interested in providing charging stations. The Company can use these results to not only prioritize interested site hosts for the Charging Forward program but also to raise awareness among potential site hosts wanting to learn more.

Q. What is the Company's rationale and approach to MUD stations?

A. MUD stations are necessary for those living in apartments to be able to drive an EV. The process to install MUD charging stations can be challenging since landlord, tenant, and community interests need to align, and there can be significant capital costs for installation. Because of this, DTE will prioritize any charging request from property managers and landlords to ease the capital investment required and help

[45] https://www.nrel.gov/docs/fy15osti/63230.pdf

facilitate the process. DTE will also, through it site host outreach efforts, engage this market segment to understand the potential for infrastructure deployment and ways the Charging Forward program can be helpful.

Q. What is your rationale and approach to public stations?

A. Public Level 2 charging stations are important for increasing EV awareness and "topping off" to increase eVMT. The same survey sent to employers will also be sent to businesses for DTE to use for targeting potential site hosts. The Company will also continue to engage cities to build charging into their future parking plans.

Q. What is the after-the-meter rebate for Level 2 infrastructure and how did you determine it?

A. DTE is proposing an after-the-meter rebate for Level 2 infrastructure of $2,500 per port. The Company benchmarked the same utilities it did for the DCFC rebate in addition to Louisville Gas & Electric / Kentucky Utilities and SCE. Similarly, DTE also looked at a sample of station costs across DTE's electric service territory for comparison and solicited input from industry experts. The Level 2 rebate may also be adjusted during the program from learnings to accurately reflect the average "supply infrastructure" cost. DTE will work to ensure that in no instance the amount of the rebates is greater than the total installation cost for the customer.

Q. For which types of fleet charging will DTE provide the make-ready infrastructure?

A. The Company will provide the necessary make-ready charging infrastructure required for four fleet categories including (1) public transit buses, (2) school buses,

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(3) delivery vehicles, and (4) shared mobility services.

Q. What is the Company's rationale and approach to public transit buses?

A. Because of the high utilization of transit buses, the fuel and maintenance savings in converting to an electric powertrain are powerful. In addition, electric buses significantly improve the air quality for commuters and those living in non-attainment regions. DTE is already engaged with the Detroit Department of Transportation (DDOT), Suburban Mobility Authority for Regional Transportation (SMART), Ann Arbor Transit Authority (AATA), Blue Water Area Transit, and the University of Michigan to discuss their electrification strategies. The Company will seek to partner with regional transit agencies like these that are interested in piloting and integrating electrified buses into their network by providing the make-ready charging infrastructure to support their vehicles.

Q. What is the Company's rationale and approach to school buses?

A. At the MPSC EV technical conference in February 2018, there were several stakeholders who expressed an interest in a utility program featuring a school bus component. DTE has already met with the Michigan Association for Pupil Transportation and will continue to work with them to identify a school district within its electric service territory that is ready to pilot an electric bus.

Q. What is the Company's rationale and approach to delivery vehicles?

A. Similar to electric buses, electric medium- and heavy-duty delivery vehicles also offer significant operational savings and emissions reductions. DTE will seek out potential partnerships with delivery fleet services together with the Major Account

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Services group to pilot delivery vehicles in its electric service territory.

Q. What is the Company's rationale and approach to shared mobility services?

A. Electrified Uber, Lyft, and Maven vehicles increase awareness of EVs from both a driver and rider perspective. DTE has found in its research that shared mobility fleets are unable to deploy EVs in a region where no significant DCFC infrastructure exists. Therefore, DTE seeks to partner with willing site hosts and shared mobility service companies to expand the DCFC network and create charging "hubs" for shared mobility fleets.

Q. What is the after-the-meter rebate for fleet infrastructure?

A. The needs of charging infrastructure for fleets varies greatly depending on types of vehicles and driving patterns. DTE is proposing an after-the-meter rebate for fleet infrastructure equivalent in value to the capital costs up to the meter for each station.

Q. How many charging stations will be deployed for each type of charging?

A. The Company's Charging Forward proposal estimates the following quantities of charging stations to be deployed over three years:

Charging Category	Estimated Quantity
DCFC	~32 chargers
Level 2	~1,000 ports
Fleet	Pending specific use cases

Because the cost of charging infrastructure can vary greatly depending on the site, DTE will consider the program fully subscribed once the approved expenditure is reached rather than an approved quantity of charging stations. To minimize cost per size and maximize deployment of the Charging Forward program, DTE's objective is to install the infrastructure where excess capacity exists in the distribution system when possible. Since fleet charging needs vary by use case, the Company's objective is to target the four categories of fleets evenly.

Q. Will DTE be responsible for operating and maintaining the charging stations?

A. No, under the current program design, the charger cost as well as the operation and maintenance of the charging stations will be the responsibility of the site host. As the Company learns from the Charging Forward program, other options will be considered, including full ownership of stations, if the program learnings were to indicate that full utility ownership is the most appropriate manner to increase EV adoption and benefit the system.

Q. How does the Company's make-ready infrastructure component benefit disadvantaged communities?

A. The Company believes every category of Charging Forward's make-ready infrastructure benefits disadvantaged communities. DCFC sites will be publicly accessible and spread throughout DTE's electric service territory to provide a charging alternative to those without access to a garage for overnight charging. Similarly, the Level 2 MUD stations can help those interested in EVs but without access to charging currently. Finally, the fleet component of Charging Forward benefits those in disadvantaged communities for a few reasons. First, the electrification of public transit and school buses will significantly improve the air quality for commuters. Second, the electrification of car-sharing and ride-hailing fleets will increase access to EVs for all. Putting EVs into shared mobility fleets increases exposure to EVs from both a driver and rider perspective, addressing one of the key barriers to EV adoption. Lastly, the load from fleets is more certain than personally-owned vehicles, making the charging easier to manage and shift to off-peak hours. This will help put downward pressure on rates by spreading fixed costs over more sales, as already highlighted above.

Q. Will the Company's proposal interfere with the development of the competitive market for EV chargers?

A. No. In the aforementioned joint comments, 19 stakeholders agreed "the private investment committed to deploy charging equipment and services in Michigan is not enough to close the infrastructure gap across the state (especially in underserved markets including multi-unit dwellings), so public and utility investments should be utilized to complement private funding sources to establish a foundational charging infrastructure in Michigan." By providing for the installation of make-ready infrastructure, the Company is enabling a system whereby a wide range of EV charging station models from multiple suppliers will likely be offered and will be determined by customers.

Q. Is technological obsolescence an issue?

A. Charging infrastructure technology will continue to evolve over time, similar to other technological investments that are made (e.g., appliances, solar PV panels, etc.). Even though the infrastructure will continue to advance, SAE is continually working on standards for the equipment so that future charging will be backwards compatible to serve existing vehicles, and future EV models will also be able to use existing charging. Therefore, existing Level 2 and DCFC technology will continue to serve important workplace and public charging demand for both new and older EVs and their drivers.

Q. How is the Company's Charging Forward program designed to avoid underutilization of the stations?

A. By pursuing a make-ready model, deployment is tied to market demand. Since site hosts will need to pay for the chargers, operation, and maintenance, DTE believes they will only seek to install stations where they will most likely be utilized. Also, in supplying new service connections (which will likely be the case for DCFC stations), the potential site host will need to provide information on anticipated load, which will help the Company understand likely utilization and help properly and efficiently prioritize deployment.

Q. How will the Company leverage other sources of funding for EV infrastructure?

A. By nature, the make-ready model requires multiple sources of funding to create a station (e.g., from DTE and the site host at a minimum). The Company is also coordinating with others to ensure infrastructure is deployed in a complementary and additive manner. For example, the Company is engaged with the Michigan Agency for Energy to help determine the best use of Environmental Mitigation Trust funds for light-duty vehicle charging infrastructure.[46] Additionally, the Company submitted a letter to Electrify America at the end of February 2018 to request Metro Detroit be considered as one of the selected areas for Cycle 2 funding and is engaged

[46] Michigan received ~$64M in funds from the Volkswagen (VW) diesel emissions settlement, and ~15% of this amount will go towards light-duty vehicle charging infrastructure

in discussions with them as the decision process continues to progress.[47] Finally, DTE submitted a request to be considered for the Michigan to Montana DOE grant partnership opportunity to deploy make-ready fast charging stations along I-94.

Q. How will site hosts set pricing and what role will DTE play in the setting / monitoring of those prices?

A. DTE expects most Level 2 charging will be offered for free to EV drivers based on current market expectations, but that DCFC will likely require a fee for EV driver use. In either case, DTE proposes that site hosts will be able to choose what they "charge for charging". DTE will educate hosts on what pricing structures are currently allowed in Michigan (i.e., on a time basis vs. a per kW-hour basis), what their expected electricity costs could be, and what the gas price equivalent would be.

Q. How will DTE Energy recruit potential site hosts?

A. The Company's Electric Marketing team has a site host acquisition strategy, which Witness Clinton explains in more detail in his direct testimony.

Charging Forward Program Costs

Q. What are the Company's proposed costs of the Charging Forward program?

A. The complete implementation of Charging Forward is expected to cost approximately \$13M – including O&M - through the end of 2021 as shown in the high-level overview table below (in millions):

[47] Another part of the VW settlement established a newly formed subsidiary of VW, Electrify America, to invest \$2B in EV infrastructure and awareness in 4 cycles over a 10-year period

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	2019	2020	2021	Total
Capital	$ 1	$ 2	$ 2	$ 5
Regulatory Asset	$ 1	$ 2	$ 2	$ 5
O&M	$ 1	$ 1	$ 1	$ 3
Total	**$ 3**	**$ 5**	**$ 5**	**$13**

Q. What are the Company's expected costs for the projected test period?

A. Exhibit A-12, Schedule B5.9 shows the projected expenditures for Charging Forward for the May 1, 2019 to April 30, 2020 projected period as follows:

- Capital expenditures: Column (c), lines 1 to 6
- Regulatory asset expenditures: Column (c), lines 7 to 12
- O&M expenditures: Column (c), lines 13-16

Total estimated program costs for the projected test period are $4.5 million as shown in line 17. The Company will not spend Charging Forward funds until it receives MPSC approval in an Order associated with this general rate case, which is expected in April 2019.

Q. What is included in the capital cost?

A. Associated costs to establish a dedicated service connection or upgrade an existing service for charger installation is included in the capital cost, or the "EV service connection" cost outlined above. Equipment costs encompass all spending necessary to provide distribution service to meet the load needs of the charger up to the point of interconnection at the Company's service meter. Costs include (but are not limited to) transformer upgrades/additions, service drops, labor and contractor costs, materials, hardware, and a new meter. DTE will own the transformer, the service, and the meter, which are all retirement units. As a result, the Company is seeking for the "EV service connection" costs to be capitalized as normal assets included in rate base.

Q. How were the capital costs developed?

A. Similar to the methodology used to determine the after-the-meter rebate amounts described above, the Company benchmarked other EV programs across the nation, sampled station costs across DTE's electric service territory for comparison, and solicited input from industry experts.

Q. What costs are included in the regulatory asset expenditures?

A. As previously outlined, the Company is proposing to offer a rebate for two components of the Charging Forward program including (1) Residential Smart Charger Support and (2) Charging Infrastructure Enablement (for after-the-meter or "supply infrastructure" costs). The total anticipated expenditures for these rebates is included in the "Regulatory Asset" category in the table above and shown on Exhibit A-12, Schedule B5.9.

Q. What specific regulatory approvals is DTE seeking relative to the regulatory asset?

A. As supported by Company Witness Ms. Uzenski, DTE is seeking accounting authority to defer and amortize the rebates as a regulatory asset over five years, like the regulatory treatment approved by the Commission in Case U-16406, the application of The Detroit Edison Company for approval of its experimental electric vehicle tariff.

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Q. What costs are included in the O&M expenditures?

A. O&M expenditures can be broken into two primary components including (1) Customer Education and Outreach and (2) Program Management. Witness Clinton will provide an overview of the test period O&M expenditures.

Program Benefits and Evaluation

Q. What is the potential value of benefits associated with widespread EV adoption in Michigan?

A. Energy and environmental consulting firm MJ Bradley & Associates (MJ Bradley) published an analysis estimating the costs and benefits of increased EV adoption in Michigan for two different adoption scenarios. The costs estimated in MJ Bradley's analysis included those borne by the EV driver (incremental vehicle cost, residential charging station cost, and electricity cost) as well as those borne by electric utility customers because of increased EV load (generation, transmission, peak capacity costs, and distribution upgrades). Two of the benefits estimated in the analysis include those accruing to the EV owner (fuel and maintenance savings) and those to utility customers through rates (net distribution revenue from increased EV charging). The study concluded the following cumulative net benefits state-wide from greater EV adoption in Michigan by 2050 (in billions):[48]

	Moderate Forecast	**High Forecast**
Reduced Electric Bills	$ 0.8	$ 2.6
Reduced Vehicle Operating Costs	$ 6.3	$ 23.1
Total	**$ 7.1**	**$ 25.7**

[48] https://mjbradley.com/sites/default/files/MI_PEV_CB_Analysis_FINAL_03aug17.pdf

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Q. Why should utility customers without an EV support an EV program?

A. In the case of the MJ Bradley analysis, $0.8-$2.6B of benefits could accrue to utility customers by 2050 in the form of reduced electric bills. The additional benefits DTE mentioned above – including increased economic opportunities in the region and reduced dependency on foreign oil – are more challenging to quantify but also accrue to the utility customer regardless of EV ownership.

Q. What are the estimated system benefits to DTE Electric customers that accrue from Charging Forward?

A. Assuming an average life of 10 years for an EV, the Company calculated that the net present value (NPV) of gross margin that each EV sale provides toward DTE electric system fixed costs over its lifetime is ~$2,800. The methodology and assumptions are outlined in the table below:

Description	Value	Key Assumptions	Source
EV usage per year (kWh)	~3,900	• 0.3 kWh/mile for BEVs • 0.35 kWh/mile for PHEVs • 27% of EVs are BEVs • 11,593 miles/year	• GTM Research • GTM Research • ZEV Sales Dashboard • M-DOT
Weighted average revenue rate ($ / kWh)	~$0.135	• Whole-Home TOU rate (70%) • General service rate (30%)	• Current rates and load profiles
Average supply cost ($ / kWh)	~$0.033	• PSCR factor	• Regulatory
NPV Energy Benefit ($ / EV)	~$2,800	• Discount rate of 6.63%	• Regulatory

The net benefit calculated above assumes that ~70% of charging takes place at home while ~30% of charging takes place in public (e.g., workplace or other) and none of the charging impacts critical peak events due to the relatively small load of EVs. In the extremely rare event that all public charging takes place during critical peak times and the benefit from that load should be ignored, then the NPV energy benefit would be ~$2,100 per EV. Using this incremental NPV benefit range as a basis, DTE

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calculated that the Charging Forward program shows an NPV of affordability benefits in the $4-9 million range for the base forecast and in the $12-20 million range for the accelerated forecast in 2023 as shown in the table below:

	Base EV Forecast *(in millions)*	**Accelerated EV Forecast *(in millions)***
NPV Energy Revenue	$20-27	$31-42
NPV Supply Costs	($5-7)	($7-10)
NPV Energy Benefit	$15-20	$24-32
NPV Charging Forward Costs	($11)	($11)
NPV Affordability Benefits	**$4-9**	**$12-20**

The affordability benefits represent the incremental present value benefit that every EV sold brings to the electric system over its expected life, net of the Charging Forward program costs. It's worth noting that this estimated affordability benefit does not include electrification of medium- and heavy-duty vehicles, which will also be supported and encouraged from the fleet component of the Charging Forward program.

Q. How will the Company evaluate the Charging Forward program?

As explained earlier, DTE's objectives for its participation in the EV space are to:

- Help customers realize the benefits of EVs;

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- Efficiently integrate EV load with the DTE Electric distribution system;
- Reduce barriers to adoption; and
- Participate in infrastructure deployment through thoughtful partnerships.

The Charging Forward program will help DTE understand the market and its customers, learn about EV load and its relationship to overall system load, and understand EV impact on the distribution system. Several metrics will be tracked to gauge impact of the Charging Forward program and improve the Company's understanding of the EV market, including:

- EV volume in Michigan and DTE's electric service territory;
- Charging behavior (percent off-peak vs. on-peak);
- Customer awareness of EVs;
- Site host interest and participation in the program;
- Customer participation in TOU rates;
- Average make-ready cost per port and site; and
- Station utilization.

Q. How will the Company share the lessons learned from the EV program?

A. The Company plans to provide a summary report to the MPSC at the end of the three-year program with conclusions around each of the above-mentioned goals and metrics in addition to program achievements and key lessons learned. The report will also include information and ideas gathered from the Company's targeted outreach with various stakeholders, market developments since the time of filing, and recommended next steps.

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Q. Is it important for the Company to maintain flexibility when implementing the program?

A. Yes, it is critical for the Company to maintain flexibility in implementing the program as the EV market is continuing to evolve. DTE will seek feedback in the implementation phase as it did in the development phase to gain insights on key stakeholder feedback, site host response, market demand, and technological advances. Using these lessons learned, DTE plans to adjust Charging Forward to reflect any changes in this dynamic market and will provide updates to the MPSC periodically.

Distributed Generation Tariff

Q. Will you please summarize your conclusions and recommendations?

A. DTE strives to maintain a safe and reliable electric system that serves the reasonable needs and desires of the Company's many different types of retail electric customers. Advancing a distributed generation tariff using today's technology and regulatory context can and must ensure that the needs and desires of each of DTE's customers are accounted for in an equitable manner. Net metering, as established in Public Act 295 of 2008, was a reasonable initial approach to a distributed generation tariff given the technology available at the time it was implemented; however, net metering sacrificed adherence to equitable cost of service principles for simplicity of application. Today's metering and billing technology allows for a distributed generation tariff that is equitable, clear to communicate, and practically implementable. DTE is proposing an inflow/outflow mechanism that appropriately aligns costs to their cost drivers and provides for an outflow credit in line with market-efficient pricing for similar products. In addition, DTE's proposed inflow/outflow mechanism includes a System Access Contribution (SAC).

Distributed Generation Statutory and Regulatory Framework

Q. Why is the Company filing a distributed generation tariff in this rate case?

A. In 2016, the Governor signed into law Public Act 341 (PA 341). Section 6a (14) of PA 341 provides "Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering or distributed generation program under the clean and renewable and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. In any rate case filed after June 1, 2018, the commission shall approve such a tariff for inclusion in the rates of all customers participating in a net metering or distributed generation program under the clean and renewable and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211…"[49]. The present rate case is the Company's first following June 1, 2018.

Q. Are there additional statutory requirements germane to this proceeding?

A. Yes. In addition to PA 341, Public Act 342, Section 177(4) and (5)[50] (PA 342) are highly relevant and applicable to this proceeding and clearly define certain implementation boundaries and requirements of a new tariff. The most relevant text from PA 342 follows:

"Section 177 (4) … The credit shall appear on the bill for the following billing period and shall be limited to the total power supply charges on that bill. … Notwithstanding any law or regulation, distributed generation customers shall not receive credits for

[49] MCL 460.6a(14)
[50] MCL 460.1177(4) and (5)

electric utility transmission or distribution charges. The credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be either of the following:

(a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory, or for distributed generation customers on a time-based rate schedule, the monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.

(b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

Section 177 (5) A charge for net metering and distributed generation customers established pursuant to section 6a of 1939 PA 3, MCL 460.6a, shall not be reduced by any credit or other ratemaking mechanism for distributed generation under this section."

Although I am not an attorney and don't propose to offer a legal opinion, it seems clear to me that the plain language of these statutory provisions precludes compensating distributed generation customers for anything other than the statutorily predetermined value of their generation. And this makes sense, since to do otherwise would be inconsistent with cost of service principles and otherwise require the rates of other DTE customers to be unnecessarily higher.

Line No.

Q. What instructions has the Commission set forth for distributed generation tariffs included in rate cases after June 1, 2018?

A. The Commission Order in Case No. U-18383, dated April 18, 2018, directed utilities to file "the Inflow/Outflow tariff, attached to [that] Order as Exhibit A.[51]" It continues "the rate regulated utility may also file its own distributed generation tariff, if desired.[52]"

<u>Role of the Electric System Supporting Distributed Generation Customers</u>

Q. What is the role of the electric system?

A. "The electric power system is composed of four interacting physical elements: energy generation, high-voltage transmission, lower voltage distribution, and energy consumption, or load."[53] DTE's obligation in operating and maintaining its power system is do so in a safe, reliable, and affordable manner while providing energy and ancillary services at all hours, of every day, to every customer.

Q. What services does the electric system provide to traditional customers?

A. Traditional customers utilize the energy, in kWh, and power, in kW, available through DTE's electric system (electric system) each day and at all hours. They enjoy the ability to use their electric appliances, lights, and other fixtures as benefits their context and needs. They need not telegraph their usage but instead can utilize electric system services as required. In addition, they are users of services that are not typically bill items but are available through the existence and size of the electric distribution system. These services include power quality in the form of frequency

[51] Commission Order dated April 18, 2018 in Case No. U-18383. "In the matter, on the Commission's own motion, to implement the provisions of Sections 173 and 183(1) of 2016 PA 342, and Section 6a(14) of 2016 PA 341. Pg 18
[52] ibid
[53] MIT Study on the Future of the Electric Grid. 2011

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and voltage regulation, inrush current in the form of reactive power, and 24/7 optionality of usage.

Q. What is the role of the electric system for distributed generation customers?

A. The electric system provides the same fundamental services to distributed generation customers as it does to traditional customers. However, distributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utilize distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances).

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Q. How does a distributed generation customer's interaction with the electric system compare to the average customer?

A. As shown in Figure 1[54], distributed generation customers have a significantly different load shape and relationship with the electric system than traditional customers. Customers who do not have generation are not, at any point, exporters of electric energy. While no two customer load profiles are precisely the same, and

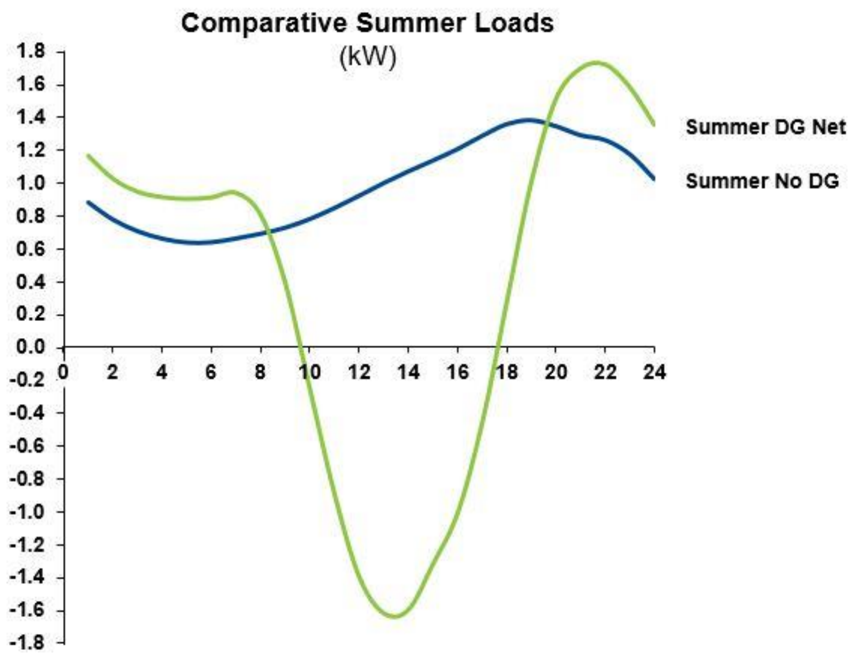

Figure 1. Comparative summer load shapes for the D-1 class average and the average of DTE's residential net energy metering customers

many groups of customers have similar load profiles based on a common feature of their home or business, traditional customers are not net producers of electricity. The bidirectional relationship between the distribution system and distributed generation customers is a key and fundamental distinction of these customers from traditional customers.

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[54] Data are 2017 hourly averages for D-1 (traditional) and distributed generation. Summer is defined as all hours in June, July, and August.

Moreover, distributed generation customers as a group have summer[55] net peak demand nearly half a kW *greater* than traditional residential Rate Schedule D-1 customers. See Exhibit A-16, Schedule F11.

Q. Can you describe the operational and technical impacts of distributed generation on electric system functions?

A. Distributed generation creates two unique electric system dynamics that are different from traditional customer impacts.

1) The nearly instantaneous change in inverter-based generation output, either because the generator trips offline or cloud cover rapidly changes, introduces potential for impacts to system protective equipment. Sharp changes in load and voltage may not be accurately interpreted by legacy protective equipment and may cause the circuit to trip offline.

2) Distributed generation may introduce reverse power flows into equipment not originally designed to accommodate them. Equipment may need to be reconfigured or replaced to safely operate on circuits with significant distributed generation penetration. In particular, this two-way flow may introduce situations in which reactive power and energy are moving in opposing directions, again impacting system operation and protection schemes.

These dynamics are distinct from the interconnection requirements themselves, which are governed by IEEE 1547 and address point of interconnection safety and interoperability.

[55] Summer defined as June, July, and August

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Cost of Service Principles for a New Distributed Generation Tariff

Q. What is the current net metering construct in Michigan?

A. The existing net metering construct in Michigan is based upon a monthly netting of total inflows and total outflows. The utility meter captures the inflow when the customer draws energy from the distribution system, and separately captures the outflow when the customer exports energy to the distribution system. The "net" meter read for the period is the basis for the customer's volumetric charges, or in the event of a net export month, the volume of kWh credits granted to the customer for future use. As a purely kWh-based approach, each kWh sent to the distribution system is effectively credited at the applicable retail volumetric rate. The monthly service charge and certain bill surcharges are not reduced by net metering credits. "True" net metering as it has been described, applies to Category 1 net metering customers, those with installed systems of less than 20 kW. "Modified" net metering, which differs somewhat in compensation structure from true net metering, applies to Category 2 (20-150 kW installed capacity) and Category 3 customers.

Q. What is the current cost recovery paradigm approved by the Commission?

A. The current cost recovery paradigm employed for residential rates in Michigan is volumetric. Thus, a customer's responsibility for fixed and demand investments is charged incrementally per kWh consumed. When kWh consumed from the distribution system declines without a concurrent and equivalent decline in cost, this continuing unrecovered cost shifts to all other customers.

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Q. Does the net metering (true or modified) construct in Michigan adhere to equitable cost of service principles?

A. No. Equitable cost of service principles dictate that a customer's billed cost recovery adheres as closely as possible to the costs (cost of service) incurred by the utility on their behalf. A cost shift occurs when the alignment is broken and customers are no longer supporting their cost of service but are instead supporting some other amount. Net metering is a clear example of a violation of equitable cost of service principles.

In the case of a "net zero" net energy metering customer who exports the same amount they import in the billing period, the customer's bill may consist of nothing more than the monthly service charge and certain bill surcharges, such as the Low Income Energy Assistance Fund (LIEAF). A customer producing sufficient quantities of energy to offset 70% of their prior kWh billing basis will have a monthly bill with 70% lower volumetric totals, but with only an incremental or no change in their peak requirements. The customer's capacity cost responsibility is consistent but their bill will have decreased by more than half.

Q. How much cost is shifted from net metering customers to traditional customers?

A. Across a survey of five states and six utilities, and with cost shift studies conducted by various parties including utilities, external experts, and state utility commissions, the estimated range of distributed generation induced annual cost shift is $444 to more than $1,700[56] per customer. Another study, which calculated incentives relative to installed nominal capacity, estimated that net energy metering is effectively an

[56] Alexander, Barbara; Brown, Ashley; Faruqui, Ahmad. *"Rethinking Rationale for Net Metering."* Public Utilities Fortnightly, Oct 2016.

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incentive worth 55% of total system cost. For a 3.9 kW system, the study estimated nearly $7,500 in total incentive payments via net metering[57]. The sum of these cost shifts is borne by the rest of the rate class, a group which has made no affirmative choice to provide such support and has no opportunity to opt-out. This violates cost of service principles.

Q. How is this being addressed nationwide?

A. In 2017, at least fourteen states initiated or implemented net metering successor policies or proceedings[58]. In addition, there are presently seventeen states, plus Michigan, reviewing net metering, utilizing a billing approach distinct from net metering, or otherwise crediting outflow at something less than retail rate[59]. The states are geographically distributed and the regulatory environments in which changes are being made are diverse and include the entire spectrum of American utility regulation. These facts serve to underscore the point that the hurdles induced by net metering are not a regional issue, nor specific to a certain regulatory environment, but are evident nationwide and in all landscapes.

Q. Are there other reasons, in addition to legislative direction, that support a new approach to net metering?

A. Net metering is a construct from a previous era of technology and regulation. It allowed early adopters an electrical and billing construct through which to interconnect their nascent distributed solar installations. However, it needs be replaced for two reasons:

[57] Consumer Energy Alliance. *"Incentivizing Solar Energy: An In-Depth Analysis of U.S. Solar Incentives"*. 2018
[58] North Carolina Clean Energy Technology Center. "50 States of Solar: 2017 Policy Review and Q4 Quarterly Report"
[59] Edison Electric Institute, 2018

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1) <u>Metering technology</u> has advanced beyond the legacy, analog equipment that was available when net metering was initially adopted in Michigan. What was previously a technical challenge is now an opportunity for improvement in cost alignment and communication.

2) <u>Legislative developments</u> created the opportunity to pursue a net metering successor tariff in this rate case. DTE believes that the legislative timing is well-aligned with the advances in electric system technology and cost understanding outlined above and together require action today.

Filed New Distributed Generation Tariff

Overview and Structure

Q. What tariff mechanism is DTE proposing?

A. DTE is proposing an inflow/outflow model for its new distributed generation tariff. *Inflows* are defined as each unit of energy (in kWh) consumed by a customer from the distribution system. *Outflows* are defined as each unit of energy (in kWh) exported from the distributed generation customer to the distribution system. They are treated separately, with total inflow charged at a given "inflow" rate and total outflow credited at a separate "outflow" rate based on their respective determinants. To complement the inflow/outflow model filed here pursuant to Commission Orders in Case No. U-18383, DTE is proposing a System Access Contribution (SAC) to account for the 24/7 optionality all distributed generation customers maintain to use the full capability of the electric system.

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Q. Why is the Company proposing the inflow / outflow method for its new distributed generation billing construct?

A. The inflow/outflow mechanism represents an advance over net metering in aligning cost causation and crediting structures. Inflow/outflow acknowledges that the cost structure of the electric system is not volumetrically driven, and that the costs offset by outflow credits (energy costs) differ in structure and amount from the costs being recovered by standard retail rates (energy, generation capacity, distribution, and transmission). Inflow/outflow reduces the cost shift by operating with more granular transactional data.

Q. What are the primary elements of the new distributed generation tariff as proposed by DTE Electric?

A. The proposed tariff includes three primary elements

1) A cost-based inflow unit price at the standard retail rate – "inflow rate"
2) A cost-based system contribution – "System Access Contribution"
3) A cost-based outflow credit at the locational marginal price – "outflow rate"

<u>Inflow Rate</u>

Q. What is DTE Electric's proposed inflow unit rate?

A. DTE proposes an inflow unit rate (per kWh) equivalent to the standard, full service retail rates for the underlying rate schedule.

Q. How is the retail rate determined?

A. The standard retail rates per kWh for each rate schedule are determined through this and other general rate cases and are valid for all customers for whom it applies,

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excluding any riders. Please refer to the testimony of Company Witnesses Ms. Holmes and Mr. Dennis, for more details on how these rates are developed.

Q. Why is this the appropriate inflow unit rate?

A. As characterized in depth by Witnesses Holmes and Dennis, the volumetric retail rates in DTE's residential, and some of the secondary commercial rate schedules, captures the entire cost of service not supported by the customer charge. Volumetric rates are fundamentally misaligned with the cost structure of electric utilities, but have traditionally been the vehicle through which most utilities recover all costs. Thus, each unit of consumption includes the cost recovery of an incremental portion of fixed and demand costs which are fundamentally invariant with energy flows.

Q. How do volumetric inflow rates fully account for utility costs incurred on behalf of distributed generation customers?

A. Volumetric pricing does not, on its own, adequately account for utility costs incurred on behalf of distributed generation customers. It reasonably accounts for the variable power supply portion of costs but does not recover the demand investments made on the utility system. Distributed generation customers rely on these non-volumetric investments for safe and reliable electric service and the cost responsibility lies equally with traditional customers as well as distributed generation customers.

__**System Access Contribution**__

Q. What is the System Access Contribution (SAC) that DTE proposes?

A. DTE is proposing a SAC that assigns a cost per kW AC of nameplate system capacity based on the system-cost responsibility of distributed generation customers. DTE's proposed SAC for customers on the new distributed generation rider is described by Witness Dennis. Customers taking service under rates with demand charges are not subject to the SAC.

Q. Why is DTE proposing this System Access Contribution?

A. A volumetric basis is an insufficient but serviceable approach to recovering fixed utility system costs when loads are stable and predictable on a time horizon consistent with demand related distribution investments. When stability and predictability are no longer assured, the recovery of costs must more closely match their incurrence. The leading edge of unpredictability is the long-term production and penetration behavior of distributed generation, and the specific characteristics of the individual installations. While distributed generation customers maintain their full electric system use optionality at every point in time, they are not supporting the costs of the infrastructure required for their service.

Q. How was this System Access Contribution determined?

A. The 24/7 optionality that all customers who utilize the electric system enjoy, including distributed generation customers, is a cost which is allocated and charged across the rate class. As discussed above, these costs have traditionally been recovered volumetrically, but with the lower inflow of distributed generation customers, utility infrastructure costs remain unrecovered and are shifted to the remaining traditional customers. I've instructed Witness Dennis to develop the SAC, and the detailed explanation of the charge is included in his testimony.

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Q. What are the electric system costs that will be recovered by a System Access Contribution?

A. As discussed in the inflow pricing section, distribution capacity related costs are currently recovered volumetrically. Distributed generation customers, while driving somewhat lower fuel and purchased power costs through their onsite generation, do not reduce their reliance on the electric system nor their option to use it at will. This is evident in two ways:

1) Renewable distributed generation is intermittent and highly variable[60], relying on solar insolation or wind to generate electricity. Periodically, these resources quickly recede and reemerge. When this occurs, the customer calls their option to access the electric system and the system must meet the entire requirement of the customer on a near instantaneous basis. This requires both the absolute capacity at the circuit and line transformer level to be available and the ability to safely ramp power flows without impacting system protective equipment. This option that distributed generation holds on electric system usage is underpinned by costs which are invariant with volumetric consumption, and which are unrecovered under volume-driven distributed generation and net metering recovery mechanisms.

2) When distributed generators are actively producing, exporting to the utility distribution system, and being compensated at the outflow credit rate, they lack sufficient electric current to support the start of common household motors, such as air conditioning and refrigerator compressors. This inrush

[60] 2017 average hourly DG customer load observations. The standard deviation of solar production relative to the relevant month-hour average is .57, and in summer net-outflow hours (June, July, and August from 10:00am to 6:00pm) it is an even more variable .76. And in 6% of all summer hours, DG customers have load more than 100% greater than the month-hour average, suggesting again highly variable solar production and subsequent grid impacts.

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current is available due to fixed and demand driven infrastructure investments providing the 24/7 electrical inertia present in the utility electric system.

Q. What would trigger the application of the System Access Contribution?

A. The proposed SAC will apply to any customer choosing to take service from DTE under the distributed generation rider, except that, as stated above, customers taking service under rates with demand charges are not subject to the SAC.

<u>Outflow Rate</u>

Q. When a distributed generation customer exports energy to the utility distribution system, which costs to the utility are offset?

A. Energy exported from distributed generation customers to the distribution system offsets only the fuel and purchased power component of the energy cost classification. It does not reduce the cost of the Company's distribution infrastructure nor to the Company's generation capacity required to serve customer load when their generator is not producing. Neither of these costs vary with volumetric energy consumption. DTE's crediting of any outflow energy is a 1:1 offset with wholesale purchases or the fuel required to generate the energy.

Q. What is DTE Electric's proposed outflow rate?

A. DTE's proposed outflow credit compensation rate is the monthly average real-time locational marginal price (LMP) for the given month based on the local resource zone of the Midcontinent Independent System Operator (MISO).

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Q. What are the determinants of a locational marginal price for a kWh?

A. The LMP is determined by three factors: supply, demand, and location.

1) Supply is the power being offered at a given time which, given the physics of the electrical system, must match load
2) Demand is the load of the system at a given time
3) Location for the pricing of wholesale energy by DTE is MISO Zone 7

Q. How is the locational marginal price a cost-based compensation basis?

A. The LMP is the actual cost at which energy is traded on wholesale markets. Producers whom do not sign offtake agreements for their production typically sell production into wholesale markets at the prevailing LMP. They have no obligation to produce at a given time or volume. Similarly, distributed generation customers make no commitment to DTE as to the volume and timing of their output. The market construct which most closely aligns with the production behavior of a distributed generator is the LMP.

Q. Why is the locational marginal price more applicable than using power supply costs less transmission costs as referenced in PA342[61]?

A. The power supply charge has two principal components: fuel and purchased power, and capacity. Given the unpredictability of distributed generation customer outflow, either due to higher load on-site or lower than expected production, no capacity requirement is offset by the distributed generation and net metering customer. Without capacity, the remaining power supply cost is fuel and purchased power, a category effectively represented by the LMP. Transmission charges are a pass

[61] MCL 460.1 177

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through over which DTE has no direct control and which are invariant with the change in net consumption of a distributed generation or net metering customer. Transmission costs are also determined outside of MPSC proceedings.

Q. **Why is the locational marginal price more applicable than the "avoided cost" methodology as MPSC Staff has suggested is a viable option in their distributed generation Report?**

A. The avoided cost methodology proposed by the Commission would credit distributed generation customers at the theoretical calculation of a hybrid proxy plant[62]. There are issues with this approach.

1) A hybrid proxy plant can neither actually be built nor actually purchased from, and payments made on this basis have no meaningful relationship to the actual cost of service or value of the generation provided by a distributed generation customer.

2) The proposed avoided cost method assigns significant capacity value to purchased energy. These generators have no temporal production contract with DTE, they have no total production contract with DTE, and their primary purpose is not to provide DTE with energy or capacity but to offset on-site consumption. Simply stated, distributed generation customers cannot be counted on to generate when needed by the DTE system and have no obligation to do so. Therefore, there is no tangible capacity value or capacity offset provided by the distributed generation.

[62] See U-18090 and MPSC Staff. "Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff." February 21, 2018

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Q. How does the new PA 342 address outflow credit compensation in the context of a distributed generation tariff?

A. I am not an attorney and don't propose to offer a legal opinion, but it seems clear to me that the plain language of these statutory provisions precludes compensating distributed generation customers for anything other than the statutorily predetermined value of their generation. Michigan Public Act 342 of 2016[63], Section 177(4) explicitly describes one of these two legislatively determined options as the *"monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory…"* The legislation also precludes any alternative that credits distributed generation customers for transmission or distribution charges, plainly stating <u>both</u> that "… *Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges…*" and "*A charge for net metering and distributed generation customers established pursuant to section 6a of 1939 PA 3, MCL 460.6a, shall not be reduced by any credit or other ratemaking mechanism for distributed generation under this section."*(See Section 177 (4) and (5))

I don't see how this language in Michigan law would permit implementation of an avoided cost or other construct that deviates from Section 177(4)(a) or (b).

[63] MCL 460.1177(4)

Q. How is DTE's proposed new distributed generation tariff consistent with PA 341 and PA 342?

A. The legislation offers two key procedural and substantive tests for any new distributed generation tariff:

1) PA 341 dictates that the first DTE Electric rate case following June 1, 2018, will include a filing for a new distributed generation tariff. The Company's proposal meets that requirement.

2) PA 342 177(4) defines acceptable outflow credit values as either power supply less transmission or the wholesale LMP rate. The Company's proposal meets that requirement.

Q. Is the proposed tariff consistent with Commission orders in Case No. U-18383?

A. This tariff aligns with the inflow/outflow construct propounded by Staff and required to be filed by the Commission. It further reflects the ability of utilities to file alternatives, which manifest in this filing through the SAC as well as through an outflow valued at the LMP. It is important to note, however, that this filing is largely congruent with the structure of the Staff's tariff.

<u>Technical and Administrative Implementation</u>

Q. What technical or administrative features of DTE Electric's proposed distributed generation tariff cannot be implemented?

A. DTE has the technical and administrative ability to fully implement the tariff as proposed.

Q. How is the proposed inflow/outflow mechanism supported by currently installed retail metering technology?

A. The advanced metering infrastructure (AMI) installed across the DTE electric service territory allows for a far more precise accounting of energy flows and power requirements than the traditional, analog electric utility meter. The devices are capable of separately recording energy drawn by the customer from the distribution system (inflow) and energy produced by the customer and sent out to the distribution system (outflow). This distinction allows for an accurate billing of inflow energy and an accurate crediting of outflow energy.

Q. What is the most appropriate time-period over which to net flows?

A. The most precise accounting of the inflow/outflow mechanism is over an instantaneous time-period. In practice this consists of addressing total inflows and outflows as distinct categories for the billing period, capturing each incremental unit of both and representing the truest view of this bidirectional relationship.

Q. Does the Company's proposed tariff require any additional hardware investments by customers?

A. The Company's proposed tariff does not require any additional hardware investments by customers related to metering or billing. There is no change in the metering hardware required relative to the existing net metering construct.

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Q. Does the Company's tariff filing impact the current net energy metering categories?

A. The Company's proposed tariff would apply across generation projects currently classified as Category 1, 2, and 3 distributed generation and net metering projects. The legislatively defined[64], capacity-aligned program caps would remain unchanged.

Q. What is DTE Electric's proposal for grandfathering existing net energy metering customers?

A. DTE concurs with Staff's Report[65], recognizing PA 341 and PA 342 call for a ten-year grandfathering period from the original date of enrollment in a net metering program. This approach provides an opportunity for existing net metering customers to recover their own investment costs while transitioning them to the new distributed generation tariff in a reasonable time-period. DTE Electric will develop a communications plan to ensure notification of rate transition.

Q. What is DTE's proposal for closing eligibility for the existing, net energy metering tariff?

A. A customer should be considered "participating" in the existing net metering program based on three criteria. If these criteria are not met, then an applying customer should no longer be considered eligible for a net metering rate and should instead be subject to the new distributed generation tariff approved in this rate case.

1) They have submitted a complete application to DTE before the new distributed generation tariff is approved by Commission Order in this rate case

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[64] See MCL 460.1173(3)

[65] MPSC Staff. "Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff." February 21, 2018

2) If the application is deemed deficient by DTE, the deficiencies must be corrected by the effective date of the Commission Order in this rate case

3) If the application has been approved pursuant to the above timing, the customer must have a completed and approved installation within six months of application approval. Any unbounded time-period in which an approved customer may install their distributed generation asset and receive the net metering rate may create a system planning and operational issue. Moreover, six months is a reasonable time-period in which to construct a distributed generator, a premise with which the Commission has concurred[66].

Conclusion

Q. Why does DTE believe its proposed tariff benefits Michigan, customers, and the distributed generation community?

A. The conditions from which net metering arose have evolved and today DTE and the Commission can do better for customers. DTE's responsibility to all customers demands that the Company seek a more effective, efficient, and equitable approach for integrating distributed generation onto the Company's distribution system. Renewable generation assets are a present and permanent feature of the Company's electric system and a more equitable rate design will help DTE customers capture the benefits of their own energy choices without underwriting their neighbor's decisions. A well-reasoned and clear net metering successor policy will help ensure the equitable and reliable continuation of the services DTE provides to all customers.

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[66] Commission Order dated April 18, 2018 in case U-18255. "In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rule governing the distribution and supply of electric energy, and for miscellaneous accounting authority". Pg 17

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Q. Based on the rules for new distributed generation customers discussed above, who is supporting the new distributed generation tariff?

A. I’ve instructed Company Witness Dennis to develop a new tariff consistent with the principles I have discussed throughout my testimony

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KENNETH L. SLATER

DTE ELECTRIC COMPANY
QUALIFICATIONS OF KENNETH L. SLATER

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Q. What is your name, business address and by whom are you employed?

A. My name is Kenneth L. Slater. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy) within Regulatory Affairs as Manager of Revenue Requirements.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Business Administration, with a major in Accounting, from Lawrence Technological University in 1980.

Q. What work experience do you have?

A. In June 1980, I joined MichCon and through August 1986, I had several positions of increasing responsibilities within Regulatory Affairs. In September 1986, I transferred to Gas Accounting as Supervisor, Michigan Gas Production Accounting with responsibilities for the recording of gas volumes and purchases from producers in Michigan. In September 1989, I transferred back to Regulatory Affairs where I held several positions of increasing responsibilities. In July 2002, I was promoted to Manager, Case Litigation within Regulatory Affairs with responsibility for the management of activities relative to MichCon's regulatory activities. In January 2014, I was appointed to my current position.

Q. What is your current position?

A. As Manager of Revenue Requirement within DTE Energy's Regulatory Affairs organization, I am responsible for revenue requirement studies, depreciation rate studies, cost of service studies, as well as regulatory analysis and research for both DTE Electric and DTE Gas Company (DTE Gas).

Q. Have you previously been involved in DTE Electric's and DTE Gas's general rate case filings?

A. Yes. I have sponsored testimony before the MPSC in a number of MichCon Gas Cost Recovery (GCR) factor and reconciliation cases regarding the forecasted and actual costs of transportation from MichCon's interstate pipeline transporters as well as the following cases:

U-20106	DTE Electric Company TCJA Credit A
U-20105	DTE Gas Company TCJA Credit A
U-20051	DTE Electric Company's 2017 TRM Reconciliation
U-18999	DTE Gas Company's Rate
U-18338	DTE Gas 2016 Energy Optimization (EO) Reconciliation
U-18332	DTE Electric 2016 Energy Optimization (EO) Reconciliation
U-18268	DTE Gas 2018-2019 Energy Waste Reduction (EWR) Plan
U-18262	DTE Electric 2018-2019 Energy Waste Reduction (EWR) Plan
U-18255	DTE Electric Company's Rate Case
U-18251	DTE Electric Company's 2016 TRM Reconciliation
U-18082	DTE Electric 2015 REP Reconciliation
U-18024	DTE Gas 2015 Energy Optimization Reconciliation
U-18023	DTE Electric 2015 Energy Optimization Reconciliation

U-18005	DTE Electric Company’s 2015 TRM Reconciliation
U-17999	DTE Gas Company’s Rate Case
U-17761	DTE Electric Company’s 2013 -2014 TRM Reconciliation
U-17238	DTE Gas Company’s Self-Implementation Refund
U-17103	MichCon 2011-2012 Revenue Decoupling Mechanism Reconciliation
U-16877	MichCon 2010-2011 Revenue Decoupling Mechanism Reconciliation
U-16447	MichCon Self-Implementation Refund
U-13898	MichCon Rate Case
U-13342	MichCon 2001 Income Sharing Calculation
U-11210	Complaint Case (Title Transfer Fees)

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Q. What is the purpose of your testimony in this proceeding?

A. I am providing testimony related to the historical and the projected sections of this rate case filing. In Section A – Historical Test Year, I am supporting DTE Electric's twelve months ended December 31, 2017 Total Electric historical revenue deficiency. In preparing my rate case exhibits, I relied on financial information supplied by DTE Electric Witnesses Ms. Uzenski and Mr. Solomon. I am sponsoring the derivation of the historical overall rate of return, Net Operating Income (NOI) adjustments for interest synchronization and income tax savings, and the revenue conversion factor.

In Section B – Projected Test Period, I am sponsoring DTE Electric’s twelve months ending April 30, 2020 Total Electric projected revenue deficiency as well as, the derivation of the projected overall rate of return, the NOI adjustments for interest synchronization and income tax savings, and the projected revenue conversion factor. I also calculate the incremental revenue requirement for DTE Electric’s Tree Trim Surge Amortization request and the projected value of the Tree Trim Surge Program. In addition, I am supporting the calculation of the incremental revenue requirements for DTE Electric’s Infrastructure Recovery Mechanism (IRM) and the Company’s proposed reconciliation related to over and under spending of capital dollars under the IRM.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am supporting the following historical and projected exhibits:

Section A – Historical Test Period Ended December 31, 2017 Exhibits

Exhibit	Schedule	Description
A-1	A1	Historical Revenue Deficiency (Sufficiency)
A-2	B1	Historical Rate Base
A-3	C2	Historical Revenue Conversion Factor
A-3	C12	Historical Adjusted Net Operating Income – Income Tax Savings
A-3	C13	Historical Tax Effect of Interest Synchronization Adjustment
A-4	D1	Historical Rate of Return Summary

Section B – Projected Test Period Ending April 30, 2020 Exhibits

Exhibit	Schedule	Description
A-11	A1	Projected Revenue Deficiency (Sufficiency)
A-12	B1	Projected Rate Base
A-13	C2	Projected Revenue Conversion Factor
A-13	C14	Projected Income Tax Effect of Interest Allowed in Ratemaking Formula - 12 Months Ended 12/31/2017 and 4/30/2020
A-13	C15	Projected Tax Effect of Interest-Synchronization Adjustment - 12 Months Ended 12/31/2017 and 4/30/2020
A-14	D1	Projected Rate of Return Summary
A-22	L1	Projected Value of Tree Trim Surge Program
A-22	L2	Tree Trim Surge - Revenue Deficiency Calculation

Line No.			
	A-30	T5	Infrastructure Recovery Mechanism - Incremental Revenue Requirement – Distribution Operations
	A-30	T6	Infrastructure Recovery Mechanism - Incremental Revenue Requirement – Generation
	A-30	T7	Infrastructure Recovery Mechanism - Incremental Revenue Requirement – New 1,100 MW Combined Cycle
	A-30	T11	Infrastructure Recovery Mechanism 2020 Incremental Revenue Requirement – Distribution Operations Example of $40.0 MM Under Spend
	A-30	T12	Infrastructure Recovery Mechanism 2020 Incremental Revenue Requirement – Generation Operations Example of $40.0 MM Over Spend
	A-30	T13	Infrastructure Recovery Mechanism 2020 Incremental Revenue Requirement Reconciliation Example

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

<u>Section A – Historical Test Period (Twelve Months Ended December 31, 2017)</u>

Q. What information is displayed on Exhibit A-1, Schedule A1?

A. Exhibit A-1, Schedule A1 titled “Historical Revenue Deficiency (Sufficiency)” for the period ended December 31, 2017, shows the calculation of the Company’s revenue deficiency for the historical test period based on this period’s adjusted rate base, overall rate of return, adjusted NOI and revenue conversion factor. Line 8, of

Schedule A1 shows that the Company experienced a revenue deficiency of $18.3 million for the historical test period ended December 31, 2017. The revenue deficiency is based on a rate base of $15.2 billion, adjusted NOI of $815.6 million, and an overall rate of return of 5.36%. The rate base balance is carried forward from Exhibit A-2, Schedule B1. The adjusted NOI is carried forward from Exhibit A-3, Schedule C1, which is supported by Witness Uzenski. The defined historical overall rate of return of 5.44% is set forth in Exhibit A-4, Schedule D1.

Q. What is the Historical Rate Base?

A. Historical Rate Base is the end of period balances for net plant amounts for the historical test period and 13-month average balances for the allowance for working capital for the period ended December 31, 2017. See Exhibit A-2, Schedule B1. Total Historical Rate Base of $15.2 billion, shown on line 14, is comprised of Net Utility Plant of $13.9 billion and Working Capital of $1.3 billion.

Q. What is the purpose of the Revenue Conversion Factor?

A. The Revenue Conversion Factor, also known as the Revenue Multiplier, is a multiplication factor that converts a utility's after-tax income deficiency / (sufficiency) into the required change in the pre-tax revenue requirement. In 2017, each dollar of revenue the Company received was subject to Michigan Business Income Tax, Municipal Income Tax, and Federal Income Tax. Line 9 of Exhibit A-3, Schedule C2, shows DTE Electric's historical test period Revenue Multiplier of 1.6393, which means DTE Electric was required to collect $1.6393 in revenue to produce $1.00 of after-tax income.

Line
No.

Q. How did you calculate the Income Tax Savings of Interest reflected in Exhibit A-3, Schedule C12?

A. Exhibit A-3, Schedule C12, reflects the difference between the tax deduction amounts of allowable interest expense included in the rate case Rate of Return and DTE Electric's actual interest expense for the Year Ended December 31, 2017 as supplied to me by Witness Uzenski. Allowable interest expense starts with the Historical Rate Base of $15.2 billion multiplied by the weighted cost of debt of 1.63%. The 1.63% is the summation of the weighted costs associated with long-term debt (LTD) and short-term debt (STD) from Exhibit A-4, Schedule D1. Line 3 calculates the allowable ratemaking debt interest expense deduction of $248.1 million. DTE Electric's actual interest expense deduction of $267.3 million is what was included in DTE Electric's computation of federal income tax per Company books. Allowable ratemaking interest expense is less than actual interest expense, which results in reducing the tax deduction by $19.2 million. This lower tax deduction increased federal income tax, state income tax and municipal tax expense and creates a corresponding decrease in NOI of $7.5 million, see line 12 of Schedule C12.

Q. What is the Synchronization Adjustment calculated on Exhibit A-3, Schedule C13?

A. Tax law requires, and prior Commission Orders have allowed, a return on Job Development Investment Tax Credits (JDITC) at the rate of return for permanent capital. JDITC is afforded a return equal to the weighted cost of permanent capital as required by law and prior Commission orders. This tax adjustment represents the interest deduction for the debt component of that return and is intended to align the

Line No.

level of interest expense inherent in the capital structure with the Company's rate base. Exhibit A-3, Schedule C13, shows a reduction in income tax expense of $157,000 due to the interest deduction associated with the debt component portion of JDITC. This Synchronization Adjustment reduces income tax expense by $157,000, and, as shown on line 11, results in a corresponding increase in NOI.

Q. What is DTE Electric's historical rate of return?

A. Exhibit A-4, Schedule D1, titled "Historical Rate of Return Summary" shows DTE Electric's historical test period overall rate of return of 5.44% (line 10, column (g)). The capital structure is carried forward from the balance sheet on line 95, columns (h) through (l) of Exhibit A-2, Schedule B5, and equals the rate base amount on line 14, column (c) of Exhibit A-2, Schedule B1.

On Exhibit A-4, Schedule D1, the long-term debt, shown on line 1 includes reductions for the net amount of unamortized premium / discount, any funds on deposit with trustees, and the debt financing related to regulatory assets; offset by unamortized debt expense. DTE Electric's total long-term debt outstanding at December 31, 2017 is detailed on Exhibit A-4, Schedule D2, sponsored by Witness Solomon. The weighted long-term debt cost for the historical period of 4.37% was calculated on Exhibit A-4, Schedule D2 using the net proceeds method, as specified by the Commission, for each issue outstanding at December 31, 2017.

Line 2 of Schedule D1 reflects that the Company has no preferred stock outstanding.

Line No.

Line 3 of Schedule D1 shows common shareholders' equity, which includes common stock outstanding, less expense, plus premium, retained earnings and Other Comprehensive Income (OCI) adjustments. The cost of common shareholders' equity utilized for this exhibit is the 10.10% that was authorized by the Commission in Case No. U-18014 as indicated on Exhibit A-4, Schedule D5.

The cost of short-term debt, on line 5, of 1.59% is the actual average short-term borrowing cost of the Company in the historical period ended December 31, 2017.

The Job Development – ITC amounts on lines 6 (JDITC – Debt) and 7 (JDITC – Equity) of Schedule D1 reflect the corresponding permanent capital percentages of 49.37% for long-term debt and 50.63% for common equity. The associated returns for JDITC – Debt and JDITC – Equity reflect the corresponding permanent capital rates of 4.37% and 10.10%, respectively. This calculation complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to assign a rate of return to JDITC at the weighted average cost of permanent capital.

Net deferred income taxes (line 9) are at zero cost.

Section B – Projected Test Period

Q. What is the Revenue Deficiency for the Projected Test Year?

A. Line 10 of Exhibit A-11, Schedule A1, shows absent rate relief, DTE Electric will experience, for the projected test period ending April 30, 2020, a Total Revenue Deficiency of $328.4 million, including the revenue deficiency from the Tree Trim Surge calculated on Exhibit A-22, Schedule L2 and shown on Line 9 of Exhibit A-

11, Schedule A1. This deficiency is based on the Company's projected financial outlook for the 12 months ending April 30, 2020. The revenue deficiency on Line 8 is based on the following: an adjusted rate base of $17.2 billion, adjusted NOI of $750.9 million, and an overall rate of return of 4.37%. Rate base of $17.2 billion is detailed in Exhibit A-12, Schedule B1. The twelve months ending April 30, 2020 NOI is developed on Exhibit A-13, Schedule C1 sponsored by Witness Uzenski. The defined projected test period overall rate of return of 5.76% is set forth in Exhibit A-14, Schedule D1. The components of rate base, NOI, capitalization, and required rate of return are detailed within the exhibits and schedules of Witnesses Uzenski, Solomon and myself.

Q. What information is displayed on Exhibit A-12, Schedule B1, entitled "Projected Rate Base"?

A. Exhibit A-12, Schedule B1 shows the detailed composition of the Projected (column (d)) rate base for the projected test period ending April 30, 2020, on a simple average basis. Line 15, column (d), shows total projected rate base of $17.2 billion, consisting of $15.7 billion of net plant and $1.5 billion of working capital. These amounts are carried forward to Exhibit A-11, Schedule A1. This exhibit also provides a comparison of rate base as of December 31, 2017 to the average rate base balances for the projected test period ending April 30, 2020.

Q. What is the Projected Revenue Conversion Factor?

A. Projected Revenue Conversion Factor is 1.3496 and is used to convert after tax income into pre-tax revenue for the Projected Test Year. Exhibit A-13, Schedule C2 calculates the Revenue Conversion Factor for the projected test period. The derivation of the revenue conversion factor is the same mathematical format as my Exhibit A-3, Schedule C2 from Section A, however, the Federal Income Tax Rate is now 21%.

Q. What adjustments on Exhibit A-13, Schedule C1, "Projected Net Operating Income" for the Projected 12 Month Period Ending April 30, 2020 are you supporting?

A. On this exhibit, I am supporting the adjustments for:

1) Income Tax Effect of Interest (line 16) supported by Exhibit A-13, Schedule C14.

2) Interest Synchronization Tax Adjustment (line 17) supported by Exhibit A-13, Schedule C15.

Q. What is the adjustment for "Income Tax Effect of Interest" on Exhibit A-13, Schedule C1, line 16?

A. This NOI adjustment on line 16 of Exhibit A-13, Schedule C1, is the difference between the forecasted ratemaking amount of interest tax deductions allowed and the forecasted interest tax deductions included in the 12 months ending April 30, 2020 NOI supported by Witness Uzenski. This change in the income tax expense is set forth on Exhibit A-13, Schedule C14. The sum of line 8 and line 11 of Schedule C14, column (c) reflects an adjustment to decrease income tax expenses resulting in a corresponding increase in NOI as shown on line 12 column (c).

Line No.

Q. What is the "Synchronization Adjustment" on Exhibit A-13, Schedule C1, line 17?

A. This NOI adjustment on line 17 of Exhibit A-13, Schedule C1 is the rate case Synchronization Adjustment for the April 30, 2020, test period. As I have discussed previously in Section A of my testimony, tax law requires and prior Commission Orders have allowed, a return on JDITC at the rate of return for permanent capital. This change in the income tax expenses is set forth on Exhibit A-13, Schedule C15. The sum of line 7 and line 10 of Schedule C15, column (c) reflects an adjustment to decrease income tax expenses resulting in a corresponding increase in NOI as shown on line 11 column (c).

Q. What information is reflected on Exhibit A-14, Schedule D1, entitled "Projected Rate of Return Summary"?

A. Exhibit A-14, Schedule D1, develops DTE Electric's projected overall rate of return for the projected test period ending April 30, 2020. The projected April 30, 2020 average balance sheet capital structure amounts, in column (b), are carried over from Exhibit A-12, Schedule B4.1, line 97, columns (e) through (i) and equals the rate base amount on line 15, column (d) of Exhibit A-12, Schedule B1 of $17.2 billion. Schedule D1 calculates DTE Electric's weighted after-tax projected rate of return as 5.76%, line 10, column (g). This 5.76% weighted projected rate of return is carried forward to Exhibit A-11, Schedule A1, line 4 and is used in the determination of the projected revenue deficiency. Schedule D1 also calculates DTE Electric's weighted pre-tax projected rate of return as 7.19%, line 10, column (i).

Line No.

Long-term debt of $6.4 billion, shown on line 1 of Schedule D1, has been reduced by the net amount of unamortized premium, discount, any funds on deposit with trustees and the debt financing related to regulatory assets eliminated by Witness Uzenski in the historical balance sheet. This balance of long-term debt represents 49.0% of DTE Electric's permanent capital. DTE Electric's projected total long-term debt outstanding at April 30, 2020 is detailed on Exhibit A-14, Schedule D2, sponsored by Witness Solomon. The weighted long-term debt cost of 4.36% was calculated by Witness Solomon on Schedule D2 using the net proceeds method for each issue outstanding as of April 30, 2020 including the financing cost of new debt issues.

Line 2 of Schedule D1 reflects that the Company has no preferred stock outstanding.

Line 3 of Schedule D1 shows common shareholders' equity of $6.7 billion, which includes common stock outstanding, less expense, plus premium, retained earnings and OCI adjustments. This level of common equity represents 51.0% of DTE Electric's permanent capital in the projected test period. The cost of common shareholders' equity utilized for this exhibit is 10.50%, which is supported by DTE Electric Witness Dr. Vilbert on Exhibit A-14, Schedule D5.19.

The cost of short-term debt, on line 5, of 3.56% is the forecasted average short-term borrowing cost of the Company for the projected test period supported by Witness Solomon on Exhibit A-14, Schedule D3.

The Job Development – ITC amounts on line 6 (JDITC – Debt) and line 7 (JDITC – Equity) of Schedule D1 reflect the corresponding permanent capital percentages of

49.0% for long-term debt and 51.0% for common equity. The associated returns for JDITC–Debt and JDITC–Equity reflect the corresponding permanent capital rates of 4.36% and 10.50%, respectively. This calculation complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to assign a rate of return to JDITC at the weighted average cost of permanent capital.

Average projected deferred income taxes of $3.9 billion (line 9) are at zero cost of capital.

Projected Value of Tree Trimming Surge Program

Q. What information on Exhibit A-22, Schedule L1 entitled "Projected Value of Tree Trimming Surge Program" do you support?

A. I support the calculation of the Return on the Tree Trim Surge Deferral shown on Pages 3 and 4, line 10 and the Amortization Expense of the Tree Trim Surge Deferral shown on Pages 3 and 4, line 21. I also support the calculation of the total revenue requirement savings shown on pages 5 and 6, line 23 resulting from comparing the Total Tree Trim revenue requirement on line 19 to the deferral costs on line 22. I then calculate the Net Present Value of $46.1 million on line 24 of the total revenue requirement savings on line 23 over the 22-year period ending 2040.

Revenue Requirement for DTE Electric's Tree Trim Surge Proposal

Q. What information is provided on Exhibit A-22, Schedule L2 entitled "Tree Trim Surge – Revenue Deficiency Calculation"?

A. Exhibit A-22, Schedule L2, identifies the annual revenue requirement for the projected test period in this case, the 12 months ending April 30, 2020, relating to the Tree Trim Surge proposal as discussed by DTE Electric Witnesses Mr. Stanczak and Ms. Rivard. The Revenue Requirement components consist of Return on Net Rate Base and Amortization Expense. Lines 2 and 3 are the 2019 and 2020 deferral amounts supported by Witness Ms. Rivard on Exhibit A-22, Schedule L1. Line 4 is the amortization of the 2019 vintage layer supported by Witness Ms. Uzenski on Exhibit A-22, Schedule L3. Lines 5 through 8, calculate the Average Net Rate Base. This incremental "Net Rate Base" reflects traditional Rate Base (Net Utility Plant) less Accumulated Deferred Income Taxes. The Return on Net Rate Base, shown on line 10, is based on the Average Net Rate Base multiplied by a pre-tax rate of return of 9.36%. Since rate base for the Tree Trim Surge is shown net of deferred taxes, the weighted cost of permanent capital is used. Amortization Expense, line 11, is calculated by Witness Ms. Uzenski, as stated above.

<u>Revenue Requirement for DTE Electric's Infrastructure Recovery Mechanism</u>

Q. What information is provided on Exhibit A-30, Schedule T5 entitled "Infrastructure Recovery Mechanism – Incremental Revenue Requirement – Distribution Operations"?

A. Exhibit A-30, Schedule T5, page 1, identifies the annual incremental Revenue Requirements for years 2020 through 2022 relating to the Distribution Operations capital costs associated with DTE Electric's IRM, as discussed by DTE Electric Witness Mr. Bruzzano. The Revenue Requirement components consist of Return on Net Rate Base, Depreciation, and Property Taxes. Lines 10 through 13, on Page 1 of Exhibit A-30, Schedule T5 show the underlying Revenue Requirement amounts for years 2020 through 2022 that are used by DTE Electric Witness Mr. Lacey to derive the IRM Cost of Service by Rate Schedule for the respective years.

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Line 2 is the Distribution Operations capital investment amounts supported by Witness Mr. Bruzzano, on Exhibit A-30, Schedule T2. Lines 3 through 8, calculate the Average Net Rate Base. This incremental "Net Rate Base" reflects traditional Rate Base (Net Utility Plant) less Accumulated Deferred Income Taxes. The Return on Net Rate Base, shown on line 10, is based on the Average Net Rate Base multiplied by a pre-tax rate of return of 9.36%. Since rate base for the IRM is shown net of deferred taxes, the weighted cost of permanent capital is used. Depreciation, line 11, is based on the half year convention, using a depreciation rate of 3.98% filed in DTE Electric's depreciation case U-18150 for Distribution Operations. The line 12 Property Taxes are derived on page 2 of this exhibit.

Q. Why do you have a Capital Investment amount for 2019 on Line 2 of Exhibit A-30, Schedule T5?

A. The base revenue requirement calculated for the projected test period, twelve months ending April 30, 2020, included six months of the annual Distribution capital spend for the asset categories identified on Exhibit A-30, Schedule T2. The Company is proposing that the IRM mechanism include the other six months of the projected test period, the twelve months ending April 30, 2020. To calculate the six-month amount, I used an annual 2020 Distribution capital spend as a proxy starting point. I divided the May to December 2020 amount of capital by eight to get a monthly amount, and then multiplied that figure by six. The amount excluded from base rates for the six months of the projected test period capital spend for these areas is $326,816,000 ($435,755,000 for the 8 months of 2020 divided by 8 months multiplied by 6 months).

Line No.

Q. What information is provided on Exhibit A-30, Schedule T6 entitled "Infrastructure Recovery Mechanism – Incremental Revenue Requirement – Generation"?

A. Exhibit A-30, Schedule T6, page 1, identifies the annual incremental Revenue Requirements for years 2020 through 2022 relating to the Generation capital costs associated with DTE Electric's IRM, as discussed by DTE Electric Witnesses Mr. Paul and Mr. Davis. The Revenue Requirement components consist of Return on Net Rate Base, Depreciation, and Property Taxes. Lines 11 through 15, on Page 1 of Exhibit A-30, Schedule T6 show the underlying Revenue Requirement amounts for years 2020 through 2022 that are used by Witness Mr. Lacey to derive the IRM Cost of Service by Rate Schedule for the respective years. Line 2 is the Fossil Generation capital investment amounts supported by Witness Mr. Paul and Line 3 is the Nuclear Generation amounts supported by Witness Mr. Davis, and carried over from Exhibit A-30, Schedule T1. Line 4 shows the Total Generation capital investment consisting of the Fossil Generation amount on Line 2 and the Nuclear Generation amount on Line 3. Lines 5 through 10, calculate the Average Net Rate Base. This incremental "Net Rate Base" reflects traditional Rate Base (Net Utility Plant) less Accumulated Deferred Income Taxes. The Return on Net Rate Base, shown on line 12, is based on the Average Net Rate Base multiplied by a pre-tax rate of return of 9.36%. Since rate base for the IRM is shown net of deferred taxes, the weighted cost of permanent capital is used. Depreciation, line 13, is based on the half year convention, using a weighted depreciation rate of 4.15%. The line 13 Property Taxes are derived on page 2 of this exhibit.

Q. Why do you have a Capital Investment amount for 2019 on Line 2 and Line 3 of Exhibit A-30, Schedule T6?

A. As described above for the Distribution IRM category, in calculating the revenue requirement for the projected test period, the Company included six months of the annual Fossil and Nuclear Generation capital spend for the areas identified on Exhibit A-30, Schedules T3 and T4. The Company is proposing that the IRM mechanism include the other six months of the projected test period, the twelve months ending April 30, 2020, by including, as a proxy for the six months of the projected test period capital spend for these areas; six months of the 2020 annualized capital spend for Fossil Generation and Nuclear Generation or $69,000,000 ($92,000,000 for the 8 months of 2020 divided by 8 months multiplied by 6 months) for Fossil Generation and $55,504,000 ($74,006,000 for the 8 months of 2020 divided by 8 months multiplied by 6 months) for Nuclear Generation.

Q. What information is provided on Exhibit A-30, Schedule T7 entitled "Infrastructure Recovery Mechanism – Incremental Revenue Requirement – New 1,100 MW Combined Cycle"?

A. Exhibit A-30, Schedule T7, page 1, identifies the annual incremental Revenue Requirements for years 2020 through 2022 relating to the New 1,100 MW Combined Cycle (New Build) capital spend associated with DTE Electric's IRM, as discussed by Witness Mr. Paul. The Revenue Requirement components consist of Return on Net Rate Base and Property Taxes. Since the New Build is not in service, no depreciation is calculated. Lines 11 through 15, on Page 1 of Exhibit A-30, Schedule T7 show the underlying Revenue Requirement amounts for years 2020 through 2022 that are used by Witness Mr. Lacey to derive the IRM Cost of

Service by Rate Schedule for the respective years. Line 2 is the New Build capital investment amounts supported by Witness Mr. Paul, on Exhibit A-30, Schedule T1, line 4. Line 4 shows the Total capital investment of the New Build amount on Line 2. Lines 5 through 10, calculate the Average Net Rate Base. This incremental "Net Rate Base" reflects traditional Rate Base (Net Utility Plant) less Accumulated Deferred Income Taxes. The Return on Net Rate Base, shown on line 12, is based on the Average Net Rate Base multiplied by a pre-tax rate of return of 9.36%. Since rate base for the IRM is shown net of deferred taxes, the weighted cost of permanent capital is used. Depreciation, line 13, is zero since the New Build is not in service. The line 13 Property Taxes are derived on page 2 of this exhibit.

Q. Why do you have a Capital Investment amount for 2019 on Line 2 of Exhibit A-30, Schedule T7?

A. Consistent with the calculations for Distribution and Generation, in calculating the revenue requirement for the projected test period, twelve months ending April 30, 2020, in this case the Company included six months of the annual New Build capital spend shown on Exhibit A-30, Schedule T3, line 4. The Company is proposing that the IRM mechanism include the other six months of the projected test period, the twelve months ended April 30, 2020, annual New Build capital spend by including, as a proxy for the six months of the projected test period capital spend; six months of the 2020 annualized capital spend or $153,942,000 ($205,256,000 for the 8 months of 2020 divided by 8 months multiplied by 6 months).

Line No.

Q. What is the basis for the pre-tax rate of return of 9.36%?

A. The 9.36% pre-tax rate of return is DTE Electric's permanent capital projected weighted cost rates from Exhibit A-14, D-1, grossed up by the appropriate pre-tax multiplier discussed previously in my testimony.

Q. What is the basis for the depreciation rate of 3.98% on Exhibit A-30, Schedule T5?

A. The 3.98% depreciation rate is the depreciation rate filed in DTE Electric's depreciation case U-18150 for Distribution Plant. The depreciation rate is applied to the program spend for distribution operations projected for the three years shown on Exhibit A-30, Schedule T5, column (f).

Q. What is the basis for the weighted depreciation rate of 4.15% on Exhibit A-30, Schedule T6?

A. The 4.15% depreciation rate is the weighted average depreciation rates filed in DTE Electric's depreciation case U-18150 for Production Plant Steam and Production Plant Nuclear. The respective depreciation rates are applied to the program spend for generation investments projected for the three years shown on Exhibit A-30, Schedule T6, column (f).

Q. What is the purpose of page 2 of Exhibit A-30, Schedules T5, T6, and T7?

A. Page 2 of Exhibit A-30, Schedules T5, T6, and T7 shows the calculations of the accumulated deferred tax expense used in the derivation of Net Rate Base and the property taxes included in the revenue requirement, shown on page 1 of Exhibit A-30, Schedules T5, T6, and T7.

Line No.

Q. How will over and under spends of capital dollars approved for recovery under the IRM mechanism be handled in a reconciliation?

A. If the Company spends more capital dollars than were approved for recovery under any one of the three areas, Distribution Operations, Generation Operations, or the New Build, then the revenue requirement will not change. If the Company spends less capital dollars than were approved for recovery in any one or more of the three areas, then the revenue requirement will be reduced to reflect that lower level of capital spending utilizing the revenue requirement methodology and inputs, i.e., pre-tax rate of return, depreciation rates, and property tax rate, approved in this case. This reduced IRM revenue requirement will then be given to Witness Lacey who will allocate the reduced revenue requirement to the various rate schedules. Witness Lacey will then provide the cost of service by rate class to Witness Bloch who will utilize that cost of service to determine whether the Company over or under collected from each rate schedule. Witness Stanczak proposes that any over or under recovery of the IRM be deferred as a regulatory liability or regulatory asset until the next IRM reconciliation.

Q. Have you prepared an example to illustrate this?

A. Yes. Utilizing the Company's filed IRM revenue requirement methodology and inputs, I have calculated the revenue requirement of a $40.0 million under spend in the Distribution Operations area, a $40.0 million over spend in the Generation Operations area and the New Build spending exactly as planned. Exhibit A-30, Schedule T11, calculates the revenue requirement for Distribution Operations assuming a $40.0 million under spend in capital dollars in the first year of the IRM mechanism, 2020, and Exhibit A-30, Schedule T12, calculates the revenue requirement for Generation Operations assuming a $40.0 million over spend in capital dollars in the first year of the IRM mechanism. Exhibit A-30, Schedule T13, Column (c), shows the amounts that the Company proposes would be recoverable under the IRM in the 2020 IRM Reconciliation.

As shown on Line 1 of Exhibit A-30, Schedule T13, the recoverable amount for Distribution Operations shown in column (c) is the lower actual spend amount shown in column (b) reflecting the $40.0 million lower capital spend. As shown on Line 2 of Exhibit A-30, Schedule T13, the recoverable amount for Generation Operations shown in column (c) is the lower original approved spend amount shown in column (a), reflecting the approved capital spend. Line 3 of Exhibit A-30, Schedule T13, shows that there is no change in the New Build spend amount. So, even though the total actual revenue requirement amount shown in column (b), line 4, is higher the total original approved revenue requirement amount shown in column (a), line 4, the reduced revenue requirement amount in column (c), line 4, is the amount that would be recoverable under the Company's proposal to reconcile over and under spending of capital dollars.

Summary

Q. What are you proposing based on your testimony in this proceeding?

A. I am proposing that the Commission issue findings consistent with the matters presented in my testimony. Specifically, as shown in Section B, on Exhibit A-11, Schedule A1, that DTE Electric's revenue deficiency for the projected test period ending April 30, 2020 is $328.4 million.

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Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

EDWARD J. SOLOMON

DTE ELECTRIC COMPANY
QUALIFICATIONS OF EDWARD J. SOLOMON

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Q. What is your name, business address, and by whom are you employed?

A. My name is Edward J. Solomon. My business address is DTE Energy Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

Q. What is your position and on whose behalf are you testifying?

A. I am Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy Company (DTE Energy) and its subsidiaries including DTE Electric Company (DTE Electric or Company). I accepted the position of Assistant Treasurer and Director of Corporate Finance in January 2014, and had also held this position from October 2008 to April 2010. I am testifying on behalf of DTE Electric.

Q. What are your responsibilities as Assistant Treasurer and Director of Corporate Finance for DTE Electric?

A. I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities, including the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric and DTE Gas Company (“DTE Gas”). I assist with maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial policies, particularly in the areas of balance sheet management, debt issuances, and agency ratings. In addition, I manage the Company’s capital investment approval and review process along with managing the Company’s property and liability insurance function.

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Q. What is your educational background?

A. I graduated from the University of Michigan in 1987 with a Bachelor of Business degree, with a concentration in Accounting. In 1991 I graduated with my MBA from the University of Michigan, with a focus in Finance and Corporate Strategy.

Q. What is your professional experience?

A. I began my employment with Arthur Andersen & Co. in July 1987 as an auditor in the New York office. While there I earned my CPA. In 1989 I left to pursue my MBA. In 1991, after graduation, I went to work for Air Products & Chemicals in their career development program. I worked at Air Products from 1991 until 1998 when I joined DTE Energy.

In 1998, I joined DTE Energy as a Senior Financial Analyst and was the lead analyst for various subsidiary projects and studies. In 2004, I was appointed Director of Finance for DTE Energy Services, responsible for leading the financial analyst group.

In 2006, I accepted the position of Assistant Treasurer, and Director of Corporate Development. There I was responsible for managing DTE Energy's capital investment process and participated in broader strategy initiatives. In 2008, I accepted the position of Assistant Treasurer and Director of Corporate Finance and was responsible for managing the capital needs of the Company.

In 2010, I accepted the position of Chief Risk Officer and was responsible for enterprise risk management at DTE Energy. This included market risk management,

Line No.

trading company risk management monitoring and middle office operations, credit risk management, corporate insurance administration and procurement. In 2014, I accepted my current position, Assistant Treasurer and Director of Corporate Finance, Insurance and Development.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony in the following cases:

U-15768	2009 Detroit Edison General Rate Case
U-15985	2009 MichCon General Rate Case
U-16146	2009 MichCon GCR Plan
U-17680-R	DTE Electric’s 2015 PSCR Reconciliation Rate Case
U-17767	2014 DTE Electric General Rate Case
U-17999	2015 DTE Gas General Rate Case
U-18014	2016 DTE Electric General Rate Case
U-18255	2017 DTE Electric General Rate Case
U-18999	2017 DTE Gas General Rate Case

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support DTE Electric's projected capital structure and the cost of its long and short-term debt to be used in the determination of DTE Electric's overall rate of return in this proceeding. In addition, I support DTE Electric's proposed regulatory asset treatment for the tree trimming surge, with the final intent to file a securitization order for the unamortized balance of the surge costs. I provide an overview of how we plan to finance the regulatory asset, securitization bonds in general and DTE Electric's intended securitization.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. Summary of Recommendations
II. Development of Capital Structure
III. Development of Cost Rates
IV. Securitization of Tree Trimming Costs
V. Summary and Conclusions

Q. Are you supporting any exhibits?

A. Yes, I am supporting the following exhibits:

Exhibit	Schedule	Description
A-1	A2	Historical Financial Metrics
A-4	D2	Cost of Long-Term Debt – as of December 31, 2017
A-4	D3	Cost of Short-Term Debt – Twelve Month Period Ending December 31, 2017

A-4	D4	Cost of Preferred and Preference Stock – Twelve Month Period Ending December 31, 2017
A-4	D5	Cost of Common Shareholders' Equity – Twelve Month Period Ending December 31, 2017
A-11	A2	Forecasted Metrics
A-14	D1.1	Peer Group Common Equity
A-14	D1.2	Peer Group Common Equity S&P Calculation
A-14	D1.3	FFO to Debt
A-14	D2	Cost of Long-Term Debt – as of April 30, 2020
A-14	D3	Cost of Short-Term Debt – for Period Ending April 30, 2020
A-14	D4	Cost of Preferred and Preference Stock – For Period Ending April 30, 2020
A-18	H1	Current and Historical Credit Ratings
A-18	H2	Recent Utility Corporate Bond Issuances

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

I. SUMMARY OF RECOMMENDATIONS

Q. What permanent capital structure are you recommending for the projected test year to be utilized in determining the overall rate of return calculation for DTE Electric?

A. I am recommending a projected permanent capital structure of 49% long-term debt and 51% equity. Permanent capital is long-term perpetual capital. Common equity,

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preferred stock and long-term debt are sources of permanent capital. Since the Company does not have any preferred stock, I am recommending the permanent capital structure to be made up of 49% long-term debt and 51% common equity. This permanent capital structure is reflected in DTE Electric's projected permanent capital structure as of April 30, 2020, as shown in Exhibit A-14, Schedule D1, supported by Company Witness Mr. Slater. This capital structure is necessitated by the business and financial risks confronting DTE Electric, as I will discuss in greater detail later in my testimony.

Q. What is your forecast for DTE Electric's cost of long-term debt, short term debt and preferred stock for the 12-month period ending April 30, 2020?

A. I am forecasting 4.36% for the cost of DTE Electric's long-term debt, and 3.56% for the cost of DTE Electric's short-term debt. The Company does not have preferred stock and therefore it has no cost rate. Exhibit A-14, Schedule D2 supports the cost rate for long-term debt. Exhibit A-14, Schedule D3 supports the cost rate for short-term debt.

II. DEVELOPMENT OF CAPITAL STRUCTURE

Q. What do you mean by capital structure?

A. A company's capital structure includes the amount of equity and debt necessary to support the operations of its business and is defined differently by regulators, finance professionals and rating agencies. Total regulatory capital structure typically includes long-term debt, short-term debt, preferred stock, common equity, deferred taxes, deferred job development investment tax credits, and deferred investment tax credits. Permanent capital structure includes only long-term debt

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and equity. Rating agencies calculate a company's capital structure using short-term debt, long-term debt, preferred stock common equity and debt adjustments. The rating agencies adjusts debt to include items like capital and operating leases, unfunded pension liabilities, power purchase agreements and asset retirement obligations.

Q. Why is a sound capital structure important?

A. It is important to have a financially sound capital structure in order to ensure that a company can obtain needed capital. A sound capital structure produces capital costs that are reasonable and equitable. Also, it is important that the overall return on capital be sufficient to assure financial confidence in a firm and to allow it to raise the funds that are necessary to operate its business at reasonable costs and terms.

Q. How does risk affect a firm's capital structure?

A. In general, a firm such as DTE Electric faces two types of risk: business risk and financial risk. Business risk is a result of systematic and non-systematic risk. Systematic risks are broad economic risks faced by all firms. Non-systematic risks are risks specifically identified as those faced by the individual firm. Financial risk is the risk that common equity shareholders face to the extent that a firm issues debt to finance real assets. Debtholders (also known as bondholders) have priority over equity shareholders in the event of corporate bankruptcy. Thus, the greater the amount of debt held by a firm, the greater the risk to common shareholders. It is essential that a firm recognizes the dynamics of these risks and adjusts its underlying debt and equity components to produce a sound capital structure.

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Q. How does a company's capital structure impact its ability to attract capital?

A. Having a weak or highly leveraged capital structure may lead to higher required returns on equity and a higher cost of debt. It also can impact the company's ability to obtain capital. For example, a company with a highly leveraged capital structure may lose its investment grade rating from the rating agencies. Non-investment grade companies have a limited investor base and a more limited access to capital than investment grade companies. Moreover, during periods of diminished capital liquidity, even investment grade companies can have limited access to new capital sources. Furthermore, rating agencies allow little or no time for a company to correct and improve its capital structure before lowering its credit rating. Conversely, companies must be proactive to target and achieve the midpoint of the range of rating agency financial metrics to have a better chance to maintain current ratings.

Q. Will higher debt levels in a capital structure affect the cost of debt?

A. Yes. The cost of debt increases as more debt is added to the capital structure. Further, higher debt levels can increase the risk of a downgrade by the rating agencies. A lower credit rating means greater credit risk such that investors will require a higher return to invest in a company, thereby increasing the cost of debt for that company.

Q. For DTE Electric's defined projected test year, what capital structure are you recommending to be used for DTE Electric in this case?

A. For the projected test year, the permanent capital structure that I am recommending includes long-term debt and equity as shown on Exhibit A-14, Schedule D1 supported

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by Witness Slater. Within this regulatory capital structure, I am recommending a projected test year permanent capital structure that has 49% long-term debt and 51% common equity. The 51% is one percent higher than the amount approved in DTE Electric's prior rate case.

Q. What is the basis for this permanent capital structure recommendation of 49% debt and 51% equity?

A. DTE Electric is requesting an increase in its authorized equity ratio to 51% from the 50% equity level approved in the rate case U-18255. The capital structure recommendation increases the financial soundness and creditworthiness of the Company at a time when it is facing the material, negative impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA" or "tax reform"). The requested equity ratio of 51% is below the peer average, and even lower than peers when considering the significant adjustments the rating agencies make to the Company's debt calculations. The increased equity level is especially important given the significant capital investments the Company is making over the next 5 years to maintain and improve the electric infrastructure to benefit our customers. These factors are described more fully below. It is reasonable and prudent to increase the equity ratio to 51%. I will describe each of these in more detail below.

Q. Does the TCJA adversely affect the Company and its credit ratios?

A. Yes, the recently enacted federal tax reform provides uncertainty for U.S. utilities. The TCJA has significant negative impacts on a utility's cash flow and in turn its credit metrics. In June 2018, Moody's Investors Service ("Moody's") downgraded its outlook on the entire regulated utilities sector to "negative" citing lower cash flows and higher debt levels as federal tax reform and increased capital spending continue to weigh on the sector. The combination of the loss of bonus depreciation and a lower tax rate means that utilities lose some of their cash flow contribution from deferred taxes. This drives down FFO to debt and does so for DTE Electric as I will explain later.

Previously, in January 2018, Moody's revised downward the outlook of 24 regulated utilities. Moody's stated in a January 2018 publication:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.

S&P, in their January 2018 report, stated:

> While most of corporate America is bullish about the new tax regime, we believe the effect on creditworthiness of regulated utilities and their holding companies could be negative. The effect will depend on the reaction of utility regulators. The accelerated deductibility of capital expenditures is not available to utilities, and the loss of that kind of stimulus is negative for cash flow

S&P took recent action on several utilities, in part due to tax reform

- PNM Resources Inc. and subs: outlook revised to negative on New Mexico regulatory order, effects of new US tax code
- Allete Inc.: outlook revised to negative following rate decision, effects of tax reform
- Connecticut Water Service Inc. and sub: outlook revised to negative on

- weaker financial metrics, effects of tax reform
- OGE Energy Corp. and sub: outlook revised to negative on weaker financial metrics
- Fortis Inc. and subs: outlook revised to negative on weaker forecast metrics from tax reform

S&P specifically notes that the effect of the tax reform will be dependent on utility regulators. The regulator's response in rate cases post tax reform is key. Supporting DTE Electric's request for a 51% equity ratio, which will help support our credit metrics, would be viewed positively by credit rating agencies.

Most recently, on May 30, 2018, Moody's put DTE Gas on negative outlook. This is a direct result of the weakened credit metrics stemming from the changes due to tax reform.

DTE Electric's cash flow credit metrics, including Funds from Operations ("FFO") to Debt are materially weakened post tax reform. FFO to Debt is a key metric the credit rating agencies use to measure the credit quality of a utility. Exhibit A-14 Schedule D1.3 shows DTE Electric's FFO to Debt calculation as of December 31, 2017 (pre-tax reform) and a proforma calculation given the impacts of the TCJA (post-tax reform). The financial metric was calculated using S&P's methodology. The Company's FFO to Debt at December 31, 2017 was 21.2% pre-tax reform and is 17.8% post-tax reform, a 3.4% decline. This significant and material decline in a key credit metric is further evidence that the Company needs to maintain a strong balance sheet to avoid a potential downgrade or a deterioration in credit ratings outlook.

Q. Are other regulatory jurisdictions considering the impact of tax reform on rate making proceedings?

A. Yes. As the tax law changes impact utilities across the country, regulators are acknowledging the negative impact on the credit metrics of utilities and in some cases specifically allowing an increase in a company's equity ratio.

In Moody's June 2018 article, they cite regulatory efforts that allow early tax reform relief.

In Florida, the Florida Public Service Commission allowed several of the state's utilities including Florida Power & Light Company (A1 stable), Duke Energy Florida, LLC (A3 stable) and Tampa Electric Company (A3 stable) to use the bulk of customer refunds resulting from tax reform changes to offset rate increases for power restoration costs associated with the utilities' response to Hurricane Irma. Duke Energy Florida was also permitted to use a portion of the savings to accelerate the depreciation of existing coal plants.

In April, the Georgia Public Service Commission (GPSC) approved a tax reform settlement agreement allowing Georgia Power Company (A3 negative) to increase its authorized retail equity ratio, currently around 51%, to the utility's actual equity capitalization percentage or 55% (whichever is lower) until its next rate case filing, scheduled to be filed 1 July 2019.

In May, the Alabama Public Service Commission approved two supportive rate proposal requests by Alabama Power Company (A1 negative), including 1) a plan designed to improve the company's balance sheet and credit quality over time by gradually increasing its equity ratio to 55% by 2025 and 2) allowing up to $30 million of excess deferred tax liability deferrals to offset under-recovered fuel costs.

Also, in March 2018 the Florida Public Service Commission approved the establishment of a 53.5% equity ratio cap for Gulf Power, an increase from 52.5% addressing the effects of the passage of the TCJA.

Q. Is the proposed ratio of 51% equity total permanent capitalization in line with DTE Electric's peers?

A. No. The common equity ratio requested in this case is lower than that of the Company's peers. As shown on Exhibit A-14 Schedule D1.1, the average equity ratio (as a percentage of permanent capital) for DTE Electric peers was 52.8%. DTE Electric's targeted 51% equity ratio is a reasonable level given that the average ratio of the peer group is a much higher 52.8%. The peer group was selected by using Witness Vilbert's ROE proxy group, then filtering it for the operating subsidiaries with generation assets and with a rating of A or above, a peer group most similar to DTE Electric. The data was obtained from S&P Global Market Intelligence (SNL) for 2016.

In a review of other major peer utility rate cases brought before the MPSC recently, a 51% equity ratio is the lowest requested ratio among those cases. In fact, the Commission has authorized a 52% or higher equity ratio for all utilities except for DTE Electric.

Company	Case	Requested Equity %	Authorized Equity %
DTE Gas	U-17999	52.0%	52.0%
Consumers	U-18124	53.1%	53.1%
DTE Electric	U-18255	51.0%	50.0%
Consumers	U-18322	52.9%	52.6%
Consumers	U-18424	52.5%	tbd
Northern States Power	U-18462	52.5%	settled
DTE Gas	U-18999	52.0%	tbd
Consumers	U-20134	52.5%	tbd

DTE Electric believes it's requested 51% is reasonable considering the equity ratio of its peers across the country and within Michigan.

Q. What is the impact of rating agency adjustments to debt in calculating the Company's equity ratio?

A. Another reason that the equity ratio proposed in this case is justified relates to how rating agencies view the Company's equity ratio. Credit rating agencies adjust debt when calculating debt to equity ratios. Moody's and Standard and Poor's ("S&P") add unfunded pensions, operating leases and other items to their calculation of DTE Electric's debt.

The average equity ratio (as a percentage of permanent capital at the regulated subsidiary level) for the Company's peer group before rating agency adjustment was 52.8%, comparable to the 51.0% proposed for DTE Electric in this case. This is reflected on Exhibit A-14 Schedule D1.1. However, after considering S&P adjustments to debt, the average equity ratio for the peer group is 47.8%, compared to 44.6% for DTE Electric. This is reflected on Exhibit A-14 Schedule D1.2. On an adjusted basis, the Company's equity ratio is 3.2% lower than peers, reflecting the relatively higher amount of debt assigned to DTE Electric by S&P. This supports the need for the Company to maintain a relatively higher equity ratio before adjustment to be on par with comparable utility companies after adjustment. However, even though this analysis would support an equity ratio before adjustment for the Company of up to 55.9% (peer average before rating agency adjustment of 52.8% plus 3.1%), I am proposing a rate of 51.0% which balances capital investment plans, credit metrics, and customer rate impacts, and is consistent with recent actual balances as well as recent rate case results.

Q. Does the intense capital investment program contribute to the need for a higher level of equity within the capital structure?

A. It is imperative that DTE Electric be viewed as a financially sound firm with a solid investment grade rating to ensure the reasonableness and competitiveness of capital costs. DTE Electric will be financing and funding over $4 billion of electric capital expenditures for the period January 2018 through April 2020 as shown in Exhibit A-12, Schedule B5. A capital structure consisting of 51% equity will enhance the credit quality and financial soundness of DTE Electric during this period of significant system investment. The common equity balance and equity ratio projected for the test year in this case enables the Company to maintain strong credit ratings and better withstand any shocks in the financial markets, thereby ensuring a smooth implementation of its capital expenditure program.

Q. Is DTE Electric committed to maintaining a 51% equity ratio in its capital structure?

A. Yes. At December 31, 2017, DTE Electric’s equity ratio was 51%. DTE Electric is committed to maintaining a 51% equity ratio and has demonstrated its commitment to its targeted equity ratio by receiving equity infusions from DTE Energy. DTE Energy has made reasonable efforts to strengthen DTE Electric's credit quality by infusing $1.7 billion of common equity since 2006, including recent equity infusions of $190 million in 2014, $300 million in 2015, $120 million in 2016, and $100 million in 2017. DTE Electric has planned equity infusions of $372.2 million in 2018, $200 million in 2019, and $200 million in January to April 2020, which will result in a 51% equity ratio for the projected test period.

Q. How does a capital structure of 51% equity to permanent capital benefit customers?

A. DTE Electric is requesting an increase in its authorized equity ratio to 51% from the 50% authorized in the last rate case. The capital structure recommendation increases the financial soundness and creditworthiness of the Company at a time when it is facing the material, negative impacts of the TCJA. The negative impacts of the TCJA could potentially lead to a downgrade. Strengthening the balance sheet will help provide stability to withstand cash flow volatility. A ratings downgrade reduces access to capital and could negatively impact credit spreads by 25-50 basis points (bps), increasing the cost of debt and adding to customer costs. Maintaining our current ratings and leaving an adequate cushion for unforeseen events allows for lower borrowing costs which results in lower rates to customers and customer rate stability.

III. DEVELOPMENT OF COST RATES

Q. What were DTE Electric's historical financial and ratemaking metrics from 2013 through 2017?

A. DTE Electric's historical financial and ratemaking metrics for each of the previous five

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years (2013 through 2017) are detailed in Exhibit A-1, Schedule A2. The historical financial calculations include year-end financial metrics and are calculated on a financial basis from DTE Electric's financial reports. The historical ratemaking metrics include year-end financial metrics and are calculated from DTE Electric's annual regulatory filings

Q. What is the cost of long-term debt outstanding at December 31, 2017?

A. Exhibit A-4, Schedule D2 calculates the cost of the long-term debt outstanding at December 31, 2017. As shown in the exhibit and schedule, the cost of long-term debt also includes agent's fees, commissions and financing expenses and is calculated on the net proceeds to the Company. The weighted average cost of debt is computed based on the total annual costs to the Company divided by the total principal amount outstanding at year-end. The cost of long-term debt at December 31, 2017 was 4.37%.

Q. What is the cost of short-term debt outstanding at December 31, 2017?

A. The cost of short-term borrowings for the 13-month period ended December 31, 2017 was 1.59%. The cost of short-term debt consists of the 1) interest rate on short-term borrowings and, 2) facility fees associated with the credit agreements necessary for the issuance of short-term debt. See Exhibit A-4, Schedule D3.

Q. What was the approved cost of equity in 2017?

A. DTE Electric's authorized cost of common shareholders' equity as of December 31, 2017 was 10.1% and was approved in Case No. U-18014. DTE Electric does not have any preferred stock. See Exhibit A-4, Schedules D4 and D5.

Q. What does DTE Electric project its financial metrics to be in the test year?

A. DTE Electric's forecasted ratemaking metrics are available in Exhibit A-11, Schedule A2. Forecasted calculations include metrics for the fully projected test year. The forecasted ratemaking metrics for the projected test year are to be reported assuming (i) full rate relief as requested, and (ii) zero rate relief.

Q. What is the purpose of Exhibit A-14, Schedule D2?

A. The purpose of Exhibit A-14, Schedule D2 is to calculate DTE Electric's projected weighted average long-term debt costs as of April 30, 2020. Starting with the actual December 31, 2017 long-term debt outstanding, any known and measurable changes for each year were made to arrive at the projected balance as of April 30, 2020. Known and measurable changes that have occurred or are projected to occur from January 1, 2018 through April 30, 2020 include:

	Amount ($000)	**Date**	**Rate**
issuance	$525,000	May 2018	4.05%
issuance	250,000	April 2019	4.42%
issuance	305,000	Oct 2019	4.42%
Net change in debt	$1,080,0000		

The interest rate for the debt issuances is projected to be 4.42% for the debt issued in 2019 and is based on forward long-term borrowing rates of A-rated utilities, which is comparable to DTE Electric's credit rating. These forward rates were obtained from Bloomberg, a leading provider of financial data, news and analytics, in May 2018. Including the planned long-term debt issuance, the weighted average long-term debt cost as of April 30, 2020 is projected to be

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4.36%.

Q. Why did you use long-term debt cost on a net proceeds basis?

A. The actual costs would be understated if the net proceeds were not used in the base calculation. The net proceeds methodology accounts for underwriters' compensation and other financing expenses and is shown on Exhibit A-14, Schedule D2. A portion of any amount financed is used to fund these costs, such that the Company has access to less than the full amount financed. As a result, these fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the effective cost of the issuance above the stated coupon rate.

Q. How did you determine the interest rate on short-term debt on Exhibit A-14, Schedule D3?

A. The cost of short-term debt consists of: 1) the interest rate on short-term borrowings, and 2) facility fees associated with the credit agreements necessary for the issuance of short-term debt (Facility Fees).

The interest rate on short-term borrowings was determined by adding 8 bps to forecasted London Interbank Offering Rate (LIBOR). A spread of 8 bps was added to LIBOR because that is the average spread on DTE Electric's recent commercial paper issuances.

The average forecast for 1 month LIBOR for the 13-month period ending April 30, 2020 is 2.77%. The forecast was obtained from Bloomberg in May 2018. Adding

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the spread of 8 bps to the forecasted 1 month LIBOR rate of 2.77% brings the interest rate on short-term borrowings to a total of 2.85%.

The cost of short-term debt also includes Facility Fees associated with maintaining credit facilities. Credit facilities provide short-term liquidity and can be used to support the issuance of commercial paper or can be drawn upon to provide short-term funding. DTE Electric presently has a $400 million credit agreement that expires in April 2022, so the costs related to the facility are known and measurable. Facility Fees for the credit agreement for the 12 months ending April 30, 2020 are $0.8 million. The cost of short-term debt including Facility Fees for the projected test period is 3.56%.

Q. What is the purpose of Exhibit A-14, Schedule D4?

A. Exhibit A-14, Schedule D4 shows that DTE Electric does not plan to have preferred or preference stock during the projected test period.

Q. What are the Company's current and historical credit ratings?

A. Exhibit A-18, Schedule H1 shows DTE Electric's and DTE Energy's current and historical credit ratings, along with associated rating agency outlooks, for the previous five years as published by S&P, Moody's and Fitch Ratings (Fitch). The credit ratings include senior unsecured debt, senior secured debt, and commercial paper ratings.

Q. Have there been recent public utility bond issuances?

A. Yes, I have provided details of public utility bond issuances for the three-month period prior to, through the three-month period after, each of DTE Electric's long-term debt offerings issued during the twenty-four months prior to the date of the filing of this case. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, maturity date, structure of offering, S&P and Moody's ratings, and issue spread. See Exhibit A-18, Schedule H2.

IV. SECURITIZATION OF TREE TRIMMIMNG COSTS

Q. Do you support DTE Electric's intent to file a securitization order in connection with tree trimming costs?

A: Yes, I support DTE Electric's proposed regulatory asset treatment for the tree trimming surge program, with the final intent to file a securitization application for the unamortized balance of the surge costs. I provide an overview of how we plan to finance the regulatory asset, securitization bonds in general and DTE Electric's intended securitization.

Q. How will the Company finance the regulatory asset prior to issuing the securitization bonds?

A. Prior to securitization, the regulatory asset will be financed consistent with the capital structure requested in this case – 51% equity and 49% debt of permanent capital.

Q. When does the Company intend to file for securitization?

A. The Company intends to securitize the regulatory asset when the surge cost regulatory asset balance reaches approximately $100 million. The Company will

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securitize additional surge costs in future securitizations. This is currently expected to occur every other year.

Q. Please provide a simple description of securitization.

A. Securitization is the financing of a discrete asset or group of assets by a utility with securities whose credit quality is separated from that of the utility in order to achieve higher credit ratings and lower financing costs. An example of securitization can be found in Case No. U-12478, which relate to DTE Electric's 2001 FERMI II securitization financing. To accomplish this, the utility sells the revenue stream and other entitlements and property created by the financing order to a newly-established bankruptcy remote special purpose entity ("SPE" or "Issuer") in a transaction which, consistent with the Act, represents a "true sale" for bankruptcy purposes. This sale insulates the securitization property from the creditors of the utility and, thereby, from the credit risk of the utility. The SPE then issues bonds backed by the securitization property and other collateral to investors / bondholders. A trustee acts on behalf of bondholders, remits payments to bondholders and ensures bondholders' rights are protected in accordance with the terms of the financing documents. The Company will perform routine billing, collection, and reporting duties as the servicer for the Issuer pursuant to a servicing agreement between the Company, the Issuer and the trustee. In addition to the bankruptcy remote status of the Issuer, credit enhancements, such as a capital contribution to the Issuer and a true-up mechanism, are necessary to reach the rating standard for this type of securitization, which is the highest rating (a "triple-A rating") from each of two or more of the major rating agencies.

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Q. Will the intended securitizations benefit customers?

A. Yes. Customers will receive tangible and quantifiable benefits from the intended securitizations since the net present value (NPV) of the estimated revenue requirements collected under the intended securitization financing orders will be less than the NPV of the estimated revenue requirements that would be recovered over the remaining life of the qualified costs using conventional financing. These benefits from intended securitizations are due to the fact that the interest rate on the intended securitization bonds is expected to be less than the pre-tax cost of capital of 6.63% used in the Company's rates based on conventional financing.

Q. Please describe the structure of DTE Electric's Intended Securitization.

A. The precise terms and conditions of the Intended Securitization will not be known until just prior to the time of sale, which is anticipated to take place around Q4 2020 for the first bond. The bond structure will reflect specific input from the rating agencies and be adjusted to current market conditions and investor preferences so that the lowest financing costs and highest credit ratings can be achieved. This flexibility will serve the goal of obtaining the lowest interest rates consistent with market conditions and the terms of the future financing orders.

There will be up-front costs associated with each intended securitization bond. These costs are yet to be determined, but the Company will attempt to reduce these costs if possible at time of execution.

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Q. Will the intended securitization bonds pay fixed or floating rates?

A. It is my recommendation that the future issued bonds pay fixed rates, which is consistent with recent similar utility securitization bonds precedent. Fixed rates enable the costs and benefits to be evaluated in advance and insure roughly equal charges over time.

Q. What is the expected tenor of each future securitization bond?

A. The precise terms and conditions of the Intended Securitization will not be known until just prior to the time of sale, which is anticipated to take place around Q4 2020 for the first bond. The term of the bond could range up to 14 years, and it is expected that the debt service payment dates will occur every six months after their corresponding issue date.

Q. How does the company intend to use the proceeds of the future intended securitization?

A. The proceeds of the intended securitization bonds will be used to retire debt and equity at the capitalization rate approved (i.e., 51% equity and 49% debt).

Q. Please describe the ongoing billing, collection and remittance of securitization charges over the life of the Intended Securitization.

A. As is the case for the prior issuances of securitization bonds, DTE Electric, as servicer, will be responsible for billing and collecting securitization charges for the future issuance of securitization bonds. All of the infrastructure necessary to accomplish this is in place and has worked well. DTE Electric as servicer will remit collections to the trustee and the trustee will distribute amounts to bondholders in accordance with the terms of the transaction.

Q. What discount rate do you recommend is used to evaluate the tree trimming surge program?

A. I recommend a discount rate of 6.63% be used to evaluate the tree trimming surge program. This rate is based on the current authorized pre-tax cost of capital per Order in Case No. U-18255, adjusted for a lower tax multiplier due to change in federal corporate income tax rate which went into effect January 1, 2018.

V. SUMMARY AND CONCLUSIONS

Q. Can you summarize your recommendation and conclusions?

A. Due to the material impacts of tax reform on the Company's credit metrics and significant business risks faced by the Company as outlined in my testimony, a projected permanent capital structure of 49% long-term debt and 51% equity is reasonable and prudent. DTE Energy has taken reasonable actions to strengthen DTE Electric's credit quality and has done so by infusing $1.6 billion of common equity since 2006 and will continue to do so as needed. The plan calls for additional equity infusions and retained earnings growth through the test period in the amount necessary to maintain the Company at no less than a ratio of 51% equity to permanent capital at April 30, 2020. For the projected year, the cost of short-term debt is projected to be 3.56%, and the cost of long-term debt is projected to be 4.36%. I believe these expenses and measures are reasonable, prudent and necessary. In addition, I support DTE Electric's proposed regulatory

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asset treatment for the tree trimming surge, with the final intent to file a securitization order for the unamortized balance of the surge costs.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS OF THERESA M. UZENSKI

Q. What is your name, business address and by whom are you employed?

A. My name is Theresa M. Uzenski. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company. My business address is One Energy Plaza, Detroit, MI 48226.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I have a Bachelor of Science in Accounting from the University of Detroit and a Masters of Business Administration with a concentration in Finance from Wayne State University.

Q. What is your work experience and what position do you currently hold at DTE Energy?

A. I have worked for DTE Energy or one of its affiliated regulated utilities for twenty-nine years in various accounting, finance and management positions. I am currently the Manager of Regulatory Accounting for DTE Electric Company as well as DTE Gas Company. As Manager of Regulatory Accounting, I am responsible for the development and management of regulatory accounting policies and practices, as well as supporting regulatory filings. My department analyzes the accounting implications of new legislation and Michigan Public Service Commission (Commission or MPSC) orders, and provides expert testimony on accounting issues and financial projections in various proceedings before the MPSC. We research and establish accounting policies, and assist the accounting operations departments with

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implementation. My department also supports other Company expert witnesses in various proceedings before the MPSC by preparing historical and projected financial statements as well as other financial analysis.

Q. Do you hold any certifications and are you a member of any professional organizations?

A. I am a Certified Management Accountant, a member of the Institute of Management Accountants, and a member of the Corporate Accounting Committee of the Edison Electric Institute and American Gas Association.

Q. To what extent have you participated in prior rate cases and other regulatory proceedings?

A. I have sponsored testimony in the following cases:

U-11222	Michigan Consolidated Gas Company (MichCon) Depreciation
U-13898	MichCon UETM
U-14702	Detroit Edison 2006 PSCR Plan
U-15160	Detroit Edison Enhanced Security Cost Recovery
U-15244	Detroit Edison Choice Incentive Mechanism Reconciliation
U-15259	Detroit Edison Pension Equalization Mechanism
U-15417-R	Detroit Edison Pension Equalization Mechanism
U-15806-EO	Detroit Edison Energy Optimization
U-15768	Detroit Edison UETM
U-15890	MichCon Energy Optimization
U-16009	Complaint Case against Detroit Edison
U-16246-R	Detroit Edison 2009 RETM Reconciliation

U-16246-R	Detroit Edison 2010 RETM Reconciliation
U-16356	Detroit Edison 2009 REP Reconciliation
U-16472	Detroit Edison 2010 Rate Case
U-16574	Detroit Edison 2010 UETM Reconciliation
U-16582	Detroit Edison 2011 REP Plan
U-16769	MichCon Depreciation
U-16952	Detroit Edison 2011 CIM Reconciliation
U-16956	Detroit Edison 2011 RETM Reconciliation
U-16964	Detroit Edison 2011 UETM Reconciliation
U-17302	DTE Electric Company 2016 REP Plan Update
U-17437	DTE Electric Company Transitional Cost Recovery Mechanism
U-17767	DTE Electric Company 2014 Rate Case
U-17999	DTE Gas Company 2015 Rate Case
U-18014	DTE Electric Company 2016 Rate Case
U-18122	DTE Electric Company Customer 360 Program Accounting
U-18255	DTE Electric Company 2017 Rate Case
U-18419	DTE Electric Company Certificates of Necessity
U-18999	DTE Gas Company 2017 Rate Case
U-20106	DTE Gas Tax Cut & Jobs Act – Credit A
U-20105	DTE Electric Tax Cut & Jobs Act – Credit A

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support DTE Electric's financial statements for the historical test year ended December 31, 2017, the interim forecast period and a twelve-month projected test period ending April 30, 2020, with certain adjustments necessary for presenting the financial information in the appropriate format for ratemaking purposes. My testimony supports the development of the projected test year adjusted electric operating income based on forecasted changes from the normalized historical electric operating income. I will discuss how costs recovered from other mechanisms are excluded from the financial statements in this case (including the Transitional Recovery Mechanism for the transition of Detroit Public Lighting Department customers, Renewable Energy Program, Energy Waste Reduction, etc.). I will explain the Company's treatment of the non-service components of pension and other post-retirement benefits (OPEB) expense as approved in Case No. U-18255.

I will support the Corporate Staff Group (CSG) capital and O&M expenses for the historical and forecasted periods and explain the function of this group and the method for allocating costs to DTE Electric and the other DTE subsidiaries. I will support the inclusion of Customer 360 post implementation expenses incurred in June through December 2017 in the regulatory asset. I will request regulatory asset treatment for rebates related to the Company's proposed Electric Vehicle Infrastructure program supported by Company Witnesses Mr. Serna and Mr. Clinton. I will request regulatory asset treatment for certain costs related to a new Advanced Distribution Management System (ADMS), supported by Company Witness Mr. Bruzzano. I will request regulatory asset treatment for the Company's proposed Tree

Trim Surge program supported by Company Witness Ms. Rivard. I will explain the accounting for the Company's proposed capital Investment Recovery Mechanism (IRM) supported by Company Witness Mr. Stanczak. Finally, I will request regulatory asset treatment for one-time costs to implement new time-of-use rates.

Q. Are you sponsoring any exhibits along with your testimony?

A. Yes. I am supporting the following exhibits for the historical period:

Exhibit	Schedule	Description
A-2	B2	Historical Utility Plant
A-2	B3	Historical Depreciation Reserve
A-2	B4	Historical Working Capital
A-2	B5	Historical Adjusted Balance Sheet with Classifications
A-2	B5.1	Historical Year Ended Balance Sheet with Classifications
A-2	B6	Historical Adjusted Balance Sheet – Year Ended and 13-month Average
A-2	B6.1	Historical Year-End Adjusted Balance Sheet
A-2	B6.2	Historical 13 Month Average Adjusted Balance Sheet
A-2	B7	ARO & Nuclear Decommissioning Trust Fund
A-3	C1	Historical Adjusted Net Operating Income
A-3	C1.1	Adjustments to Historical Net Operating Income
A-3	C3	Historical Operating Revenue
A-3	C4	Historical Fuel and Purchased Power
A-3	C5	Historical Operation and Maintenance Expenses
A-3	C6	Historical Depreciation and Amortization Expenses

A-3	C11	Historical Allowance for Funds Used During Construction
A-3	C14	Historical Corporate Membership Adjustment
A-3	C15	Historical Advertising Adjustment
A-3	C16	Historical MERC Net Operating Income
A-3	C17	Historical Executive Incentive Compensation Elimination
A-3	C18	Historical Employee Incentive Plan Normalization Adjustment
A-3	C19	Historical Weather Normalization Adjustment

I am supporting the following exhibits for the projected test year:

Exhibit	Schedule	Description
A-12	B2	Projected Utility Plant
A-12	B3	Projected Depreciation Reserve
A-12	B4	Projected Working Capital
A-12	B4.1	Balance Average Balance Sheet with Classification
A-12	B4.2	Projected Balance Sheet
A-12	B4.3	Common Equity Reconciliation
A-12	B5	Projected Capital Expenditures - Summary
A-12	B5.8	Projected Capital Expenditures – Corporate Staff
A-13	C1	Projected Net Operating Income
A-13	C3	Projected Operating Revenue
A-13	C5	Projected O&M Expense – Summary
A-13	C5.9	Projected Administrative and General Expenses

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A-13	C5.13	Customer 360 Regulatory Asset
A-13	C5.15	Inflation Factors
A-13	C5.17	PERC (Nuclear Projects) Regulatory Asset
A-13	C6	Projected Depreciation and Amortization Expense
A-13	C11	Projected Allowance for Funds Used During Construction
A-13	C12	Projected Amortization of the loss on Reacquired Debt
A-13	C13	Projected Other Income / (Deductions)
A-22	L3	Amortization of Deferred Surge Program Costs
A-30	T1	IRM Capital Summary

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How were your exhibits prepared?

A. My team uses an excel model to create historical and projected balance sheets and income statements, and the supporting exhibits. We also have models to capture historical and projected O&M and capital expenditures. The O&M and capital models feed into the financial statement model. Our models start with historical financial information from the MPSC Annual Report on Form P-521. I calculate most of the rate case normalizations and adjustments to the historical balance sheet and income statement, but other Company witnesses calculate the adjustments to the O&M and capital expenditures for the business unit costs that they support. In addition, Company Witnesses Mr. Slater and Ms. Wisniewski support certain adjustments to interest and taxes. I support the O&M and capital costs for the

Corporate Support Group (CSG) other than Information Technology (IT).

After the normalizations and adjustments are made to the historical period, I use the adjusted amounts to develop the financial statements for the projected period. Again, the witnesses supporting their business unit costs provide the known and measurable adjustments to O&M expense and the details for the capital expenditures. Sales revenue and fuel and purchased power are calculated by Company Witnesses Mr. Bloch and Ms. Holmes. Income and property taxes are calculated by Witness Wisniewski. All the data from these witnesses are captured in my models to create the consolidated financial statements for the projected period. My projected financial statement data is then used by Witness Slater to calculate the revenue deficiency.

Historical Test Year

Q. What information are you providing regarding the Historical Test Year ended December 2017?

A. For the historical test year ended December 2017, I am providing the balance sheet and net operating income information with certain adjustments that are necessary to present the financial information in the appropriate ratemaking format. The adjusted historical financial statements are the starting point in creating the financial statements for the projected test period.

Historical Balance Sheet

Q. What historical test year balance sheet information are your providing?

A. Exhibit A-2, Schedules B2 and B3 provide the historical utility plant and depreciation reserves, respectively. Schedule B4 provides the historical thirteen-month average

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for working capital. Schedule B5 classifies the historical balance sheet information into the categories of net plant, working capital, and the various financing components adjusted to use a thirteen-month average for working capital. Schedule B5.1 provides the same classifications based on a historical year-end balance.

Exhibit A-2, Schedule B6 shows the historical balance sheet amounts incorporating the adjustments detailed on schedules B6.1 and B6.2. Schedule B6.1 contains the historical test year balance sheet information as of December 31, 2017. Schedule B6.2 is a 13-month average balance sheet for the periods December 2016 through December 2017. The columns for both schedules detail the same types of adjustments.

Column (b) values are from the MPSC Annual Report on Form P-521. Column (c) adds the balance sheet values for the Midwest Energy Resources Company (MERC), a wholly owned subsidiary of DTE Electric involved in low-sulfur western coal storage and transshipment operations. MERC has been incorporated in the preparation of all exhibits. Pursuant to the Commission's Order in Case No. U-5108, capital costs incurred by MERC, including depreciation and property taxes, administrative expenses, income tax, interest, and return on rate base are to be considered in the Company’s main electric ratemaking process. Column (d) is the consolidated balance on which I base my adjustments.

Q. What adjustments are you making to the consolidated historical period financial statements?

A. Consistent with the treatment in past cases, I am reclassifying certain items, removing non-utility items, and removing balances that are being recovered or refunded via other mechanisms or surcharges including Energy Waste Reduction, Renewable Energy Program, Transitional Recovery Mechanism, and Power Supply Cost Recovery. For each regulatory asset and liability amount excluded, I removed the related Accumulated Deferred Federal Income Tax (ADFIT) with the remaining capital removed from short-term debt, as these items are considered temporary working capital requirements. Additionally, I am removing the Combined Operating License (COL).

The adjustments are shown on the balance sheets on Exhibit A-2, Schedules B6.1 and B6.2, columns (e) through (l). Since I used the adjusted historical period to build the forecast, I did not have to make these same adjustments to the projected period. I discuss each adjustment below.

Q. What is the adjustment for taxes?

A. Column (e) nets the Accumulated Deferred Income Tax Asset on line 50 and the Investment Tax Credit (ITC) related to the Ludington facility on line 90, with the Accumulated Deferred Income Tax Liability on line 89. The ITC amount reflected in the reclassification is supported by Witness Wisniewski.

Q. What is the adjustment for the COL?

A. Per the Commission's orders in Case Nos. U-18014 and U-17767, the COL asset is being amortized over twenty years but the balance remaining must be excluded from rate base. Therefore, in column (f) I have removed both the COL asset reflected on the books of DTE Electric and the related accumulated deferred federal income tax liability. I removed the remaining capitalization of debt and equity at 50% and 50%, respectively.

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Q. What are the adjustments for programs and recovery mechanisms in columns (g) through (i)?

A. Column (g) eliminates DTE Electric's Energy Waste Reduction (EWR) program. Column (h) eliminates our Renewable Energy Program (REP), except for the regulatory liability, and column (i) eliminates the Transitional Recovery Mechanism (TRM) related to the conversion of Detroit's Public Lighting Department customers to DTE Electric. The associated debt and equity eliminations are consistent with the capital structures authorized by the Commission for each program.

Q. If the REP is excluded from base rates, then why are you not eliminating the associated regulatory liability?

A. The regulatory liability generated from the REP program is not eliminated because it is being used as a source of financing for DTE Electric's general rate base. Therefore, I have reclassified the balance out of the regulatory liability on line 84 and reflected it as short-term debt on line 76.

Q. Why are you showing the REP regulatory liability as a source of financing for general rate base instead of REP rate base?

A. Consistent with the Commission's order in Case No. U-15806 the return embedded in the REP surcharge reflects DTE Electric's approved cost of capital, primarily long-term debt and equity. However, because the REP revenue requirement is being collected in a surcharge separate from base rates, the liability generated from the surcharge is available to reduce DTE Electric's other short-term debt, as approved by the Commission in Case No. U-15806.

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Q. If DTE Electric is using the regulatory liability as a source of financing, then how are DTE Electric's customers compensated?

A. The REP revenue requirement and surcharge is reduced by interest accrued on the regulatory liability.

Q. What accounting adjustments are reflected in the Company's financial presentation for the historical test year in this case?

A. This rate case reflects adjustments for ASC 410, Accounting for Asset Retirement Obligations, (f/k/a FAS 143 and FIN 47) and ASC 715, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans (f/k/a FAS 158) because the accounting impacts are excluded from the revenue requirement.

Q. What is the adjustment for asset retirement obligations?

A. The accounting for asset retirement obligations (ARO) results in timing differences in the recognition of legal asset retirement costs for accounting purposes, compared to the recognition of amounts the Company is currently recovering in rates. ARO accounting requires an up-front accrual for future legal removal costs as a liability. Utility accounting recognizes the removal obligation in accumulated depreciation and accrues it through depreciation expense over the life of the asset. The timing differences are deferred under ASC 980, Accounting for the Effects of Certain Types of Regulation, (f/k/a FAS 71). The ARO liability is offset by a corresponding net plant Asset Retirement Cost and a regulatory asset, resulting in no impact on the revenue requirements in this case. A regulatory asset does not offset the incremental liability related to the non-utility Fermi 1 site.

Line
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To ensure that there is no impact on revenue requirements from ARO accounting in the forecast years, I have removed all 2017 regulated balance sheet impacts on Exhibit A-2, Schedules B6.1 and B6.2, column (j). I also removed the ARO for Fermi 1 and the related decommissioning trust fund asset. In addition, I have removed the decommissioning obligation and related trust fund assets for Fermi 2. The details of the balance sheet eliminations are shown on Exhibit A-2, Schedule B7.

Q. What are the ARO and Nuclear Decommissioning Trust Fund eliminations shown on Exhibit A-2, Schedule B7?

A. Exhibit A-2, Schedule B7 shows the components of ARO accounting as well as nuclear decommissioning that are included in the unadjusted historical balance sheet. The removal of the ARO items is consistent with DTE Electric's presentation that was reviewed and accepted by the Commission in all its rate cases beginning with Case No. U-15244.

Q. Why did you eliminate the Nuclear Decommissioning Trust Fund for Fermi 2?

A. The assets and related liabilities for Fermi 2 decommissioning net to zero with no impact to rate base. To make this transparent, I removed all the line items from the historical balance sheet consistent with the Company's presentation that was reviewed and accepted by the Commission in its rate cases beginning with Case No. U-18014.

Q. Can you explain the adjustment for benefit plans?

A. ASC 715 requires the recognition of the unfunded liabilities for defined benefit pension and other postretirement plans with a charge to other comprehensive income within equity. DTE Electric recorded a regulatory asset in place of the charge to other comprehensive income because the costs are included in rates consistent with when the expense is recognized in the income statement. Since the liability and offsetting regulatory asset result in no change to revenue requirements, Exhibit A-2, Schedules B6.1 and B6.2, column (k) eliminates the 2017 balance sheet impacts related to ASC 715. This treatment is also consistent with DTE Electric's presentation in all its rate cases starting with Case No. U-15244.

Q. Why are you eliminating the items in column (l), Other?

A. Column (l) eliminates an asset for power supply cost recovery that is reconciled in the PSCR mechanism. It also removes non-utility amounts from DTE Electric's consolidated balance sheets including the Detroit Investment Fund and a pre-paid lease for a parking structure and a related deferred gain on the sale of land that is amortized below the line. In prior cases, the Commission ordered that these items are to be excluded from rate base.

Q. What information is contained in column (m), on Exhibit A-2, Schedule B6.1?

A. Column (m), "Total Electric" represents the DTE Electric balance sheet as of December 31, 2017, after adjustments. This Total Electric December 2017 balance sheet is used by Witness Slater in determining DTE Electric's year-end historical rate base and capitalization.

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Q. What information is contained in column (m), Total Electric, on Exhibit A-2, Schedule B6.2?

A. Column (m), Total Electric, represents the DTE Electric balance sheet after the adjustments previously discussed. These 2017 Total Electric 13-month average balances are used by Witness Slater in determining DTE Electric's average historical rate base and capitalization.

Q. What information is shown on Exhibit A-2, Schedule B6?

A. Exhibit A-2, Schedule B6, page 1 is the Assets and Other Debits portion, and page 2 is the Liabilities and Other Credits portion of the DTE Electric Adjusted Balance Sheet for December 2017. Column (b) reflects December 31, 2017 balances while Column (c) represents the 13-month average balances. Both columns are carried from column (m) of Exhibit A-2, Schedules B6.1 and Schedule B6.2, respectively.

Historical Income Statement

Q. What information are you supporting on Exhibit A-3, Schedules C1 and C1.1, Adjustments to Historical Net Operating Income?

A. On Exhibit A-3, Schedules C1 and C1.1, DTE Electric's Adjusted Net Operating Income for the year ended December 31, 2017 was determined by starting with the financial information reported on the Company's MPSC Annual Report Form P-521, page 114. Then I adjusted the reported financial information for certain exclusions and inclusions to get to a rate case filing level. The rate case filing level was further adjusted by normalizations to remove unusual or one-time events. I support all adjustments to Net Operating Income on Exhibit A-3, Schedule C1.1, except for line 22 which is supported by Company Witness Mr. Paul; line 23 supported by Witness

Bruzzano; lines 24 and 25 which are supported by Company Witness Ms. Johnson; line 27 supported by Company Witness Mr. Cooper; and lines 34 and 35 which are supported by Witness Slater.

Q. What information is displayed in Exhibit A-3, Schedule C3, Historical Operating Revenue?

A. Schedule C3 provides the amounts as reported on MPSC Annual Report Form P-521 for retail, wholesale, refund provisions and miscellaneous revenues, underlying the total revenue for the 12-month period ended December 31, 2017 and is carried forward to line 1, column (c), of Exhibit A-3, Schedule C1.1.

Q. What is the purpose of Exhibit A-3, Schedule C4, Historical Fuel and Purchased Power?

A. Schedule C4 provides the amounts as reported on MPSC Annual Report Form P-521 for various accounts associated with power supply expenses for the 12-month period ended December 31, 2017 and is carried forward to Exhibit A-3, Schedule C1.1, column (d), line 1. Purchased Power is included to tie out DTE Electric's historical net operating income. As described by Witness Holmes, the Company is not proposing to re-set the cost of base power supply in this case and has calculated its power supply costs equal to the associated power supply revenues so no under or over recovery is projected. Any actual under or over recovery of power supply costs are reconciled in the annual Power Supply Cost Recovery (PSCR) reconciliation filings.

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Q. What information is displayed in Exhibit A-3, Schedule C5, Historical Operation and Maintenance Expense?

A. Schedule C5 provides the amounts as reported on MPSC Annual Report Form P-521 for operation and maintenance expenses, adjusted to exclude fuel and purchased power expense, for the 12-month period ended December 31, 2017 and is carried forward to Exhibit A-3, Schedule C1.1, column (e), line 1.

Q. What information is displayed in Exhibit A-3, Schedule C6, Historical Depreciation and Amortization Expenses?

A. Schedule C6 provides the amounts as reported on MPSC Annual Report Form P-521 for various accounts related to depreciation and amortization expense for the 12-month period ended December 31, 2017 and is carried forward to Exhibit A-3, Schedule C1.1, column (f), line 1.

Q. What information is contained on line 1 of Exhibit A-3, Schedule C1.1?

A. Net Operating Income of $851.6 million is on line 1, column (m) and ties to the MPSC Annual Report Form P-521, page 114, line 26.

Q. Why do you adjust Net Operating Income on Exhibit A-3, Schedule C1.1, lines 3 through 36?

A. These adjustments reflect certain inclusions and exclusions to the reported Net Operating Income amount to arrive at an allowable rate case filing level. The inclusions for AFUDC, interest and dividend income, MERC operating income, customer interest, and amortization of loss on reacquired debt are allowable for ratemaking, but they fall below the calculation of Net Operating Income on the

Line No.

Income Statement. Conversely, the exclusions for certain corporate memberships and advertising, executive incentives, and regulatory assets and liabilities recovered under separate surcharges <u>are not</u> allowable for ratemaking, but they fall within the calculation of Net Operating Income on the Income Statement.

Q. What adjustments to Net Operating Income did you make on lines 3 and 4 of Exhibit A-3, Schedule C1.1?

A. Line 3 reclassifies fuel handling from Fuel and Purchased Power to O&M. Line 4 represents interest income of $0.1 million relating primarily to inter-company loans. Similar to AFUDC, the benefit of interest income is included as an adjustment to Electric Net Operating Income.

Q. What are the adjustments on lines 5 through 8, and how are these adjustments supported by Schedules C14 through C17?

A. Exhibit A-3, Schedule C14, supports line 5, Disallowed Corporate Memberships. This schedule calculates the disallowance of social and service organization membership expense for the year ended December 2017. The adjustment decreases O&M expense by $0.6 million and increases net operating income by $0.3 million.

Line 6, Disallowed Advertising Expenses, is supported by Schedule C15, which classifies year ended December 2017 electric advertising expenses by categories as prescribed by the standard filing requirements. Allowable advertising expenses for ratemaking include public safety, conservation and billing practices. This exhibit identifies the advertising expenses that are allowed by the Commission and removes the remaining advertising expense. This adjustment results in a decrease in O&M

expense of $0.9 million and an increase in net operating income of $0.6 million.

Line 7, MERC NOI Adjustment, is supported on Schedule C16. MERC's net income is effectively included in DTE Electric's net operating income (NOI) on Schedule C1.1, line 1. This occurs in two ways. First, MERC charges DTE Electric for fuel handling and that charge is included in DTE Electric's fuel expense (account 501) on Schedule C1.1, line 1, column (d), which is then part of the fuel handling reclassification to O&M expense on line 3, column (e). Second, MERC returns its profit to DTE Electric customers via a credit to the PSCR. Third Party Revenues (consisting of Third Party Dock Services plus Net Coal & Transportation Sales) are credited, and Net Site Operating Expenses are expensed to customers in the PSCR mechanism (through a change in the delivered cost of coal). This inventory change is embedded in Fuel and Purchased Power expense shown on Exhibit A-3, Schedule C1.1, line 1, column (d).

These two items are shown on Schedule C16, page 1 of 2. The fuel handling charge of $10.3 million together with the PSCR inventory change of $79,000, results in a net contribution to consolidated DTE Electric for rate making of $10.4 million as shown on Schedule C16, column (b).

I will now explain details of the adjustment on Schedule C1.1, line 7. First, a portion of the fuel handling charge recorded as O&M by DTE Electric is for MERC's depreciation, taxes and interest. As detailed on Schedule C16, page 2 of 2, column (c), I subtracted out the $10.3 million fuel handling expense recorded by DTE Electric and replaced it with the same amount but in the detailed classifications shown in column (d). The total impact of the reclassification is shown on Schedule C16, page 2 of 2, column (e) and is carried forward to Schedule C1.1, line 7. The impact of this reclassification increases NOI by $2.7 million, representing MERC's interest expense. This net addition to NOI is necessary to offset the expense reflected in DTE Electric's consolidated interest expense, which includes debt for MERC. This ensures there is no impact to customers in base rates.

The Commission first authorized the above-described MERC accounting treatment in MPSC Case No. U-5041 (Accounting and Ratemaking for MERC), order dated September 17, 1976 and reaffirmed its findings in MPSC Case No. U-5108 (Main Electric Case) order dated May 27, 1977 as well as in MPSC Case No. U-8578 (Detroit Edison's 1987 PSCR Plan Case), order dated December 8, 1987.

Consistent with past practice, line 8 reduces incentive plan expense by $10.2 million to remove the incentive compensation for DTE Electric's top five executive officers. The adjustment is shown on Schedule C17.

Line 9, MGM Rent, supported by Work paper TMU-11, is for an expense included in O&M related to DTE Energy's use of a parking deck. I removed this expense to match the treatment of a related gain on the sale of land underlying the parking deck that is classified below the line. This adjustment results in a decrease in O&M expense of $0.9 million and an increase in net operating income of $0.6 million.

Line 10, Customer Deposit Interest, is supported by Work paper TMU-12 and reduces net operating income by $1.4 million for interest on customer deposits recorded below the line as other interest in account 431, but which are included in revenue requirements.

Line 11, Power Supply Cost Recovery Offsets, is supported by Work paper TMU-13 that details three adjustments between revenue and fuel and purchased power. The first adjustment eliminates the amount of revenues that are collected via the PSCR factor to reset historical revenue to the PSCR base level. The second adjustment is to eliminate interconnection and ancillary transmission revenues that are netted against PSCR costs. Since these amounts are credited to customers in the PSCR reconciliation, they need to be eliminated from revenues in net operating income for base rates. The last adjustment is for Steam Revenue which is included in net operating income but the related fuel cost is not recovered in the PSCR. To make up for this shortfall, I reduced the revenue amount by the un-recovered cost. The sum of these three adjustments is a $14.8 million reclassification between revenue and fuel on Exhibit A-3, Schedule C1.1, line 11.

Line 12 eliminates the revenues and expenses from the Energy Waste Reduction (EWR) program because it is recovered via a separate surcharge and is not a part of base rates. Work paper TMU-14 details the components supporting the $11.5 million net operating income adjustment.

Line 13 eliminates the revenues and expenses from the Renewable Energy program (REP) because it is recovered via a separate surcharge and is not a part of base rates. Work paper TMU-15 details the components supporting the $63.3 million net operating income adjustment.

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Line 14 eliminates revenues and expenses related to the Low-Income Energy Assistance Fund (LIEAF). This is a separate surcharge program which has no income impact. This adjustment as shown on Work paper TMU-16 is necessary so that the normalized net operating income detail is comparable to the forecast period.

Line 15 eliminates the revenues and expenses included in the nuclear surcharge. Work paper TMU-17 details the components supporting the $0.6 million net operating income adjustment.

Line 16 eliminates the revenues and expenses from the Transitional Recovery Mechanism (TRM) related to former City of Detroit Public Lighting Department customers because it is recovered via a separate surcharge and is not a part of base rates. Work paper TMU-18 details the components supporting the $4.1 million net income adjustment.

Q. Why are you making normalization adjustments to Net Operating Income as reflected on Exhibit A-3, Schedule C1.1, lines 20 through 29?

A. Consistent with current Commission policy, DTE Electric developed a projected test year ending April 30, 2020 based on projected changes from the year ended December 31, 2017 historical or actual test year. The year ended December 31, 2017 historic test year was adjusted to reflect the same normal baseline as the year ending April 30, 2020 test year as far as rate levels, weather impacts and one-time revenue or expense impacts. All adjustments were made to the year ended December 31, 2017 reported Net Operating Income amount to arrive at a rate case filing level as the starting point to develop the year ending April 30, 2020 test year.

Line
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Q. What is the employee incentive plan normalization adjustment on line 20 of Exhibit A-3, Schedule C1.1?

A. Line 20, Employee Incentive Plan Adjustment, is supported by Schedule C18 and reduces 2017 incentives expense by $8.3 million. Starting in 2014, the Company changed from the liability method of accounting for performance shares to the equity method. Under the equity method, any changes in the final payout are reflected in DTE equity when the final award is paid, with no impact to expense. However, approximately 20% of the performance shares will be paid out in cash instead of DTE shares; so, any expected changes in final payout for that 20% portion is recognized as expense. Incentive expense in 2017 includes a $1.8 million accrual for an anticipated increase in cash payouts for the 2014 through 2017 performance shares based on stock price changes. Since the cash payout adjustments are non-recurring items, I removed them from the adjusted historical period. In addition, the short-term incentive plan design (discussed in more detail by Witness Cooper) allows for a payout within a range of zero to 175% of the target, depending on actual results achieved. Incentive expense in 2017 includes $6.5 million for amounts paid above the 100% target. Since payments above the target may not recur, I have removed that amount.

Q. What is the basis for the $6.2 million net operating income Weather Normalization Adjustment you are supporting on Exhibit A-3, Schedule C1, line 21?

A. The rate case assumes that for electric sales, historical normal weather will occur for the forecast period. Thus, for comparison purposes the historical test year must be adjusted to a normal weather basis. Weather was warmer than normal in 2017;

increasing DTE Electric's pretax margin by $10.1 million, and net operating income by $6.2 million, as shown on Schedule C19. Underlying the $10.1 million pretax margin increase was sales revenue of $12.6 million offset in part by an increase in power supply cost of $2.5 million. Company Witness Mr. Leuker discusses the weather impacts in more detail.

Q. What are the adjustments to O&M expense on lines 22 through 27?

A. Witnesses Paul and Johnson support the adjustments on lines 22 and 24, respectively, for steam and customer service expense items not expected to recur in the projected period. Lines 23, 25, 26 and 27 normalize expenses using averages due to the volatility in cost levels. Witness Bruzzano supports line 23, distribution normalization, Witness Johnson supports line 25, uncollectible expense, I support line 26, injuries and damages, as shown on my Exhibit A-13, Schedule C5.9; and Witness Cooper supports line 27, vacation accrual.

Q. What is the adjustment for PSCR disallowance on line 28?

A. Revenues in 2017 include a one-time reduction of $13.5 million for a disallowance in Case No. U-17680-R of power supply costs paid to AK Steel. Since this is a one-time occurrence, I have added back the revenue as a normalization adjustment.

Q. What is the adjustment to Customer Accounts Receivable on line 29?

A. During the conversion from the prior customer billing system to the Customer 360 system, an adjustment was made based on a reconciliation of customer accounts receivable that increased other revenue by $3.8 million. This one-time transaction will not recur.

Line
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Q. What are the adjustments on lines 32 through 35?

A. Line 32 adds $25 million of AFUDC income to offset the impacts of including construction work in progress (CWIP) in rate base. The federal, state and local income tax expense related to AFUDC and interest income is already included in the income tax expense displayed on line 1, columns (i) and (j) of Exhibit A-3, Schedule C1.1.

Line 33 represents Amortization of the Loss on Reacquired Debt. To reduce interest costs, DTE Electric has redeemed and refinanced long-term debt securities in prior years, in advance of their scheduled maturities. The cost related to each of these early redemptions is amortized over the life of the new issue as prescribed by the Commission's Uniform System of Accounts. The year ended December 2017 amortization of the Loss on Reacquired Debt results in a decrease in net operating income of $3 million. This expense is displayed on a pretax basis since the tax expense is already included in net operating income.

Line 34, Income Tax Effect of Interest, and line 35, Interest Synchronization, are supported and explained by Witness Slater on Schedules C12 and C13, respectively.

Q. What is the Adjusted Normalized Year ended December 2017 Net Operating Income amount?

A. Inclusion of the rate case adjustments and normalization adjustments supported by Witnesses Cooper, Johnson, Slater, Paul, Bruzzano, Wisniewski, and myself result in an Adjusted Normalized year ended December 2017 Net Operating Income of $815.6 million. This amount is detailed on Exhibit A-3, Schedule C1.1, line 37 and is included in the historical revenue deficiency/ (sufficiency) calculation supported by Witness Slater.

Forecast Period

Q. How was the financial forecast for the projected period, twelve months ending April 30, 2020, prepared?

A. Projected DTE Electric financial statements for the year ending April 30, 2020 were based on projected changes from the adjusted normalized amounts for the year ended December 31, 2017. The projected period reflects a slight increase in revenue offset by higher net operating expenses. Revenue includes a full year of increased rates from U-18255 compared to only two months of self-implemented rates during November and December, offset by lower service area sales in the projected period. Operating expenses include lower fuel and purchased power due to decreased sales volumes, and lower income tax expense from the federal tax rate reduction. These decreases are offset by increased O&M and depreciation expense that is based on higher forecasted depreciation rates. As previously discussed, regulatory assets recovered with surcharges are excluded from the forecast so they will not impact base rate determination. I prepared the forecasted financial statements using inputs from numerous DTE Electric witnesses.

Electric Income Statement Forecast

Q. What information is included in the forecasted electric income statement contained within this filing?

A. The income statement shown on Exhibit A-13, Schedule C1, column (e), represents the projected DTE Electric net operating income for the year ending April 30, 2020.

DTE Electric's financial statements represent DTE Electric Company plus MERC.

Q. How did you develop the revenues reflected in DTE Electric's operating income?

A. Line 1 of Exhibit A-13, Schedule C1, contains DTE Electric's revenues for the forecasted year ending April 30, 2020. Generally, these revenues were derived from the projected electric sales volumes provided by Witness Leuker multiplied by existing tariff rates, as calculated by Company Witnesses Mr. Dennis, Mr. Johnston, Bloch and Holmes. These tariff rates include electric base tariff rates authorized in Case No. U-18255. Total revenues also include certain utility related Miscellaneous Revenues that I support. As shown on Exhibit A-13, Schedule C3, page 2, I have excluded Nuclear, TRM, EWR, REP and LIEAF surcharge revenues because they do not affect the revenue deficiency in base rates.

Q. What is the projected change in revenues from the historical normalized period to the projected period?

A. Exhibit A-13, Schedule C1, column (d) shows that the projected change in revenues is a $3.2 million increase. Schedule C3, page 1, of this exhibit compares the 2017 normalized revenue amount to the year ending April 30, 2020 revenue amount.

Q. Can you explain the revenue items on Exhibit A-13, Schedule C3?

A. Line 1 of Exhibit A-13, Schedule C3, page 1, represents electric sales distribution revenue. Line 2 is the revenue that recovers base fuel and purchased power. These projected revenues reflect lower service area sales in the projected period, and the increase in tariff rates authorized in Case No. U-18255. Witnesses Dennis, Holmes,

Line No.

Johnston and Bloch support the year ending April 30, 2020 tariff revenue and explain the change from 2017 actual revenues in their testimonies and exhibits.

Line 5 is Other Operating Revenues primarily consisting of: late payment charges, service charges, real estate rentals, and inter-company capital usage charges. The increase in the inter-company capital usage charge is due to higher charges to DTE Gas for investments in strategic customer service initiatives, primarily Customer 360, that support both Electric and Gas operations. Line 7 reflects Rider 2 revenues related to special purpose facilities supported by Company Witness Mr. Lacey.

Comparing the projected twelve months ending April 30, 2020 revenue of $4,785.3 million to the 2017 normalized revenue of $4,782.2 million, results in an increase in projected revenue of $3.2 million as shown on Exhibit A-13, Schedule C3, line 8.

Q. How was the Fuel and Purchased Power Expense portion of DTE Electric's operating expense developed?

A. Line 3 of Exhibit A-13, Schedule C1, contains DTE Electric's fuel and purchased power expense for the forecast period utilizing the rate in effect since Case No. U-15244. As explained by Witness Holmes, any actual under or over recoveries of fuel and purchased power will be reconciled in DTE Electric's annual PSCR filings. As previously discussed, I adjusted the historical period to eliminate items captured in the PSCR as shown on Work paper TMU-13. Therefore, the change in fuel and purchased power expense related to full service sales is due to the change in forecasted sales volumes.

Line
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Q. How was the O&M Expense portion of DTE Electric's operating expense developed?

A. To determine the projected test year O&M expenses for this case, DTE Electric started with actual year ended December 31, 2017 results normalized for unusual, non-recurring items and eliminations/reclassifications for ratemaking purposes. The normalized O&M amounts were then escalated for the effects of inflation and adjusted to reflect anticipated material changes. Line 4 of Exhibit A-13, Schedule C1, contains DTE Electric's O&M expenses for the forecasted period.

In addition to me, Witnesses Paul, Mr. Davis, Bruzzano, Johnson, Cooper, and Mr. Clinton support the O&M expenses and describe them in their direct testimony. These witnesses also support the changes from the historic to the projected period within their respective areas. I support the inflation rates used in their projections. I support the Corporate Staff Group forecast and will explain the details later in my testimony. I also developed Injuries and Damages Expense based on a five-year historical average. I have summarized the development of the forecasted O&M expenses in Exhibit A-13, Schedule C5.

Q. How did you develop the inflation rates?

A. As shown on Exhibit A-13, Schedule C5.15, I have calculated a composite inflation rate based on a labor factor and a non-labor factor. The inflation rate of 3% for internal labor is supported by Witness Cooper. I assumed the same rate for contract labor since a portion of our contract workforce comes from the same unions as the DTE union employees. The inflation rate for non-labor costs is based on consumer price index (CPI)-Urban as supported by Witness Leuker. I used the labor and non-labor rates to calculate a composite rate of inflation for 2018, 2019, and 2020 as shown on line 15.

Q. Why are you using a 3% inflation rate for labor rather than the CPI?

A. As discussed by Witness Cooper, DTE Electric's labor costs are driven by either contracts covering the Company's represented employees, or market based pay practices, and thus are not tied to CPI. To forecast future labor costs, it is more appropriate to use a specific and known wage factor, rather than an overall measure of inflation.

Q. What is the projected change in O&M Expense from the historic normalized amount to the projected period year ending April 2020?

A. Line 4 of Exhibit A-13, Schedule C1, column (d), shows the projected change in O&M increasing expense by $78.3 million. The increase is due primarily to inflation and the amortization of deferred nuclear Program Evaluation and Review Committee (PERC) project costs. O&M also includes new pilot program expenses and increases in tree trim expenses, customer service costs, and software maintenance fees. Lower benefits expense and capital lease costs partially offset the increases.

Q. Did you provide any inputs to the other DTE Electric witnesses' O&M projections?

A. Yes. The Other Post Employment Benefit cost (OPEB) deferral mechanism effects the expense projections supported by Witness Cooper. In addition, a new accounting standard impacts the classification of certain capitalized OPEB and Pension costs. I am also sponsoring the amortization of deferred Customer 360 costs reflected on Witness Johnson's O&M exhibit and the amortization of the PERC regulatory asset approved by the Commission in Case No. U-18014, reflected on Witness Davis' O&M exhibit. I am requesting deferral treatment for certain ADMS program costs supported by Witness Bruzzano. I am also requesting deferral treatment for Charging Forward program costs sponsored by Witness Serna, and have reflected the related amortization expense on Witness Clinton's O&M exhibits. I discuss the Customer 360, PERC, ADMS, and Charging Forward assets in more detail in my testimony describing the balance sheet.

Q. Can you explain the adjustment you made to Witness Cooper's forecast?

A. Yes, Witness Cooper has forecasted retiree health care costs including DTE Electric's traditional Other Post-Employment Benefit (OPEB) plan. Since OPEB costs have been negative, a deferral was approved by the Commission in Case Nos. U-17767, U-18014, and U-18255. I have reflected the deferral impact on Witness Cooper's Exhibit A-13, Schedule C5.10, pages 1 and 2, line 4, consistent with prior treatment. If OPEB costs become positive in the future, the expense will be charged against the regulatory liability.

Q. What is the classification change related to capitalized Pension and OPEB costs?

A. In March 2017, the Financial Accounting Standards Board (FASB) issued ASC 2017-07 that was required to be implemented on January 1, 2018. Previously, all components of OPEB and pension were capitalized when the related labor cost was capitalized. The new accounting rules now require all the elements of OPEB and pension, except current service costs, to be charged to expense. These elements include interest, return on assets; and amortization of prior service costs and unrecognized gains/losses. (I will subsequently refer to this list of items collectively as "non-service" costs.) Only the current service cost component may be capitalized.

Q. What is the impact of the new accounting standard?

A. Since the new accounting standard only allows capitalization of service costs, under GAAP, the non-service costs must be charged to expense in the current period instead of being recognized over the life of the constructed plant by inclusion in the plant balance being depreciated. However, in Case No. U-18255, the Commission approved regulatory accounting treatment to avoid this issue and ensure consistency with past rate-making treatment.

Q. What is the regulatory accounting treatment approved in Case No. U-18255?

A. The non-service costs that would have been capitalized under the traditional accounting treatment (but expensed under GAAP) are being recorded to a regulatory asset (or liability if negative) instead of plant. The regulatory asset or liability is depreciated using the prior year's composite depreciation rate for plant in service, with the expense recorded to a unique account within Depreciation and Amortization expense. This treatment results in recognizing the same expense and rate base that would have occurred under the historical accounting and rate-making method.

Q. How does this impact Witness Cooper's exhibits?

A. The regulatory treatment is reflected on Witness Cooper's Exhibit A-13, Schedules C5.11.1 and C5.11.2, line 17. Basically, the amount previously shown as capitalized to plant has been bifurcated into two lines. Line 16 represents the capitalized service costs recorded to CWIP/Plant, and line 17 represents the capitalized non-service costs which are now recorded to a regulatory asset or liability.

Q. How was the Depreciation and Amortization Expense portion of DTE Electric's operating expense developed?

A. Line 5 of Exhibit A-13, Schedule C1, contains DTE Electric's depreciation and amortization (D&A) expenses for the forecasted period. D&A includes book depreciation, which is based on existing plant balances, plus new capital expenditures and assumed retirements, using a half year convention. Depreciation expense is calculated using the rates authorized by the Commission in Case No. U-16117 for the historical and interim periods. The projected period is calculated using rates as filed in DTE Electric's pending depreciation case, No. U-18150.

Q. What is the projected change in D&A Expense from the historic normalized amount to the projected period?

A. Exhibit A-13, Schedule C1, column (d) shows the projected change in D&A, increasing expense by $250.8 million. Schedule C6 of this exhibit shows the development of the projected period ending April 30, 2020 D&A expense of $949.0 million from the 2017 normalized D&A expense of $698.2 million. The D&A projected increase is due primarily to $170 million for the change in depreciation rates and $138 million for capital in-service movement. The increase is partially offset by approximately $47 million for plant retirements and $10 million from the CTA and DTE2 regulatory assets being fully amortized before the projected period.

Line
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Q. What is the amortization of Capitalized Pension and OBEB?

A. As I previously discussed regarding Witness Cooper's exhibits, the non-service cost components of pension and OPEB costs are being charged to a regulatory asset or liability instead of to plant. These items are expensed using the composite depreciation rate for plant in service.

Q. What plant retirements have been forecasted?

A. There are no retirements of generating units forecasted through the projected period. I am estimating about $195 million in annual routine retirements based on recent history of depreciable plant; and $261 million of scheduled retirements of amortizable plant from January 2018 to April 2020.

Q. How does DTE Electric account for the plant retirements?

A. The original cost is credited out of plant in service and debited to accumulated depreciation. This treatment is prescribed by the Uniform System of Accounts Electric Plant Instruction number 10 (F) which states, "The book cost less net salvage of depreciable electric plant retired shall be charged in its entirety to Account 108, Accumulated provision for depreciation and amortization."

Q. What is the projected change in Property Tax Expense?

A. Line 6 of Exhibit A-13, Schedule C1, column (d) shows that the total projected change in property tax expense is an increase of $34.9 million due primarily to increases in plant balances. Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedule C7.1.

Q. What is the projected change in Other Tax Expense?

A. Line 7 of Exhibit A13, Schedule C1, column (d) shows that the total projected change in other tax expense is an increase of $2.7 million due to an increase in payroll taxes resulting from higher labor costs.

Q. What is the projected change in State and Local Income Tax expense?

A. Line 8 of Exhibit A-13, Schedule C1, column (d) reflects a $28.9 million decrease in state and local tax expense, including Michigan Corporate Income Tax (MCIT) and municipal income taxes. Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedules C9 and C10.

Q. What is the projected change in Federal Income Tax Expense from the historic normalized amount to projected period?

A. The change in federal income tax expense decreases expense by $231.4 million as shown on Line 9 of Exhibit A-13, Schedule C1, column (d). Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedule C8.

Q. How did you compute Operating Income?

A. Revenues less Operating Expenses yields Operating Income shown on line 12 of Exhibit A-13, Schedule C1. Operating Income is projected to decrease due to increased depreciation and property taxes related to capital additions, higher depreciation rates, O&M inflationary increases and nuclear operating costs. The decrease in operating income is partially offset by lower state and federal taxes, including the reduction in the federal income tax rate.

Line No.

Q. What information is contained on the income statement line items below Operating Income?

A. Lines 14 and 15 on Exhibit A-13, Schedule C1, represent items that are includable for ratemaking but which fall below the calculation of Net Operating Income on the income statement. Line 14 reflects AFUDC related to capital expenditures. Line 15 is the annual amortization of losses on reacquired debt. Consistent with past practice, the loss on reacquired debt results from the early redemption of securities, which are refinanced with lower cost issues. Lines 16 and 17 include the federal and state and local tax impact of Income Tax Effect of Interest and Interest Synchronization adjustments supported by Witnesses Slater on Schedules C14 and C15, respectively. Finally, line 19 provides Net Operating Income. Net Operating Income is projected to decrease from the historical test period due to the same factors that impact Operating Income.

Q. What is the projected period Net Operating Income amount as shown in Exhibit A-13, Schedule C1?

A. Line 19 displays the year ending April 2020 Net Operating Income amount of $750.9 million.

Corporate Staff Group Costs

Q. What is the Corporate Staff Group (CSG)?

A. The CSG is a shared services organization, “DTE Energy Corporate Services LLC” (LLC), which includes corporate staff functions. This business model provides efficiencies, cost savings and enhanced governance and internal controls. Each organization within the CSG provides enterprise wide services.

Line No.

Q. What organizations are included in the CSG?

A. The organizations within the CSG provide a variety of Administrative and General (A&G) type services to the Company. These include:

- Audit Services
- Accounting and Finance
- Tax
- Treasury
- Corporate and Governmental Affairs
- Communications
- Corporate Offices and Services
- Human Resources
- Information Technology
- Legal
- Regulatory Affairs
- Environmental Management
- Major Enterprise Projects

Q. Does the LLC provide other services in addition to Corporate Services?

A. Yes. Customer Service also resides at the LLC and operates under a shared service model, but their span of support is only to the regulated DTE Electric and DTE Gas distribution operations versus the enterprise-wide orientation of the CSG. Customer Service expenses are sponsored by Witness Johnson.

Q. What type of O&M expense do you support for the CSG organizations?

A. I support the CSG expense projections except for benefits. (See Witness Cooper for discussion of DTE Electric benefit expenses.) Exhibit A-13, Schedule C5.9, provides the detailed expense projections for the CSG organizations, before employee benefit costs.

Q. Can you explain the rate case adjustments and normalizations reflected in columns (d) and (e), respectively on Exhibit A-13, Schedule C5.9?

A. Column (d) shows rate case adjustments including the elimination of costs recovered via the renewable energy program and certain disallowed costs (advertising, corporate memberships and MGM rent expense). In addition, line 3 includes a reduction of $10.2 million to remove the incentive compensation for DTE Electric's top five executives. Column (e) on line 16 is an O&M net reduction of $8.9 million that includes a $0.6 million decrease for injuries and damages and an $8.3 million reduction in incentives expense as previously discussed.

Q. What adjustment did you make to Injuries and Damages?

A. Consistent with past practice approved by the Commission, I used a five-year average to determine the projected test year amount for injuries and damages to smooth out any year over year variance.

Q. What projected adjustments did you make to O&M as reflected in columns (g) through (j)?

A. Increases based on the weighted inflation rate were applied to the adjusted historical test period expenses for the period January 2018 through April 2020. The projected period also reflects $3.0 million on line 4 for the software maintenance fee related to the C360 system. On line 14, I reduced expense by $5.7 million for software and hardware leases that expire in 2018 and 2019.

Q. With these adjustments, what is the projected test period amount for Administrative and General O&M expense?

A. Based on the adjustments described above, A&G expense is $184.8 million for the projected test period ending April 30, 2020.

Q. How are the CSG cost allocations to DTE Energy companies accomplished?

A. CSG costs are first incurred and accumulated at the LLC. Each department within a corporate staff organization identifies products and services it expects to provide to legal entities and/or business units based on the corporate staff organization's scope of work. These products and services are then analyzed to determine the most appropriate measure, which represents a unit of work, to be used in determining the billing of products or services being provided to DTE Electric and other DTE entities, by the administrative function. This measurement mechanism is called a cost driver. The cost driver, in cost accounting terms, is the unit of work/output that is used to determine a formula for billing the products or services to DTE Electric and other DTE entities. As departments incur expenses during the year they are accumulated in cost pools. The pools are distributed and billed to DTE Electric and other DTE entities pursuant to the appropriate cost driver.

Line No.

Q. How does this cost driver allocation process work?

A. Cost drivers represent units of work that best reflect the content of the work performed. For example, the Company's payroll department within Corporate Services processes paychecks. Given the transactional nature of this work, the volumetric cost driver of "paychecks processed" provides the best indication of work performed by this group for a specific legal entity. This department provides services for DTE Electric and other DTE entities and thus, payroll processing costs are billed based on the volume of paychecks processed for DTE Electric during the year. Other examples within the CSG include invoices paid, number of system application users, and application support hours. Cost drivers are evaluated and established based on resource consumption. These cost driver standards and levels of support are periodically reviewed and updated to reflect actual experience.

Q. Has this cost driver allocation methodology been reviewed by the Commission in prior rate cases?

A. Yes. This is the same cost allocation methodology supported by DTE Electric and approved by the Commission in DTE Electric's general rate cases going back to Case No. U-13808, and DTE Gas's general rate cases going back to Case No. U-13898.

Q. How has the Company billed costs for which no direct cost driver was discernable?

A. While most costs have been billed to DTE Electric and its affiliated companies based on the direct cost drivers I have described, a limited number of administrative activities are shared across the enterprise that do not possess cost driver attributes (a unit of work directly attributed to a legal entity), or that are incurred on behalf of the parent, DTE

Energy, that indirectly benefits DTE Electric. It is in these cases that the Company uses the commonly accepted cost allocation methodology traditionally referred to as the Massachusetts Formula (Mass Formula). The Mass Formula, which utilizes a three-factor formula of gross margin, net plant and labor costs, is designed to measure relative size and complexity as a means of assessing the degree of support services attributable to each individual company, within the context of the broader enterprise.

Q. Has the Commission approved the use of the Mass Formula in allocating common costs in prior cases?

A. Yes. Consistent with the cost driver methodology, the use of the Mass Formula for the allocation of CSG common costs was approved by the Commission in DTE Electric's last seven general rate cases as well as in DTE Gas's general rate cases. Examples of CSG costs that utilize the Mass Formula include certain Corporate Communication, Governmental Affairs, Investor Relations and Corporate Secretary activities, and DTE Energy Board of Director fees.

Corporate Staff Capital Expenditures

Q. What is the nature of the capital expenditures incurred by CSG functions?

A. These expenditures reflect the annual capital requirement investment levels required for CSG organizations to deliver services to DTE affiliates. The largest categories of capital expenditures relate to information technology, physical infrastructure and fleet.

Q. Why are these costs charged directly to DTE Electric?

A. CSG capital costs are generally incurred on behalf of all DTE affiliates. (Any projects or costs specific to other entities are charged directly to that company.) Thus, DTE

Electric records 100% of the shared asset capital expenditures for CSG organizations and then charges a capital usage fee to DTE affiliates for the use of these assets. The capital usage fee is included in other operating revenue.

Q. What level of capital expenditures do you expect the CSG organizations to incur?

A. The expenditures including IT and Corporate Staff are projected to be approximately $413.2 million from January 1, 2018 through April 30, 2020. Company Witness Mr. Griffin supports $169.3 million for IT projects on his Exhibit A-12, Schedule B5.7. I support Exhibit A-12, Schedule B5.8, which provides the capital projections for physical infrastructure, fleet and other projects, totaling $243.9 million.

Q. What capital expenditures are included on Exhibit A-12, Schedule B5.8, page 1, line 1, Electric Vehicle Fleet?

A. Line 1, Fleet, represents the cost of new vehicles and power operated equipment. Items such as cars, trucks, bucket trucks, trailers, and forklifts are replaced to provide safe and reliable equipment as the fleet ages. Life cycle cost models are used to optimize the mix of spending on maintenance and replacements. For example, 2017 purchase levels for certain vehicle types and equipment will not be repeated in the next few years, resulting in about $10 million in lower costs for 2018 and almost $5 million in the projected period.

Q. What is the nature of the physical infrastructure capital expenditures on lines 2 through 4?

A. Line 2, Facilities Construction & Upgrade, includes capital maintenance items such as roofs, facades, heating and cooling equipment, elevators, cranes, and paving. Capital maintenance standards are applied to optimize life cycle costs and ensure safety, at a cost of $15 to $20 million annually. Additional larger asset preservation projects scheduled for 2018 include $3.2 million to replace electrical infrastructure at the Warren Service Center, $750,000 for safety improvements to the General Offices (GO) building tunnel, $2.7 million for fire alarms at the downtown campus and Warren Service Center, $1 million to replace HVAC controls at the downtown campus, and $2.5 million to replace water pipes and electric services in the GO. The projected period includes $2.6 million for continued water piping and electric service work in the GO and $1.2 million to replace the baseboard heat on the perimeter of the GO.

Line 3, Facilities Renovation, is a project that began in 2012 to update DTE's headquarters, service centers and power plants. The Commission approved this project in Case Nos. U-18014 and U-18255. Approximately 80% of our facilities are over 20 years old requiring costly maintenance. The project includes replacing old infrastructure such as ductwork and air vents; replacing out of date facilities used by employees such as locker rooms, showers, and cafeterias; and replacing furniture and fixtures that are at the end of their useful life. Because most of our facilities have not been through a full renovation, they did not meet current building codes. Upgrades include bringing the spaces up to code, including fire detection and suppression, and ADA compliance. In addition, the project uses a more efficient design resulting in a reduction in average space used per employee from 340 square feet to 283 square

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feet, which will allow the Company more space to accommodate additional employees if needed. The Facilities Renovation project is expected to be complete by the end of 2021.

Line 4, Service Center Optimization, is a project to replace facilities that have exceeded their useful life by consolidating sites. The older facilities experience increased costs due to aging infrastructure and critical components such as HVAC and roofs have failed. With fewer locations we will be able to realize savings opportunities, as well as increase efficiency within the sites. For example, the Mt. Clemens Service Center was renovated and expanded, and the Macomb Center was closed when the lease ended in December 2017. This project was substantially complete in 2017, with $650,000 of finishing work in 2018.

The forecast for 2018 also includes $19.7 million for a project at the Warren Service Center. This project, which started in 2017, involves consolidating activities currently in two buildings into one building and constructing a new lab on an existing DTE site. Building "H" will be closed and eventually demolished. Building H houses the Engineering Support organization's central laboratory. The current lab conditions are not ideal for proper testing and analysis of samples; and the plumbing, lighting, ventilation and IT infrastructure in Building H are not adequate. Renovating the building is not a viable option due to the excessive cost, and the excess space is not needed.

In addition, the Pontiac Service Center will be closed and moved to a larger location, and the lease on the Northwest Planning Design office in Farmington will be terminated. These changes will enable DO Planning & Design and Service Operations efficiencies by having them in the same location. The cost for this project during 2018 through April 2020 is forecasted at $29.0 million.

Q. What is the Headquarters (HQ) Energy Center on line 5?

A. The HQ Energy Center is a new facility that will include a steam plant fueled by natural gas, and a central chilled water plant for the downtown campus. It includes three 800 horse power natural gas fired steam boilers and four 1,000 ton chillers and ancillary equipment.

Q. Why does the Company need a steam production facility?

A. The Company is currently dependent on purchases of steam from Detroit Thermal. The price paid to Detroit Thermal has increased by approximately 5% annually since 2013. In 2013, the price per Mlbs was $19.95. The current rate is $25.75. The Company needs an alternative that reduces steam costs.

Q. Does the Company anticipate further price increases?

A. Yes. The Company believes Detroit Thermal will need to upgrade its system to continue operating which will drive price increases in the future.

Q. Why does the Company need a new chilled water system?

A. The current chilled water system is at the end of its useful life. The Service Building cooling towers are degraded structurally and operationally. There is significant rust on the structures, plugging within the chambers that is negatively impacting efficiencies and output capabilities, and failing components such as valves and motors. The cooling towers on the Walker Cisler Building (WCB) require major maintenance or replacement. The interior and components such as motors and drift eliminators are degraded. Maintenance work is complicated by the location, size and weight of the units. The towers are located on the 24th floor roof and are 46 years old.

Q. What benefits will the Energy Center provide?

A. The number of chillers will be reduced from the existing seven to four high efficiency units, providing energy savings estimated at 2.5 million Kwh/year. In addition, the chillers can be sized as needed based on demand. With the existing units in the high-rise building (WCB) two chillers must be used on a day when fewer tons of cooling are required, creating inefficiencies. The new chillers will have trim capabilities so that energy will not be wasted throughout the entire complex. Routine maintenance activities for the chilled water system are expected to be simplified, and the cost of maintenance reduced by using standardized equipment. The centralization of the chilled water system will also reduce labor needs as monitoring and control will take place at one location versus two separate buildings to meet City of Detroit requirements. The new Energy Center will be easily accessible; located in the backyard of the headquarter campus. Currently, the Company has a control and monitoring room in both the Service Building and the WCB, and not all the controls are automated. For example, changing temperature settings requires a manual change to control valves and the dampers in some functional areas.

In terms of the natural gas fired steam boilers, the Company believes it can better control steam costs and improve operational effectiveness using a system we own and operate. New equipment will eliminate the need to purchase steam from Detroit Thermal, preventing the steam leakage that has created corrosion to our underground electrical system, heat interruptions to our buildings and damage to landscaping.

Q. Has the Company calculated the net present value (NPV) of this project?

A. Yes. The forecasted capital investment for the Energy Center is $32.5 million, resulting in a net present value of the revenue requirement of approximately $50.0 million. This compares to an NPV revenue requirement of up to $54.1 million under the status quo, assuming continued price increases for purchased steam.

Q. Does the forecast for the Energy Center include any amounts for contingency?

A. Yes. A contingency in the amount of $4.47 million is reflected in the total $32.5 million cost projection. The design of the Center is about 30% complete. As the design is finished, the cost projection will be updated and the contingency may be allocated to specific cost components.

Q. What is NERC-Critical Infrastructure Program on line 6?

A. Line 6 represents projected costs for physical and cyber security enhancements to comply with the Critical Infrastructure Program (CIP) developed by the North American Electric Reliability Corporation (NERC). NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. Compliance with the CIP was mandated effective with a FERC order on November 22, 2015. Requirements include modifications and updates to physical and electronic systems, as well as security policies and procedures. This item was approved by the

Line No.

Commission in Case Nos. U-18014 and U-18255.

Q. How much allowance for funds used during construction (AFUDC) is assumed in the projected test period for Corporate Staff?

A. AFUDC for Corporate Staff is included on Exhibit A-12, Schedule B5.8 page 2. As shown, the Corporate Staff AFUDC is projected to be $3.2 million for the 12-month period ending April 30, 2020. A historical trend is used to estimate AFUDC on routine capital, such as the portion of Facilities, Design and Construction, where the mix of eligible projects is consistent year to year; while the AFUDC is calculated specifically on a project by project basis for eligible non-routine projects. The authorized cost of capital rate is 5.34% per the order in case No. U-18255.

Balance Sheet Forecast

Q. What projected test year balance sheet information are your providing?

A. Exhibit A-12 schedules B2 and B3 provide the projected average utility plant balances and depreciation reserves, respectively, compared to the historical period. Schedule B4 provides the projected average working capital compared to the historical period. Schedule B4.1 classifies the projected balance sheet information into the categories of net plant, working capital, and the various financing components.

Q. Can you explain what the DTE Electric balance sheet on Schedule B4.2 represents?

A. The electric balance sheet statement shown on Exhibit A-12, Schedule B4.2, represents the DTE Electric average balance sheet for the projected year using a simple average of the beginning balance plus ending balance divided by two. As previously stated, DTE Electric's financial statements represent DTE Electric Company plus MERC.

Q. What are the major components making up the Assets and Other Debits reflected in Exhibit A-12, Schedule B4.2, page 1 of 2?

A. Exhibit A-12, Schedule B4.2, page 1 of 2 has four major asset components:

1) Total Utility Plant and Property
2) Other Property and Investments
3) Current Assets
4) Deferred Debits

Total Utility Plant and Property

Q. How did you develop the projected Utility Plant and Property amount in this case?

A. Total Utility Plant and Property (lines 4 through 12) is comprised primarily of Net Utility Plant (line 9), which is projected to increase each year resulting from annual capital expenditures being greater than the annual depreciation allowance charge. These projections reflect substantial capital expenditures primarily related to natural gas plant purchases, system reliability improvements, nuclear standards compliance and maintenance projects, facility upgrades and maintenance, and information technology investments. Exhibit A-12, Schedule B5 provides a functional summary of DTE Electric's total projected capital expenditures. Further, the various operational witnesses provide details on the capital expenditures they are sponsoring.

Line
No.

Q. How did you develop the projected capital expenditure amounts DTE Electric included in this case?

A. To determine the projected test year capital expenditure levels for this case, DTE Electric started with historical amounts normalized for unusual, non-recurring items. In some cases, the routine capital expenditures were escalated for the effects of inflation. Capital expenditures for unique or one-time projects were individually forecasted. Capital expenditures are supported by Witnesses Paul, Milo, Bruzzano, Davis, Dimitry, Johnston, Griffin, Serna, and myself. (Removal costs included in capital expenditures on the individual witness exhibits are reflected as a charge to the accumulated depreciation reserve.)

Q. What is the projected change in Total Utility Plant and Property?

A. Exhibit A-12, Schedule B4.2, line 4, reflects a plant-in-service change from December 2017 to April 2019 of $1,144 million. This change is due to $1,509.7 million of base capital in-service movement, less $365.8 million of plant retirements transferred to the depreciation reserve. The plant-in-service change from April 2019 to April 2020 is $1,020.5 million. This change is due to $1,370.9 million of in-service movement less $350.4 million for plant retirements.

Plant held for future use on line 5 reflects the FERMI 2 license extension. The costs incurred to obtain the extension have been capitalized and include project management; engineering planning and design; and NRC required inspections of, and updates to, the physical assets. DTE Electric will incur $10 million of additional costs through the projected period to complete work related to commitments made to the NRC as a condition of obtaining the extension. Trailing costs are added to the asset when incurred. Since the license extension relates to a period beginning in 2025, the asset is classified in account 105, Plant Held for Future Use until 2025. It will then be re-classified to Plant in Service and amortized over its 20-year service life.

The CWIP change on line 6 from December 2017 to April 2019 is an increase of $552.5 million. This change is primarily due to $2,062.2 million of capital expenditures offset by $1,509.7 million of projects transferred to plant-in-service. The CWIP increase from April 2019 to April 2020 of $193 million reflects $1,563.9 million of capital expenditures, less transfers to plant-in-service of $1,370.9 million.

The decrease in acquisition adjustments on line 7 from December 2017 to April 2020 of $13.5 million results from amortization of the adjustment for the Renaissance Power plant.

The increase in depreciation reserve on line 8 from December 2017 to April 2019 of $326.2 million is due to $964 million of depreciation expense partially offset by $272.1 million of removal costs and $365.8 million of plant retirements. The increase of $376 million from April 2019 to April 2020 represents depreciation expense of $938.3 million partially offset by $211.9 million of removal costs and $350.4 million of plant retirements.

The change in Nuclear Fuel Property on line 11 from December 2017 to April 2019 is a decrease of $29.8 million from nuclear fuel purchases of $74.4 million less nuclear fuel expense of $104.2 million. The change in Nuclear Fuel Property from

April 2019 to April 2020 is an increase of $29.1 million due to fuel purchases of $77.7 million less nuclear fuel expense of $48.6 million. Witness Davis supports the nuclear fuel purchase amounts.

Q. Why is CWIP included in Net Utility Plant for rate making purposes?

A. CWIP is included in this rate filing as required by the Commission's May 10, 1976 Order in Case No. U-4771. CWIP is forecasted (in part) based on the expected in-service date for large projects, when they are reclassified from CWIP to Plant in Service. These projects generally include an allowance for funds used during construction (AFUDC) which is credited on the income statement, reducing the revenue deficiency and offsetting the impact of the assets in rate base. AFUDC is applied to projects greater than $50,000 and lasting more than six months, with an exception for environmental projects. Per the Commission's March 14, 1980 Order in Case No. U-5281, a generic proceeding on the Commission's own motion to examine the accounting treatment of CWIP and AFUDC, the Commission required that pollution control related CWIP should not accrue AFUDC but instead be included in rate base. This position was affirmed in the Commission's August 16, 2011 Order in Case No. U-15244 (page 72).

CWIP also includes non-environmental projects that are not eligible for AFUDC. They are lower cost, short duration items. Projects involving smaller dollar assets, or mass assets, are initially charged to CWIP but are soon transferred to Plant in Service. The type of work included in the short duration items is generally standard and on-going throughout the year. Thus, as the prior balance for these types of assets is cleared to Plant in Service, another wave of construction is adding new amounts to

Line
No.

the CWIP balance. For these types of recurring items, I forecasted CWIP based on a historical trend of balances in the account.

Lastly, capital expenditures for a new natural gas plant are included in rate base without an AFUDC offset as ordered by the Commission in Case No. U-18419.

<u>Other Property and Investments</u>

Q. What are you forecasting for Other Property and Investments?

A. Line 16 is held constant at historical levels. As previously discussed, the Nuclear Decommissioning Trust Fund balance on line 17 was eliminated from the historical period because it does not impact base rates.

<u>Current Assets</u>

Q. What is included in Current Assets on lines 20 through 29 of Exhibit A-12, Schedule B4.2?

A. Current assets include cash, receivables, unbilled revenues, inventories and supplies. Individual line items were generally held constant at historical levels because they tend not to fluctuate materially.

Q. How did you forecast the balance for Accounts Receivable on line 22 and Unbilled Revenues on line 25?

A. These items were forecasted based on the actual, weather normalized balance as of April 2018. The balances were reduced by a related reserve to reflect a Federal tax rate of 21%. DTE Electric is currently billing revenues calculated based on a 35% Federal tax rate but expects to implement a surcharge credit upon an order in its

Credit A tax case, No. U-20105.

Q. How did you forecast the balance for Fuel Inventory on line 26?

A. Fuel Inventory increases by $69.2 million due to the expiration of reduced emissions fuel contracts with Huron, St Clair, and Belle River Fuels Company at the end of 2019. The 2020 balance of inventory at the Belle River facility includes a transfer of inventory from these Fuels Companies back to DTE Electric.

<u>Deferred Debits</u>

Q. What is included in Deferred Debits on lines 32 through 51 of Exhibit A-12, Schedule B4.2?

A. This section contains various regulatory assets and deferred tax items. Unamortized Debt Expense on line 32 is reduced by annual straight-line amortization of about $3 million, offset by projected issuance expense of $2.5 million assumed at 1% of new debt issues. Unamortized Loss on Reacquired Debt on line 33 is reduced by annual straight-line amortization of $3.2 million. These balances are tied to specific debt issues and are amortized over the life of the issues. Line 35, Prepaid Pension represents the funded pension obligation. The year over year changes reflect pension expense accruals offset by pension fund contributions. The pension plans are explained by Witness Cooper.

Q. How was the Customer 360 Regulatory Asset on line 40 of Exhibit A-12, Schedule B4.2 developed?

A. The Company implemented a new Customer Relationship and Billing system in 2017 called Customer 360. Pursuant to the September 26, 2016 Order in Case No. U-17666,

Line No.

the Company deferred $47 million for certain project expenses in Account 182.3, Other Regulatory Assets. The deferred costs are being amortized over a 15-year period. The Company also incurred $16.6 million of post implementation costs during 2017 as supported by Witness Johnson. The Commission's Order Case No. U-18122 stated that the additional costs should be addressed in a base rate case so the Company requested recovery in Case No. U-18255.

Q. Did the Commission grant recovery of the additional costs in Case No. U-18255?

A. No. At the time the Company filed its application in case No. U-18255, the post implementation costs were forecasted, but not yet incurred. The Staff recommended that the costs be disallowed until the Staff could audit the actual costs incurred, and the Commission agreed. Therefore, since the costs have since been incurred and are available for audit by the Staff, I am requesting regulatory asset treatment for the $16.6 million expense, and recovery of the related annual amortization expense of $0.7 million (Electric's share of $1.1 million) in the instant case. My Exhibit A-13, Schedule C5.13 shows the calculation of the regulatory asset and annual amortization expense.

Q. What is the Program Evaluation & Review Committee (PERC) regulatory asset on line 41?

A. This balance represents deferred costs for certain nuclear O&M projects. As further explained by Witness Davis, the Company has plans for various PERC operations and maintenance projects. The Order in Case No. U-18014 approved $4.9 million in annual O&M for PERC projects, but also provided deferral treatment for any expenses over or under the $4.9 million amount. As supported by Witness Davis on Exhibit A-13, Schedule C5.16, the Company spent $27.0 million on PERC projects in 2017; therefore, it deferred $22.1 million. The Company expects to spend $31.5 million in 2018, $19.5 million in 2019 and $16.8 million in 2020. The difference between the forecasted expenses and $4.9 million annually is reflected as a regulatory asset. Per the Commission's Order, the deferred costs are amortized over a five-year period beginning with the first month of a projected test period as shown on Exhibit A-13, Schedule C5.17. The balance at April 2020 reflects $64.1 million of deferred expense less $18.4 million cumulative amortization.

Q. What is the ADMS regulatory asset on line 42?

A. As supported and described by Witness Bruzzano, the Company is installing an Advanced Distribution Management System (ADMS). The project started in 2017 and will run through 2021. Similar to other major system implementation projects (e.g., C360), some costs of the project will be capitalized, but other costs must be expensed per Generally Accepted Accounting Principles. These other project costs for ADMS include consulting and process reviews, process development, training, and software fees while the system is under development. As shown on Witness Bruzzano's Exhibit A-12, Schedule B5.4, page 1 of 10, line 24 these expenses are projected to be $9.8 million through the test period ending April 30, 2020. Key components of the project will become operational in 2019, 2020 and 2021. The Company is requesting deferral of the other project costs as a regulatory asset to be amortized over 15 years following the system in-service date of the related component, consistent with the expected service life of the system.

Line
No.

Q. What is the Charging Forward Regulatory Asset on line 43?

A. As discussed by Witness Serna, the Company is proposing a program called Charging Forward to incentivize third parties to build charging stations for electric vehicles by providing rebates. I am requesting authority to use account 182.3, Other Regulatory Assets, to record the rebates. The rebates provide the long-term benefit of encouraging investment in electric vehicle infrastructure, consistent with the Commission's objectives. I am also requesting recovery of the deferred costs over five years by inclusion of the amortization expense in O&M, as shown on Witness Clinton's Exhibit A-13, Schedule C5.8, Column (i), line 12. This treatment is consistent with the deferral and recovery treatment approved by the Commission in Case No. U-17767 for rebates to customers for installing charging equipment.

Q. What is the Pension Capitalized on line 44?

A. As previously described regarding pension expense, this balance represents the capitalized non-service cost components of pension expense.

Q. What is causing the increase in Prepaid OPEB on line 45?

A. The Prepaid Post-Retirement Benefit asset increases from $11.9 million at December 2017 to $84.2 million by April 2020. The year-to-year changes are primarily the result of negative OPEB expense, as explained by Witness Cooper.

Q. Can you explain the tax items on lines 48 and 49 of Exhibit A-12, Schedule B4.2?

A. Witness Wisniewski supports these tax-related assets. Line 48, Miscellaneous Tax Related, represents regulatory assets resulting from changes in tax law such as Medicare Part D and the Michigan Corporate Income Tax. Line 49, Recoverable

Income Taxes, reflects a regulatory asset recorded in conjunction with an offsetting ADFIT liability when ASC 740 (formerly FAS 109) was adopted in 1993. It has scheduled reductions of $2.4 million per year supported by Witness Wisniewski. The ASC 740 balance sheet accounts do not affect the revenue requirement. This accounting and rate treatment was approved by the Commission in Case No. U-10083.

Q. How was Other Deferred Debits on line 51 of Exhibit A-12, Schedule B4.2 developed?

A. The change in Other Deferred Debits reflects the amortization of deferred plug-in electric vehicle costs. Other balances, including a long-term receivable, are held constant at with the historical period.

Q. What components make up the Liabilities and Other Credits reflected in Exhibit A-12, Schedule B4.2, page 2 of 2?

A. Exhibit A-12, Schedule B4.2, page 2 of 2 has four major components:

1) Capitalization
2) Non-Current Liabilities
3) Current Liabilities
4) Deferred Credits

<u>Capitalization</u>

Q. How were the projected capitalization amounts determined in this case?

A. Capitalization (lines 55 through 66) reflects DTE Electric’s permanent capital in the form of long–term debt and common equity. Key long-term debt drivers include:

new capital requirements, scheduled retirements, refinancing, level of equity, and the amount of short-term debt. As previously discussed, the regulatory liability related to the REP is a source of short-term debt. Schedule B4.2, line 59, shows that long-term debt balances will increase during the forecast periods to support DTE Electric's increasing asset base, as supported by Company Witness Mr. Solomon.

Common equity balances on line 65 will also increase to finance the growing asset base and to meet targeted capitalization percentages. Since projected earnings are not sufficient to meet the targeted equity capital percentages, common equity will need to be funded from additional equity infusions as discussed and supported by Witness Solomon. Projected common equity also reflects dividends required to sustain and attract equity investors, as supported by Witness Solomon.

Q. What is the projected change in Capitalization?

A. Exhibit A-12, Schedule B4.2, line 59, reflects a long-term debt increase from December 2017 to April 2019 of $775.9 million due to new debt issues. The $305.7 million long-term debt increase from April 2019 to April 2020 is also due to anticipated new debt issuances. There are no debt redemptions scheduled during the projected period. Line 62 reflects Common Stock increases of $1,029.5 million through April 2020 due to planned equity infusions as addressed by Witness Solomon. A portion of the Common Stock increases may be reduced from additional equity based on the Commission Order in this case granting both the rate relief and the level of common equity requested. Retained Earnings (line 63) increases by $108.9 million from December 2017 to April 2019, resulting from net income of $821.2 million, less common dividend payments of $712.3 million. Retained

Earnings decreases from April 2019 to April 2020 by $59.0 million resulting from twelve-months ending April 2020 net income of $466.0 million less common dividend payments of $525 million. The changes in common equity are reconciled on Exhibit A-12, Schedule B4.3.

Non-Current Liabilities

Q. What is included in Non-Current Liabilities on lines 68 through 74 of Exhibit A-12, Schedule B4.2?

A. This section includes the liability for capital leases, injuries and damages and a reserve for Michigan Business Tax issues. The accumulated provision for injuries and damages on line 69 is being held constant during the forecast period as new claims and settlements cannot be predicted.

Current Liabilities

Q. What is included in Current Liabilities on lines 76 through 82 of Exhibit A-12, Schedule B4.2?

A. This section includes short-term debt and payables. DTE Electric's short-term debt balances on line 76 include the balances available from the REP regulatory liability. The REP regulatory liability represents the temporary over-collection of DTE Electric's Renewable Energy Program surcharge. This liability is used by DTE Electric as an additional source of financing in base rates. Interest on this liability is paid to our customers via a credit in the Renewables Plan, lowering the revenue requirement for that program.

Line No.

Q. How did you forecast the balance for Accounts Payable on line 77?

A. Accounts payable was forecasted based on the actual balance as of April 2018.

Q. How did you forecast the remaining current liabilities?

A. The changes in Taxes Payable on line 78 reflect accruals and payments, as supported by Witness Wisniewski. The changes in Interest Payable on line 79 reflect the timing of accruals and payments. Capital Leases Current on line 80 represents the liability to offset the Net Capital Lease Property on line 10. Other Current Liabilities on line 81 include vacation and payroll accruals, and the Fermi 2 outage accrual. The fluctuations in this line result from forecasted accruals and expenditures for the Fermi 2 planned outages supported by Witness Davis.

<u>Deferred Credits</u>

Q. What is included in Deferred Credits on lines 84 through 92 of Exhibit A-12, Schedule B4.2?

A. The December 2017 balance related to Line 84 Regulatory Liability - Renewable Energy Program, was re-classified to short-term debt on my historical Exhibit A-2, Schedule B6.2. Line 86 represents the balance of the OPEB deferral. Other Deferred Credits on line 91 includes refundable customer advances, environmental reserves, and accrued long-term payables held constant at historic levels.

Q. What is the OPEB Capitalized on line 87?

A. As previously described regarding OPEB expense, this balance represents the capitalized non-service cost components of OPEB expense.

Line No.

Q. What are the tax items on lines 89 through 91?

A. Witness Wisniewski supports lines 89 through 91. Accumulated Deferred Income Taxes represents timing differences in the recognition of tax expenses for the financial statements compared to the tax return. Both the federal and state deferred tax balances reflect the netting of Deferred Tax Assets (Account 190) against Deferred Tax Liabilities (Accounts 281, 282, and 283), consistent with the presentation in the cost of capital calculation.

Deferred taxes on line 89 includes the outstanding tax liability balance to account for tax benefits previously flowed through to ratepayers stemming from the 1993 enactment of ASC 740 as previously discussed. It is offset by the Regulatory Asset (Recoverable Income Taxes) as shown on Schedule B4.2, line 49. This accounting and rate treatment was approved by the Commission in Case No. U-10083.

Accumulated Deferred Investment Tax Credits on line 90, supported by Witness Wisniewski, are deferred tax credits generated and utilized by the Company with the tax benefits flowing back to ratepayers on the same basis as ratepayers pay for the assets that generated these tax credits.

The Tax Reform Regulatory Liability on line 91 results from the Tax Cuts and Jobs Act of 2017, which among other things, lowered the corporate Federal tax rate from 35% to 21%. The reduction in the tax rate required that all existing deferred tax balances be re-measured using the 21% rate. The reduction in deferred taxes was recorded to a regulatory liability to be refunded, generally, over the life of the items causing the deferred tax, primarily Property, Plant and Equipment. Witness

Wisniewski explains the calculation of the regulatory liability and the Company's proposed refund schedule.

Accounting Request

Tree Trim Surge Regulatory Asset

Q. What is the Tree Trim Surge Regulatory Asset?

A. As discussed and supported by Witness Rivard, the Company is proposing a significant investment for vegetation management intended to provide long term benefits including a reduction in safety hazards and the volume of tree-related trouble cases. The Company is requesting regulatory asset treatment to defer the costs of this temporary "surge" program in account 182.3, Other Regulatory Assets, and to amortize each vintage year balance over a 14-year period to be consistent with the maximum bond term discussed by Witness Solomon. As shown on Exhibit A-22, Schedule L3, the deferred cost of $43.3 million supported by Witness Rivard, divided by 14 years, results in annual amortization expense of approximately $3.1 million.

Q. How is a regulatory asset different from a capital asset?

A. Per the Uniform System of Accounts, a regulatory asset includes "those charges which would have been included in net income determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period for purposes of developing rates…" Basically, regulatory assets represent costs that will be expensed in future periods even though they are normally expensed (as incurred) in the current period. Tree trim costs that are normally booked as maintenance expense and that cannot be capitalized as plant, can be recorded as a regulatory asset if authorized by

Line No.

the Commission.

Q. Is the Tree Trim Surge Regulatory Asset and associated amortization reflected in the projected balance sheet and income statement?

A. No. The revenue requirement for the asset, including the amortization expense and financing, is shown separately on Witness Slater's Exhibit A-22, Schedule L2. Witness Slater adds the revenue requirement for the surge program to the revenue deficiency on his Exhibit A-11, Schedule A1, line 9.

<u>Infrastructure Recovery Mechanism Accounting</u>

Q. How does the Infrastructure Recovery Mechanism (IRM) impact the projected financials?

A. An overview of the mechanism is provided by Witness Stanczak. The Company is proposing to recover certain capital expenditures and plant balances, and the related costs and debt and equity for the periods after April 2020, in an IRM that is separate and distinct from the revenue requirement for base rates. Any related net plant forecasted through April 2020 is reflected in base rates in this case. All IRM-related net plant forecasted for May 2020 through December 2022 is included in the proposed new IRM and supported by Company Witnesses Bruzzano, Paul and Davis. My Exhibit A-30, Schedule T1 summarizes the capital expenditures included in the IRM. This information is used by Witness Slater to develop the revenue requirement.

Q. How should the IRM spend be reviewed?

A. The Company proposes to file a report with the Commission regarding the expenditures and metrics for the period May to December 2020 by April 30, 2021.

Annual reports for 2021 and 2022 would be filed by April 30 of the following year.

Q. How does DTE Electric intend to record activity under the IRM?

A. DTE Electric proposes to record revenue on an accrual basis consistent with its accounting policies for other customer revenues. The capital expenditures will be recorded to unique accounting codes to isolate the costs. Also, as proposed by Witness Stanczak, any over or under recovery of the IRM would be deferred as a regulatory liability or regulatory asset.

Q. Is DTE Electric proposing to reduce its future recovery by the amount of plant that is being retired in this program?

A. No. When plant is retired, the original recorded cost of the plant is both credited to the plant in service accounts and charged to accumulated depreciation reserve; thus, there is no change in the net plant balance related to the retirement. With no change in net plant, there is no adjustment to the largest portion of the return on portion of the cost of service calculation. As depreciation rates are periodically adjusted in subsequent depreciation cases, the impact of any abnormal retirements will be incorporated.

<u>Rate Schedule D1 Time-Of-Use Implementation Costs</u>

Q. What is the company requesting with respect to the implementation of new time of use rates for D1 residential customers?

A. Witness Dennis supports the design of new time of use rates ordered by the MPSC in Case No. U-18255. The Company expects to incur one-time expenses and capital costs to implement the new rates. As supported by Witness Johnson, the one-time

Customer Service operating expenses could be up to $12 million. Witness Clinton supports that communications to inform and educate customers could cost over $9 million. In addition, Witness Griffin supports that IT implementation costs could be approximately $24 million. The IT costs could be capitalizable but the accounting treatment has not yet been determined. I am requesting the Commission authorize deferral treatment and future recovery of the one-time operating expenses, not to exceed $45 million. If 100% of the IT costs are capitalized, then the high end of the deferral would be approximately $22 million. I propose that the costs be recorded to account 182.3, Other Regulatory Assets, until reflected in rates in a future proceeding. Any capital costs incurred will be recorded using standard plant accounting as provided in the Uniform System of Accounts.

Q. Are the implementation costs or capital expenditures reflected in the projected financial statements in the instant case?

A. No.

Summary

Q. Would you please summarize what Commission approvals the Company is requesting?

A. In addition to the forecasted costs and revenues included herein, the Company is requesting the following:

1. Regulatory Asset treatment of 2017 Customer 360 post-implementation O&M expenses
2. Regulatory Asset treatment for certain ADMS costs
3. Regulatory Asset treatment for rebates in the Charging Forward program (electric

Line
No.

vehicle charging stations)

4. Regulatory Asset treatment for Tree Trim Surge costs
5. Regulatory Liability or Regulatory Asset treatment for any over or under recovery of the IRM
6. Regulatory Asset treatment for time-of-use rate implementation expenses.

Q. Does this complete your direct testimony?

A. Yes, it does.

**BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION**

	)	
DTE ELECTRIC COMPANY	)	**CASE NO. U-20162**
	)	
	)	

DIRECT TESTIMONY

OF

MICHAEL J. VILBERT

LIST OF TOPICS ADDRESSED:

COST OF COMMON EQUITY CAPITAL

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BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION

DTE ELECTRIC COMPANY	**)** **)** **)** **)**	**CASE NO. U-20162**

DIRECT TESTIMONY OF MICHAEL J. VILBERT

I. INTRODUCTION AND SUMMARY

Q1. Please state your name and address for the record.

A1. My name is Michael J. Vilbert. My business address is The Brattle Group, 201 Mission Street, Suite 2800, San Francisco, CA 94105, USA.

Q2. Please summarize your background and experience.

A2. I am a Principal Emeritus of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm with offices in Boston, Washington D.C, London, San Francisco, Madrid, Rome, New York City, Toronto, and Sydney. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy, an M.B.A from the University of Utah, and a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania. Appendix A provides more detail on my qualifications.

Q3. What is the purpose of your testimony in this proceeding?

A3. I have been asked by DTE Electric Company ("DTE" or the "Company") to estimate the cost of capital for the Company. Specifically, I provide return on equity ("ROE") estimates derived from a sample of comparable risk, regulated electric utility companies ("electric sample"). I also consider the relative risk of the Company and its proposed regulatory capital structure ratio to arrive at my recommendation for the allowed ROE.

Q4. Are you sponsoring any exhibits?

A4. Yes, I am sponsoring Exhibit A-14 which includes the following schedules:

Schedule	Description
D5.1	Table of Contents
D5.2	Classification of Companies by Assets
D5.3	Market Value of the Electric Sample
D5.4	Capital Structure Summary of the Electric Sample
D5.5	Estimated Growth Rates of the Electric Sample
D5.6	DCF Cost of Equity of the Electric Sample
D5.7	Overall After-Tax DCF Cost of Capital of the Electric Sample
D5.8	DCF Cost of Equity at DTE Electric Company's Proposed Capital Structure
D5.9	Risk-Free Rates
D5.10	Risk Positioning Cost of Equity of the Electric Sample
D5.11	Overall After-Tax Risk Positioning Cost of Capital of the Electric Sample
D5.12	Risk Positioning Cost of Equity at DTE Electric Company's Proposed Capital Structure
D5.13	Hamada Adjustment to Obtain Unlevered Asset Beta
D5.14	Electric Sample Average Asset Beta Relevered at DTE Electric Company's Proposed Capital Structure
D5.15	Risk-Positioning Cost of Equity using Hamada-Adjusted Betas
D5.16	Risk Premiums Determined by Relationship Between Authorized ROEs and Long-term Treasury Bond Rates
D5.17	Academic Literature on Financial Risk Adjustments
D5.18	Academic Literature on the Tests of the CAPM
D5.19	Cost of Common Shareholders' Equity

Q5. Were these exhibits and schedules prepared by you or under your direction?

A5. Yes.

Q6. Can you summarize the parts of your background and experience that are particularly relevant to your testimony on these matters?

A6. Brattle's specialties include financial economics, regulatory economics, and the gas, water, and electric industries. I have worked in the areas of cost of capital, investment risk and related matters for many industries, regulated and unregulated alike, in many forums. A partial list of the regulators before which I have testified or filed cost of capital testimony include the Arizona Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia, the Public Utilities Commission of Ohio, the Tennessee Regulatory Authority, the Public Service Commission of Wisconsin, the South Dakota Utilities Commission, the California Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). I have also testified in Canada before the Canadian National Energy Board, the Alberta Energy and Utilities Board, the Ontario Energy Board, the Quebec Régie de l'énergie, and the Labrador & Newfoundland Board of Commissioners of Public Utilities. I have previously testified before the Michigan Public Service Commission ("Commission"). Appendix A contains more information on my professional qualifications.

Q7. What are the steps in your analysis?

A7. To estimate the Company's cost of capital, I analyzed a sample of electric utilities, identified as being in the same line of business as DTE, specifically the regulated electric utility business. I estimate the ROE for each sample company using both the risk positioning and the discounted cash flow ("DCF") approaches. The risk positioning approach consists of analyses based upon the Capital Asset Pricing Model ("CAPM") and the Empirical CAPM ("ECAPM"). The ROE estimates from both models are then combined with market value capital structure information and the market costs of debt and preferred stock for each sample company to compute each firm's overall cost of capital. I also estimate an ROE using the risk premium approach.

Q8. What is the result of the cost of capital estimation process?

A8. The result of this process is a sample average overall cost of capital for each cost of equity estimation method. I then report the cost of equity consistent with the sample's average estimated overall cost of capital as if the sample's average market-value capital structure had been one with a 51 percent equity ratio, which is the equity ratio DTE has proposed in this proceeding. This procedure results in a ROE that is consistent with both the financial risk inherent in the Company's proposed capital structure and the market-determined information on the sample's average overall cost of capital.

Q9. Do you present any other methods to take differences in financial risk into account?

A9. Yes. Other than the overall cost of capital, I use the method originally proposed by Professor Robert S. Hamada to account for the[1] differences in financial risk through adjustments to the beta estimate for a firm. This procedure is common amongst finance practitioners and well-established in academic literature. I present this method, which I refer to as the Hamada adjustment procedures, for the risk positioning analyses alongside the overall cost of capital method in order to further inform my recommendations that account for differences in the financial risk between companies in my electric sample and DTE Electric Company. Appendix B presents the academic support for and details on the application of these methods.

Q10. How does the ongoing uncertainty in the financial markets affect the cost of capital for a regulated utility?

A10. The cost of capital is higher than a mechanical implementation of the ROE estimation models may suggest, and multiple economic factors indicate that the cost of capital has increased since DTE's last rate case. Although economic conditions have improved substantially since the start of the crisis in about mid-2008, uncertainty

[1] Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock," *The Journal of Finance*, 27(2), 1971, pp. 435-452. See Exhibit A-14, Schedule No. D5.17 at 2-20.

remains in the capital markets due, in part, to the disappointing rate of economic growth, not only in the U.S., but also worldwide. This volatility and uncertainty in the capital markets has increased since the Company's prior rate case application. Worries about the global economic and political instability have added to the concern, including the possibility of a trade war. In addition, the negative effects of the recent tax reform on regulated companies' cash flow further increase the risk of electric utilities.

While long-term government bond yields, which had dropped after the 2008-2009 credit crisis to unusually low levels, remain depressed relative to forecasts of future interest rates, recent economic activity and actions by the Federal Reserve (the "Fed") have caused an increase in current bond yields. As a result, bond yield spreads are declining from their elevated levels since the credit crisis,[2] both for riskier assets as well as for less risky investments such as investment grade-rated utility debt. Although the capital market indices have returned to or exceeded their pre-crisis levels, the recovery remains fragile in part because of the weakness in the rest of the world. I discuss economic conditions and the effect of the credit crisis on the cost of capital and its various components in more detail in Section III below.

This uncertainty in the financial markets also affects the results of the estimation models, because both the risk positioning model and the DCF model are based upon the assumption that economic conditions are stable. That assumption is not currently met, so estimating the cost of capital under current conditions is more complicated than it would normally be.

Q11. Do you adjust your analyses to account for the remaining market uncertainty?

A11. Yes. Because the uncertainty in financial markets affects the cost of capital for all companies, including regulated utilities such as DTE, I modified the parameters of the risk positioning model to recognize the effect of the increased volatility in the capital

[2] The yield spread in this case is the difference between the yield on a risky corporate debt security and the yield on U.S. Treasury debt of comparable maturity.

markets as well as the overall decline in long-term risk-free interest rates on the cost of capital. Specifically, I analyzed scenarios using two different estimates of the market risk premium ("MRP"), one based on historical data and an alternative based on forward-looking estimates of the MRP, for use in the risk positioning model. These scenarios are discussed in more detail below.

Q12. Can you summarize your findings about the electric sample's costs of capital?

A12. The sample ROE estimates range from a low of 8.8 percent to a high of 10.6 percent, but I believe that the estimates at the lower end of the range are not completely reliable because they do not consider the effect of the ongoing uncertainty in the financial markets and the downward pressure on the risk-free interest rate. Conversely, the estimates at the upper end of the range reflect the adjustment for the ongoing uncertainty in the capital market and are more reliable. But the full effects of the tax reform, which have increased the risk to regulated electric utilities, is likely not yet captured by the estimation models. For an electric utility company of average business risk and with an equity ratio of approximately 51 percent the best estimate of the range for the cost of equity is from 9¾ percent to 10¾ percent.

Q13. What ROE do you recommend for the Company in this proceeding?

A13. I recommend that the Company be allowed an ROE of 10½ percent on the equity financed portion of its rate base.[3] This is above the midpoint of the range of 9¾ percent to 10¾ percent that I believe is reasonable for electric utilities of DTE Electric Company's financial and business risk because I believe that DTE is of greater risk than the average company in the sample.

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[3] I report my recommended ROE to the nearest ¼ percentage point because I do not believe that the cost of capital can be estimated more precisely than that even though the model results can be reported to several decimal places.

Q14. How is your testimony organized?

A14. Section II formally defines the cost of capital and touches on the principles relating to estimating the cost of capital and the effect of capital structure on the cost of equity. Section III discusses the impact of the slow recovery from the credit crisis on the cost of capital, compares the change in economic conditions since DTE's prior rate case in U-18255, and evaluates the credit-negative impacts to regulated utilities due to tax reform. Section IV discusses the selection of the electric sample, and Section V presents the methods used to estimate the cost of capital for the sample; provides the associated numerical analyses; and explains the basis of my conclusions for the sample's overall costs of capital. Section VI concludes my testimony. The calculations supporting my analyses are provided in Exhibit A-14. Appendix A contains more information on my professional qualifications. Appendix B discusses the effect of financial risk on the cost of equity capital.

II. COST OF CAPITAL THEORY

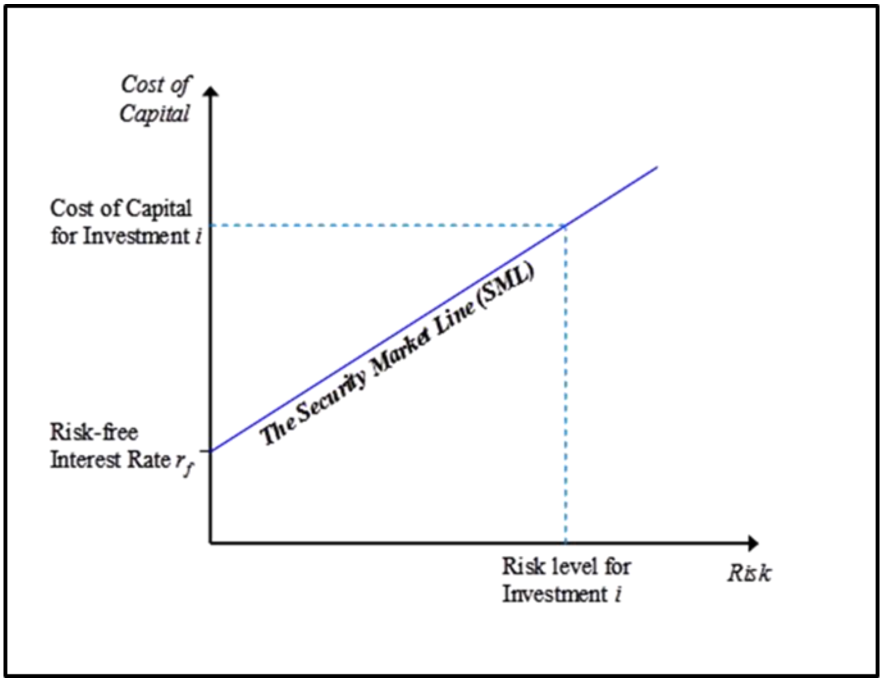
A. COST OF CAPITAL AND RISK

Q15. How is the "cost of capital" formally defined?

A15. The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line" or "Security Market Line" for short. This line is depicted in Figure 1. The higher the risk, the higher the cost of capital required.

Figure 1
The Security Market Line



Q16. Why is the cost of capital relevant in rate regulation?

A16. It has become routine in U.S. rate regulation to accept the "cost of capital" as the right expected rate of return on utility investments.[4] That practice is viewed as consistent with the U.S. Supreme Court's opinions in Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. Regulatory commissions normally try to prevent such outcomes unless there are offsetting benefits (e.g., from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital

[4] A formal link between the cost of capital as defined by financial economics and the right expected rate of return for utilities is set forth by Stewart C. Myers, *Application of Finance Theory to Public Utility Rate Cases, Bell Journal of Economics & Management Science* 3:58-97 (1972).

does a disservice not just to investors but, importantly, to customers as well. Such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the broader economic consequences of providing an inadequate return to the company's investors. In the short run, deviations from the expected rate of return on the rate base from the cost of capital may seemingly create a "zero-sum game"—investors gain if customers are overcharged, and customers gain if investors are shortchanged. But in fact, in the short run, such actions may adversely affect the utility's ability to provide stable and favorable rates because some potential efficiency investments may be delayed or because the company is forced to file more frequent rate cases. Moreover, in the long run, inadequate returns are likely to cost customers—and society generally—far more than may be saved in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. Without access to investor capital, the company may be forced to forgo opportunities to maintain, upgrade, and expand its systems and facilities in ways that decrease long run costs. Indeed, the cost to consumers of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. This is especially true in capital-intensive industries (such as the electric utility industry), which feature systems that take a long time to decay. Such long-lived infrastructure assets cannot be repaired or replaced overnight, because of the time necessary to plan and construct the facilities. Thus, it is in the customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that the return does not fall short of the cost of capital. In fact, research has shown that there is a positive correlation between allowed ROEs from the regulators and customer satisfaction ratings.[5] In other words, the customers of utilities in more supportive regulatory environments have higher satisfaction in the quality of service.

[5] Barclay's Research, "North America Power & Utilities: March Preview/February Review," February 17, 2017.

Of course, the cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital, even if the allowed rate of return equals the cost of capital exactly. However, a commission that sets rates so investors expect to earn the cost of capital on average treats both customers and investors fairly, and acts in the long-run interests of both groups.

B. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND THE COST OF EQUITY

Q17. Please summarize how you accounted for risk when determining the cost of equity.

A17. I account for two main categories of risk: business risk and financial risk. According to financial theory, the overall business risk of a diversified company equals the market-value weighted average of the risks of its components, so I selected a sample concentrated in the regulated company's line of business to ensure comparable business risk. More details on this sample selection can be found in Section IV. I also considered the effects of recent economic uncertainty on estimating the cost of capital, which can be found in Section III. In regards to financial risk, I analyzed the difference in leverage among the sample utilities as compared to the regulatory capital structure of DTE to account for differences in financial risk. Finally, I evaluated any differences in the business and financial risk characteristics of DTE in comparison to the sample companies to determine where in the estimated range the Company's ROE reasonably falls. Appendix B provides further discussion on the effect of financial risk on the cost of capital.

III. IMPACT OF THE RECENT ECONOMIC UNCERTAINTY

Q18. What is the topic of this section of your testimony?

A18. This section addresses the effect of the current economic situation on the cost of capital and the adjustments to my standard procedures required to estimate the cost of capital more accurately.

Q19. Do you believe that capital markets are fully "back to normal"?

A19. No. Although the Fed has decided to raise the target range for the federal funds rate to 1½ to 1¾ percent[6] and the yield spreads between corporate utility and government bonds has decreased, substantial volatility in the financial markets persists (and by some metrics has increased relative to levels one year ago) and economic conditions are not yet back to normal as measured by their status prior to the 2008-2009 credit crisis. This is the 5th time the Fed has chosen to raise its target interest rate since the end of 2016 and is the highest the federal funds rate has been in over a decade. Furthermore, the Fed expects 2-3 additional rate increases before the end of 2018.[7] While the markets have largely recovered from the credit crisis, they are certainly not yet normalized.

A. CHANGES IN ECONOMIC CONDITIONS SINCE U-18255

Q20. Did the Commission address the economic conditions present during the Company's prior rate case?

A20. Yes. In their Order for Case No. U-18255, the Commission specifically stated that there was evidence of "atypical market conditions."[8] The Commission further noted that they "will continue to monitor a variety of market factors in future applications to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE."[9]

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6 See Federal Open Market Committee, Press Release, March 21, 2018.

7 Federal Open Market Committee, "Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents under their individual assessments of projected appropriate monetary policy, March 2018", Figure 2.

8 Michigan Public Service Commission, Order for Case No. U-18255, April 18, 2018, p. 33.

9 *Ibid.*

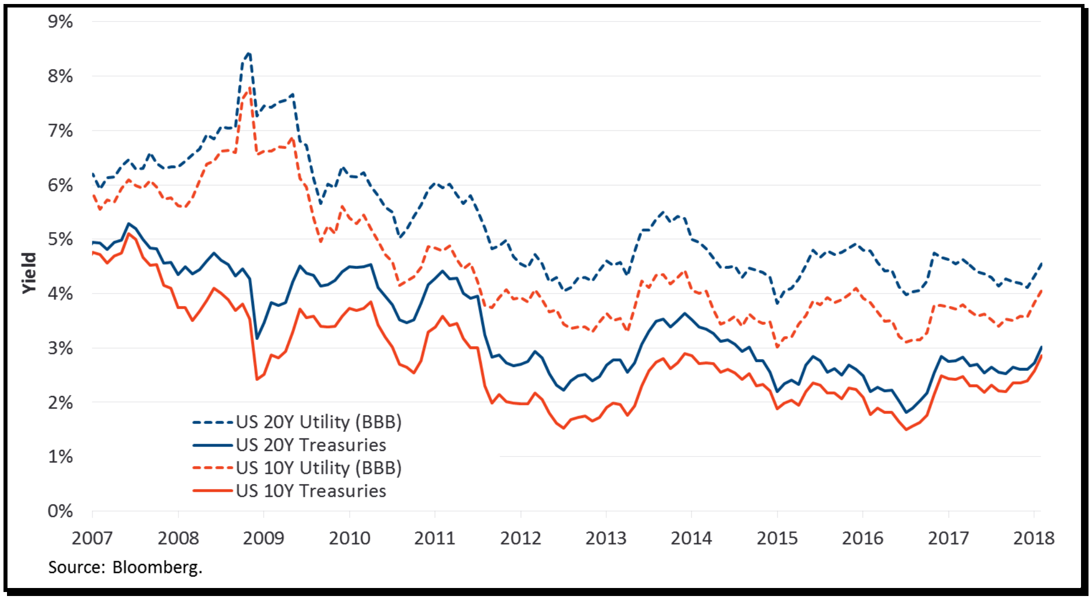
Q21. Do you believe that the "volatility and uncertainty" present in the economy during the prior rate case continue to affect the Company's ROE in the current proceeding?

A21. Yes. Multiple economic factors actually suggest that the volatility and uncertainty have currently increased relative to the conditions existing during the prior rate case. In U-18255, I presented evidence on economic conditions as of the beginning of 2017. Recent conditions through early 2018 indicate that volatility indexes have increased, and global economic conditions are at least as uncertain as during the U-18255 proceeding. Considered in parallel with the increases in interest rates and the credit-negative impacts of the tax reform since the prior rate case, an increase in the Company's ROE relative to that allowed in the U-18255 order is clearly warranted.

Q22. Please describe in more detail the recent trends of interest rates for U.S. government and utility bonds.

A22. Interest rates on U.S. government and utility bonds have certainly declined from the height of their 2008-2009 credit crisis levels, but recent trends indicate that this downward trend has stopped, and forecasts indicate an increase in yields. Due to the credit crisis, the yield spread between U.S. government and utility corporate bonds increased significantly above long-term historical trends. These yield spreads remained elevated in relation to pre-crisis levels in response to world economic events and the efforts of the Fed. The length of this phenomenon, lasting almost 10 years since the credit crisis, exemplifies how impacted markets were by that event. Figure 2 below depicts the historical trend of long-term U.S. government and corporate BBB-rated utility bond yields since 2007.

Figure 2
Bond Yields



Source: Bloomberg.

The yield for U.S. Treasury bonds considered in the record for U-18255 had dropped to a low of 1.50 percent for the 10-year bond and 1.82 percent for the 20-year bond as of July 2016 before rebounding to an average 2.44 percent for the 10-year and 2.78 percent for the 20-year in Q1 2017. These government yields increased further through Q1 2018, rising to an average 2.76 percent and 2.91 percent for the 10-year and 20-year bonds, respectively. These government yields continue to increase, exceeding 3 percent during May 2018, and are expected to continue to increase in part due to the Fed's monetary actions. There has not been as much increase in corporate utility bond yields during this time, meaning that the post-crisis increase in the yield spread discussed above is reverting to historical levels. However, normalization in the spread between government and utility bond yields suggests that further increases in government bond yields due to economic developments and actions by the Fed would lead to equivalent utility bond yield increases.

Q23. What is the implication of the Fed's recent actions?

A23. The pace of increases to the federal funds target rate over the past year indicate that economic activity has been strengthening, and the Fed is monitoring inflationary pressures. After increasing the Federal Funds target interest rate just once in 2016, the

Fed increased the target three times in 2017 and anticipates three to four increases to the target rate during 2018. However, this process of normalization has not yet been completed and actions by the Fed are expected to further increase bond yields relative to their currently depressed levels.

Q24. What further evidence can you provide that U.S. medium- and long-term government bond yields are currently depressed?

A24. Annual yields on long-term U.S. government bonds have continued to be lower than historical values. For instance, the historical average of annual yields on long-term government bonds was 5.23 percent from 1926 to 2010, but the long-term government bond yield declined to just 2.72 percent in 2016.[10] Although the U.S. Fed has discontinued its large-scale asset purchases program, which pushed down yields on medium- and long-term U.S. government bonds, it still holds over $4.3 trillion in assets from this purchasing program. The Fed has said that upon maturity of some of its portfolio of debt, it will not replace that debt with new debt or other assets in its portfolio.[11] The Fed expects to continue to reduce its portfolio by about $50 billion per month.[12] As a result, the supply of debt held by entities other than the Fed will increase. An increase in the supply of debt will likely lead to an increase in interest rates. Effectively, the process is the reverse of how the Fed used its purchases of assets to drive down interest rates.

Furthermore, elevated levels of uncertainty in the global capital markets continue to affect the U.S. economy, which remains sensitive to those disruptions. In other words, major capital markets globally have not yet returned to their pre-credit crisis status, and they continue to affect the U.S. capital markets. The accommodative stance by

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10 See Duff & Phelps's Ibbotson *2017 Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook*.

11 Federal Open Market Committee, Implementation Note, September 20, 2017.

12 Federal Open Market Committee, Addendum to the Policy Normalization Principles and Plans, June 14, 2017.

the European Central Bank (ECB), which targets a *negative* 0.4% interest rate,[13] and the Bank of Japan, which has maintained negative yields on government bonds since early 2016,[14] represent a divergent approach from that currently of the Fed, which halted its asset purchases and has recently decided on a modest increase in interest rates. According to the press release following the March 2018 meeting of the U.S. Federal Reserve Bank's Federal Open Market Committee (FOMC), the FOMC "expects that economic conditions will evolve in a manner that will warrant further gradual increases in the federal funds rate."[15] It is unclear whether the ECB and other central banks will choose to cut already negative interest rates further or whether the Fed might abandon its plans to raise the federal funds target rate even gradually in 2018. Meanwhile, the ECB has held its own target interest rate low while continuing its asset purchase program, now at 30 billion euros (monthly), to promote economic activity. These actions reflect increased uncertainty about the outlook for Eurozone economies. The low interest rate outlook for European and Japanese markets—coupled with the volatility and uncertainty that investors face in global capital markets—are driving bond investors to seek potential upside in the U.S. debt market, pushing yields down.

Q25. Do you expect interest rates and treasury yields to rise in the future?

A25. Yes. The current yield on the 20-year U.S. Treasury bond has increased to 3.07 percent since the Federal Reserve announced its increase to the federal funds rate and the yield on the 10-year U.S. Treasury note is 3.00 percent,[16] but these rates are still much lower than the historical averages. Projections from the March 2018 meeting

[13] European Central Bank, Key ECB Interest Rates, EUROPEAN CENTRAL BANK, https://www.ecb.europa.eu/stats/monetary/rates/html/index.en.html (last visited Apr. 12, 2018).

[14] See Takashi Nakamichi and Rachel Rosenthal, *Bank of Japan Sets Bond-Rate Target in Policy Revamp*, WALL ST. J., September 21, 2016, http://www.wsj.com/articles/boj-changes-policy-framework-after-review-of-measures-1474432869.

[15] See Federal Open Market Committee, Press Release, March 21, 2018.

[16] Average yields of the past 15 trading days ending May 30, 2018. As of 15 trading days ending March 29, 2018, the yield on the 20-year U.S. Treasury bond was 2.96 percent and the yield on the 10-year U.S. Treasury note was 2.83 percent.

indicate that the Federal Reserve expects to increase federal funds rates another 50-75 basis points by the end of 2018, placing more upward pressure on long-term government bond yields.[17] Additionally, according to the *Blue Chip Economic Indicators* report dated March 10, 2018, the consensus economic projections for the yield on 10-year U.S. Treasury notes are 3.7 percent on average in 2020 to 2024 and 3.8 percent on average from 2025 to 2029.[18] These forecasts are substantially higher than the current yield on 10-year U.S. government notes.[19] This highlights the fact that current long-term and medium-term U.S. government bond yields are low relative to historical levels as well as compared to consensus forecasts of future rates. The unusually low current long-term government bond yields, along with elevated yield spreads due to risk aversion, must be considered when evaluating the results of my risk-positioning model, because the downward bias in the long-term risk-free interest rate will inappropriately lower the sample companies' ROE estimates generated by the CAPM method.

Q26. Do other financial practitioners recognize the downward bias that uncertain economic conditions may place on the cost of capital estimates?

A26. Yes. Duff & Phelps, specifically, recognizes this fact in explaining why normalizing certain parameters for the models may be necessary. For example, standard applications of the cost of capital models would have shown lower equity costs of capital at the height of the 2008-2009 credit crisis, when risks were perceived to be much higher, than prior to the crisis. According to Duff & Phelps:

> This demonstrates that a mechanical application of the data may result in nonsensical results.[20]

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[17] Federal Open Market Committee, "Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents under their individual assessments of projected appropriate monetary policy, March 2018", Figure 2.

[18] *Blue Chip Economic Indicators*, dated March 10, 2018, page 14.

[19] See Exhibit A-14, Schedule No. D5.9 at 1.

[20] Duff & Phelps, *2017 Valuation Handbook: U.S. Guide to Cost of Capital*, p. 3-23.

Q27. What have been recent trends in the volatility of financial markets?

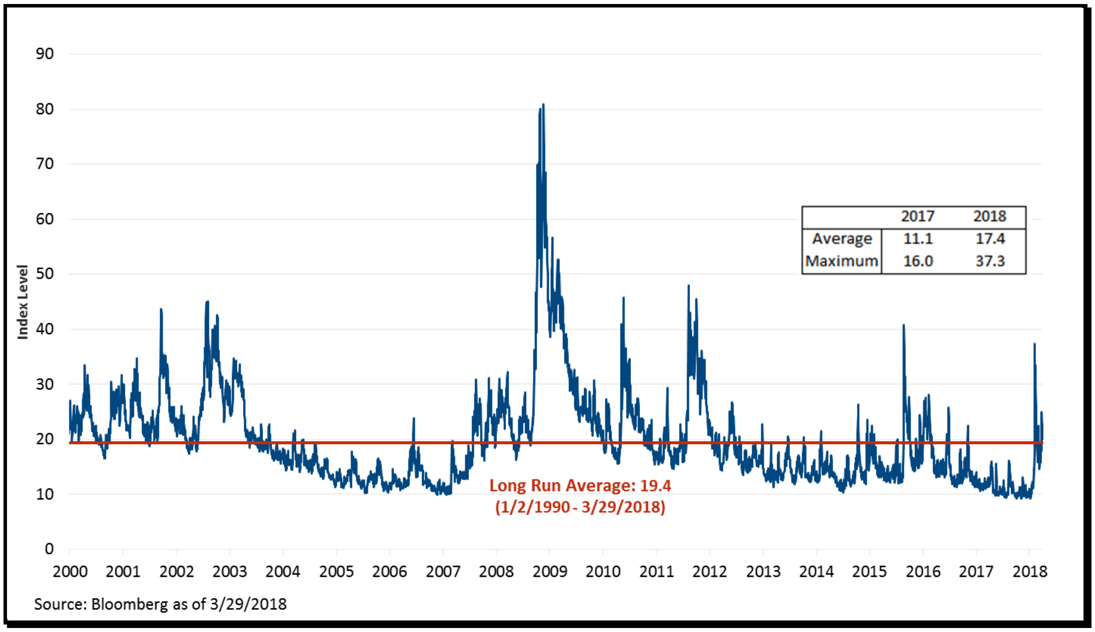
A27. The S&P 500 VIX measures the 30-day implied volatility of the S&P 500 index. This index, often called the investor fear gauge in that it provides a market indication of how investors in stock index options perceive the likelihood of large swings in the stock market within the next month, is a prominent metric for understanding market volatility and risks.

At the time of U-18255 proceeding (with record evidence presented from 2016 through early 2017), the VIX was reported to be significantly below its long-run average. The VIX index averaged approximately 12 during Q1 2017 and has risen to on average 17 during Q1 2018. At present, the VIX index stands at about 20, which is an increase from the levels considered in U-18255.[21]

While near-term expectations for market volatility have increased since 2016-2017 and become more aligned with the average long-term trends, the recent history of the VIX index (Figure 3) reveals that there can be considerable movements in short-term volatility expectations. For example, the VIX recently spiked as high as 37 in 2018, far above the maximum of 16 and minimum of 9 experienced in 2017.

[21] Bloomberg as of March 29, 2018.

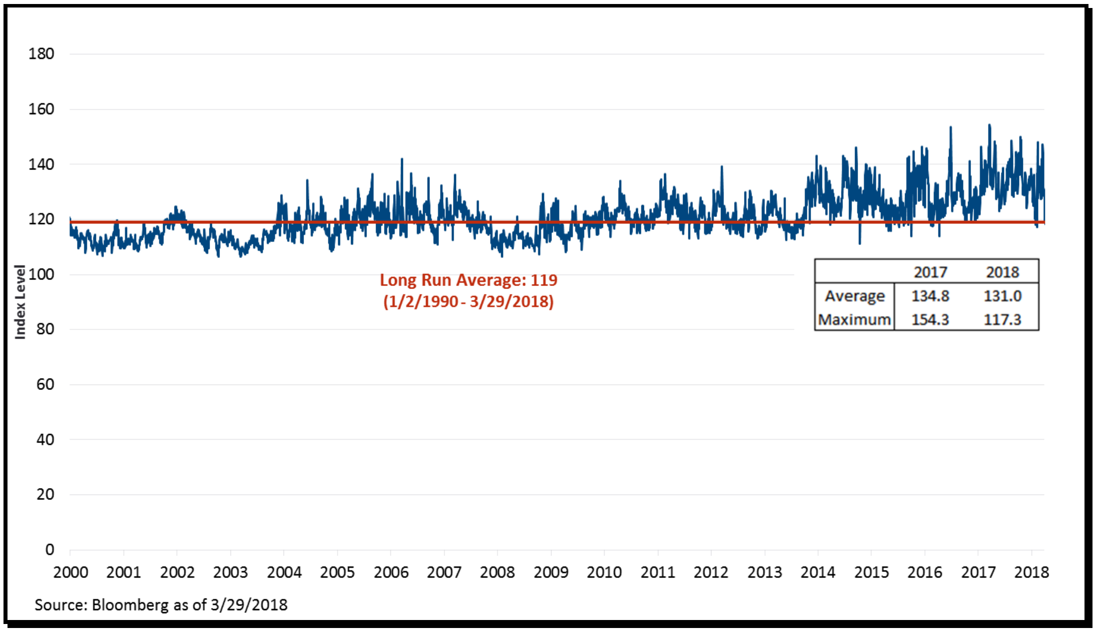
Figure 3
US Volatility Index



Q28. Are there any other indices related to market volatility which you consider?

A28. Yes, I also reviewed the Chicago Board Options Exchange SKEW Index ("SKEW"). The SKEW indicates investors' perception of the tail risks, or extreme negative moves, of the U.S. equity market. A SKEW value of 100 would indicate that investors believe market returns are normally distributed. The SKEW increases as investors become more fearful of tail risk or extreme negative events. As shown in Figure 4 below, the SKEW has averaged 130 since the beginning of 2018 while its 10-year average has been approximately 120. The 2017 average of 135 is similar, though slightly higher than, the 2018 average of 131. Thus investors perceive higher tail risk under current market conditions than long-term historical conditions and this risk is similar to levels present during the prior rate case.

Figure 4
U.S. SKEW Index



Q29. What do these volatility trends imply about the cost of capital?

A29. Academic research has found that, all else equal, investors, demand higher risk premiums during more volatile periods.[22] However, it is important to remember that the VIX measures expectations for market volatility in the *near-term*—specifically over the coming 30 days. By contrast, the market risk premium that is relevant in this proceeding represents the compensation investors require to take on risk over a long investment horizon. So while the levels of the VIX is a useful indicator of current investor sentiment and uncertainty in equity markets, it is too simplistic to say that average or lower implied volatility necessarily corresponds to average or lower risk premiums required by investors.

[22] K. French, W. Schwert and R. Stambaugh (1987), "Expected Stock Returns and Volatility," *Journal of Financial Economics*, Vol. 19, p. 3.

Q30. Are there any other global conditions that have increased global economic uncertainty since the prior rate case?

A30. Yes. It is also worth considering that global political and economic uncertainty is quite high at present, driven by multiple new occurrences not present at the time of my direct testimony in U-18255. Specifically, I note that potential tariff wars with China, Mexico, and the European Union, uncertainty regarding economic sanctions with Iran and Europe related to the Iran nuclear deal, and negative impacts to regulated utilities from the tax reform are recent issues that impact the risk to a regulated electric utility (and the broader U.S. economy). The global issues of trade wars and sanctions with some of the world's largest economies are already affecting U.S. capital markets and have the potential to cause even more turmoil. I discuss the effects of tax reform further in the next sub-section.

Q31. How do you adjust your cost of capital estimation methods to correct for current economic conditions?

A31. I make no adjustment to the DCF method. For the risk positioning method, I recognize the large uncertainty that impacts the current economic conditions. I therefore consider both a historical measure of the MRP as well as a forward-looking estimate of the MRP. I discuss my estimates of the MRP in Section V.

Q32. Can you summarize your thoughts with regard to the MRP and the financial crisis?

A32. Yes. There remain serious concerns of a very slow growth recovery and many factors indicate that these concerns have increased since the U-18255 proceeding. The Commission should consider the rapidly increasing U.S. Treasury bond yields and the ongoing volatility and uncertainty, as it did in the U-18255 order. All of these factors support an increase to the ROE for the Company relative to its previously allowed ROE in U-18255.

It is highly likely the MRP is higher than its level in more normal times, whether there is any particular agreed model for how to calculate the increase or not. In light of these circumstances and the calculations described above, I submit that a 100-150 bps increase in the MRP presents a reasonable span of the adjustments that might be made. As discussed in the Empirical CAPM estimation below, I have analyzed two scenarios with a range of estimates for the MRP. These scenarios recognize the simple reality that while the financial turmoil and interventions by the Fed and the U.S. government have made it more difficult to measure the cost of equity accurately, the required return on equity has increased, not decreased, as a mechanical implementation of the models might suggest.

B. FEDERAL INCOME TAX REDUCTION

Q33. How does the Tax Cuts and Jobs Act of 2017 affect a regulated utility such as DTE?

A33. The Tax Cuts and Jobs Act ("TCJA"), signed into law on December 22, 2017, included multiple provisions which apply to regulated utilities. For one, the tax code reduced the federal corporate marginal income tax rate from 35 percent to 21 percent. Additionally, the tax reform restricted regulated utilities from claiming bonus tax depreciation in exchange for continuing to allow these entities to fully deduct their interest expense.

Q34. How does a reduction in the marginal corporate tax rate impact the revenue requirement of a regulated electric utility?

A34. The reduced corporate tax rate impacts the utility's revenue requirement in three main areas: (1) the income tax allowance ("ITA"), (2) the accumulated deferred income taxes ("ADIT"), and (3) the excess accumulated deferred income taxes ("EDIT"). A reduction in the income tax rate reduces the ITA included in the revenue requirement and reduces the costs that an electric utility collects from its customers. A reduced income tax decreases the future tax liabilities (ADIT) of a regulated electric utility; the reduction in ADIT increases the utility's regulated rate base, all else equal. Finally, the electric utility returns to customers over the lifetime of its assets the EDIT that it no longer expects to pay as tax expenses, which reduces the costs to customers.

On net, the reduction in tax rate is expected to reduce the total rates charged to customers and, therefore, the revenues collected by an electric utility.

Q35. Have credit rating agencies expressed any concern for regulated electric utilities due to this tax reform?

A35. Yes, multiple credit ratings reports have expressed concern for the financial health of regulated electric utilities given the negative impact that the tax reform will have on the companies' cash flow and credit metrics:

- Moody's changed the outlook for 24 regulated utilities to negative, explaining the "change in outlook to negative from stable for the 24 companies affected in this rating action primarily reflects the incremental cash flow shortfall caused by tax reform." They estimated that cash flow to debt ratios could decline by 150-200 basis points. They note that corrective measures implemented through regulatory channels, such as changes in equity ratios or allowed ROEs, could offset the credit-negative impacts and return the outlooks to stable.[23]
- S&P believes that the "impact of tax reform on utilities is likely to be negative" and they "expect companies to request stronger capital structures and other means to offset some of the negative impact." S&P specifically notes its negative outlook to PNM Resources Inc. and its subsidiaries after the recent "Public Service Co. of New Mexico rate case decision incorporated tax savings with no offsetting measures taken to alleviate the weaker cash flows."[24]
- Fitch also recognizes that the TCJA "has negative credit implications for regulated utilities," estimating that there would be a 15% decrease to funds

[23] Moody's Investors Service, Regulated Utilities – US, "Tax reform is credit negative for sector, but impact varies by company," 24 Jan 2018. Moody's Investors Service, "Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform," 19 Jan 2018.

[24] S&P Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound," 24 Jan 2018.

> from operation due to the tax reform. In addition, they identify multiple regulatory actions that may be taken to support the creditworthiness of utilities, including an "increase in authorized equity ratio and/or return on equity."[25]

Credit ratings are likely to be negatively impacted due to a reduction in the regulated utilities' credit metrics because cash flow metrics are closely observed by the ratings agencies. Yet the tax reform has not impacted the amount of assets, a portion of which will be debt-financed, necessary to serve the utilities' customers. Decreases to the cash flow metrics, such as cash flow to debt ratios closely monitored by credit rating agencies to inform their credit opinions, negatively affects the credit profile of many regulated utilities.

The TCJA has already affected the Company's financing decisions. As noted in DTE Energy's investor presentation for Q1 2018, the Company will issue $300 million incremental equity in 2018-2020 due to the tax reform to maintain its BBB credit rating.[26]

Q36. Was DTE Electric or DTE Gas one of the 24 regulated utilities originally identified for a negative outlook by Moody's?[27]

A36. No. However, Moody's has recently changed DTE Gas's outlook to negative, citing the "company's decision to maintain existing capital expenditure levels near their record highs, at a time when it is grappling with the negative cash flow impacts from federal tax reform, will result in a sustained weakening of its financial metrics."[28]

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[25] Fitch Ratings, "Tax Reform Impact on the U.S. Utilities, Power, & Gas Sector," 24 Jan. 2018.

[26] DTE Energy Investor Relations, "1st Quarter 2018 Earnings Conference Call," 25 Apr 2018.

[27] *Op. cit.*, Moody's, 19 January 2018.

[28] Moody's Investor Service, Rating Action: "Moody's changes outlook of DTE Gas to negative," 30 May 2018,

Q37. What do these findings suggest about the risks for regulated electric utilities?

A37. These effects suggest that the allowed ROE and/or the amount of equity in the capital structure should be increased to offset the negative effects of the income tax law. It is vital to maintain the financial health of the utility and the ability of that utility to raise capital on favorable terms, especially during periods of significant capital expenditures. Declining credit metrics and ratings indicate increased risk for the company, suggesting that a higher ROE would be appropriate to compensate for this risk to equity holders and/or a higher equity share in the capital structure should be allowed in order to improve the financial profile of the company.

IV. SAMPLE SELECTION

A. The Electric Sample

Q38. What factors do you consider in selecting a proxy group?

A38. The cost of capital for any part of a company depends on the risk of the lines of business in which the part is engaged, not on the overall risk of the parent company on a consolidated basis. According to financial theory, the overall risk of a diversified company equals the market-value weighted average of the risks of its components, so selecting a sample concentrated in the regulated company's line of business is important. DTE is a regulated electric utility, and there is currently available a relatively large sample of publicly-traded electric utilities whose primary business is generation and distribution of electricity under cost of service regulation.

Q39. Can you summarize how you selected the electric sample?

A39. I formed the sample from the universe of publicly traded electric utilities as classified by the *Value Line Investment Survey Plus Edition*.[29] This resulted in an initial group of 44 companies. I then eliminated companies by applying additional selection criteria designed to remove companies with unique circumstances which may bias the cost of capital estimates.

[29] The 44 companies are from *Value Line Investment Analyzer*, accessed as of March 30, 2018.

Q40. What additional selection criteria did you apply?

A40. The companies must own substantial regulated assets, must not exhibit any signs of financial distress, and must not be involved in any substantial merger and acquisition ("M&A") activities that could bias the estimation process.[30] In general, this requires that over a five year study period and up to the date of the analysis, the sample companies have an investment grade credit rating, a high percentage of regulated assets (greater than 50 percent),[31] no significant merger activity, no dividend cuts, and no other activity that could cause the growth rates or beta estimates to be biased. I also require that each of the sample companies has more than $300 million in market capitalization over the last four quarters of available financial data. Finally, I require that data from S&P or Moody's, *Value Line*, and Bloomberg—each widely known and utilized by investors—be available for all sample companies.

Q41. Did you consider any additional selection criteria to filter companies based on their size?

A41. Yes. In Case No. U-18014, Michigan Public Service Commission Staff ("Staff") proposed that each sample electric company be comparable in size to DTE Electric and restricted the sample to include companies that have net plant greater than $6.0 billion but less than $20.0.[32] The Order in Case No. U-18014 notes that "the ALJ further found that the Staff's approach most reasonably establishes a minimum and maximum size for the companies to be included in the proxy group."[33]

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[30] This includes pending (but announced) M&A activity but adjusts for M&A activity that does not appear to bias the beta estimates substantively, (such as small, spaced-out transactions, transactions involving multiple parties or parent drop-downs).

[31] I use the Edison Electric Institute's classification of electric utilities as Regulated (greater than 80 percent of total assets are regulated), Mostly Regulated (50 to 80 percent of total assets are regulated) or Diversified (less than 50 percent of total assets are regulated). My sample includes only electric utilities classified by EEI as Regulated or Mostly Regulated.

[32] Case No. U-18014, Revised Qualifications and Direct Testimony of Kirk D. Megginson, Michigan Public Service Commission Staff, 5 T 1391.

[33] Case No. U-18014, Order, January 31, 2017, p. 55.

I do not believe that the size difference between companies in my electric sample creates any bias in estimating the cost of equity. Nearly all sample companies have market capitalizations which exceed $2.5 billion, placing them at or above the mid-cap grouping (deciles 3-5) as defined by Duff and Phelps.[34] Duff and Phelps calculates that mid-cap companies merit a size premium of 1 percent so any difference in size premium between companies in this sample must be less than 1 percent. I therefore disagree that the minimum and maximum constraints on net plant are necessary. However, I present a subsample of electric companies which have net plant greater than $6 billion but less than $20 billion as a comparison.

Q42. Do you make any other adjustments to your electric subsample?

A42. Yes, I also exclude DTE Energy from the electric subsample based on the Order to Case No. U-18014.[35] I do not, however, believe it is reasonable to remove DTE Energy from the proxy group for its subsidiary DTE Electric. DTE Electric is the regulated entity whose rates are at issue in this proceeding. It is both practically and conceptually distinct from its corporate parent, DTE Energy. Since DTE Electric's equity is not publicly traded, it is necessary to estimate its cost of capital in relation to a sample group of public companies whose operations are concentrated in the same line of business, namely regulated generation and distribution of electricity. Each company in my full electric sample, including DTE Energy, meets all selection criteria and provides useful information about the cost of capital of a representative regulated electric company. I therefore present this subsample of electric companies excluding DTE Energy as a comparison but I place less weight on these results for my final ROE recommendation.

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[34] Duff & Phelps's Ibbotson *2017 SBBI Yearbook*, 7-16. Four of the 25 sample companies had market capitalizations below $2.5bn at the end of 2017: El Paso Electric, MGE Energy, Otter Tail Corp., and Unitil Corp.

[35] Case No. U-18014, Order, January 31, 2017, p. 55.

B. COMPARISON OF DTE TO THE ELECTRIC SAMPLE COMPANIES

Q43. What are the characteristics of the sample of electric utility companies you have chosen?

A43. The electric sample is comprised of regulated companies whose primary source of revenues and majority of assets are in the regulated portion of the electric industry. The final sample consists of the 25 electric utilities listed in Table 1 below. The subsample consists of 6 electric utilities.[36]

Q44. Can you describe the financial and regulatory characteristics of the sample in comparison to DTE?

A44. Table 1 below reports the sample companies' annual revenues for the trailing twelve months ended December 2017 and the percentage of their assets devoted to regulated electric operations according to EEI's classifications of electric utilities as being either regulated ("R"), having greater than 80 percent regulated electric assets or mostly regulated ("MR"), having 50-80 percent regulated electric assets. Table 1 also displays the Market Capitalization and the S&P Credit Rating for each company in 2018, and the average long-term (5-year) earnings growth rate estimate from Thomson Reuters IBES and *Value Line* for all of the companies in the electric sample.

The Company had operating revenue of approximately $5.1 billion in 2017.[37] By comparison, the average sample company had $6.8 billion in revenues during the twelve months ended December 2017.[38] DTE's parent company, DTE Energy Company, had $12.6 billion in revenue over that same period.[39] So while the Company individually is somewhat smaller than the average sample company, it

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36 The subsample consists of Alliant Energy, CenterPoint Energy, CMS Energy Corp., OGE Energy, Pinnacle West Capital, and Portland General.

37 DTE Energy Company's 2017 SEC Form 10-K at 67.

38 The revenue figures in Table 1 are the reported annual revenue over the four fiscal quarters ending December 31, 2017.

39 DTE Energy Company's 2017 SEC Form 10-K at 59.

likely does not face significant risk of financial distress due to its size. DTE Energy Company and DTE both have S&P credit ratings of BBB+, which is average for the sample.[40]

Table 1
Financial Characteristics of the Electric Sample

Company	Sub-Sample	Annual Revenue (4Q 2017) ($MM)	Regulated Assets	Market Cap. (4Q 2017) ($MM)	S&P Credit Rating	Moody's Credit Rating	Long Term Growth Est	Value Line Net Plant
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
ALLETE		1,419	M	3,869	BBB+	WR	6.0%	3,822
Alliant Energy	*	3,382	R	10,029	A-	WR	5.5%	9,810
Amer. Elec. Power		15,425	R	36,891	A-	Baa1	5.6%	50,262
Ameren Corp.		6,177	R	14,589	BBB+	WR	6.4%	21,466
AVANGRID Inc.		5,963	M	15,847	BBB+	N/A	10.7%	21,548
CenterPoint Energy	*	9,614	M	12,218	A-	Baa1	8.5%	13,057
CMS Energy Corp.	*	6,583	R	13,583	BBB+	Baa1	7.0%	16,761
Consol. Edison		12,033	R	26,799	A-	A3	3.1%	37,600
DTE Energy		12,607	M	19,942	BBB+	Baa1	5.6%	20,721
Duke Energy		23,565	R	60,046	A-	Baa1	4.2%	86,391
Edison Int'l		12,320	R	22,056	BBB+	A3	2.6%	39,050
El Paso Electric		917	R	2,299	BBB	Baa1	5.2%	2,928
Entergy Corp.		11,074	R	14,790	BBB+	Baa2	-6.7%	29,664
Eversource Energy		7,752	R	20,139	A+	Baa1	5.7%	23,618
IDACORP Inc.		1,349	R	4,694	BBB	Baa1	3.1%	4,284
MGE Energy		563	M	2,178	AA-	N/A	n/a	1,341
OGE Energy	*	2,261	R	6,686	A-	A3	5.8%	8,340
Otter Tail Corp.		849	R	1,782	BBB	WR	9.0%	1,540
Pinnacle West Capital	*	3,565	R	9,753	A-	WR	3.6%	13,445
PNM Resources		1,445	R	3,381	BBB+	Baa3	4.3%	4,980
Portland General	*	2,009	R	4,164	BBB	WR	3.5%	6,741
PPL Corp.		7,447	R	22,584	A-	N/A	2.1%	30,074
Public Serv. Enterprise		9,084	M	26,055	BBB+	Baa1	3.4%	29,286
Unitil Corp.		406	R	693	BBB+	N/A	3.9%	972
Xcel Energy Inc.		11,404	R	25,102	A-	A3	6.1%	34,329

Sources and Notes:
[2]: Subsample includes companies with a Net Plant between $6bn and $20bn as reported by Value Line.
[3]: Bloomberg as of March 30, 2018.
[4]: Key R - Regulated (More than 80% of assets regulated).
M - Mostly Regulated (50%-80% of assets regulated).
D - Diversified (Less than 50% of assets regulated).
Source: Calculations based on EEI definitions and Company 10-Ks.
[5]: See Schedule No. D6.3 Panels A through Y.
[6]: Bloomberg as of March 30, 2018.
[7]: Bloomberg as of March 30, 2018.
[8]: See Schedule No. D6.5.
[9]: From Valueline Investment Analyzer as of 3/29/2018.

[40] S&P Capital IQ.

Like many of the sample companies, DTE benefits from certain regulatory policies that reduce regulatory lag, including a forward test year for rate cases, and an annual Power Supply Cost Recovery ("PSCR") clause for expenses such as fuel, capacity, energy, transmission, and purchased power.[41] Subject to Commission review, the Company is permitted to include construction work in progress ("CWIP") for pollution control measures and significant new infrastructure projects in rate base.[42] Cost-tracking mechanisms such as these are also in effect in states affecting several of the sample companies.[43] However, unlike some of the sample companies, DTE does not currently have a revenue decoupling mechanism (since a 2012 Court of Appeals ruling reversed Michigan Public Service Commission approval for such a program that DTE had implemented) or lost revenue adjustment mechanism ("LRAM") in place, as some sample companies do.[44]

Q45. How does the business risk of DTE compare to that of the sample?

A45. Like the sample companies, DTE Electric Company's business is concentrated in regulated electric generation and distribution, and as mentioned above, DTE does have some regulatory mechanisms in place that are comparable to those of the proxy group companies. It also has a credit rating (BBB+) that is comparable to those of the sample companies.

Regulatory policy plays a role in the business risk of the Company. In the current environment of low electric demand growth, the fact that DTE does not have a revenue decoupling mechanism or a fixed variable pricing policy places it at

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[41] SNL Regulatory Research Associates.

[42] *Id.*

[43] SNL Regulator Research Associates and Edison Electric Institute, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," January 2013.

[44] Edison Electric Institute, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," January 2013. Several of the companies in my comparable sample have a decoupling mechanism in place. This means that these companies benefit from regulatory provisions allowing them to recover their fixed costs independently of volumetric charges: if the utilities' customers use less electricity than was forecast, the decoupling mechanism ensures that the utilities can recover their cost despite the decrease in variable revenues.

increased risk of under-recovering its cost of service relative to some companies in the sample group that benefit from such mechanisms. Because the Company recovers much of its fixed costs through per-kWh charges to their customers (i.e., does not benefit from full revenue decoupling or fixed-variable pricing), it will be at risk for under-recovery if electric sales do not reach forecast levels.

Brattle has studied the effect of decoupling on the cost of capital[45] and found a lack of statistical support for the hypothesis that the adoption of decoupling results in a decrease in the cost of capital; however, the test does not provide the reason. The paper offers two possible explanations. One is that decoupling primarily affects diversifiable risk, which is the kind of risk that does not affect the cost of capital because investors can eliminate diversifiable risk through formation of a portfolio. The second possible explanation is that decoupling merely offsets the increased risk from economic circumstances that favor energy conservation. If the second explanation is the correct one, then companies that face declining energy consumption without the benefit of a decoupling mechanism would indeed face higher systematic risk than their peers that can rely on such a mechanism. This would suggest that DTE represents a higher than average risk to investors relative to the sample companies, some of which benefit from full revenue decoupling mechanisms.

Michigan also allows competitive retail choice for electricity, which may erode sales volume, although state law caps the alternative supply in a utility's service territory at 10 percent of the preceding years' sales.

[45] "Effect on the Cost of Capital of Ratemaking that Relaxes the Linkage between Revenue and kWh Sales: An Updated Empirical Investigation of the Electric Industry," Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang, and James Hall, *The Brattle Group*, November 2016. "The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation," by Michael J. Vilbert, Joseph B. Wharton, Charles Gibbons, Melanie Rosenberg, Yang Wei Neo of *The Brattle Group* on behalf of The Energy Foundation, March 20, 2014.

Q46. The Company has proposed the use of an Infrastructure Recovery Mechanism ("IRM") to recover some forecast investment between rate cases. Do you believe that this mechanism would reduce the cost of capital of the Company?

A46. No, I do not believe that this proposed recovery mechanism would reduce the systematic risk of the Company relative to the Electric Sample. This recovery mechanism is intended to change the timing of the recovery of cash flows and to reduce the need for general rate cases, not to change the risk profile of those cash flows. Currently, the Company receives no cash flow on its investments in new construction projects until the capital projects are included in the Company's rate base after a general rate case.[46] The difference in timing, often referred to as regulatory lag, between when the investment is made and when the Company is able to recover costs related to that investment can be quite long. Significant regulatory lag, especially during periods of large capital expenditure programs, could stress the cash flow management of companies.

Pursuing rate cases more often, such as every year, is one option for regulated utilities to manage this cash flow timing issue. The Company's proposed IRM offers an alternative method to address this cash flow timing issue. The proposed IRM would better align the timing of capital expenditures, based on the Company's approved forecasts, with the recovery of and on those expenses. However, the proposed mechanism does not change the systematic risk associated with earning a return of and on those electric utility assets.[47]

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[46] The Company does receive an Allowance for Funds Used During Construction ("AFUDC"), but AFUDC does not provide current cash flow.

[47] The proposed IRM would include asymmetrical capital spend reconciliation and symmetrical revenue reconciliation. Thus any capital spend below the approved forecast would necessitate a decrease in the IRM surcharge while capital spend above the approved forecast would not change the IRM surcharge. The Company would therefore be accepting the risk of rate base growth that exceeds forecasts. Further, the under- or over-collection of the IRM surcharge due to volumetric consumption different from forecasts would be exactly reconciled. This is functionally similar to a decoupling mechanism, though only on a subset of the Company's operations. As discussed above, Brattle has studied the effect of decoupling mechanisms on the cost of capital for regulated utilities and found a lack of statistical support for the hypothesis that the adoption of decoupling results in a decrease in the cost of capital.

Q47. How does the state of the economy in DTE's service territory affect the Company's business risk?

A47. The economy of Detroit has improved substantially over the last few years. However, the risk of under-recovery of DTE's fixed costs due to its reliance on volumetric charges to recover fixed costs is increased by the state of Michigan's economy relative to the other companies in the sample. Michigan's economy is heavily dependent upon the auto industry, and Detroit's economy in particular is currently weak. The City of Detroit ("City"), which was in bankruptcy until December 10, 2014, is recovering, but it continues to experience a high unemployment rate and approximately 40 percent of the its population lives under the federal poverty threshold.[48] The City has experienced falling population year-over-year since 2005. In spite of the State of Michigan's financial woes as evidenced by the City of Detroit's bankruptcy, the Federal government has reduced the amount of LIHEAP assistance provided to Michigan and thus to Detroit.

The Company's sensitivity to the state of the auto industry is apparent with regard to the steel industry. Steel production in DTE's service territory is forecast to decline, owing to a combination of forces including the gradual substitution of other materials for steel in the production of automobiles.

The weak local economic conditions and declining population and industrial activity in the Company's service territory contribute to and exacerbate the effect of declining sales which—in conjunction with a rate structure that relies on volumetric charges to recover fixed costs—increases the downside risk that DTE may not be able to earn its authorized return. To the extent these forces make the Company more sensitive to volatility in the broader economy, they increase DTE Electric's systematic business risk and thus its cost of capital.

[48] U.S. Census Bureau 2012-2016 American Community Survey 5-Year Estimates.

Q48. How do the weaker economic conditions in DTE's service territory contribute to specific operational and financial challenges for the Company?

A48. The City of Detroit is geographically large, and while some neighborhoods are recovering, others are being abandoned and/or demolished. Shifting population poses a challenge for electric distribution, since infrastructure is built to serve a particular population distribution. While DTE's system is in some sense "overbuilt" relative to its remaining residential load, it must still serve diminishing neighborhoods, leading to operational inefficiencies. New investment and operating budget must be allocated to recovering areas while maintaining underutilized infrastructure elsewhere.

Q49. What other capital investments does the Company need to make?

A49. The Company has identified over $4 billion of necessary capital expenditures from January 2018 through April 2020. A portion of the forecast capital expenditures is to improve reliability, meet environmental compliance, and procure additional capacity. Currently, DTE generates the majority of its energy from coal which may be forced out of service depending upon future environmental legislation as well as the cost of natural gas and renewable energy. The company has already announced plans to retire 11 of its 17 coal-fired units by 2023 and expects to replace the capacity with a mix of natural gas, wind, and solar generation.[49] A report developed for Governor Rick Snyder identified the risk of inadequate capacity in Michigan to meet reserve requirements and calls for significant capital investment to upgrade the energy distribution system.[50]

Given the significant capital investment plans, it is vital that the financial health of the Company be well-supported by the Commission in order to ensure access to capital markets at favorable costs. The negative credit rating impacts from the TCJA,

[49] DTE Energy News Release, "DTE Energy announces plan to reduce carbon emissions by 80 percent," May 16, 2017.

[50] "21st Century Infrastructure Commission Report, Prepared for Governor Rick Snyder," November 30, 2016.

increases in government bond yields, and increased volatility and uncertainty in capital markets all indicate increased risk and an increased cost of capital for DTE.

Q50. Does DTE's ownership of the Fermi 2 nuclear generating plant affect the Company's risk?

A50. Yes. Although empirical tests of the effect of the ownership of nuclear generating plants on the cost of capital have not shown a statistically significant increase in the cost of capital, ownership clearly increases the total risk of the Company. The cost of capital is affected by business risk which is the risk remaining after diversifiable risk is removed from total risk.

The additional risk of the Fermi 2 nuclear generating plant is likely to largely be diversifiable, but it is also asymmetric. Asymmetric risk refers to a downside risk for which there is no corresponding upside to balance the risk.

Q51. If the risk of Fermi 2 does not affect the cost of capital, what do you recommend that the Commission do?

A51. First, the Commission should recognize that the risk of nuclear power plants is asymmetric. The Commission should remove the asymmetric risk if there is an event at the plant because the Company has not been previously compensated through its cost of capital for the potential loss. Second, the empirical tests of the effect of nuclear power on the cost of capital are likely to be "weak" in the sense that it is extremely difficult to develop a test likely to detect the effect of nuclear generating assets on the cost of capital for a company because there are so many other factors that affect the cost of capital. For example, nuclear plants are generally owned by holding companies with many other types of assets and are affected by varying regulatory policies. It may well be that nuclear generating plants increase the cost of capital even though empirical tests have not been able to detect it. I regard ownership of Fermi 2 as one more factor indicating that the Company is riskier than the sample on average.

Q52. Can you please summarize your assessment of DTE's business risk relative to the sample?

A52. In consideration of the factors mentioned above, I believe DTE Electric is of higher than average business risk relative to the sample companies.

C. CAPITAL STRUCTURE

Q53. What regulatory capital structure is DTE requesting in this proceeding?

A53. DTE has proposed a regulatory capital structure consisting of approximately 51 percent equity and 49 percent debt,[51] as further explained by Witness Edward J. Solomon. This capital structure is consistent with the book value capital structures of my sample companies. My recommended range for ROE is a function of the requested capital structure, the sample average cost of capital estimates, the Hamada adjustment procedures, and the relative risk of the Company compared to the sample.

As discussed above and in Appendix B, there is a clear relationship between the capital structure of a company, its level of financial risk, and its cost of capital. Credit rating agencies have also recognized this relationship, specifically in the context for the negative cash flow impacts due to tax reform, and have identified regulatory options to mitigate such effects. These options include increasing the allowed equity share in the utility's capital structure and increased the allowed ROE. Any reduction in the requested equity ratio without consideration for the increased financial risk that implies for the Company would be inappropriate.

V. COST OF CAPITAL ESTIMATES

Q54. How do you estimate the sample companies' costs of equity?

A54. As noted earlier, I apply two general methodologies—risk positioning and DCF—both of which are standard ways of estimating a company's cost of equity. For my CAPM (risk positioning) based estimates, I consider a range of sensitivities to reflect

[51] By regulatory capital structure, I mean the capital structure used to set rates in this proceeding.

well-documented empirical deficiencies in the CAPM when used in conjunction with an equity market index. These sensitivities are called the Empirical CAPM. I also report results generated by two versions of the DCF approach: the single-stage and the multistage DCF models.

A. THE CAPM-BASED ESTIMATES

Q55. Can you explain the CAPM?

A55. Modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a market risk premium. The CAPM is the longest-standing and most widely used of these theories. To implement the model requires specification of (1) the current values of the benchmarks that determine the Security Market Line (see Figure 1 above); (2) the relative risk of a security or investment; and (3) how the benchmarks combine to produce the Security Market Line. Given these specifications, the company's cost of capital can be calculated based on its relative risk. Specifically, the CAPM states that the cost of capital for an investment, S (e.g., a particular common stock), is given by the following equation:

$$r_s = r_f + \beta_s \times MRP \tag{1}$$

where r_S is the cost of capital for investment S;
r_f is the risk-free interest rate;
β_S is the beta risk measure for the investment S; and
MRP is the market risk premium.

The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. It says that the Security Market Line starts at the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 1, equals the risk-free interest rate). Further, it says that the risk premium of a security over the risk-free rate equals the product of the beta of that security and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

1. The Risk-free Interest Rate

Q56. What interest rates do your calculations require?

A56. Modern capital market theories of risk and return (e.g., the theoretical version of the CAPM as originally developed) use the short-term risk-free rate of return as the starting benchmark, but regulatory bodies frequently use a version of the risk positioning model that is based upon the long-term risk-free rate. In this proceeding, I rely upon the long-term version of the risk positioning model. Accordingly, the implementation of my procedures requires use of long-term U.S. Treasury bond interest rates. Normally, I obtain this information from the 15-day average yield on 20-year Treasury bonds as reported by Bloomberg for the period ending on the date of my analysis. However, the cost of capital being set in this proceeding will apply to the going-forward rates. As such, I do not believe the current yield on the long-term Treasury bond is a good estimate for the risk-free rate that will prevail over the relevant future time period. For this reason, I use a risk-free rate based on the forecasted value from *Blue Chip Economic Indicators*. Specifically, I use the 3.4 percent yield on the 10-year U.S Treasury bond forecasted to be in effect in 2019,[52] and adjust upward by 30 bps, which is my estimate of the representative maturity premium for the 20-year over the 10-year Treasury Bond. The resulting value for the forecasted risk-free rate is 3.7 percent.

Q57. Why didn't you use the version of the CAPM that relies on the short-term risk-free rate in this proceeding?

A57. Short-term Treasury bill yields remain at artificially low levels due to the efforts of the Fed to stimulate the economy. As a result, the risk positioning required ROE estimates using the short-term Treasury bill yields as the risk-free interest rate are unreasonably low. For example, the estimates are sometimes less than the corresponding company's current market cost of debt, which is unreasonable. A company's equity is always riskier than its debt and requires a higher return, because

[52] *Blue Chip Economic Indicators*, dated March 10, 2018.

debt holders are always paid before equity holders in the event of bankruptcy or other financial distress.

2. The Market Risk Premium

Q58. Why is a risk premium necessary?

A58. Experience (e.g., the recent credit crisis in stock markets worldwide and the U.S. market's October Crash of 1987) demonstrates that shareholders, even well-diversified shareholders, are exposed to enormous risks. By investing in stocks instead of risk-free government Treasury bills, investors subject themselves not only to the risk of earning a return well below that which they expected in any year but also to the risk that they might lose much of their initial capital. This is fundamentally why investors demand a risk premium.

Q59. How do these factors affect the cost of capital for the Company?

A59. The Company invests in long-lived assets which cannot be easily liquidated (they are hard physical assets that once put in place cannot be moved). Investment is a voluntary activity, and investors generally require a return that is consistent with the risk they take on; therefore, it could damage the ability to access capital if investors view the allowed rate of return as lower than the required rate of return. The problem is not avoided for companies that are 100 percent owned subsidiaries because the parent company must consider the opportunity cost of capital when making investments. Investors expect managers to invest in projects which provide expected returns at least equal to the cost of capital.

Q60. Has the estimate of the MRP been controversial over the recent past?

A60. Yes. Historically, it was generally accepted that the appropriate method to estimate the MRP was to consider the historical average realized return on the market minus the return on a risk-free asset over as long a series of time as possible; however, this procedure came under attack during the period of time generally referred to as the “tech bubble” when the stock markets in the U.S. reached very high valuation levels relative to traditional metrics of value. The period of the tech bubble also resulted in the average realized return on the market increasing to a very high level. Attempts to explain the high stock market valuation levels centered on the hypothesis that the MRP must be dramatically lower than previously believed, but this hypothesis conflicted with the fact that realized returns over the period were very high. The result was an academic debate on the level of the forward-looking MRP and how best to estimate it—a debate that has still not been fully resolved.

In determining the going-forward cost of capital, I typically use the historical average MRP to inform one of my scenarios. I rely on Duff & Phelps' measurement of the average MRP over the longest historical time period possible so that the historical estimation period is not biased by any one specific economic event. The average historical MRP from 1926 to 2016 is 6.94 percent.[53]

As discussed in Section III, stock markets declined as a result of the credit crisis, and stock prices became extremely volatile. It is likely the MRP is now higher than the historical average realized return on the market minus the return on the risk-free asset.

Q61. How have you accounted for the likely increase in the MRP relative to the historical average?

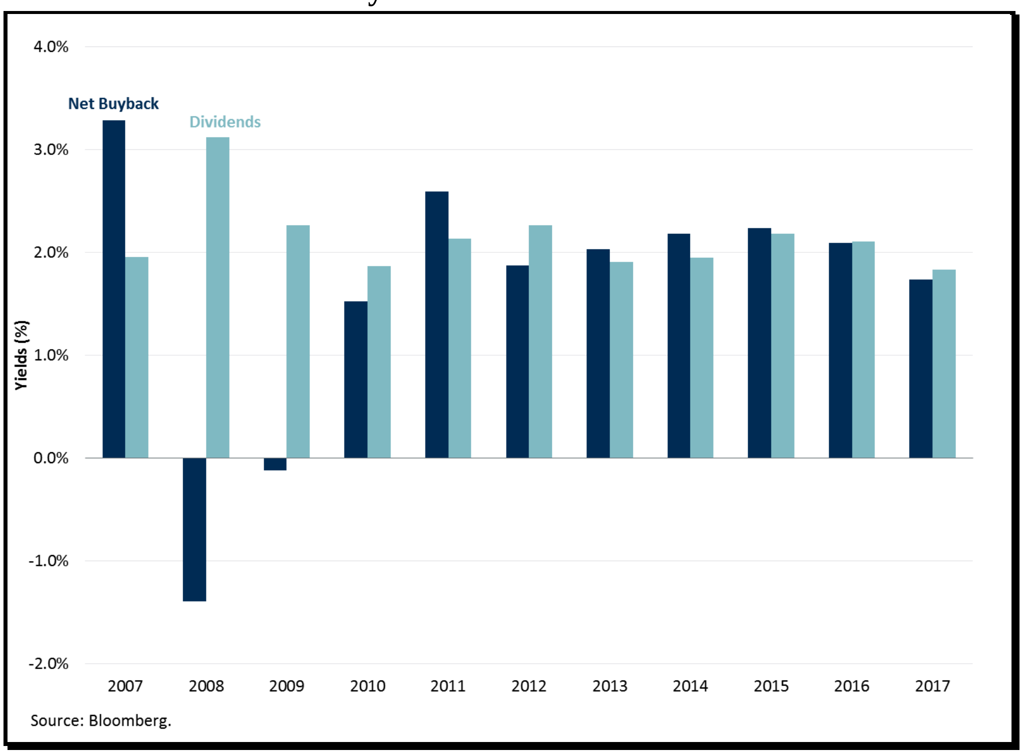
A61. As an alternative to the historical MRP, I also consider a forecasted MRP to better account for the market's current expected returns given the existing financial conditions. Bloomberg performs such a calculation of the expected market returns using the S&P 500 as the reference market index. According to Bloomberg, their market return calculation is based on a multi-stage dividend discount model applied to every company in the reference market index. It is therefore a forward-looking estimate of the expected market return. However, it only considers the dividends paid by the companies and ignores the share buybacks by which companies also return cash to their investors.

[53] Duff and Phelps, *2017 Valuation Handbook: U.S. Guide to Cost of Capital*, p. 3-33.

Q62. Have share buybacks been a significant source of returns for equity investors?

A62. Yes. I reviewed the amount of share buybacks, equity issuances, and dividends for the S&P 500 companies over the past 11 years using data from Bloomberg. I then compared the annual dividend yields to those from net buybacks.[54] Figure 5 below shows this comparison. It is clear that in most years, excluding the credit crisis, the yield from net buybacks has been comparable to the dividend yields. Therefore, any estimate of the forecasted market returns that excludes share buybacks would be downwardly biased.

Figure 5
Net Buybacks and Dividend Yields



Q63. What estimate of the forecasted market returns do you consider in your analysis?

A63. Since Bloomberg's forecasted market returns do not include share buybacks, it is necessary to increase their estimate of the expected market return in order to correct

[54] I use the term "net buybacks" to refer to equity share buybacks less any equity issuances.

for this downward bias. I find it reasonable to increase the market return by 170 basis points, or the net buyback yield in 2017. This is a conservative and reasonable adjustment given that net buyback yields have been at least 1.5 percent and have averaged 2.0 percent over the past 8 years. This approach estimates a forecasted MRP of 8.1 percent. Table 2 summarizes my calculations.

Table 2
Forecasted Market Risk Premium

Bloomberg Estimated Market Return	[1]	10.1%
Forecasted Long-Term Risk-Free Rate	[2]	3.7%
Bloomberg Estimated Market Risk Premium	[3]	6.4%
Adjustment for Share Buybacks	[4]	1.7%
Forecasted Market Risk Premium	[5]	8.1%

Sources and Notes:
[1]: From Bloomberg as of 3/29/2018.
[2]: Blue Chip Economic Indicators as of March 2018, adjusted for maturity premium.
[3] = [1] - [2]
[4]: Historical Net Buyback Yields.
[5] = [3] + [4], rounded to nearest decimal.

Q64. What is your conclusion regarding the MRP?

A64. Historically, much of the controversy over market risk premium centered on various reasons why it may not be as high as frequently estimated. Although none of the arguments were completely persuasive, I generally gave some weight to these issues in past testimony and reduced my estimate of the MRP. Conversely, recent events have strongly suggested an increase in the MRP from its previous levels. I would typically consider an MRP of 7 percent over the long-bond rate as reasonable based on my review of the relevant academic literature. However, current market conditions—as reflected in elevated bond yield spreads as described above in Section III—suggest that a value of 7.5 percent or even 8.5 percent could be more appropriate at this time. To remain conservative, I include two analyses using an MRP of 6.94 and 8.1 percent.

3. Beta

Q65. Can you more fully explain beta?

A65. The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that cannot be eliminated by diversification. That is, it measures the "systematic" risk of a stock—the extent to which a stock's value fluctuates more or less than average when the market fluctuates.

Diversification is a vital concept in the study of risk and return. (Harry Markowitz won a Nobel Prize for work showing just how important it was.) Over the long run, the rate of return on the stock market has a very high standard deviation, on the order of 20 percent per year.[55] Many individual stocks have much higher standard deviations than this. The stock market's standard deviation is "only" about 15-20 percent because when stocks are combined into portfolios, some of the risk of individual stocks is eliminated by diversification. Some stocks go up when others go down, and the average portfolio return—whether positive or negative—is usually less extreme than that of many individual stocks within it. The fact that the market's actual annual standard deviation is so large means that, in practice, the returns on stocks are positively correlated with one another, and to a material degree. The reason is that many factors that make a particular stock go up or down also affect other stocks. Examples include the state of the economy, the balance of trade, and inflation. Thus some risk is "non-diversifiable" in that even a well-diversified portfolio of stocks will experience changes in value caused by these shared risk factors. Single-factor equity risk premium models (such as the CAPM) are based upon the assumption that all of the systematic factors that affect stock returns can be considered simultaneously, through their impact on one factor: the market portfolio. Other models derive somewhat less restrictive conditions under which several factors might be individually relevant.

55 See Brealey, Myers and Allen (2017), *Principles of Corporate Finance, 12th Edition*, McGraw-Hill Irwin, New York, p. 172.

Again, the basic idea behind all of these models is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification, because there are a large number of large portfolios whose managers actively seek the best risk-reward tradeoffs available. (Of course, undiversified investors would like to get a premium for bearing diversifiable risk, but they cannot.)

Q66. What does a particular value of beta signify?

A66. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk: it goes up or down by 10 percent on average when the market goes up or down by 10 percent. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20 percent when the market falls 10 percent, for example. Stocks with betas below 1.0 are less volatile than the market. A stock with a beta of 0.5 will tend to rise 5 percent when the market rises 10 percent.

Q67. How is beta measured?

A67. The usual approach to calculating beta is a statistical comparison of the sensitivity of a stock's (or a portfolio's) return to the market's return. Many investment services report betas, including Bloomberg and the *Value Line Investment Survey*. Betas are not always calculated in precisely the same way, and therefore must be used with a degree of caution. However, the basic principle that a high beta indicates a risky stock has long been widely accepted by both financial theorists and investment professionals, and is universally reflected in all calculations of beta. *Value Line* calculates betas using five years of weekly data for a company.[56] In my analyses for these proceedings, I present results using the beta estimates reported by *Value Line*.

Q68. What are the betas that you used for the sample companies?

A68. Table 3 below lists the *Value Line* betas I used to calculate my risk-positioning estimates of the cost of capital for the sample of regulated electric utilities.

[56] *Value Line* Glossary, http://www.valueline.com/Glossary/Glossary.aspx

Table 3
***Value Line* Betas for the Electric Sample**

Company	Subsample Inclusion [1]	Value Line Betas [2]
ALLETE		0.75
Alliant Energy	*	0.70
Amer. Elec. Power		0.65
Ameren Corp.		0.65
AVANGRID Inc.		0.35
CenterPoint Energy	*	0.85
CMS Energy Corp.	*	0.65
Consol. Edison		0.50
DTE Energy		0.65
Duke Energy		0.60
Edison Int'l		0.60
El Paso Electric		0.75
Entergy Corp.		0.65
Eversource Energy		0.65
IDACORP Inc.		0.70
MGE Energy		0.70
OGE Energy	*	0.95
Otter Tail Corp.		0.85
Pinnacle West Capital	*	0.65
PNM Resources		0.70
Portland General	*	0.65
PPL Corp.		0.75
Public Serv. Enterprise		0.70
Unitil Corp.		0.65
Xcel Energy Inc.		0.60
Average		0.68
Subsample Average		0.74

Sources and Notes:
[2]: From Valueline Investment Analyzer as of 3/29/2018.

4. The Empirical CAPM

Q69. What other equity risk premium model do you use?

A69. Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

This second model makes use of these empirical findings. It estimates the cost of capital with the equation,

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \qquad (2)$$

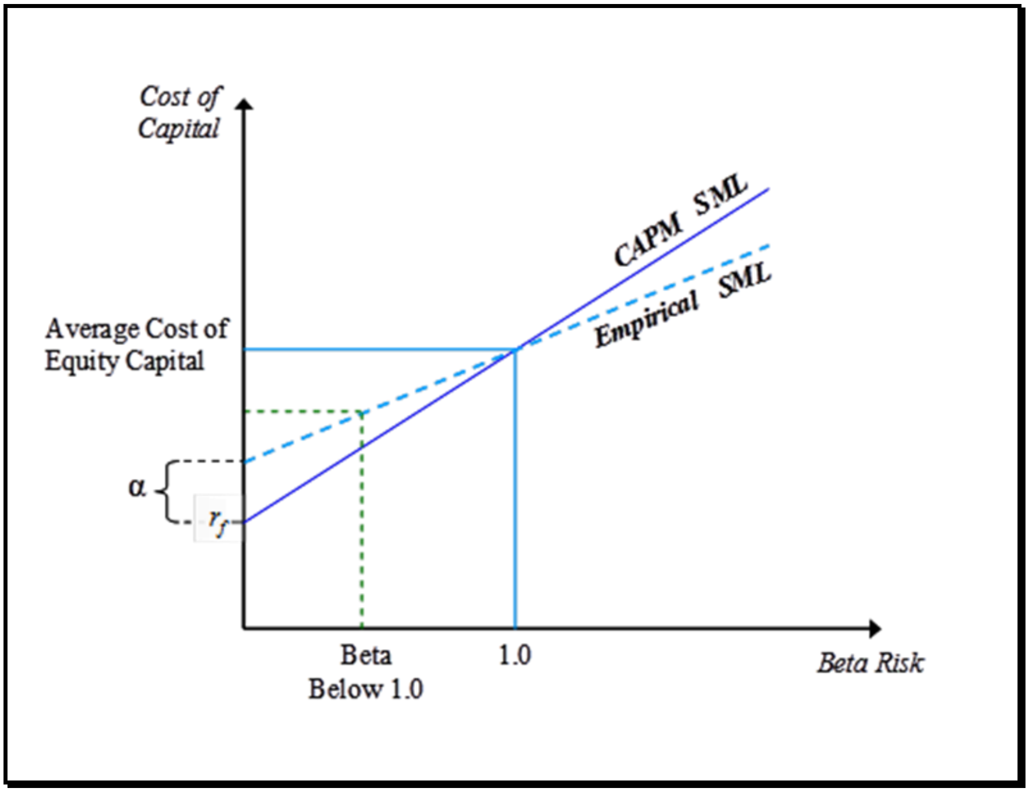
where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (1) above).

I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 1 earlier in my testimony which results in a Security Market Line that more closely matches the results of empirical tests. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Q70. Why is it appropriate to use the Empirical CAPM?

A70. The CAPM has not generally performed well as an empirical model, but its short-comings are directly addressed by the ECAPM. Specifically, the ECAPM recognizes the consistent empirical observation that the CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. In other words, the ECAPM is based on recognizing that the actual observed risk-return line is flatter and has a higher intercept than that predicted by the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact, which has been established by repeated empirical tests of the CAPM. The difference between the CAPM and the type of relationship identified in the empirical studies is depicted in Figure 6 below.

Figure 6
The Empirical Security Market Line



Q71. Does *Value Line* make any adjustments to the beta estimates it reports?

A71. Yes, but *Value Line*'s adjustments are fundamentally different and separate from the ECAPM adjustment I perform. *Value Line*'s adjustments do not correct for the issues raised by the empirical tests of the CAPM. The adjustment to beta corrects the estimate of the relative risk of the company, which is measured along the horizontal axis of the SML. The ECAPM adjusts the risk-return tradeoff (i.e., the slope) in the SML. In other words, the expected return (measured on the vertical axis) for a given level of risk (measured on the horizontal axis) is different from the predictions of the theoretical CAPM. Getting the relative risk of the investment correct does not adjust for the slope of the SML, nor does adjusting the slope correct for errors in the estimation of relative risk.

Q72. Can you explain further why using *Value Line*'s adjusted betas do not correct for the issues raised by empirical tests of the CAPM?

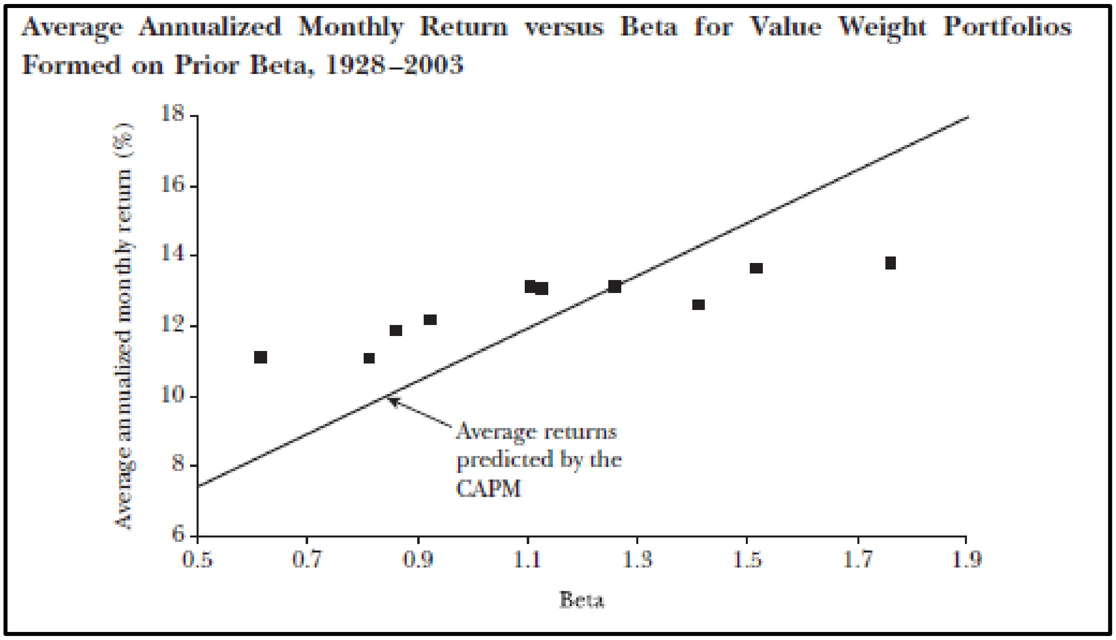
A72. Yes. It is because the issues raised by the empirical tests are completely independent from the reason betas are adjusted. The beta adjustment performed by *Value Line* is based on the method outlined by Professor Marshall Blume,[57] based on his empirical observation that historical measurements of a firm's beta are not the best predictors of what that firm's systematic risk *will be* going forward. Professor Blume was able to apply a consistent adjustment procedure to historical betas that increased their accuracy in *forecasting* eventual realized betas. Essentially, Professor Blume's adjustment transforms a historical beta into a better estimate of expected future beta. It is this expected "true" beta that drives investors' expected returns according to the CAPM. Therefore, it is appropriate to use *Value Line's* adjusted betas, rather than raw historical betas, when employing the CAPM to estimate the forward-looking cost of equity capital.

However, the backward-looking empirical tests of the CAPM that gave rise to the ECAPM did not suffer from bias in the measurement of betas. Researchers plotted realized stock portfolio returns against betas measured *over the same time period* to produce plots such as Figure 7 below, which comes from the 2004 paper by Professors Eugene Fama and Kenneth French.[58] The fact that betas and returns were measured contemporaneously means that the betas used in the tests were *already the best possible measure* of the "true" systematic risk over the relevant time period. In other words, no adjustments were needed for these betas. Despite this, researchers observed that the risk-return trade-off predicted by the CAPM was too steep to accurately explain the realized returns. As explained above the ECAPM explicitly corrects for this empirical observation.

[57] Blume, Marshall E. (1971), "On the Assessment of Risk," *The Journal of Finance*, 26, pp. 1-10.

[58] Fama, Eugene F. & French, Kenneth R, (2004), "The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives, 18(3)*, pp. 25-46.

Figure 7
Evidence from Empirical Tests of the CAPM[59]



Q73. Did the empirical tests that gave rise to the ECAPM use raw betas in their analyses?

A73. They did. However, this is simply because the researchers were able to measure raw betas and realized returns from the same historical period. In other words, no adjustment to the raw beta was necessary to evaluate the market return realized for the same historical period. Hence, the raw betas they measured accurately captured the systematic risk that impacted the returns they measured. In a sense, the measured betas and realized returns were already contemporaneous in the tests of the CAPM that identified the effect shown in Figure 7.

Q74. Does the use of adjusted betas in the ECAPM double count the adjustment to the estimated required return on equity?

A74. No. The Blume adjustment to beta and the ECAPM are separate adjustments with no redundancy between them. In fact, both adjustments are necessary to produce the most accurate possible forward-looking estimate of the required return on equity.

[59] *Ibid.*, p. 33.

A rate of return analyst must use a historical measurement of beta to make a forecast of the expected *future* return on equity. Therefore, the analyst should first apply the Blume adjustment (as *Value Line* does) to get the best estimate of the systematic risk over the (future) period in which she will estimate the ROE. Once the risk measurement is contemporaneous with the returns to be estimated, the analyst should apply the ECAPM to adjust for the empirical shortcomings of the CAPM.

Q75. Can you summarize the independent reasons for using adjusted betas and employing the ECAPM?

A75. Raw historical betas are adjusted to provide a better estimate of *expected* "true" betas, which are the appropriate measure of risk that predicts expected future returns in the CAPM. The ECAPM is used because empirical tests show that *even when the best possible estimate* of "true" beta is used, the CAPM tends to under-predict required returns for low-beta stocks and over-predict required returns for high-beta stocks.

These are independent but complementary adjustments supported by empirical tests of this model of financial theory. Both adjustments are appropriate when using risk-positioning models to estimate the cost of equity. See Exhibit A-14, Schedule No. D5.18 for academic papers on the early tests of the CAPM that support the need for an adjustment to the estimates from the CAPM.

5. Results from the Risk Positioning Models

Q76. What are the parameters of the scenarios you considered in your risk positioning analyses?

A76. The parameters for the two scenarios, which consider a reasonable range of MRP based on historical and forward-looking estimates, are displayed in Table 4 below.

Table 4
Risk Positioning Scenario Parameters

	Scenario 1	Scenario 2
Risk-Free Interest Rate	3.70%	3.70%
Market Risk Premium	6.94%	8.10%

Q77. Can you summarize the results from applying the CAPM and ECAPM methodologies to the sample?

A77. The results of the risk positioning analyses (the CAPM and the ECAPM) are presented in Table 5 using *Value Line*'s estimated betas for the sample of electric companies. (The underlying calculations are also presented in Exhibit A-14.[60]) For the ECAPM, there are two sensitivities: α = 0.5 percent and α = 1.5 percent. The columns display the scenario results for MRP estimates of 6.94 and 8.1. The long-term risk-free interest rate as of March 2018 was 3.7 percent. The ROE estimates in Table 5 reflect the overall cost of capital and Hamada adjustment procedure estimates adjusted for differences in capital structure between the sample companies and DTE. Specifically, the ROE associated with each method and a capital structure with 51 percent equity is displayed in Table 5 for the *Value Line* betas.

60 Results for the CAPM and ECAPM based on the overall cost of capital financial risk adjustment can be found in Exhibit A-14, Schedule No. D5.12 at 1. Results for the CAPM and ECAPM based on the Hamada adjustment can be found in Exhibit A-14, Schedule No. D5.15 at 1-2.

Table 5
Risk Positioning Cost of Equity Estimates

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Full Sample		
Financial Risk Adjusted Method		
CAPM	9.1%	10.0%
ECAPM (α = 0.5%)	9.3%	10.2%
ECAPM (α = 1.5%)	9.7%	10.6%
Hamada Adjustment Without Taxes		
CAPM	8.9%	9.8%
ECAPM (α = 0.5%)	9.0%	9.9%
ECAPM (α = 1.5%)	9.3%	10.2%
Hamada Adjustment With Taxes		
CAPM	8.8%	9.7%
ECAPM (α = 0.5%)	9.0%	9.8%
ECAPM (α = 1.5%)	9.2%	10.1%
Sub-Sample		
Financial Risk Adjusted Method		
CAPM	9.5%	10.5%
ECAPM (α = 0.5%)	9.7%	10.7%
ECAPM (α = 1.5%)	10.0%	11.0%
Hamada Adjustment Without Taxes		
CAPM	9.3%	10.3%
ECAPM (α = 0.5%)	9.4%	10.4%
ECAPM (α = 1.5%)	9.6%	10.6%
Hamada Adjustment With Taxes		
CAPM	9.3%	10.2%
ECAPM (α = 0.5%)	9.4%	10.3%
ECAPM (α = 1.5%)	9.6%	10.5%

Q78. What conclusions do you draw from the risk positioning model (i.e., CAPM and ECAPM) results?

A78. Of the risk positioning estimates, the CAPM values deserve the least weight, because this method does not adjust for the empirical finding that the cost of capital is less sensitive to beta than predicted by the CAPM (which my testimony and exhibits consider by using the ECAPM). Conversely, the ECAPM numbers deserve more weight, because this method adjusts for the empirical findings. The results for Scenario 1 do not fully account for the ongoing uncertainty in the capital markets and deserve less weight than the results for Scenario 2 in column [2]. Focusing on the ECAPM results for the sample, the results range from 9.0 percent to 10.6 percent.

Focusing on the latter scenario, the ECAPM risk positioning results range from 9.8 percent to 10.6 percent. Furthermore, should the Commission rely on the subsample, estimates from the CAPM and ECAPM from the electric subsample suggest a similar, if not slightly higher, ROE for the average regulated electric utility.

B. RISK PREMIUM MODEL ESTIMATES

Q79. Please describe what you mean by a "risk premium model".

A79. For a "risk premium model" the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROE's in utility rate cases and the risk-free rate of interest at the time the ROE's were granted. These estimates add a "risk premium" implied by this relationship to the relevant (prevailing or forecast) risk-free interest rate:

$$Cost\ of\ Equity = r_f + Risk\ Premium \tag{3}$$

Q80. What are the merits of this approach?

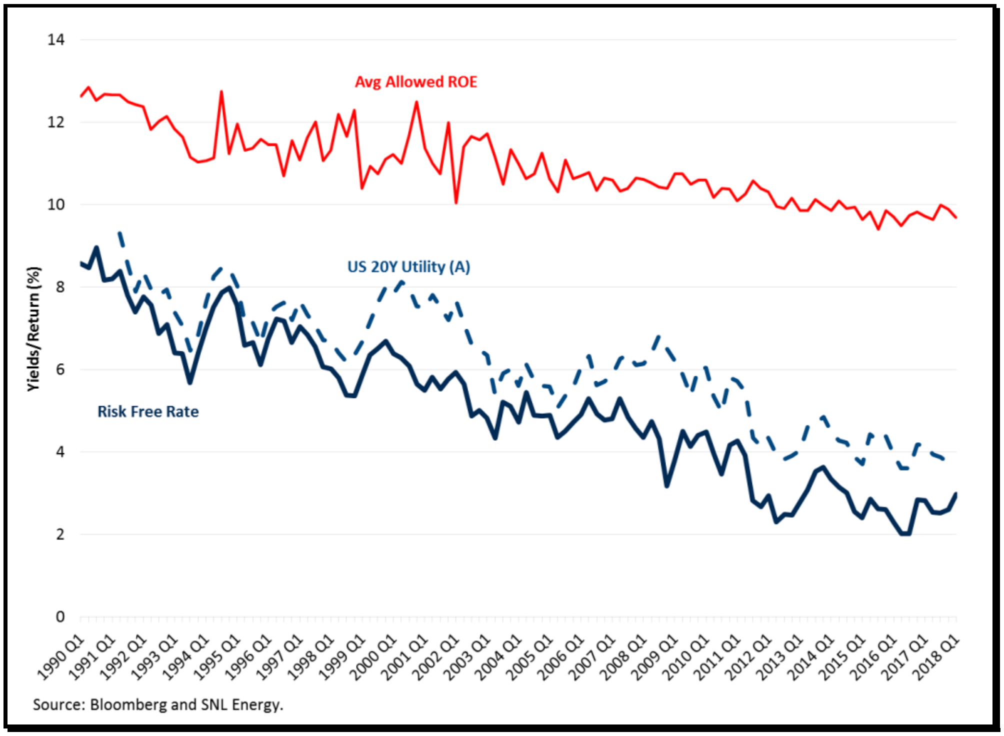
A80. First, it estimates the cost of equity from regulated entities as opposed to holding companies, so that the relied upon figure is directly applicable to a rate base. Second, the allowed returns are clearly observable to market participants, who will use this one data input to making investment decisions, so that the information is at the very least a good check on whether the return is comparable to that of other investments. Third, I analyze the spread between the allowed ROE at a given time and the then prevailing interest rate to ensure that I properly consider the interest rate regime at the time the ROE was awarded. This implementation ensures that I can compare allowed ROE granted at different times and under different interest rate regimes.

Q81. Did you estimate the cost of equity that results from an analysis of risk premiums implied by allowed ROE's in past utility rate cases?

A81. Yes. Since 1990, the average long-term U.S. Treasury bonds have declined from yields above 8 percent down to close to 2 percent. Corporate bonds for utility companies declined mostly in line with the long-term U.S. Treasury bonds except for the recent period since the 2008-2009 credit crises as discussed in Section III. The average allowed ROE for vertically integrated electric utilities, however, has changed at a slower rate than the change in U.S. Treasury and corporate bond yields. Figure 8 presented below shows this increase in the risk premium between the allowed ROE and long-term bonds at lower interest rates. The risk premium over the long-term U.S. Treasury bond (the risk-free rate) averaged 7.1 percentage points since 2017.

This recent historical data, assuming a risk premium of 7.1 percentage points, suggests that average allowed ROEs would increase to 10.8 percent as risk-free rates increase to the 3.7 percent forecast. However, I believe that a more robust statistical approach is necessary.

Figure 8
Bond Yields and Allowed ROEs for Electric Utilities



Q82. How did you use rate case data to estimate the risk premiums for your analysis?

A82. The rate case data from 1990-2018 is derived from Regulatory Research Associates.[61] Using this data I compared (statistically) the average allowed rate of return on equity granted by U.S. state regulatory agencies in electric utility rate cases to the average 20-year Treasury bond yield that prevailed in each quarter.[62] I calculated the allowed utility "risk premium" in each quarter as the difference between allowed returns and the Treasury bond yield, since this represents the compensation for risk allowed by regulators. Given the inverse relationship between the risk premium and the risk-free rate (increasing risk premium with declining risk-free rates), I determined that simply applying the average historical risk premium would be inappropriate as interest rates are expected to increase in the future. I therefore used the statistical technique of

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[61] *SNL Financial* as of April 12, 2018.

[62] I rely on the 20-year government bond to be consistent with the analysis using the CAPM to avoid confusion about the risk-free rate. While it is important to use a long-term risk-free rate to match the long-lived nature of the assets, the exact maturity is a matter of choice.

ordinary least squares ("OLS") regression to estimate the parameters of the linear equation:

$$Risk\ Premium\ =\ A_0\ +\ A_1 \times (Treausury\ Bond\ Yield) \qquad (4)$$

The Treasury Bond Yield is the same as used in my CAPM-based models for the risk-free rate, representing the market's expectations that long-term bond yields will continue to increase. Thus the risk premium I estimate would be applicable for the going-forward cost of capital and not a backward-looking analysis.

I derived my estimates of A_0 and A_1 using standard statistical methods (OLS regression) and find that the regression has a high degree of explanatory power in a statistical sense (R^2=0.84) and the parameter estimates, A_0 equals 8.775 percent and A_1 equals -0.579, are statistically significant.

The negative slope coefficient reflects the empirical fact that regulators grant smaller risk premiums when risk-free interest rates (as measured by Treasury bond yields) are higher. This is consistent with past observations that the premium investors require to hold equity over government bonds increases as government bond yields decline. In the regression described above the risk premium declined by less than the increase in Treasury bond yields. Therefore, as interest rates are expected to increase going-forward, the allowed ROE on average would increase but by less than the change in government bond yields.

Q83. What ROE do you estimate for the average utility based on the risk premium method?

A83. Based on this statistical analysis, I find that the current market conditions are consistent with an ROE of 10.3 percent for the average electric utility.[63]

[63] Results for the Risk Premium analysis can be found in Exhibit A-14, Schedule No. D5.16 at 1.

Q84. What conclusions did you draw from your risk premium analysis?

A84. While the risk premium models based on historical allowed returns are not underpinned by fundamental finance principles in the manner of the CAPM or DCF models, I believe that this analysis, when properly designed and executed and placed in the proper context, can provide useful benchmarks for evaluating whether the estimated ROE is consistent with recent practice. My risk premium model cost of equity estimates demonstrate that the results of my single-stage DCF (presented below) and Scenario 2 ECAPM analyses are in line with the actions of utility regulators. Because the risk premium analysis as implemented takes into account the interest rate prevailing during the quarter the decision was issued, it provides a useful benchmark for the cost of equity in any interest environment.

However, the risk premium analysis is not wholly a forward-looking model to estimate the going-forward cost of capital. The forecasted risk-free rate is included, but the relationship between this risk-free rate and previously allowed ROEs is based on historical data available at the time of those rate case proceedings. It has not, for example, incorporated the effects on regulated utilities from the recent tax reform. I therefore believe that its estimation of 10.3 percent for an electric utility of average risk is conservative and may underestimate the true cost of equity capital given recent economic conditions.

C. THE DCF BASED ESTIMATES

Q85. Can you describe the discounted cash flow approach to estimating the cost of equity?

A85. The DCF model takes the first approach to cost of capital estimation described above, i.e., to attempt to estimate the cost of capital in one step instead of estimating the cost of capital for the entire market and then determining the cost of capital for an individual investment. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \tag{5}$$

where P_0 is the current market price of the stock;
D_t is the dividend cash flow expected at the end of period t;
T is the last period in which a dividend cash flow is to be received; and
r is the cost of equity capital

The formula simply says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

Most DCF applications go even further, and make strong assumptions that yield a simplification of the standard formula, which then can be rearranged to estimate the cost of capital. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of the stock will be given by a very simple formula,

$$P_0 = \frac{D_1}{r-g} \tag{6}$$

where D_1 is the dividend expected at the end of the first period, g is the perpetual growth rate, and P_0 and r are the current market price and the cost of equity capital, as before.

Equation (6) is a simplified version of Equation (5) that can be solved to yield the well-known "DCF formula" for the cost of capital:

$$r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1+g) + g \tag{7}$$

where D_0 is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before.

Equation (7) says that if Equation (6) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the "simple DCF" model. Of course, the "simple" model is simple because it relies on strong assumptions.[64]

Q86. Are there other versions of the DCF models in addition to the "simple" one?

A86. Yes. One such alternative version is the multistage DCF model. In its "simple" or constant growth rate formulation, the DCF model requires that dividends and earnings grow at a constant rate for companies that earn their cost of capital on average.[65] It is inconsistent with the theory on which this formulation is based to have varying growth rates in earnings and dividends. If, however, the growth rates for dividends and earnings were expected to vary over some number of years before settling down into a constant growth period, then it would be appropriate to utilize a multistage DCF model. In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period.

Q87. What is your assessment of the DCF model?

A87. The DCF approach is grounded in solid finance theory. It is widely accepted by regulatory commissions and provides useful insight regarding the cost of capital based on forward-looking metrics. DCF estimates of the cost of capital complement those of the CAPM and the ECAPM because the two methods rely on different inputs and assumptions. The DCF method is particularly valuable in the current economic environment, because of the effects on capital market conditions of the Fed's efforts

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64 In this context "strong" means assumptions that are unlikely to reflect reality but that also are not expected to have a large effect on the estimate.

65 Why must the two growth rates be equal in a steady-growth DCF model? Think of earnings as divided between reinvestment, which funds future growth, and dividends. If dividends grow faster than earnings, then there is less investment and slower growth each year. Sooner or later dividends will equal earnings. At that point, growth is zero because nothing is being reinvested (dividends are constant). If dividends grow more slowly than earnings, each year a bigger fraction of earnings are reinvested. That makes for ever faster growth. Both scenarios contradict the steady-growth assumption. So if you observe a company with different expectations for dividend and earnings growth, you know the company's stock price and its dividend growth forecast are inconsistent with the assumptions of the steady-growth DCF model.

to maintain interest rates at historically low levels which bias the CAPM and ECAPM estimates downward.

However, I recognize that the DCF model, like most models, relies upon assumptions that do not always correspond to reality. For example, the DCF approach assumes that the variant of the present value formula that is used matches the variations in investor expectations for the growth of dividends, and that the growth rate(s) used in that formula match current investor expectations. Less frequently noted conditions, such as the value of real options incorporated in a company's market price, may create issues that the DCF model does not incorporate. Nevertheless, under current economic conditions, because of its forward looking nature, the strengths of the DCF method far outweigh any weaknesses the method may have.

Q88. What growth rate information do you use?

A88. The first step in my DCF analysis (either constant growth or multistage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates from Thomson Reuters IBES and from *Value Line* for companies in the electric sample.[66] For the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, I use the most recent long-run GDP growth forecast from Blue Chip Economic Indicators.[67]

Q89. How do these growth rates correspond to the theoretical criteria you discuss above?

A89. The constant-growth formulation of the DCF model, in principle, requires forecasted growth rates, but it is also necessary that the growth rates used go far enough out into the future so that it is reasonable to believe that investors expect a stable growth path afterwards. Under current economic conditions, I believe the forecasted growth rates of investment analysts provide the best available representation of the longer term,

[66] Short-term (5 year) EPS growth rates as of March 30, 2018. I develop a weighted average growth rate weighted by the number of analysts and counting *Value Line* as one analyst.

[67] *Blue Chip Economic Indicators*, March 10, 2018.

steady-state growth rate expectations of investors. Therefore, I feel these growth parameters available to apply to the simple, constant-growth DCF model provide useful estimates of the cost of capital.

Q90. Does the multistage DCF improve upon the simple DCF?

A90. Potentially, but the multistage method assumes a particular smoothing pattern and a long-term growth rate afterwards. These assumptions may not be a more accurate representation of investor expectation than those of the simple DCF. The smoother growth pattern, for example, might not be representative of investor expectations, in which case the multistage model would not increase the accuracy of the estimates. Indeed, amidst uncertainty in capital markets, assuming a simple constant growth rate may be preferable to attempting to model growth patterns in greater detail over multiple stages. While it is difficult to determine which set of assumptions comprises a closer approximation of the actual conditions of capital markets, I believe both forms of the DCF model provide useful information about the cost of capital.

Q91. What are the relative strengths and weaknesses of the DCF and risk-positioning methodologies?

A91. Current market conditions affect all cost of capital estimation models to some degree, but the DCF model has at least one advantage over the risk positioning models. Specifically, the DCF model reflects current market conditions more quickly because the market price of a company's stock changes daily. Dividend yields increase when market prices fall and reflect the increased cost of capital. The challenge for the DCF model is that the model requires forecasts of earnings growth rates that are based upon stable economic conditions which are required to satisfy the constant dividend growth rate assumption. Although the dividend yield quickly reacts to changes in the market, the growth rate estimates may be less precise during times of market uncertainty because future growth rates may be more volatile. Nevertheless, because dividend yields and forecast growth rates change quickly, the DCF model is likely to better reflect investors' current cost of capital expectations than the CAPM and

ECAPM, specifically that relying on a historical MRP, which relies upon 5 years of historical data.

Q92. What are the DCF estimates for the sample?

A92. The corresponding DCF estimates for the sample are presented in Table 6. The ROE estimate is 10.2 percent for the single-stage "simple DCF" model and 8.9 percent for the multistage model.[68] The results for the electric company subsample are higher at 10.7 percent for the single-stage DCF and 9.2 percent for the multistage model.

Table 6
DCF Cost of Equity Estimates

	DCF Simple	DCF Multi-stage
Full Sample		
Cost of Equity	10.2%	8.9%
Subsample		
Cost of Equity	10.7%	9.2%

Q93. What conclusions do you draw from the DCF analysis?

A93. Although I made no adjustment for the current market turmoil for the DCF model, the DCF cost of equity estimates are in line with those from the risk positioning models displayed above in Table 5. Specifically, the simple DCF estimate is within the range suggested by the risk positioning analysis while the multistage DCF is slightly lower. At this time, I believe that the DCF estimates indicate that the estimates from Scenario 2 for the risk positioning model are more reliable than those from Scenario 1.

In Case No. U-18014, Staff proposed the use of a sample restricted to companies with net plant between $6 billion and $20 billion and excluding DTE Energy. I replicate

[68] Results for the DCF analysis can be found in Exhibit A-14, Schedule No. D5.8 at 1.

these criteria in my subsample and compare the results to my proposed full electric sample. Using Staff's criteria, I find that DCF estimates range between 9.2 percent for the multistage and 10.7 percent for the simple DCF. Should the Commission find value in sub-setting the sample based on net plant as they have in the past, then the Commission must also recognize the higher ROE estimates of the subsample relative to my full sample estimates. Staff's criteria for the appropriate sample would suggest ROE estimates which are 20 to 50 basis points higher.

VI. CONCLUSIONS

Q94. Can you summarize the evidence from the sample regarding the ROE for an electric utility of average risk?

A94. The sample's cost of capital estimates range from 8.8 percent (CAPM) to 10.6 percent (ECAPM). However, the results from the CAPM are less reliable than the results from the ECAPM because they do not consider the consistent empirical evidence that the CAPM underestimates the cost of capital for low beta companies, such as DTE. Similarly, the results for Scenario 1 are not as reliable as those from Scenario 2 because Scenario 1 ignores the increased MRP resulting from the ongoing uncertainty in the capital markets.

Focusing on the ECAPM results from Scenario 2 suggests a range of 9.8 percent to 10.6 percent. This range is also consistent with the 10.2 percent ROE estimate from the single-stage DCF and with the 10.3 percent allowed ROE for an average electric company suggested by the risk premium model. Should the Commission rely on a subsample based on net plant, the appropriate allowed ROE should be increased by 20 to 50 basis points.

While the single-stage DCF and ECAPM results have accounted for many of the current market conditions, I believe that there is still significant uncertainty and risk for electric utilities related to the TCJA impacts. Realigning earnings and dividend expectations (which affect the DCF estimates) along with measuring the changes to company betas (which affect the CAPM/ECAPM estimates) will take time given this significant financial shift. Credit rating agencies have stated their expectations of negative cash flow impacts, but much uncertainty still exists as companies and regulatory bodies determine how to adjust and possibly mitigate these negative impacts. Yet it is clear that the going forward risk for electric utilities has increased.

Based on the range of estimates and the effect of current economic conditions, I believe a company of average business risk with 51 percent equity should have an allowed ROE in the range 9¾ percent to 10¾ percent.

Q95. What is your recommended range of the ROE for the Company?

A95. As noted above, I judge DTE Electric to be of higher risk than the sample companies on average. I therefore recommend that the Company be allowed an ROE of 10½ percent on the equity financed portion of its rate base.

Q96. Why doesn't your recommended range for the samples cover all of the estimates?

A96. I provide an estimate of a reasonable range of required ROE for the sample, and the range of uncertainty is based upon all of the analyses I have done, placing relatively more weight on more reliable methodologies and estimates. I do not try to include all of the resulting estimates in the range because I regard some of the estimates as more reliable than others. For example, the estimates based upon the CAPM are not as reliable as those based upon the ECAPM because the CAPM estimates do not account for the empirical observation that low beta stocks have higher costs of capital than estimated by the CAPM, and high beta stocks have lower costs of capital. Nor is it likely that the lowest estimates in the tables are as reliable as those in the upper end of the range because those estimates do not adequately consider the continued uncertainty in the financial markets.

Q97. Is there any other reason to support an allowed ROE of 10½ percent?

A97. Yes. It is important to maintain DTE Electric Company's access to capital, and maintaining a solid credit rating and outlook is one important aspect to maintaining access to capital. Credit rating agencies are concerned about cash flows. This involves both an increase in the Company's equity share in the capital structure and a supportive allowed return on equity. As recognized by the credit rating agencies, these two factors (capital structure and ROE) are directly related in their ability to provide an adequate level of stable cash flows. The Company has requested an increase in its equity share from 50 percent to 51 percent given its increased risk profile and to avoid putting downward pressure on its credit metrics. I have recommended a 10½ ROE that is consistent with the 51 percent equity share; changes from this requested 51 percent equity must also consider the corresponding effects on the financial risk, and therefore cost of capital, of the Company. In this period of increased economic volatility and uncertainty, a supportive regulatory environment is important to ensure the utility's favorable access to credit markets. Moody's highlighted this factor in its rating outlook on DTE Electric by noting that "an adverse change in Michigan's supportive regulatory environment" was a risk factor that could lead to a downgrade.[69] Maintaining a strong credit rating is particularly critical during a period forecast to have substantial capital investment for infrastructure. In addition, as the Fed continues to adjust its monetary policy, one can expect that the cost of capital will increase although the pace of such an increase cannot be predicted with certainty. This means that estimates at the upper end of the range are more representative of the going-forward cost of capital.

Q98. Does this conclude your testimony?

A98. Yes.

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[69] Moody's Investor Service, "Rating Action: Moody's downgrades DTE to Baa1, affirms utility subsidiaries, outlook stable," October 25, 2016.

QUALIFICATIONS OF MICHAEL J. VILBERT

Dr. Michael J. Vilbert is a Principal in the The Brattle Group's San Francisco office and has more than 20 years of experience as an economic consultant. He is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. In the area of regulatory economics, he has testified or submitted testimony on the cost of capital for regulated companies in the water, electric, natural gas and petroleum industries in the U.S. and Canada. His testimony has addressed the effect of regulatory policies such as decoupling or must-run generation on a regulated company's cost of capital and the appropriate way to estimate the cost of capital for companies organized as Master Limited Partnerships. He analyzed issues associated with situations imposing asymmetric risk on utilities, the prudence of purchased power contracts, the economics of energy conservation programs, the appropriate incentives for investment in electric transmission assets and the effect of long-term purchased power agreements on the financial risk of a company. He has served as a neutral arbitrator in a contract dispute and analyzed the effectiveness of a company's electric power supply auction. He has also estimated economic damages and analyzed the business purpose and economic substance of tax related transactions, valued assets in arbitration for purchase at the end of the contract, estimated the stranded costs of resulting from the deregulation of electric generation and from the municipalization of an electric utility's distribution assets and addressed the appropriate regulatory accounting for depreciation and goodwill.

He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

REPRESENTATIVE CONSULTING EXPERIENCE

- Dr. Vilbert served as the consulting expert in several cases for the U.S. Department of Justice and the Internal Revenue Service regarding the business purpose and economic substance of a series of tax related transactions. These projects required the analysis of a complex series of financial transactions including the review of voluminous documentary evidence and required expertise in financial theory, financial market as well as accounting and financial statement analysis.

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain as if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analysts'= reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team that prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electric power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline=s rates, but it also allowed simulation of a variety of Awhat if@ scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company=s rate payers.

- Dr. Vilbert has testified as well as assisted in the preparation of testimony and the development of estimation models in numerous cost-of-capital cases for natural gas pipeline, water utility and electric utility clients before the Federal Energy Regulatory Commission (AFERC@) and state regulatory commissions. These have spanned standard estimation techniques (e.g., Discounted Cash Flow and Risk Positioning models). He has also developed and applied more advanced models specific to the industries or lines of business in question, e.g., based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated in its allowed cost of capital for major disallowances stemming from QF contract management.

- Dr. Vilbert analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the Northeast, Dr. Vilbert analyzed the auction of an electric utility=s purchase power agreements to determine whether the outcome of the auction was in the ratepayers= interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the cost of service for the authority required estimation of the value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including a determination of the railroad=s cost of capital. He also helped evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous shipper products, improved cost analysis and evaluation of bottlenecks in the system.

- For a utility in the Southeast, Dr. Vilbert quantified the company=s stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company=s fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company=s stranded costs as a means of reducing the cost to the ratepayers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company=s electric transmission system. The evaluation highlighted the elements of the proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the Southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company=s portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of The Brattle Group, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the province=s electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecasted remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of a petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

- Dr. Vilbert evaluated the appropriate Abareboat@ charter rate for an oil drilling platform for the renewal period following the end of a long-term lease. The evaluation required analysis of the market for oil drilling platforms around the world including trends in construction and labor costs and the demand for platforms in varying geographical environments.

- Dr. Vilbert and Dr. Villadsen, also of The Brattle Group, evaluated the offer to purchase the assets of Pentex Alaska Natural Gas Company, LLC on behalf of the Western Finance Group for presentation to the Board of the Alaska Industrial Development and Export Authority. The report compared the proposed purchase price with selected trading and transaction multiples of comparable companies.

PRESENTATIONS

"Moving Toward Value in Utility Compensation – Shareholder Value Concept," with A. Lawrence Kolbe, California PUC Workshop, June 13, 2016.

"Natural Gas Pipeline FERC ROE," INGAA Rate of Return Seminar, with Mike Tolleth, March 23, 2016.

"The Cost of Capital for Alabama Power Company," Public Service Commission public meeting, July 17, 2013.

"An Empirical Study of the Impact of Decoupling on the Cost of Capital," Center for Research in Regulated Industries, Shawnee on Delaware, PA, May 17, 2013.

"Point – Counterpoint: The Regulatory Compact and Pipeline Competition," with (Jonathan Lesser, Continental Economics), Energy Bar Association, Western Meeting, February 22, 2013

"Introduction to Retail Rates," presented to California Water Services Company, 18-19 November 2010.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", National Association of Water Companies: New York Chapter, Albany, NY, May 21, 2009.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", New York Public Service Commission, Albany, NY, April 20, 2009.

ACurrent Issues in Explaining the Cost of Capital to Utility Commissions@ Cost of Capital Seminar, Philadelphia, PA, 2008.

ARevisiting the Development of Proxy Groups and Relative Risk Analysis,@ Society of Utility and Regulatory Financial Analysts: 39th Financial Forum, April 2007.

ACurrent Issues in Estimating the Cost of Capital,@ *EEI Electric Rates Advanced Course*, Madison, WI, 2006, 2007, 2008, 2009, 2010 and 2011.

ACurrent Issues in Cost of Capital,@ with Bente Villadsen, *EEI Electric Rates Advanced Course*, Madison, WI, 2005.

ACost of Capital - Explaining to the Commission - Different ROEs for Different Parts of the Business,@ *EEI Economic Regulation & Competition Analysts Meeting*, May 2, 2005.

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AUtility Distribution Cost of Capital,@ *EEI Electric Rates Advanced Course*, Madison, WI, July 2004.

ANot Your Father=s Rate of Return Methodology,@ *Utility Commissioners/Wall Street Dialogue*, NY, May 2004.

AIssues for Cost of Capital Estimation,@ with Bente Villadsen, *Edison Electric Institute Cost of Capital Conference*, Chicago, IL, February 2004.

AUtility Distribution Cost of Capital,@ *EEI Electric Rates Advanced Course*, Bloomington, IN, 2002, 2003.

PUBLICATIONS

Risk and Return for Regulated Industries, The Brattle Group, Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, Elsevier Academic Press, Cambridge, MA, 2017.

"Effect on the Cost of Capital of Ratemaking that Relaxes the Linkage between Revenue and kWh Sales: An Updated Empirical Investigation of the Electric Industry," Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang, and James Hall, *The Brattle Group,* November 2016.

"Decoupling and the Cost of Capital," Joe Wharton and Michael Vilbert, *The Electricity Journal, Volume 28, Issue 7,* August/September 2015.

"The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation," prepared for The Energy Foundation by Michael J. Vilbert, Joseph B. Wharton, Charles Gibbons, Melanie Rosenberg, and Yang Wei Neo, March 20, 2014.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, Bente Villadsen, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the Australian Energy Regulator and the Economic Regulation Authority, Western Australia, February 2013.

"Survey of Cost of Capital Practices in Canada," (with Bente Villadsen and Toby Brown), prepared for British Columbia Utilities Commission, May 2012.

"Impact of Portland Harbor Remediation Costs on City of Portland Water and Sewer Rates," with Professor David Sunding, March 2012.

"The Impact of Decoupling on the Cost of Capital – An Empirical Study," Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg, and Toby Brown, Discussion Paper, *The Brattle Group*, March 2011, revised July 2012.

"Review of Regulatory Cost of Capital Methodologies," (with Bente Villadsen and Matthew Aharonian), Canadian Transportation Agency, September 2010.

"Understanding Debt Imputation Issues,@ by Michael J. Vilbert, Bente Villadsen and Joseph B. Wharton, *Edison Electric Institute,* June 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," by A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, *Public Utilities Fortnightly*, August 2005.

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"Flaws in the Proposed IRS Rule to Reinstate Amortization of Deferred Tax Balances Associated with Generation Assets Reorganized in Industry Restructuring," by Frank C. Graves and Michael J. Vilbert, white paper for *Edison Electric Institute* (EEI) to the IRS, July 25, 2003.

TESTIMONY

Direct testimony before the Public Utilities Commission of Ohio on behalf of Vectren Energy Delivery of Ohio, Inc., Case No. 18-0298-GA-AIR, on the cost of capital for Vectren's gas local distribution assets, April 2018.

Direct testimony before the Public Utilities Commission of the State of Hawaiʻi on behalf of Young Brothers, Limited, Docket No. 2017-0363, on the cost of capital for Young Brothers regulated intrastate barge operations, March 2018.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Gas Company, Case No. U-18999, on the cost of common equity capital for DTE Gas Company's regulated natural gas distribution assets, February 2018 and April 2018.

Supplemental testimony before the Public Utilities Commission of the State of Hawaiʻi on behalf of Hawaiian Electric Company, Inc., Docket No. 2016-0328, with regard to the effect on the cost of capital of decoupling ratemaking that relaxes the linkage between revenue and kWh sales, February 2018.

Direct testimony before the Public Utilities Commission of the State of Hawaiʻi on behalf of Maui Electric Company, Limited, Docket No. 2017-0150, with regard to the effect on the cost of capital of decoupling ratemaking that relaxes the linkage between revenue and kWh sales, October 2017 and May 2018.

Rebuttal testimony before the California Public Utilities Commission on behalf of California-American Water Company, Application 15-07-019, Phase 3A and Phase 3b, on the economic effect on the Company and the applicability of a fine based upon California-American Water Company's administration of its tariff for the Monterey Water District, August 2017.

Direct and rebuttal testimony before the Corporation Commission of Oklahoma on behalf of Public Service Company of Oklahoma, Cause No. PUD201700151, on the cost of capital for Public Service Company of Oklahoma's regulated assets, June 2017 and October 2017.

Direct and rebuttal testimony before the California Public Utilities Commission on behalf of California Water Services Company, Application No. A.1704-006, on the cost of capital for California Water Services Company's regulated assets, April 2017 and August 2017.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Electric Company, (Case No. U-18255) on the cost of common equity capital for DTE Electric's regulated electric assets, April 2017 and September 2017.

Prepared direct testimony before the Federal Energy Regulatory Commission, Docket No. RP17-

598-000 on behalf of Great Lakes Gas Transmission Limited Partnership, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, March 2017.

Prepared direct testimony before the North Carolina Utilities Commission, Docket No. G-39, Sub 38, on behalf of the Cardinal Pipeline Company, LLC regarding the appropriate allowed ROE for the Company’s pipeline assets, March 2017.

Prepared direct testimony before the Federal Energy Regulatory Commission, Docket No. ER17-706-000 on behalf of Gridliance West Transco LLC, regarding Gridliance West’s application pursuant to section 205 of the Federal Power Act regarding the appropriate ROE, cost of debt, and capital structure to allow Gridliance West Transco LLC to earn on the transmission facilities acquired from Valley Electric Association, December 2016.

Prepared direct testimony and supporting exhibits before the Federal Energy Regulatory Commission, Docket No. EC17-049-000, on behalf of Gridliance West Transco LLC, regarding GridLiance West’s application pursuant to section 203 of the Federal Power Act (FPA) to acquire certain high voltage transmission facilities from Valley Electric Transmission Association, LLC (VETA) through its parent non-profit electric cooperative parent Valley Electric Association, Inc. (Valley Electric), December 2016.

Prepared direct testimony and supporting exhibits before the Federal Energy Regulatory Commission, Docket No. ER16-2632-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE and capital structure to allow for its regulated electric transmission assets, September 2016.

Prepared direct and rebuttal testimony before the Public Utilities Commission of Hawai‘i on the effect on the cost of capital of decoupling ratemaking that relaxes the linkage between revenue and kWh sales on behalf of Hawai‘i Electric Light Company, Inc. Docket No. 2015-0170, August 2016 and June 2017.

Direct testimony before the Michigan Public Service Commission on behalf of the Detroit Thermal, LLC (Case No. U-18131) on the cost of common equity capital for Detroit Thermal’s regulated steam service, July 2016.

Pre-filed direct testimony and supporting exhibits before the Rhode Island Public Utilities Commission on behalf of The Narragansett Electric Company d/b/a National Grid Docket No. 47xx regarding Petition for the Approval of Gas Capacity Contracts and Cost Recovery, June 2016.

Prepared direct testimony and supporting exhibits before the Federal Energy Regulatory Commission, Docket No. RP16-440-000, on behalf of ANR Pipeline Company, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, January 2016.

Pre-filed direct testimony before the Massachusetts Department of Public Utilities on behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid regarding the risk transfer inherent in signing long-term contracts for natural gas pipeline capacity, Docket

No. D.P.U. 16-05, January 2016.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Electric Company (Case No. U-18014) on the cost of capital for DTE Electric Company's regulated electric assets, January 2016 and July 2016.

Rebuttal testimony before the Public Utility Commission of Texas on behalf of Ovation Acquisition I, L.L.C., Ovation Acquisition II, L.L.C., and Shary Holdings, L.L.C. concerning the adequacy of Oncor Electric Distribution Company's (Oncor) liquidity, access to capital and financial risk with regard to the proposed restructuring of Oncor, PUC Docket No. 451888, December, 2015.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Gas Company (Case No. U-17799) on the cost of capital for DTE Gas Company's natural gas distribution assets, December 2015 and May 2016.

Prepared direct testimony before the Federal Energy Regulatory Commission, Docket No. ER15-2594-000, on behalf of South Central MCN, LLC, regarding the appropriate ROE to include in the transmission rate formula (Formula Rate) to establish an annual transmission revenue requirement (ATRR) for transmission service over facilities that SCMCN will own in the Southwest Power Pool, Inc. (SPP) region, September 2015.

"Report on Gas LDC multiples," with Bente Villadsen, *Alaska Industrial Development and Export Authority*, May 2015.

Direct and reply testimony before the Regulatory Commission of Alaska on behalf of Cook Inlet Natural Gas Storage Alaska, LLC, Docket No. U-15-016 on the appropriate allocation of the proceeds from the sale of excess Found Native Gas discovered incidental to the construction of the storage facility, April 2015 and July 2015.

Direct testimony before the Michigan Public Service Commission on behalf of the Detroit Edison Electric Company (Case No. U-17767) on the cost of capital for DTE's electric utility assets, December 2014.

Direct and rebuttal testimony before the Washington Utilities and Transportation Commission on behalf of Puget Sound Energy, Inc. Docket Nos. UE-130137 and UG-130138 (consolidated) remand proceeding with regard to the effect of decoupling on the cost of capital, November 2014 and December 2014.

Initial and Reply Statement of Position before the Public Utilities Commission of Hawai‘i In the Matter of Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawai‘i Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, with Dr. Toby Brown and Dr. Joseph B. Wharton, May 2014 and September 2014.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission on behalf of Metropolitan Edison Company (Docket No. R-2014-2428745), Pennsylvania Electric Company

(Docket No. R-2014-2428743), Pennsylvania Power Company (Docket No. R-2014-2428744), and West Penn Power Company (Docket No. R-2014-2428742) regarding the appropriate cost of common equity for the companies, September 2014 and December 2014.

Direct and rebuttal testimony before the Public Service Commission of West Virginia in the Matter of the Application of Monongahela Power Company and The Potomac Edison Company, Case No. 14-0702-E-42T for approval of a general change in rates and tariffs, June 2014 and October 2014.

Direct testimony before the Public Utilities Commission of Ohio in the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2012 Under the Electric Security Plans of Ohio on behalf of the Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 14-0828-EL-UNC, May 2014.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER14-1332-000, on behalf of DATC Path 15, LLC, regarding the appropriate ROE to include in the Submission of Revisions to Appendix I in TO Tariff Reflecting Updated TRR to be Effective February, 2014.

Direct testimony, rebuttal testimony and sur-surrebuttal testimony before the Arkansas Public Service Commission regarding the appropriate ROE to allow In the Matter of the Application of SourceGas Arkansas Inc., Docket No. 13-079-U for Approval of a General Change in Rates, and Tariffs, September 2013, March 2014, and April 2014.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER13-2412-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE to include in the Submission of Revisions to Appendix I of the Trans Bay Transmission Owner Tariff to be Effective 11/23/2013, September 2013.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER13-2412-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE to include in the Submission of Revisions to Appendix I of the Trans Bay Transmission Owner Tariff to be Effective 11/23/2013, September 2013.

Presentation on behalf of Alabama Power Company with regard to the appropriate cost of capital for the Rate Stabilization and Equalization mechanism, Dockets 18117 and 18416, July 2013.

Direct testimony before the Public Utilities Commission of Ohio in the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2012 Under the Electric Security Plans of Ohio on behalf of the Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 13-1147-EL-UNC, May 2013.

Expert Report, with A. Lawrence Kolbe and Bente Villadsen, on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of the behalf of oil pipeline in arbitration, April 2013.

Direct and Rebuttal testimony before the Public Utilities Commission of the State of Colorado on behalf of Rocky Mountain Natural Gas LLC regarding the cost of capital for an intrastate natural gas pipeline, Docket No. 13AL-143G, with Advice Letter No. 77, January 2013 and October 2013.

Rebuttal Testimony before the Public Utilities Commission of the State of California on behalf of Southern California Edison regarding Application 12-04-015 of Southern California Edison Company (U 338-E) For Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism , August 2012.

Direct testimony and supporting exhibits on behalf of Transcontinental Gas Pipeline Company, LLC, before the Federal Energy Regulatory Commission, on the Cost of Capital for Interstate Natural Gas Pipeline assets, Docket No. RP12-993-000, August 2012.

Direct Testimony before the North Carolina Utilities Commission on behalf of Cardinal Pipeline Company LLC, regarding the cost of capital for an intrastate natural gas pipeline, Docket G-39, Sub 28, August 2012.

Joint Rebuttal Testimony before the California Public Utility Commission on behalf of California American Water Company, regarding Application of California-American Water Company (U210W) for Authorization to increase its Revenues for Water Service, Application 10-07-007, and In the Matter of the Application of California-American Water Company (U210W) for an Order Authorizing and Imposing a Moratorium on New Water Service Connections in its Larkfield District, Application 11-09-016, August 2012.

Direct testimony before the Public Utilities Commission of Ohio, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2011 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 12-1544-EL-UNC, May 2012.

Deposition testimony in *Tahoe City Public Utility District, Plaintiff vs. Case No. SCV 27283 Tahoe Park Water Company, Lake Forest Water Company, Defendants*, May 2012.

Deposition testimony in *Primex Farms, LLC, Plaintiff, v. Roll International Corporation, Westside Mutual Water Company, LLC, Paramount Farming Company, LLC, Defendants*, April 2012.

Direct and rebuttal testimony before the Michigan Public Service Commission, Case No. U-16999, on behalf of Michigan Consolidated Gas Company, regarding cost of service for natural gas distribution assets, April 2012 and October 2012.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. PA10-13-000, on behalf of ITC Holdings Corp. regarding a rehearing for FERC Staff, Office of Enforcement, Division of Audits, Report on the appropriate accounting for goodwill for the acquisition of ITC Midwest assets from Interstate Power and Light Company, February 2012.

Rebuttal testimony before the Florida Public Service Commission, Docket No. 110138-EL, on behalf of Gulf Power, a Southern Company, on the method to adjust the return on equity for differences in financial risk, November 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER12-296-000, on behalf of Public Service Electric and Gas Company on the Cost of Capital and for Incentive Rate Treatment for the Northeast Grid Reliability Transmission Project, October 2011.

Rebuttal Evidence before the National Energy Board in the matter of AltaGas Utilities Inc., 2010-2012 GRA Phase I, Application No. 1606694; Proceeding I.D. 904, October, 2011.

Report before the Arbitrator on behalf of Canadian National Railway Company in the matter of a Submission by Tolko Marketing and Sales LTD for Final Offer Arbitration of the Freight Rates and Conditions Associated with Respect to the Movement of Lumber by Canadian National Railway Company from High Level, Alberta to Various Destinations in the Vancouver, British Columbia Area, October, 2011.

Written direct and reply evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. NB7, as amended, and the Regulations made thereunder; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, for determining the overall fair return on capital in the business and services restructuring and Mainline 2012 – 2013 toll application, RH-003-2011, September 2011 and May 2012.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. PA10-13-000, on behalf of ITC Holdings Corp. in response to FERC Staff, Office of Enforcement, Division of Audits, Draft Report on the appropriate accounting for goodwill for the acquisition of ITC Midwest assets from Interstate Power and Light Company, July 2011.

Initial testimony before the Public Utilities Commission of Ohio, Case No. 11-4553-EL-UNC, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2010 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, July 2011.

Rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.10-09-018, on behalf of California American Water Company, on Application of California American Water Company (U210W) for Authorization to Implement the Carmel River Reroute and San Clemente Dam Removal Project and to Recover the Costs Associated with the Project in Rates, June 2011.

Direct and rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.11-05-001, on behalf of California Water Service Company, on the Cost of Capital for Water Distribution Assets, April 2011 and September 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER11-013-000, on behalf of the Atlantic Wind Connection Companies, on the Cost of Capital and Cost of Capital incentive adders for Electric Transmission Assets, December 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. RP11-1566-000, on behalf Tennessee Gas Pipeline Company, on the Cost of Capital for Natural Gas Transmission Assets, November 2010.

Direct and rebuttal testimony before the Michigan Public Service Commission, In the matter of the application of The Detroit Edison Company, for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, Case No. U-16472, October 2010 and April 2011.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, Docket No. RP10-1398-000, on behalf of El Paso Natural Gas Company, on the Cost of Capital for Natural Gas Transmission Assets, September 2010 and September 2011.

Direct testimony before the Public Utilities Commission of Ohio, Case No. 10-1265-EL-UNC, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2009 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, September 2010.

Direct testimony before the Michigan Public Service Commission, Case No. U-16400, on behalf of Michigan Consolidated Gas Company, regarding cost of service for natural gas distribution assets, July 15, 2010.

Direct testimony before the Oklahoma Corporation Commission, Cause No. PUD 201000050, on behalf of Public Service Company of Oklahoma, regarding cost of service for a regulated electric utility, June 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER10-516-000, on behalf of South Caroline Gas and Electric Company, on the Cost of Capital for Electric Transmission Assets, December 2009.

Direct and Rebuttal Testimony before the California Public Utilities Commission regarding cost of service for San Joaquin Valley crude oil pipeline on behalf of Chevron Products Company, Docket Nos. A.08-09-024, C.08-03-021, C.09-02-007 and C.09-03-027, December 2009 and April 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER10-159-000, on behalf of Public Service Electric and Gas Company, on the incentive Cost of Capital for the Branchburg-Roseland-Hudson 500 kV Line electric transmission project (“BRH Project”), October 2009.

Rebuttal testimony before the Florida Public Service Commission in re: Petition for Increase in Rates by Progress Energy Florida, Inc., Docket No. 090079-EI, August 2009.

Direct and rebuttal testimony before the State of New Jersey Board of Public Utilities in the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 14 Electric and B.P.U.N.J No. 14 Gas Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Approval of a Gas Weather Normalization Clause; a Pension Expense Tracker and for other Appropriate Relief BPU Docket No. GR09050422, June 2009 and December 2009.

Direct and rebuttal testimony before the Public Service Commission of Wisconsin, Docket No. 6680-UR-117, on behalf of Wisconsin Power and Light Company, on the cost of capital for electric and natural gas distribution assets, May 2009 and September 2009.

Written evidence before the Régie de l'Énergie on behalf of Gaz Métro Limited Partnership, Cause Tarifaire 2010, R-3690-2009, on the Cost of Capital for natural gas transmission assets, May 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-681-000, on behalf of Green Power Express, LLP, on the Cost of Capital for Electric Transmission Assets, February 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-548-000, on behalf of ITC Great Plains, LLC, on the Cost of Capital for Electric Transmission Assets, January 2009.

Written and Reply Evidence before the Alberta Utilities Commission in the matter of the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2, as amended, and the regulations made thereunder; and IN THE MATTER OF the Gas Utilities Act, R.S.A. 2000, c. G-5, as amended, and the regulations made thereunder; and IN THE MATTER OF the Public Utilities Act, R.S.A. 2000, c. P-45, as amended, and the regulations made thereunder; and IN THE MATTER OF Alberta Utilities Commission 2009 Generic Cost of Capital Hearing, Application No. 1578571/Proceeding No. 85. 2009 Generic Cost of Capital Proceeding on behalf of AltaGas Utilities Inc., November 2008 and May 2009.

Written Evidence before the Alberta Utilities Commission in the matter of the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2, as amended, and the regulations made thereunder; and IN THE MATTER OF the Gas Utilities Act, R.S.A. 2000, c. G-5, as amended, and the regulations made thereunder; and IN THE MATTER OF the Public Utilities Act, R.S.A. 2000, c. P-45, as amended, and the regulations made thereunder; and IN THE MATTER OF Alberta Utilities Commission 2009 Generic Cost of Capital Hearing, Application No. 1578571/Proceeding No. 85. 2009 Generic Cost of Capital Proceeding on behalf of NGTL, November 2008.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, Case No.

08-1783-G-PC, on behalf of Dominion Hope Gas Company concerning the Cost of Capital for Gas Local Distribution Company assets, November 2008 and May 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-249-000, on behalf of Public Service Electric and Gas Company, on the incentive Cost of Capital for Mid-Atlantic Power Pathway Electric Transmission Assets, November 2008.

Direct and rebuttal testimony before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, with regard to the test to determine Significantly Excessive Earnings within the context of Senate Bill No. 221, September 2008 and October 2008.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, Case No. 08-0900-W-42t, on behalf of West Virginia-American Water Company concerning the Cost of Capital for Water Utility assets, July 2008 and November 2008.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-1233-000, on behalf of Public Service Electric and Gas Company, on the Cost of Capital for Electric Transmission Assets, July 2008.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-1207-000, on behalf of Virginia Electric and Power Company, on the incentive Cost of Capital for investment in New Electric Transmission Assets, June 2008.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, Docket No. RP08-426-000, on behalf of El Paso Natural Gas Company, on the Cost of Capital for Natural Gas Transmission Assets, June 2008 and August 2009.

Rebuttal testimony on the financial risk of Purchased Power Agreements, before the Public Utilities Commission of the State of Colorado, Docket No. 07A-447E, in the matter of the application of Public Service Company of Colorado for approval of its 2007 Colorado Resource Plan, June 2008.

Direct and rebuttal testimony before the California Public Utilities Commission, Docket No. A.08-05-003, on behalf of California-American Water Company, concerning Cost of Capital, May 2008 and August 2008.

Post-Technical Conference Affidavit on behalf of The Interstate Natural Gas Association of America in response to the Reply Comments of the State of Alaska with regard the FERC=s Proposed Policy Statement on to the Composition of Proxy Companies for Determining Gas and Oil Pipeline Return on Equity, Docket No. PL07-2-000, March, 2008.

Direct and rebuttal testimony on the Cost of Capital before the Tennessee Regulatory Authority, Case No. 08-00039, on behalf of Tennessee American Water Company, March and August 2008.

Comments in support of The Interstate Natural Gas Association of America=s Additional Initial Comments on the FERC=s Proposed Policy Statement with regard to the Composition of Proxy Companies for Determining Gas and Oil Pipeline Return on Equity, Docket No. PL07-2-000, December, 2007.

Written direct and reply evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. NB7, as amended, and the Regulations made thereunder; and in the matter of an application by Trans Québec & Maritimes PipeLines Inc. ("TQM") for orders pursuant to Part I and Part IV of the *National Energy Board Act*, for determining the overall fair return on capital for tolls charged by TQM, December 2007 and September 2008, Decision RH-1-2008, dated March 2009.

Direct and rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-022, on behalf of California-American Water Company, on the Effect of a Water Revenue Adjustment Mechanism on the Cost of Capital, October 2007 and November 2007.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-92-000 to Docket No. ER08-92-003, on behalf of Virginia Electric and Power Company, on the Cost of Capital for Transmission Assets, October 2007.

Direct and Supplemental testimony before the Public Utilities Commission of Ohio, Case No. 07-829-GA-AIR, Case No. 07-830-GA-ALT, and Case No. 07-831-GA-AAM, on behalf of Dominion East Ohio Company, on the rate of return for Dominion East Ohio=s natural gas distribution operations, September 2007 and June 2008.

Direct and rebuttal testimony before the State Corporation Commission of Virginia, Case No. PUE-2007-00066, on behalf of Virginia Electric and Power Company on the cost of capital for its southwest Virginia coal plant, July 2007 and December 2007.

Direct testimony before the Public Service Commission of West Virginia, Case No. 07-0998-W-42T, on behalf of West Virginia American Water Company on cost of capital, July 2007.

Direct, supplemental and rebuttal testimony before the Public Utilities Commission of Ohio, Case No. 07-551-EL-AIR, Case No. 07-552-EL-ATA, Case No. 07-553-EL-AAM, and Case No. 07-554-EL-UNC, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, on the cost of capital for the FirstEnergy Company=s Ohio electric distribution utilities, June 2007, January 2008 and February 2008.

Direct testimony before the Public Utilities Commission of the State of South Dakota, Docket No. NG-07-013, on behalf of NorthWestern Corporation, on the Cost of Capital for NorthWestern Energy Company=s natural gas operations in South Dakota, June 2007.

Rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-036-39, on behalf of California-American Water Company, on the Cost of Capital, May 2007.

Direct and rebuttal testimony before the Public Service Commission of Wisconsin, Docket No. 5-UR-103, on behalf of Wisconsin Energy Corporation, on the Cost of Capital for Wisconsin Electric Power Company and Wisconsin Gas LLC, May 2007 and October 2007.

Direct and rebuttal testimony before the Tennessee Regulatory Authority, Case No. 06-00290, on behalf of Tennessee American Water Company, on the Cost of Capital, November, 2006 and April 2007.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER07-46-000, on behalf of Northwestern Corporation on the Cost of Capital for Transmission Assets, October 2006.

Direct and supplemental testimony before the Federal Energy Regulatory Commission, Docket No. ER06-427-003, on behalf of Mystic Development, LLC on the Cost of Capital for Mystic 8 and 9 Generating Plants Operating Under Reliability Must Run Contract, August 2006 and September 2006.

Expert report in the United States Tax Court, Docket No. 21309-05, 34th Street Partners, DH Petersburg Investment, LLC and Mid-Atlantic Finance, Partners Other than the Tax Matters Partner, Petitioner, v. Commissioner of Internal Revenue, Respondent, July 28, 2006.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission, Return on Equity for Metropolitan Edison Company, Docket No. R-00061366 and Pennsylvania Electric Company, Docket No. R-00061367, April 2006 and August 2006.

Written evidence before the Ontario Energy Board, Cost of Capital for Union Gas Limited, Inc., Docket No. EB-2005-0520, January 2006.

Direct testimony before the Arizona Corporation Commission, Cost of Capital for Paradise Valley Water Company, a subsidiary of Arizona-American Water Company, Docket No. WS-01303A-05, May 2005.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission on Energy Allocation of Debt Cost for Incremental Shipping Rates for Edison Mission Energy, Docket No. RP04-274-000, December 2004 and March 2005.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, on Cost of Capital for West Virginia-American Water Company, Case No 04-0373-W-42T, May 2004.

Written evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. NB7, as amended, (Act) and the Regulations made under it; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part IV of the *National Energy Board Act*, for approval of Mainline Tolls for 2004, RH-2-2004, January 2004.

Direct and rebuttal reports before the Alberta Energy and Utilities Board in the matter of the Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, and the Regulations under it; in the matter of the Gas Utilities Act, R.S.A. 2000, c. G-5, and the Regulations under it; in the matter of the Public Utilities Board Act, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and in the matter of Alberta Energy and Utilities Generic Cost of Capital Hearing, Application No. 1271597, July 2003, November 2003, Decision 2004-052, dated July 2004.

Direct report before the Arbitration Panel in the arbitration of stranded costs for the Town of Belleair, FL, Case No. 000-6487-C1-007, April 2003.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Florida Power Corporation, dba Progress Energy Florida, Inc. in Docket No. SC03-1-000, March 2003.

Direct testimony and hearing before the Arbitration Panel in the arbitration of stranded costs for the City of Winter Park, FL, In the Circuit Court of the Ninth Judicial Circuit in and for Orange County, FL, Case No. C1-01-4558-39, December 2002.

Direct reports before the Arbitration Board for Petroleum products trade in the Arbitration of the Military Sealift Command vs. Household Commercial Financial Services, fair value of sale of the Darnell, October 2002.

Direct and rebuttal reports before the Arbitration Panel in the arbitration of stranded costs for the City of Casselberry, FL, Case No. 00-CA-1107-16-L, July 2002.

Direct testimony (with William Lindsay) before the Federal Energy Regulatory Commission on behalf of DTE East China, LLC in Docket No. ER02-1599-000, April 2002.

Written evidence before the Public Utility Board on behalf of Newfoundland & Labrador Hydro - Rate Hearings, October 2001, Order No. P.U.7 (2002-2003), dated June 2002.

Written evidence, rebuttal, reply and further reply before the National Energy Board in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, Order AO-1-RH-4-2001, May 2001, Nov. 2001, Feb. 2002.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Mississippi River Transmission Corporation in Docket No. RP01-292-000, March 2001.

Direct testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation for approval of its 2001 transmission tariff, May 2000.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Central Maine Power in Docket No. ER00-982-000, December 1999.

Direct and rebuttal testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation in the matter of an application for approval of its 1999 and 2000 generation tariff, transmission tariff, and distribution revenue requirement, Docket U99099, October 1998.

EFFECT OF FINANCIAL RISK ON THE COST OF EQUITY CAPITAL

Q1. What is the purpose of your Appendix B in this proceeding?

A1. My Direct Testimony provides a recommended return on equity ("ROE") for DTE Electric Company ("DTE" or "the Company") that is reasonable for its business and financial risks. This Appendix B to my Direct Testimony explains the relationship between financial risk and the cost of equity capital for any company. I describe my approach to account for the effect of financial risk and provide a number of references to academic literature and financial textbooks to support my approach.

Q2. Why is capital structure important for the determination of the cost of equity?

A2. Owners of a company whose assets are financed with a higher percentage of debt face more financial risk, and therefore the ROE needs to be greater.[1] This is irrespective of the ownership structure as long as debt holders are paid prior to equity owners, so that debt increases risk for the residual claimants/owners (the equity holders). Consider the following example: Company A finances 50 percent of its assets with equity and 50 percent with debt (so it uses a 50-50 capital structure) while Company B is 100 percent equity financed. For illustrative purposes, assume that the cash flows will be either $5 or $15 and that these two possibilities have the same chance of occurring. Figure B-1 and Figure B-2 below depict the returns for equity owners in this example.

[1] For a discussion of the relationship between financial risk and return, see Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," *The Journal of Finance,* 24: 13-31 (March 1969).

Figure B-1
Equity Returns for Company A (50-50 Capital Structure)

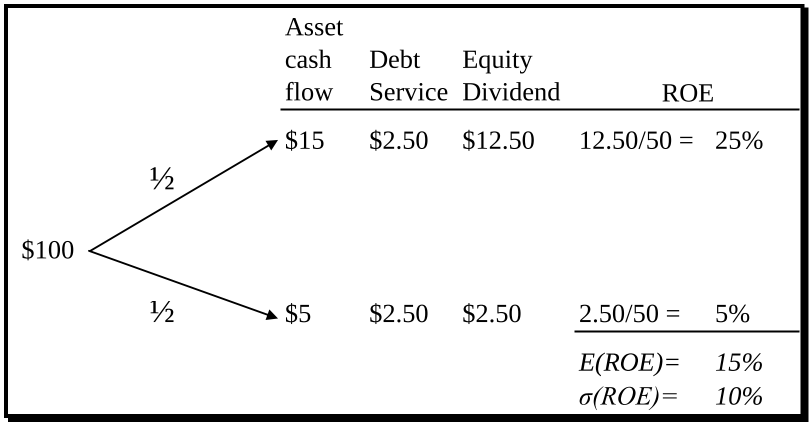
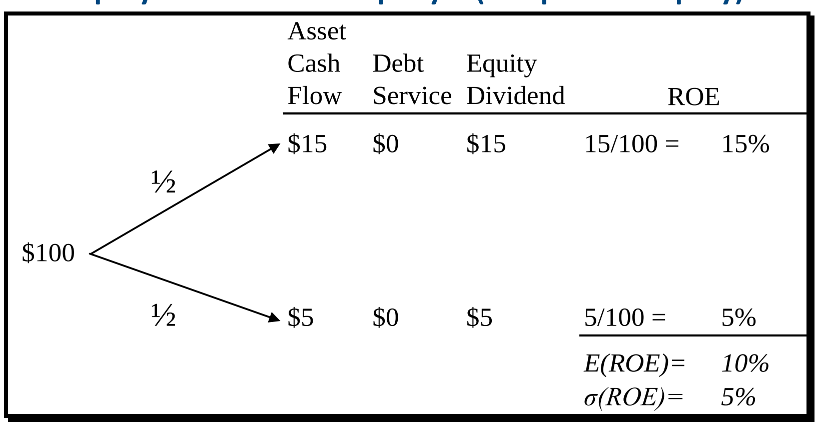


Figure B-2
Equity Returns for Company B (100 percent Equity)



In the figures, E(ROE) indicates the mean (i.e., expected) return and σ(ROE) represents the variability. Equity returns are equal for Company A and Company B if cash flow (i.e., revenues) turns out to be $5. However, if cash flow were $15, then the equity holders of Company A would have higher returns (larger ROE in positive outcomes). Although not depicted above, cash flows of $2.50 would mean Company A would have lower returns (lower ROE in negative outcomes). This simple example illustrates that the introduction of debt increases both the mean (expected) return to equity holders and the variability of that return, even though the firm's expected cash flows—which are a property of the line of business in which its assets are invested—are unaffected by the firm's financing choices.[2] The "magic" of financial leverage is not magic at all—leveraged equity investors can only earn a higher return because they take on greater risk.

Q3. What did you mean by the "overall cost of capital" mentioned earlier?

A3. The overall cost of capital is calculated as the average of the (after-tax) cost of debt capital and the cost of equity, weighted by their market value shares in the capital structure. Specifically, the following equation pertains:[3]

$$r^* = r_D \times (1 - T_c) \times \%D + r_E \times \%E \qquad \text{(B-1)}$$

where r^* = overall cost of capital,

r_D = market cost of debt,

r_E = market cost of equity,

T_C = corporate income tax rate,

$\%D$ = percent debt in the capital structure, and

$\%E$ = percent equity in the capital structure

The overall cost of capital is commonly referred to as the WACC in financial textbooks and is used in investment decisions.[4] The return on equity consistent with the sample's overall cost of capital estimate, the market cost of debt, the corporate income tax rate, and the amount of debt and common equity in the capital structure can be determined by solving Equation (B-1) for r_E. Alternatively, if r_E is given and the capital structure is not, one can solve for $\%E$ instead. Having determined the cost of capital for the sample

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[2] The effect of financial leverage on cost of equity has been developed since the 1958 paper by Prof. Franco Modigliani and Merton Miller ("MM"), two economists who won Nobel Prizes in part for their body of work on the effects of debt on firm value. *See*, Franco Modigliani and Merton H. Miller (1958), "The cost of capital, corporation finance and the theory of investment," *American Economic Review*, 48, pp. 261-297.

[3] The equation is shown with only debt and common equity. If the capital structure has preferred equity, add the following term ($r_P \times \%P$) to the right-hand side of the equation.

[4] See, for example, Brealey, Myers and Allen (2017), *Principles of Corporate Finance, 12th Edition*, McGraw-Hill Irwin, New York, pp. 448-453.

companies, I can apply that same cost of capital, which controls for differences in financial risk, to the regulated entity, in this case DTE.[5]

Q4. Why is the overall cost of capital relevant to these proceedings?

A4. The overall cost of capital is one of several procedures in my analysis; it is important because it allows a comparison between the sample companies' costs of capital estimates and the cost of capital for DTE. Two otherwise identical companies with different capital structures will typically have different costs of equity because the risks to equity holders depend on the financial leverage (i.e., the amount of debt in the capital structure of the company). As explained by the academic literature:

> *...leverage increases the risk of equity even when there is no risk that the firm will default.*[6]

This makes it difficult to compare cost-of-equity estimates among companies that have different capital structures. The effect of varying financial leverage on the risk-return tradeoffs of companies means that simply averaging individual cost-of-equity estimates across a sample generally does not provide meaningful information about an appropriate representative cost of capital for the industry. Thus it is generally incorrect to compute a sample average return on equity when estimating the cost of capital. However, two otherwise identical companies with different capital structures will generally have comparable cost of capital values. The "apples to apples" comparability of the overall cost of capital across companies with different capital structures makes it a consistent measure of the representative cost of capital in an industry.

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[5] I refer to the overall cost of capital to distinguish it from the WACC used in regulatory proceedings which is the weighted-average of the after-tax cost of equity and the *pre-tax* cost of debt instead of the after-tax cost of debt.

[6] Berk, J. & DeMarzo, P., *Corporate Finance, 3rd Edition.* 2014 Prentice Hall, p. 482. *[emphasis in original.]*

Q5. How does the overall cost of capital approach differ from procedures where the cost of equity and the regulatory capital structure are determined separately?

A5. The overall cost of capital approach avoids inconsistencies that could arrive from estimating the cost of equity for each of the sample firms without explicit consideration of the financial risk inherent in the market-value capital structure underlying those costs. If the sample's average cost of equity is used to estimate the cost of equity for the company in question, inconsistencies are likely to arise, because this method makes no adjustment for any differences among the capital structures of the sample firms used to estimate the cost of equity and the regulatory capital structure used to set rates. Consequently, the sample's estimated return on equity does not necessarily correspond to the financial risk faced by investors in the subject companies, in this case DTE. If the sample's estimated cost of equity were adopted without consideration of differences in financial risk, it could lead to an unjust and inappropriate rate of return.

Since the overall cost of capital controls for the differences in financial risk, the estimates of the sample's overall cost of capital can therefore be considered to inform an appropriate recommendation for the overall cost of capital of the regulated company. This financial risk adjustment ensures that the returns allowed on the regulated company's rate base (independent of capital structure) are comparable to the overall cost of capital as estimated by the sample.

Q6. Why is it necessary to consider the sample companies' capital structures as well as the regulatory capital structure in your analysis?

A6. Briefly, the cost of equity and the capital structure are inextricably entwined in that the use of debt increases the financial risk of the company and therefore increases the cost of equity. The more debt, the higher is the cost of equity for a given level of business risk. Rate regulation has in the past often focused on the individual components of the cost of capital. In particular, it has treated as separate questions what the "right" cost of equity capital and "right" capital structure should be. The cost of capital depends primarily on the business the firm is in, while the costs of the debt and equity components depend not only on the business risk, but also on the distribution of revenue between debt and equity.

The cost of capital is thus the more basic concept. Although the overall cost of capital is constant (ignoring taxes and costs of excessive debt), the distribution of the costs among debt and equity is not. Reporting the average cost of equity estimates from the sample without consideration of the differences in financial risk may result in material errors in the allowed return for DTE.

Q7. What is the basis for the development of the overall cost of capital method?

A7. Computing the overall cost of capital—called the weighted-average cost of capital in textbooks—is the fundamental method used by financial economists to measure the cost of capital. It is a standard topic taught in graduate level courses in corporate finance and is based upon the work of Professors Franco Modigliani and Merton Miller. Each separately won the Nobel Prize in Economics, in part, for developing the theories underlying the method.

It is critical to keep in mind that the overall cost of capital method is one useful tool to assist in the analysis of the cost of capital. All cost of capital witnesses estimate the cost of equity using the DCF or the risk positioning models, and all must interpret the results relative to the risk of the regulated company at issue. The purpose of the overall cost of capital method is to allow an “apples to apples” comparison of the results of the sample companies by adjusting for differences in financial risk due to differences in capital structure. The overall cost of capital is sometimes mischaracterized in regulatory proceedings and incorrectly criticized, possibly because the critics do not like the method’s results, but it is the standard methodology in finance. It is consistent with the use of rate base measured on the basis of book value, and does not require a regulator to “rubber stamp” the current market value of the regulated company’s stock as is sometimes asserted.

Q8. Is the use of the overall cost of capital method unconventional?

A8. No. The overall cost of capital is presented in every textbook on corporate finance of which I am aware.[7] These textbooks calculate the overall cost of capital in exactly the same way as I do.

Q9. Is the overall cost of capital approach used by other regulators?

A9. Yes, a number of regulators in the U.S. and in countries around the world rely upon the overall cost of capital to set rates. Some aspects of the regulatory procedures in these countries may vary, but they all rely upon a book value measure of rate base and a market determined cost of capital to set rates. The countries include the United Kingdom, Australia, New Zealand, and Ireland among others. These countries apparently regard the overall cost of capital as proper regulatory policy and appropriate for setting rates in a regulatory proceeding.

Q10. What regulators in the U.S. use the overall cost of capital approach?

A10. Although use of the overall cost of capital is not prevalent in the U.S., it is used by some regulators. The Surface Transportation Board ("STB") uses the overall cost of capital method to determine revenue adequacy for railroads, as does the Federal Communication Commission to set rates for local exchange carriers. Florida uses a very similar method to regulate small water companies, and the Colorado Division of Property Taxation uses the overall cost of capital to value property. In a recent decision, the FERC used the overall cost of capital (calculated as I do) as a discount rate in a valuation dispute.[8] In a recent decision, the Alabama Public Service Commission recognized that the overall cost of capital analysis may not be widely used by U.S. regulators "however, the focus of that

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[7] See, for example, Brealey, Myers and Allen (2017), *Principles of Corporate Finance, 12th Edition*, McGraw-Hill Irwin, New York, Chapter 19, Ross, Westerfield, Jaffe, and Roberts (2008), *Corporate Finance*, 5th Canadian edition, McGraw-Hill Ryerson, Toronto, Chapter 13, Bodie, Kane and Marcus (2009), *Investments*, McGraw-Hill Irwin, New York, 8th ed., 2009, Chapter 18, and Koller, Goedhart and Wessels (2005), *Valuation*, 4th ed., John Wiley & Sons, Inc. Chapter 5. See Exhibit A-14, Schedule No. D5.17 at 21-37 for the excerpt from *Valuation* textbook.

[8] Order Conditionally Accepting Tariff Revisions, Subject to Compliance Filings, Docket No. ER14-2940-000, PJM Interconnection, L.L.C., issued November 28, 2014.

methodology on the relationship between the market value and the associated financial risk of the utility is compelling."[9]

Q11. Is financial risk properly measured by the market value or book value capital structure?

A11. The notion that financial leverage is and should be measured on a market value basis is supported in every textbook on corporate finance of which I am aware.[10] Further, the view is not just an ivory-tower creation. Professional valuation books and guides advocate the use of market value capital structure.[11] Morningstar and Duff and Phelps—both off-the-shelf cost of capital providers using *Ibbotson* data and analysis—also use market-value capital structure in cost of capital estimates.[12] Similar views were also endorsed by legal decisions on bankruptcy proceedings.[13] Financial risk is a function of the market value capital structure. There is simply no debate in academic or business circles about this point.

Every day experience also indicates that market value is the measure of financial risk. The variability of your return on your investment in your home depends upon the size of your mortgage relative to the appraised (i.e., market) value of your house. For example, if you have a $100,000 mortgage on a house that is worth $200,000 in the current market, you have 50 percent equity in your home. This is true even if the "book value" of the

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9 Report and Order, *In re: Public Proceedings established to consider any necessary modifications to the Rate Stabilization and Equalization mechanism applicable to the electric service of Alabama Power Company*, Dockets 18117 and 18416, August 21, 2013, p. 20.

10 See, *e.g.*, Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2017, *Principles of Corporate Finance*, 12th edition, McGraw-Hill Irwin, at p. 467; Stephen A. Ross, Randolph W. Westerfield, and Jeffrey Jaffe, 2002, *Corporate Finance*, 6th edition, McGraw-Hill Irwin, at p.386; and Mark Grinblatt and Sheridan Titman, 1998, *Financial Markets and Corporate Strategy*, 1st edition, Irwin/McGraw-Hill, at p. 464.

11 See, *e.g.*, Tom Copeland, Tim Koller, and Jack Murrin, 2000, *Valuation: Measuring and managing the value of companies*, 3rd edition John Wiley & Sons, p. 204; and Shannon P. Pratt and Alina V. Niculita, 2008, *Valuation a business: The analysis and appraisal of closely held companies*, 5th edition, McGraw-Hill, at pp. 216 – 217.

12 See, *e.g.*, Morningstar, *Duff & Phelps 2017 Valuation Handbook – Guide to Cost of Capital*, at p. 39.

13 See, *e.g.*, Bernstein, Stan, Susan H. Seabury, and Jack F. Williams, 2008, "Squaring bankruptcy valuation practice with *Daubert* Demands," *ABI Law Review*, at p. 190.

house—the original cost of construction—is only $150,000. It is also the case that the larger the percentage of the appraised value that is financed with a mortgage, the larger will be variability in your equity return as the home value varies. It is the variability of the market value of the house that affects the home owner's risk; the "book value" of the house does not change.

Q12. Can you provide academic evidence that financial leverage is and should be measured on a market value basis?

A12. Yes. The impact of financial leverage on cost of equity has been developed since the 1958 paper by Prof. Franco Modigliani and Merton Miller ("MM"), two economists who eventually won Nobel Prizes in part for their body of work on the effects of debt on firm value.[14] One key corollary of the MM theorems and their various extensions is that cost of equity increases as financial leverage increases. Although the exact speed of increase in cost of equity differs by models of capital structure, it is universally accepted that as a firm adds debt, its cost of equity increases as a result.

While acknowledging that the cost of equity increases with financial leverage, some people assert that financial risk is measured on a book value basis. This belief is wrong for two reasons. First, in MM's classic paper and subsequent extensions of their original paper, financial leverage has been consistently measured on a market value basis. This is because MM's basic insight is that, under perfect market conditions, financial leverage does not increase the *market value* of a firm as long as different combinations of debt and equity can be selected by the investors themselves.[15] To implement such a self-help financial engineering, investors have to be able to buy and sell debt and equity to achieve their desired combination. The prices at which they transact are, by definition, *market prices.* Second, as a more practical matter, economists generally prefer to use market

[14] Franco Modigliani and Merton H. Miller (1958), "The cost of capital, corporation finance and the theory of investment," *American Economic Review*, 48, pp. 261-297. See Exhibit A-14, Schedule No. D5.17 at 38-75. For a modern textbook exposition of the capital structure theories, see Brealey, Myers, and Allen, *op cit.*, Chapter 17.

[15] In developing the theory, MM assume that investors can adjust the capital structures of their portfolios at no cost.

values because they convey timely information, rather than historical data, about the assets. Business decisions on investment, capital budgeting, and financing are all based on real time market value information.

Q13. Are there any other academic articles that discuss how a company's cost of equity changes as its capital structure changes?

A13. Yes, there are many others. An important example is from Professor Robert S. Hamada, who addressed this issue in "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks."[16] Professor Hamada's adjustment method is consistent with the overall cost of capital approach, and I present results using this method to provide further insight on the range of ROE estimates after adjusting for financial leverage. I find that the resulting ROE estimates using the Hamada adjustment procedure are similar to those estimates using the overall cost of capital approach, so the Commission should rely on estimates from either procedure to appropriately recognize the impact that differences in leverage have on the cost of equity. Both approaches are widely accepted in academic literature and commonly used amongst finance practitioners. I have included a subset of the academic literature which discusses these financial risk adjustment procedures as Schedule D5.17 in Exhibit A-14.

The alternative Hamada adjustment procedures account for the impact of financial risk recognizing that, under general conditions, the value of a firm can be decomposed into its value with and without a tax shield (Value of Firm = Present Value of Cash Flows without Tax Shield plus Value of Tax Shield).

[16] *The Journal of Finance*, Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27- 29, 1971 (May, 1972), pp. 435-452. See Exhibit A-14, Schedule No. D5.17 at 2-20.

Assuming that the CAPM is valid, Professor Hamada showed the following relationship between the beta for a firm with no leverage (e.g., 100 percent equity financing) and a firm with leverage is as follows:[17]

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \qquad \text{(B-2)}$$

Where β_L is beta associated with the "levered cost of capital"—the required return on assets if the firm's assets are financed with debt and equity—β_U is the beta associated with an unlevered firm—assets are financed with 100% equity and zero debt—, and β_D is the beta on the firm's debt. Finally, τ_c is the corporate income tax rate. Since the beta on an investment grade firm's debt is much lower than the beta of its assets (i.e., $\beta_D < \beta_U$), this equation embodies the fact that increasing financial leverage (and thereby increasing the debt to equity ratio) increases the systematic risk of levered equity (β_L).

An alternative formulation derived by Harris and Pringle (1985) provides the following equation:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \qquad \text{(B-3)}$$

Unlike Equation (B-2), Equation (B-3) does not include an adjustment for the corporate tax deduction. However, both equations account for the fact that increased financial leverage increases the systematic risk of equity that will be measured by its market beta. Both equations allow an analyst to adjust for differences in financial risk by translating back and forth between β_L and β_U. In principle, Equation (B-2) is more appropriate for use with regulated utilities, which are typically deemed to maintain a fixed book value capital structure. However, I employ both formulations when adjusting my CAPM and ECAPM estimates for financial risk, and consider the results as sensitivities in my analysis.

It is clear that the beta of debt needs to be determined as an input to either Equation (B-2), or Equation (B-3). Rather than estimating debt betas, I note that the standard financial

[17] Technically, the relationship requires that there are no additional costs to leverage and that the book value capital structure is fixed.

textbook of Professors Berk & DeMarzo report a debt beta of 0.05 for A rated debt and a beta of 0.10 for BBB rated debt[18] while other academic literature has reported debt betas of 0.26.[19] I consider this range of 0.05 to 0.26 to be reasonable for debt betas.

Once a decision on debt betas is made, the levered equity beta of each sample company can be computed (in this case by *Value Line*) from market data and then translated to an unlevered beta at the company's market value capital structure. The unlevered betas for the sample companies are comparable on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the sample companies, independent of their financing. The unlevered betas are averaged to produce an estimate of the industry's unlevered beta. To estimate the cost of equity for the regulated target company, this estimate of unlevered beta can be "re-levered" to the regulated company's capital structure, and the CAPM can be reapplied with this levered beta, which reflects both the business and financial risk of the target company.

Hamada adjustment procedures are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

Q14. Does this conclude your Appendix B?

A14. Yes.

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[18] Berk, J. & DeMarzo, P., *Corporate Finance, 3rd Edition*. 2014 Prentice Hall, p. 413.

[19] "Explaining the Rate Spread on Corporate Bonds," Edwin J. Elton, Martin J. Gruber, Deepak Agarwal, and Christopher Mann, *The Journal of Finance*, February 2001, pp. 247-277. See Exhibit A-14, Schedule No. D6.17 at 76-106.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHERRI L. WISNIEWSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS OF SHERRI L. WISNIEWSKI

Line
No.

Q. What is your name, business address, and by whom are you employed?

A. My name is Sherri L. Wisniewski. My business address is DTE Energy, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I earned a Bachelor of Business Administration from Western Michigan University in 1993 and a Master of Business Administration from The University of Michigan in 1998.

Q. What work experience do you have?

A. I have been with DTE Energy Company in the Tax Department since 1996. I became Director of Tax Operations in July 2016 and am currently responsible for state and local income and franchise returns, tax accounting, tax forecasting, and regulatory tax.

Q. To what extent have you participated in prior rate cases and other regulatory proceedings?

A. I have sponsored testimony in the following cases:

U-18255	DTE Electric Rate Case
U-18232	DTE Electric REP Amended Plan
U- 20051	DTE Electric 2017 TRM Reconciliation

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U-20106	DTE Gas Credit A Rate Case
U-20029	DTE Electric EWR 2017 Reconciliation
U-18999	DTE Gas Rate Case
U-20105	DTE Electric Credit A Rate Case

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss and support the reasonableness of DTE Electric's Federal Income Tax (FIT), Michigan Corporate Income Tax (MCIT), municipal (city) income tax, property tax and other general taxes for the 2017 calendar year historical period and the twelve months ending April 30, 2020, projected test period. I also propose how re-measurement of deferred taxes resulting from the 2017 Tax Cuts and Jobs Act will be returned to customers through amortization of the tax regulatory liability starting on May 1, 2019.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-3	C7	Historical General Taxes
A-3	C8	Historical Federal Income Taxes
A-3	C9	Historical State and Local Income Taxes
A-3	C10	Historical Other Taxes
A-13	C7	Projected General Taxes – Other
A-13	C7.1	Projected General Taxes – Property
A-13	C8	Projected Federal Income Tax
A-13	C8.1	Projected Tax Reform Regulatory Liability
A-13	C9	Projected State Income Tax
A-13	C10	Projected Local Income Tax

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. What income tax rates are you assuming in this case?

A. I am assuming a FIT rate of 35% for the 2017 historical period and 21% for 2018 and subsequent years, and a MCIT rate of 5.82% (6% statutory rate at 97% apportionment) for the 2017 historical period and 5.88% (6% statutory rate at 98% for 2018 and subsequent years. In addition, I am assuming for all periods in this case a municipal income tax rate of 0.33%, which represents a composite rate including all cities in which DTE Electric has a municipal income tax obligation.

HISTORIC PERIOD

Q. How was the 2017 historical period property tax expense derived for the rate case?

A. The 2017 historical period property tax expense in Exhibit A-3, Schedule C7, line 1 of $250.0 million represents property tax expense on all of DTE Electric's property. $239.4 million of this expense was applicable to property reflected in DTE Electric's general rate case filings (referred to hereafter as general rate case property) and $10.5 million was applicable to Renewable Energy Program (REP) and Transition Reconciliation Mechanism (TRM) property. Property tax *expense* refers to the amount of property taxes deducted for book purposes. Property tax *liability* refers to the amount of property taxes payable to local governments. Because the Company expenses its property tax liability over a two-year period[1], you will see a difference annually between liability and expense.

[1]The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years and is based, generally, on the fiscal years of the various taxing jurisdictions to which property taxes are paid.

Q. Is there anything unique or unusual regarding 2017 historical period income tax expense?

A. No. 2017 historical period income tax expense, which includes FIT expense, MCIT expense, and municipal income tax expense, is calculated in the same general manner as it was in Case No. U-18255. Income tax expense includes both current income taxes (taxes payable currently) and deferred taxes (taxes payable in the future).

The income tax expense amounts shown on Exhibit A-3, Schedule C8 and C9 reflect income tax expense for DTE Electric as a whole. These are adjusted for the rate case in Exhibit A-3, Schedule C1.1, which is supported by Company Witness Ms. Uzenski. Total 2017 historical year income tax expense, after rate case and normalization adjustments, is $356.4 million.

Q. How was the 2017 historical period payroll tax expense derived?

A. There are three payroll-related taxes included in Exhibit A-3, Schedule C7. These three payroll taxes consist of a federal social security tax and a Medicare tax referred to collectively as "FICA," a federal unemployment tax referred to as "FUTA," and a Michigan state unemployment tax referred to as "SUTA." These payroll taxes for the historic period are derived from the Company's payroll system based on individual employees' wages up to a maximum taxable limit times a prescribed rate. Total payroll tax expense for the historic period is $38.1 million.

Q. What are the Other General Taxes reflected on Exhibit A-3 Schedule C7?

A. In addition to payroll taxes of $38.1 million, Public Utility Assessment fees of

Line No.

$11.6 million and Use Tax and Other tax totaling $0.1 million are included in the Total Other General Taxes of $49.9 million.

Q. What does the balance sheet reclass for Accumulated Deferred Income Taxes and Accumulated Deferred Investment Tax Credit on Witness Uzenski's Exhibit A-2, Schedule B6.1, column (e) represent?

A. There are two adjustments that are reflected in Witness Uzenski's exhibit that are reclassified to Accumulated Deferred Income Tax Liability.

The first adjustment is to reclassify the Accumulated Deferred Income Tax Asset on Exhibit A-2, Schedule B6.1, pages 1 of 2, row 50 to Accumulated Deferred Income Tax liabilities for proper balance sheet presentation. This is consistent with prior rate case filings.

The second adjustment is to reclassify the regulatory liability for DTE Electric's 2015, 2016 and 2017 Ludington Investment Tax Credit to deferred taxes. A deferred tax asset was recorded for tax credits generated in 2015, 2016 and 2017 because the Company had no federal tax liability and was, therefore, unable to utilized any tax credits in those years. Because DTE Electric has not recognized the cash benefit of the Investment Tax Credit, the regulatory liability for these credits must be reclassified to eliminate any impact it would have on the cost of capital.

FORECAST PERIOD

Q. What subjects will your testimony and exhibits cover related to the twelve months ending April 30, 2020 projected test period?

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A. I am supporting the FIT, MCIT, Municipal Income Tax, Property Tax and Other general taxes shown on Exhibit A-13, Schedules C7 through C10. These schedules, which are primarily based on forecasted amounts sponsored by other Company witnesses, are used to derive the various tax expense amounts for the projected test period.

Q. How are Michigan property taxes assessed?

A. Michigan property tax is imposed annually by local governments on the taxable value of all real and tangible personal property including construction work in progress (CWIP), unless specifically exempted by law. The liability for any given year is based on the taxable value of property on December 31 of the previous year, which is referred to as the assessment date. For example, the 2018 liability is based on the taxable value of property on December 31, 2017.

The taxable value is calculated by multiplying the true cash value (see below) of the property by 50%. The liability is then derived by multiplying the taxable value by the millage rate (can also be referred to as a tax rate). Millage rates vary throughout the state and represent the aggregate levies for all taxing units (county, township, city, village, and school districts) within which the property is located. The liability is billed in two parts, with one bill generally received in December (referred to as the winter bill) and the other bill generally received in June (referred to as the summer bill). The billing dates and allocation of the liability between the billing dates is driven by the fiscal year of the taxing jurisdiction and, therefore, will vary by jurisdiction.

Line
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Q. In the calculation of the property tax liability, what is 'true cash value' and how is it calculated?

A. True cash value is meant to represent fair market value and is determined by local assessors who apply guidelines set forth by the State Tax Commission (STC), which supervises the valuation and assessment of property. To determine true cash value, assessors will utilize multiplier tables established by the STC. An STC multiplier is utilized to enable an assessor to determine true cash value without performing a comprehensive market value analysis every year. The tables are designed to mimic the expected life cycle of the property. STC multipliers will change over the life of the property to represent the change in value over time driven by factors such as typical usage patterns and obsolescence. True cash value is calculated by multiplying the appropriate STC multiplier by the historical cost of the property.

Q. When does the Company know its property tax liability for any given year?

A. The Company files property tax returns (referred to as renditions) in late February and early March to report property on hand as of the assessment date (December 31). A separate rendition is filed with each assessor in each location where property is owned. The liability is still an estimate at that time and will continue to be trued-up as the Company receives assessments from local assessors in March and April and bills in June and December.

Q. How are the 2017 and 2018 property tax liabilities reflected in your exhibits?

A. Exhibit A-13, Schedule C7.1 shows the 2017 and 2018 property tax liabilities in column (c) on lines 3 and 4, respectively.

Line No.

The 2017 tax liability[2] of $242.5 million (line 3, column (c)) represents the actual property taxes assessed and paid on all general rate case property on hand as of December 31, 2016.

The 2018 tax liability of $256.5 million (line 4, column (c)) represents the estimated property taxes that will be assessed paid on all general rate case property on hand as of December 31, 2017. This 2018 estimated property tax liability increased $14.0 million over the 2017 tax liability of $242.5 million. The estimate is based on the actual taxable value per the 2018 property tax returns filed in February and March of 2018 and assumes an additional assessment from the City of Highland Park and a composite millage rate of 59.0.

Q. How is the 2019 Property tax liability reflected in your exhibits?

A. Exhibit A-13, Schedule C7.1, shows the projected 2019 property tax liability of $279.8 million on line 54, column (c).

Q. How was the projected 2019 Property Tax liability on Exhibit A-13, Schedule C7.1, line 54 calculated?

A. This represents the projected property taxes that will be assessed and paid on all general rate case property projected to be on hand at December 31, 2018. This is based on the 2018 estimated tax liability of $256.5 million (line 52, column (c)) plus the increase in liability projected for 2019 of $23.3 million (line 50, column

[2] Property tax *liability* refers to the amount of property taxes payable to local governments, whereas property tax *expense* refers to the amount of property taxes deducted for book purposes. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. The 2017 Property tax expense as stated in the historical section of my testimony was $240.6 million.

(c)). The increase in liability projected for 2019 is calculated in column (c) on lines 25 through 50. The taxable value of 2018 additions is estimated to be $395.8 million (line 35, column (c)), driven primarily by 2018 capital additions less retirements and nontaxable expenditures. It also takes into consideration the change in CWIP and applies first year STC multipliers to both the capital additions and the change in CWIP. Annual inflation of real property on hand as of December 31, 2017 is estimated to be an increase in taxable value of $37.5 million (line 41, column (c)). Annual obsolescence of personal property on hand as of December 31, 2017 is estimated to be a reduction in taxable value of $38.9 million (line 47, column (c)). The estimated composite millage rate of 59.0 is then applied to the net increase in taxable value of $394.4 million (line 48, column (c)) resulting in the $23.3 million incremental tax liability. The 2018 capital additions and retirements are supported by Company Witnesses Mr. Paul, Mr. Milo, Mr. Bruzzano, Mr. Davis, Mr. Griffin, Mr. Serna, Ms. Dimitry, Ms. Johnson and Ms. Uzenski.

Q. How is the 2020 Property tax liability reflected in your exhibits?

A. Exhibit A-13, Schedule C7.1, shows the projected 2020 property tax liability of $310.8 million on line 56, column (e).

Q. How was the projected 2020 Property Tax liability on Exhibit A-13, Schedule C7.1, line 56 calculated?

A. This represents the projected property taxes that will be assessed and paid on all general rate case property projected to be on hand at December 31, 2019. This is based on the 2019 projected tax liability of $279.8 million (line 54, column (e)) plus the increase in liability projected for 2020 of $31.0 million (line 55, column (e)).

The increase in liability projected for 2020 is calculated in column (e) on lines 25 through 50. The taxable value of 2019 additions is estimated to be $521.3 million (line 35, column (e)), driven primarily by 2019 capital additions less retirements and nontaxable expenditures. It also takes into consideration the change in CWIP and applies first year STC multipliers to both the capital additions and the change in CWIP. Annual inflation of real property on hand as of December 31, 2018 is estimated to be an increase in taxable value of $38.3 million (line 41, column (e)). Annual obsolescence of personal property on hand as of December 31, 2018 is estimated to be a reduction in taxable value of $38.3 million (line 47, column (e)). The estimated composite millage rate of 59.5 is then applied to the net increase in taxable value of $521.4 million (line 48, column (e)) resulting in the $31.0 million incremental tax liability. The 2019 capital additions and retirements are supported by Company Witnesses Mr. Paul, Mr. Milo, Mr. Bruzzano, Mr. Davis, Mr. Griffin, Mr. Serna, Ms. Dimitry, Ms. Johnson and Ms. Uzenski.

Q. What is the amount of property tax expense the Company is seeking recovery of, and how is it calculated?

A. The Company is seeking recovery of property tax expense of $275.5 million for the projected test period (May 1, 2019 thru April 30, 2020), which is included in Exhibit A-13, Schedule C1, line 6, column (e). Property tax *expense* refers to the amount of property taxes deducted for book purposes. Property tax *liability* refers to the amount of property taxes payable to local governments. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years and is based, generally, on the fiscal years of the various taxing jurisdictions to which property taxes are paid.

The 2019 calendar year property tax expense of $266.8 million represents 61% of the 2018 property tax liability and 39% of the 2019 property tax liability. Due to the two-year expensing methodology, the increase of $17.6 million over the 2018 property tax expense of $249.2 million was driven by the increases in both the 2018 estimated tax liability and the 2019 projected tax liability.

The 2020 calendar year property tax expense of $293.1 million represents 61% of the 2019 projected property tax liability and 39% of the 2020 projected property tax liability. Due to the two-year expensing methodology, the increase of $26.3 million over the 2019 property tax expense of $266.8 million is driven by the increases in both the 2019 projected tax liability and the 2020 projected tax liability.

Projected test period property tax expense of $275.5 million is calculated by taking 8/12^{ths} of the 2019 calendar year expense plus 4/12^{ths} of the 2020 calendar year expense.

Q. What is the Other Tax Expense portion of DTE Electric's operating expense?

A. DTE Electric is seeking recovery of Other Tax expense for the projected test period of $52.2 million. Other Tax expense consists of payroll taxes ($40.5 million), Public Utility Assessment fees ($11.6 million), and miscellaneous other taxes ($0.1 million, primarily use taxes) as shown on Exhibit A-13, Schedule C7 on lines 2 through 5 in column (g).

Line
No.

Q. How did you forecast the Other Tax Expense?

A. DTE Electric's O&M forecast is driven primarily by inflation increases. Because payroll taxes generally follow O&M expense, I have forecasted payroll tax by incrementing the historic period actual amounts by DTE Electric's assumed annual inflation rate. Exhibit A-13, Schedule C5.15, which is supported by Witness Uzenski, lists inflation rates for the interim forecast and projected test periods. Public Utility Assessment Fee and other miscellaneous tax expense was held to the 2017 historical amount.

Q. How much total income tax expense is the Company seeking recovery of?

A. DTE Electric is seeking recovery of total income tax expense of $87.4 million. This is comprised of FIT expense of $44.9 million, MCIT and municipal income tax expense of $42.5 million. Total income tax expense is $ 235.9 million less than 2017 income tax expense of $323.3 million driven primarily by the reduction in federal tax rate from 35% to 21% and lower pretax book income.

Q. How was the FIT Expense portion of DTE Electric's operating expense developed?

A. Exhibit A-13, Schedule C8, line 68 shows DTE Electric's FIT expense for the projected test period is $44.9 million. Exhibit A-13, Schedule C8, illustrates that FIT expense is comprised of current FIT expense (line 5) and deferred FIT expense (line 6). Current FIT expense is calculated based on taxable income and credit utilization as shown on lines 8 through 52. Deferred FIT expense is shown on lines 53 thru 60 and is based on book versus tax temporary differences (line 44), annual amortization of several Deferred Debits and Credits (Medicare Part D Subsidy, FAS

109, Investment Tax Credit (ITC), and Tax Reform Regulatory Liability) (lines 54 – 57), the R&D Tax Credit carryforward (line 58) and utilization of tax credits generated in prior years (line 59).

Total FIT expense is adjusted for the Income Tax effect of Interest – Federal from Exhibit A-13, Schedule C14 (line 11) and Interest Synchronization Tax Adj. – Federal from Exhibit A-13, Schedule C15 (line 10). These exhibits are supported by Witness Slater.

Q. How was the MCIT expense portion of DTE Electric's operating expense developed?

A. Line 15 of Exhibit A-13, Schedule C9, shows DTE Electric's MCIT expense for the projected test period is $40.3 million. Exhibit A-13, Schedule C9, illustrates that MCIT expense is comprised of current MCIT and deferred MCIT. Current MCIT is calculated based on federal taxable income with certain state modifications relating to state and local income taxes and depreciation adjustments. Deferred MCIT is based on book versus tax temporary differences and includes the annual amortization of the MCIT Deferred Debit. The amortization of the MCIT Deferred Debit includes the impacts of the Michigan tax law changes of 2008 and 2012 and the re-measurement of MCIT deferred tax balances at December 31, 2018 as described in the accounting request below.

Q. How was the Municipal Income Tax Expense portion of DTE Electric's operating expense developed?

A. Line 11 of Exhibit A-13, Schedule C10, shows DTE Electric's municipal income tax for the projected test period is $2.1 million. Exhibit A-13, Schedule C10, illustrates that municipal income tax expense is comprised of current and deferred. Current municipal income tax is calculated based on federal taxable income with certain modification related to the local income tax adjustment. Deferred municipal income tax is based on book versus tax temporary differences and the annual amortization of the City of Detroit Deferred Debit that arose from the City of Detroit tax law change of 2012.

Q. What is the additional State & Local Tax on Exhibit A-13, Schedule C9, Lines 19 and 20?

A. Additional state and local tax expense of $0.07 million is included on Exhibit A-13, Schedule C9, Lines 19 and 20. This is for the Income Tax effect of Interest – State and Municipal from Exhibit A-13, Schedule C14 (line 8) and Interest Synchronization Tax Adj. – State and Municipal from Exhibit A-13, Schedule C15 (line 7). These exhibits are supported by Witness Slater.

Q. How does the 2017 Tax Cuts and Job Act affect DTE Electric's General Rate Case?

A. The 2017 Tax Cuts and Job Act (TCJA) enacted by Congress on December 22, 2017 reduced the federal corporate income tax rate from 35% to 21% effective January 1, 2018. Therefore, projected federal income tax for the test period on Exhibit A-13, Schedule C8 reflects the new rate of 21%.

In addition to the federal corporate tax rate reduction, the TCJA also eliminated bonus depreciation for utilities effective with respect to property acquired after

September 27, 2017. There is an exception for grandfathered property, which remains eligible for bonus depreciation under prior law. Grandfathered property includes (1) Property acquired prior to September 28, 2017, pursuant to a written binding contract, or (2) Self-constructed property for which the start of construction commenced prior to September 28, 2017.

Lastly, as discussed in the Company's response to the Commission Order in Case No. U-18494, book accounting under ASC 740 requires that the impacts of a tax law change be recorded in the period of enactment. Therefore, DTE Electric's deferred taxes were re-measured as of December 31, 2017 to reflect the reduction in the federal corporate income tax rate.

Q. How does the re-measurement of deferred taxes from the TCJA affect DTE Electric's General Rate Case?

A. The re-measurement of deferred taxes from the TCJA resulted in a one-time reduction to deferred income taxes of $1.4 billion in DTE Electric's total deferred tax liability. Of this total, $0.1 billion is related to non-base rate surcharges (Renewable Energy Plan, Energy Waste Reduction and TRM), leaving $1.3 billion to be reflected in this rate case.

In accordance with the Commission Order in Case No. U-18494 dated December 27, 2017, the reduction in the deferred tax liability was offset by a new regulatory liability of $1.3 billion, which is shown on Exhibit A-13, Schedule C8.1, line 6, column (e).

Line No.

The re-measurement of deferred taxes and new regulatory liability are estimates that are subject to change upon completion of the 2017 Federal income tax return in September 2018.

The new regulatory liability represents the excess deferred income taxes that will flow back to customers per the Commission Order in Case No. U-18494 dated February 22, 2018. The Company is proposing in this rate case how that will be returned to customers through amortization of the tax regulatory liability starting on May 1, 2019. Amortization for the test period May 1, 2019 through April 30, 2020 reduces tax expense by $54.9 million as reflected in Exhibit A-13, Schedule C8, line 57.

Q. How was the amortization of the new tax regulatory liability calculated?

A. The new tax regulatory liability is made up of three components that determine how amortization is calculated. These components are referred to as Protected Plant, Unprotected Plant, and Non-Plant and are based on the underlying cumulative timing differences that gave rise to the excess deferred taxes.

The Protected Plant component represents the excess deferred taxes related to the cumulative difference between accelerated tax depreciation and book depreciation. Tax depreciation is calculated by utilizing the Modified Accelerated Cost Recovery System (MACRS), including bonus depreciation when applicable. Both bonus and MACRS result in a faster depreciation of the investment as compared to book depreciation. The normalization requirements in the TCJA require the use of the Average Rate Assumption Method (ARAM) to feedback to customers the excess deferred taxes related to accelerated depreciation. Under the ARAM method, excess deferred taxes pertaining to a particular vintage or vintage account are flowed through to customers as the timing differences in the particular vintage account reverse (i.e. as book depreciation in the particular vintage account exceeds tax depreciation). Amortization of the Protected Plant component of the new tax regulatory liability follows the ARAM methodology, which is based on the forecasted reversal of the depreciation timing differences as shown on Exhibit A-13, Schedule C8.1, column (b).

The Unprotected Plant component represents the excess deferred taxes related to certain capital expenditures that are deducted when incurred for tax purposes but must be capitalized and depreciated as fixed assets for book purposes. For example, certain capital expenditures that must be capitalized and depreciated for book purposes qualify as deductible repairs for tax purposes when incurred. Amortization of the Unprotected Plant component of the new tax regulatory liability is calculated on a straight-line basis over 23 years as shown on Exhibit A-13, Schedule C8.1, column (c). Twenty-three years represents the remaining book life of DTE Electric's utility assets based on the study in Case No. U-18111.

The Non-Plant component represents the excess deferred taxes for all non-plant cumulative timing differences. Amortization of the Non-Plant component is calculated on a straight-line basis over 14 years as shown on Exhibit A-13, Schedule C8.1, column (d). There are many cumulative timing differences that comprise the Non-Plant component. Fourteen years is the average life of the largest cumulative timing differences making up most of the total.

Line No.

ACCOUNTING REQUESTS

Q. Do you have any accounting requests?

A. Yes, I have an accounting request regarding the re-measurement of the MCIT deferred tax liability.

Q. Why is DTE Electric's MCIT deferred tax liability being re-measured?

A. DTE Electric's MCIT deferred tax liability is being re-measured to reflect a change in DTE Electric's MCIT rate. DTE Electric's MCIT rate was previously 5.82%, representing the statutory rate of 6% multiplied by an apportionment rate of 97%. Apportionment represents the allocation of a company's income to a state. DTE Electric is increasing the MCIT rate to 5.88%, representing the statutory rate of 6% multiplied by the expected apportionment rate of 98%. DTE Electric's apportionment rate has been increasing in recent years and is expected to continue at 98% into the future. ASC 740 requires deferred taxes to be valued using the tax rate that is expected to apply when the cumulative timing differences giving rise to the deferred taxes will reverse. The increase from 5.82% to 5.88% results in an increase in the MCIT deferred tax liability of $5.9 million.

Q. What are you requesting the Commission to approve?

A. The Company is requesting that the Commission approve full normalization ratemaking for the re-measurement of MCIT deferred taxes over a period reasonably related to the reversal of the underlying cumulative timing differences consistent with Commission's policy and prior orders. The increase in the deferred tax liability of $5.9 million will be offset by a corresponding increase in a regulatory asset of $5.9 million. This regulatory asset will be amortized over 23

Line No.

years, representing the remaining book life of DTE Electric's utility assets based on the study in case No. U-18111.

Q. What is the impact of this re-measurement on state deferred tax expense in this rate case?

A. An additional $0.3 million of MCIT deferred tax expense is being included on the amortization of MCIT Miscellaneous Deferred Debit line 12 of Exhibit A-13, Schedule C9.

Q. Does this complete your direct testimony?

A. Yes, it does.

DIRECT TESTIMONY OF JOAN KOWAL

on behalf of

EMORY UNIVERSITY

Docket No. 42310

Exhibit 3

Distributed Energy Resources Program

Technology Overview

Distributed energy resources (DER) consist of energy generation and storage systems placed at or near the point of use. This provides the consumer with greater reliability, adequate power quality, and the possibility to participate in competitive electric power markets. DER also has the potential to mitigate transmission congestion, control price fluctuations, strengthen security, and provide greater stability to the grid. DER can lead to lower emissions and, particularly in combined heat and power (CHP) applications, to improved efficiency.

Distributed energy encompasses a range of technologies including fuel cells, microturbines, reciprocating engines, and energy storage systems. Renewable energy technologies—such as solar electricity, solar buildings, small-scale hydropower, biopower, and wind turbines—also play an important role. DER also involves power electronic interfaces, as well as communications and control devices for efficient dispatch and operation of single units, multiple system packages, and aggregated blocks of power.

The primary fuel for many distributed generation systems is natural gas, but hydrogen may well play a role in the future.

Energy storage technologies are essential for meeting the levels of power quality and reliability required by high-tech industries. Storage can provide emergency power and peak-shaving benefits. Energy storage gives other DER devices more load-following capability, and also supports renewable technologies such as wind and solar electricity by making them dispatchable.

End-use technologies include demand management techniques for reducing peak power requirements and using electrical load as a resource. CHP systems can provide electricity as well as heating, cooling, and humidity control, while achieving efficiencies as high as 70%. Advanced techniques such as absorption cooling and desiccant devices also benefit the end user.

U.S. Department of Energy Program

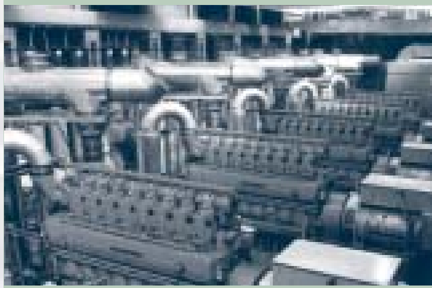
The mission of the U.S. Department of Energy (DOE) Distributed Energy Resources Program is to lead a national effort to develop the next generation of clean, efficient, reliable, and affordable distributed energy technologies and to support the transmission and distribution system.

The Program is establishing partnerships with manufacturers, energy service providers, and project developers. The DER Program also works with state and federal agencies, public interest groups and consumers. Research and development efforts are cost shared and involve the following main areas:

- Technology development—developing a portfolio of technologies for advanced on-site, small-scale, and modular energy generation, storage, and delivery systems. These may be deployed in industrial, commercial, or residential applications. The scope includes advanced turbines and microturbines, reciprocating engines, fuel cells, thermally activated technologies, and energy storage devices. The program also addresses crosscutting technologies such as advanced materials, power electronics, hybrid systems, and communication and control systems.

- End-use systems and integration—integrating distributed energy systems into customer facilities, as well as into electricity and natural gas distribution systems. Packaged, integrated systems promote reliability and allow effective demand-management techniques. Regulatory and institutional barriers to the expanded use of distributed energy systems are addressed through education, analysis, and outreach. The Program has taken the lead in developing national interconnection standards for integrating DER into the electricity grid.

Microturbine



Reciprocating Engine

Fuel Cell

Energy Storage Unit

Triple Effect Chiller

Distributed Energy Resources Program

Transmission Reliability

The Transmission Reliability (TR) Program is partnering with the electric power industry to develop advanced technologies to enhance the reliability of the power system, while enabling efficient, competitive electricity markets that integrate DER.

The TR program consists of three research and development areas.

1. Reliability-analysis tools that assist transmission system operators to manage real-time grid operations in a reliable and efficient manner. Tools under development include visualization systems that display deviations and corrections for the following parameters:

- Transmission voltages
- System frequency
- Power flow between regions
- Generator reliability performance

2. Wide Area Measurement Systems (WAMS) collect satellite-synchronized data to control the grid reliably while operating the grid closer to its capacity limits.

3. "Load as a resource" allows load to be controlled to lower the customer's energy costs, and to reduce load in system emergencies.

Market Potential

Market forces are beginning to demand small, modular energy generation and storage systems that can provide backup power during outages, hedge against energy price spikes, eliminate power quality problems, mitigate future emissions costs, and contribute to grid stability. The result is a growing market demand for smaller scale, fuel-flexible energy systems that can be deployed close to the point of use.

Estimates from a recent Electric Power Research Institute study show that losses to the U.S. due to outages amount to about $119 billion per year. An appreciable percentage of such losses could be eliminated by distributed generation and energy storage. The potential market for providing power during peak price periods is as high as 460 GW, according to a recent DOE study.

The digital economy—including telecommunication companies, internet service providers, and high-tech manufacturing facilities— faces massive financial losses from power outages and disruptions that may last only seconds. Reliability is paramount for such facilities. Distributed energy resources can provide ultrareliable power, free from voltage sags and harmonic distortions. It is expected that high-tech facilities will become a primary market for distributed generation and storage. A broad array of less digitally oriented businesses also relies on continuous power, including food retailers and hospitals.

Potential markets for distributed resources are varied, extensive, and still expanding. The Program expects that 20% of all new generation will be distributed generation by 2010.

Summary of Potential Benefits

Distributed energy resources offer advantages to the nation's energy system that large-scale, capital-intensive, central-station power plants cannot provide. By siting smaller, more fuel-flexible systems near the consumer, distributed resources avoid transmission and distribution power losses, and provide a wider choice of energy systems to the customer. Distributed energy systems offer reliability for U.S. businesses and consumers who need dependable power to run sensitive digital equipment, and can provide alternative, less-expensive power sources during peak price periods. They increase productivity by utilizing waste heat created during power generation for additional heating, cooling, and humidity control in buildings. By shifting peak loads, distributed systems offer demand relief for the already strained electric power system, and reduce transmission congestion. Distributed resources also play a crucial role in maintaining national security.

For More Information:

Distributed Energy Resources Program
www.eren.doe.gov/der

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DIRECT TESTIMONY OF JOAN KOWAL

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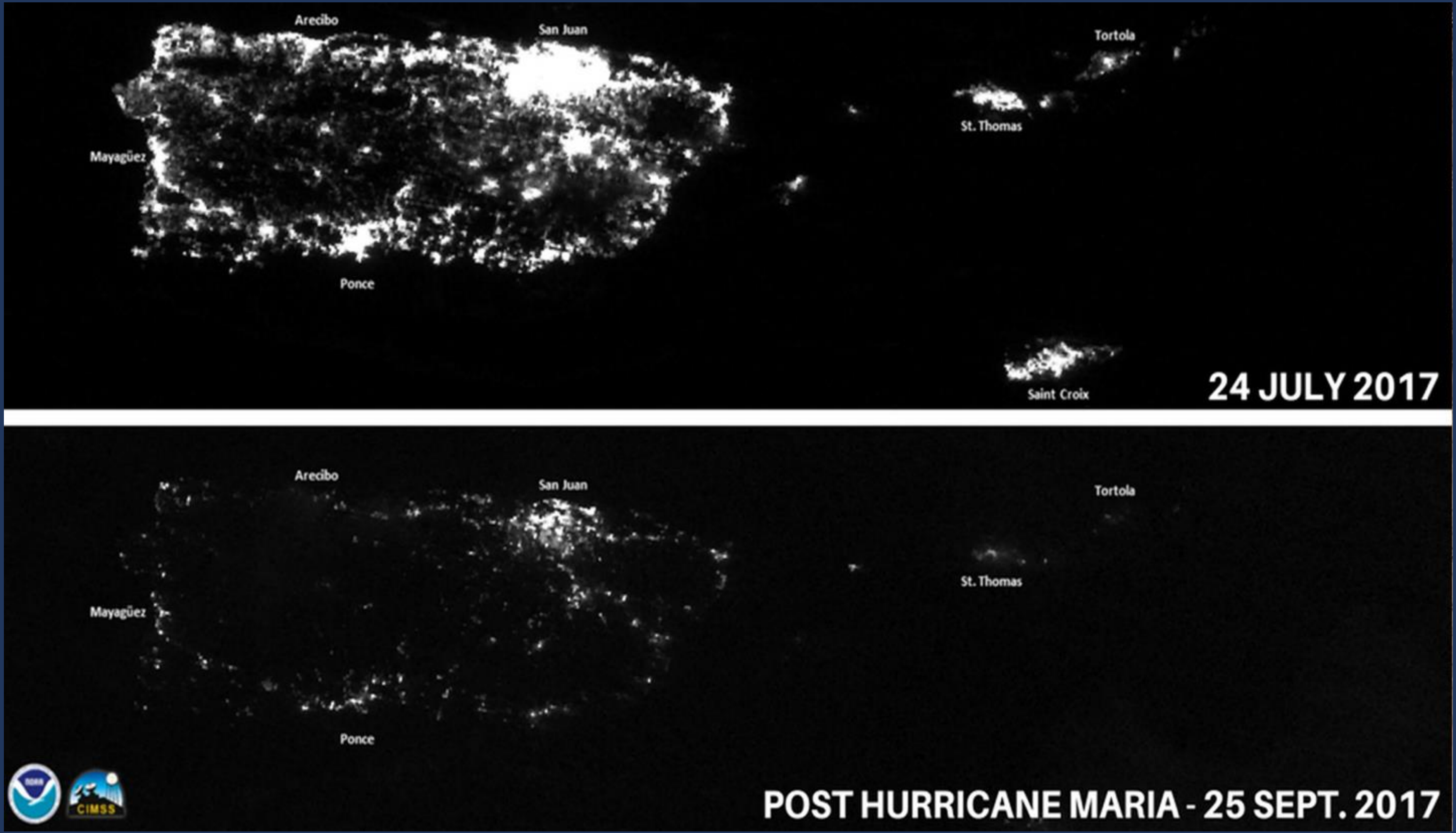
EMORY UNIVERSITY

Docket No. 42310

Exhibit 4

Powered Together
Tapping the Water–Energy Nexus
130th NARUC Annual Meeting and Education Conference

Microgrids Policy: Forbidden Journey, Wizarding World, or Islands of Adventure?

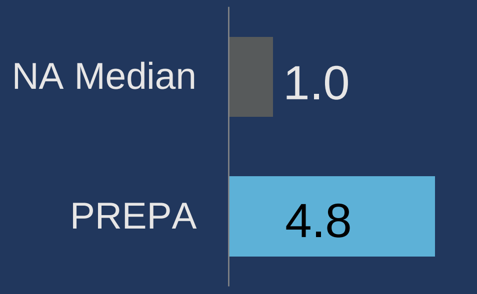


Arecibo
San Juan
Tortola
St. Thomas
Mayagüez
Ponce
Saint Croix
24 JULY 2017
Arecibo
San Juan
Tortola
St. Thomas
Mayagüez
Ponce
CIMSS
POST HURRICANE MARIA - 25 SEPT. 2017

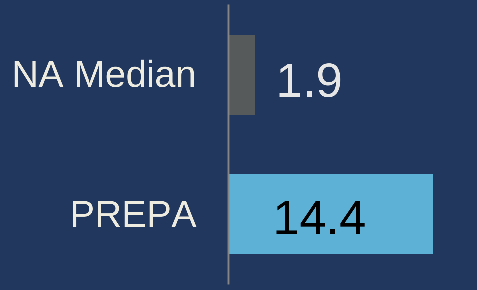
The Puerto Rican power system was struggling before the storms

Poor reliability

SAIFI, FY17

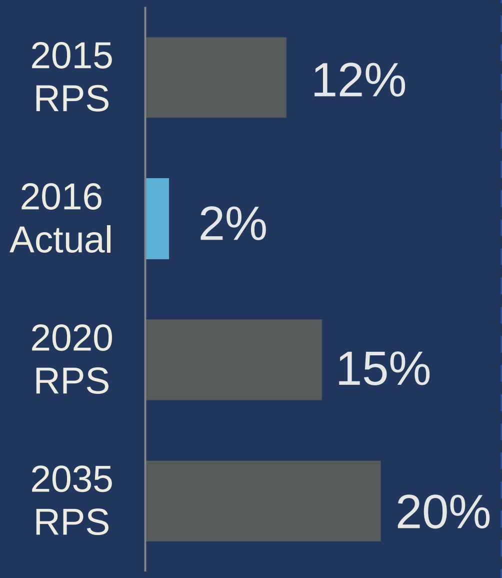


SAIDI, FY17



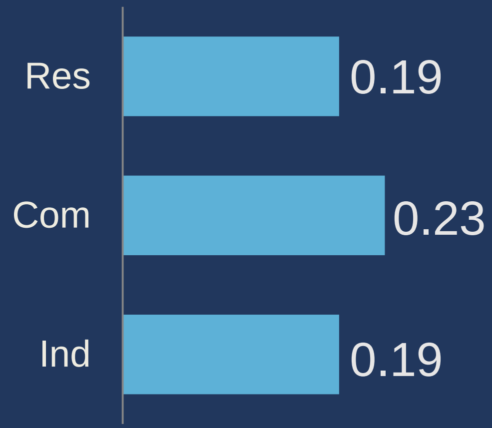
Minimal renewables

RE generation (%)



Expensive energy

Average rates ($ / kWh)



Debt burden

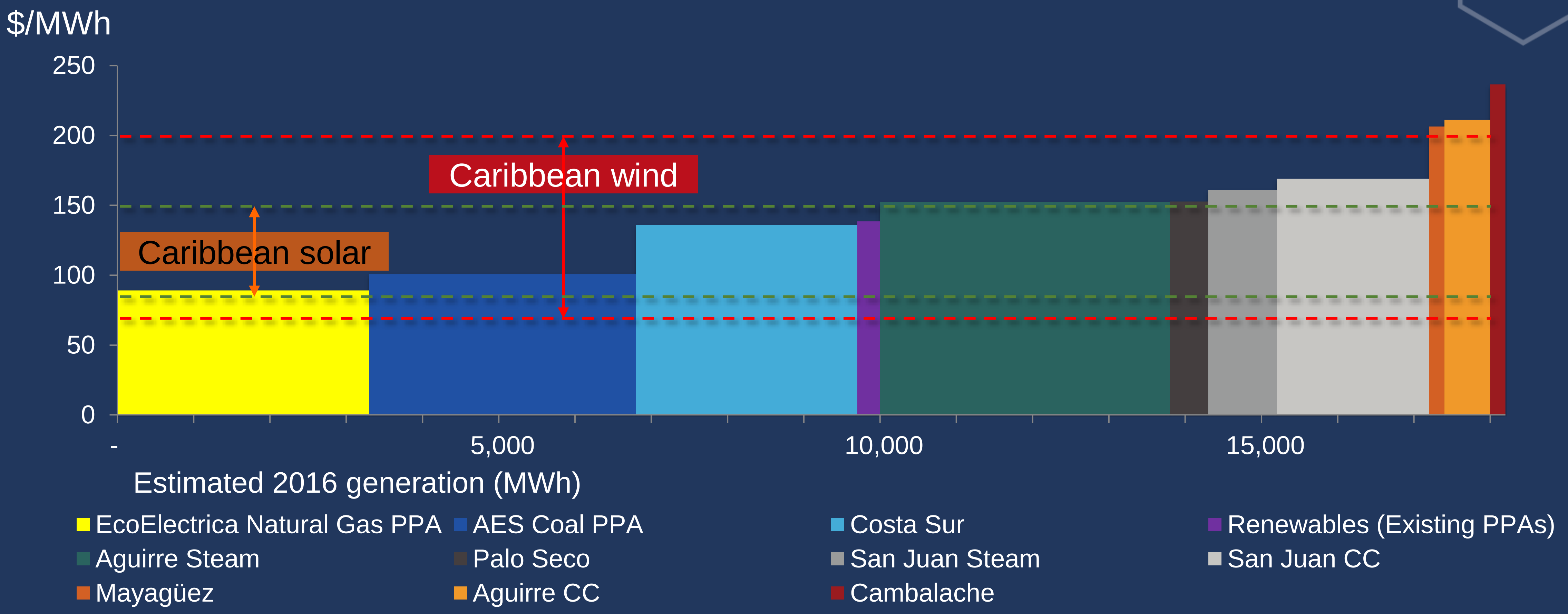
$11.4 B

Total PREPA liabilities

Source: PREPA Fiscal Plan, January 2018; EIA

Renewable energy is cost-effective for Puerto Rico

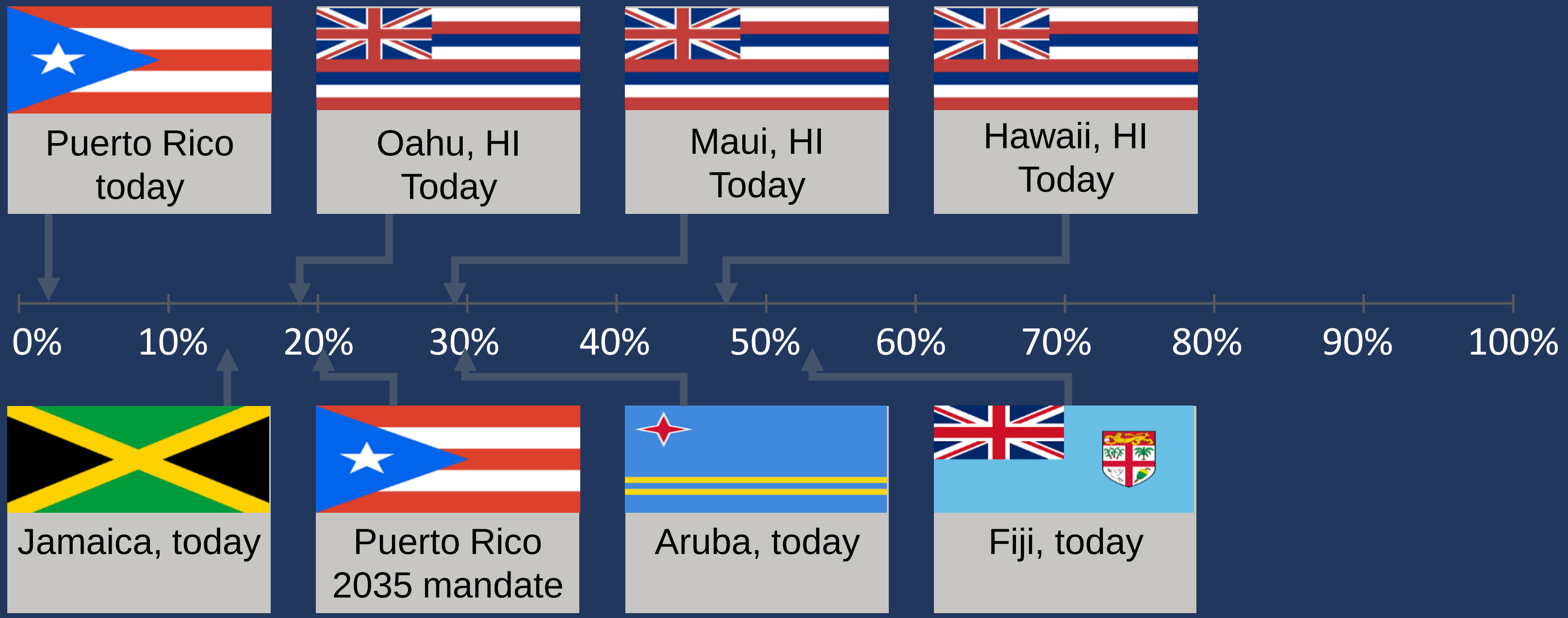
Operating cost of existing power generation in Puerto Rico, $/MWh



Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

Island systems are already operating at much higher renewable penetrations than Puerto Rico

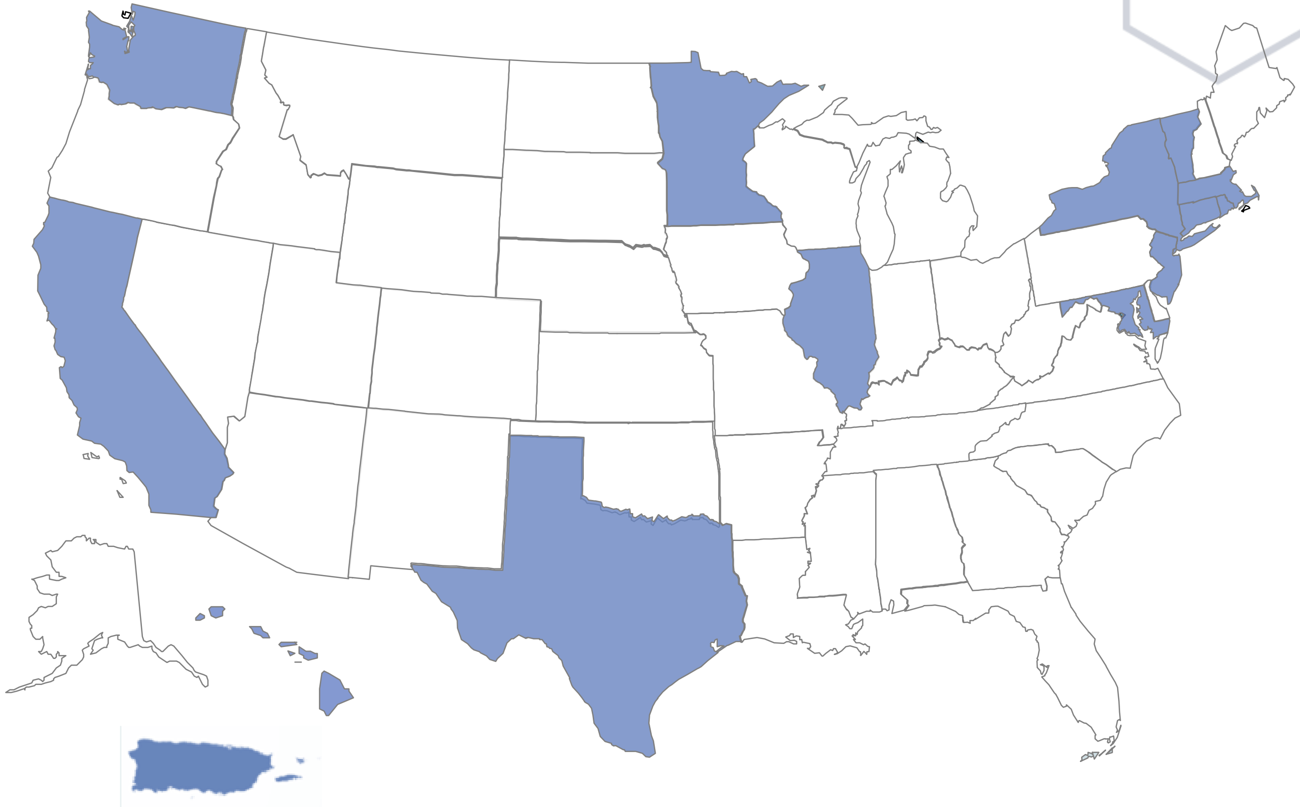
Current and potential renewable energy penetration rates without loss to reliability



Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

Motivations for microgrids vary by region, customer, and utility

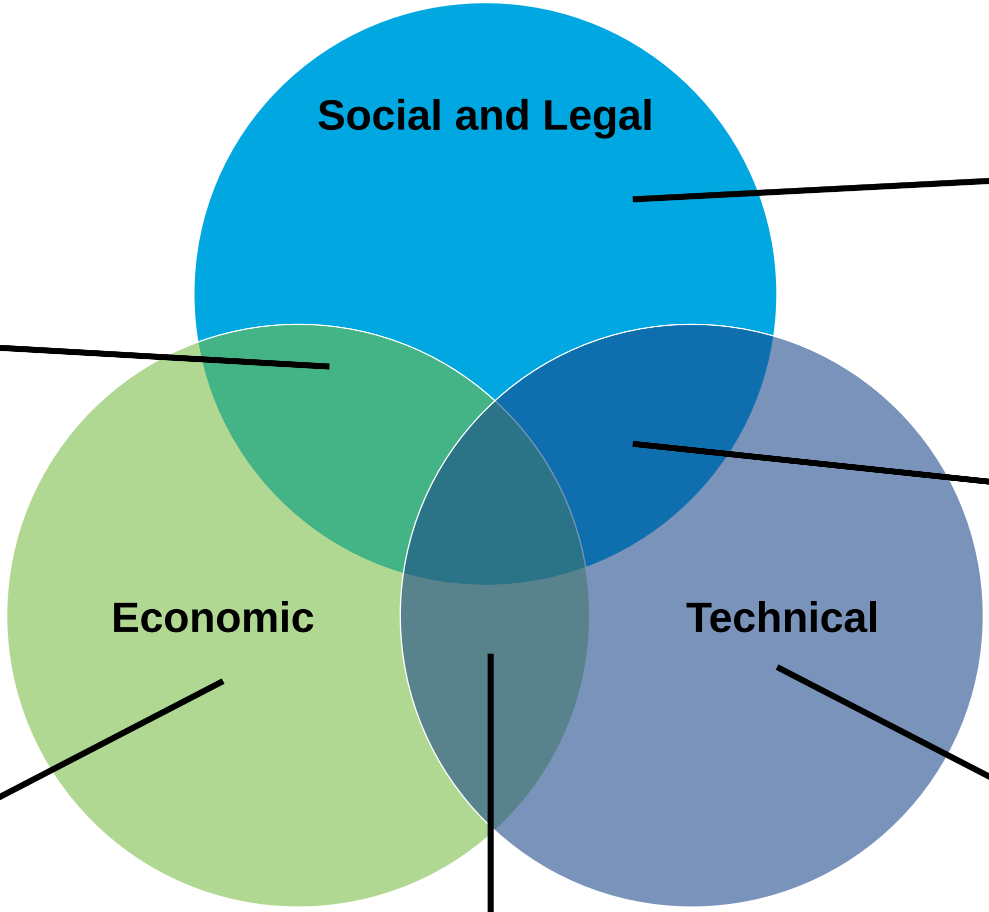
- Establish island-able shelters and critical loads during emergencies
- Reduce costs
- Integrate more DERs
- Provide grid services
- Catalyze experimentation and learning
- Economic development
- Respond to community and customer needs
- Decentralization
- Security
- Erosion of “natural” utility monopoly



States with microgrid policies or programs

Source: Converge Strategies, NREL / MassCEC (2018)

The ‘answers’ are not easy or obvious



- Regulatory Policies
- Utility Franchise laws
- Lack of understanding and education
- Skills of Owner/Operators
- Underdeveloped work force
- Institutional Bureaucracy

- Inconsistent and unclear policies for markets and market participation
- Limited ownership models
- Contractual uncertainty and lack of flexibility

- Inconsistent and unclear Interconnection Policies and Procedures

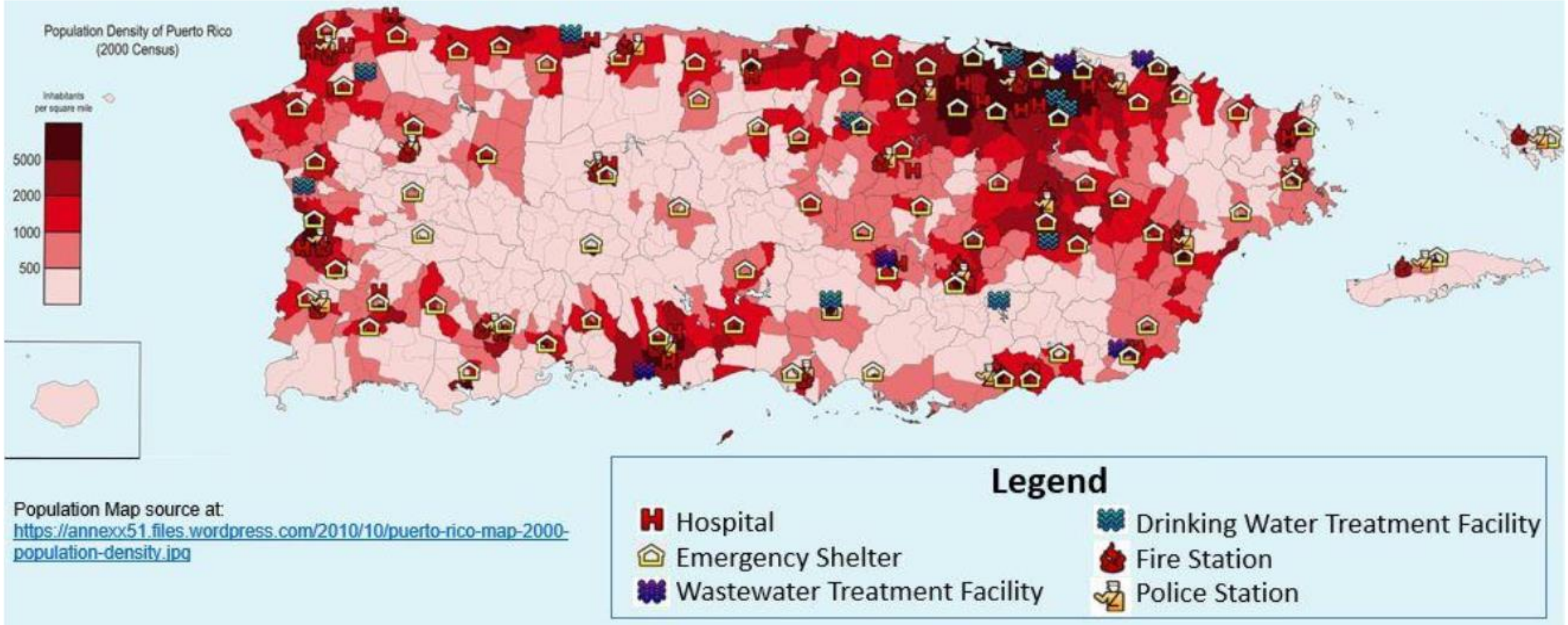
- Inconsistent and unproven costs and benefits
- Lack of Financing
- Small inventory of existing and proven project creates risk and uncertainty for investors

- Variability of renewables
- Evolving control capabilities
- Lack of visibility and forecasting for system operations
- Reliability
- Leveraging diversity of resources

- Lack of interoperability standards and specifications

Microgrids can cost-effectively improve resilience

Hypothetical islanding of critical infrastructure (NYPA)



Costs may be less than storm-hardening remote communities and carry additional benefits:

- Minimized lost economic activity during outage
- Minimized land use and transmission requirements for central generation
- Deferred or reduced need for new plants
- Reduced dependence on imported fossil fuels

What’s next?

Navigating partnerships and roles	Translating value into $	Distinguish the “what” from the “why
• Have you talked to the utility? • 3rd Parties – who’s going to build this thing anyway? • Do customers actually want it? If so, what do they want?	• Energy efficiency first • Putting a price tag on resilience, power quality, insurance, etc. • What’s in the public good? Private good? What does that imply for cost allocation?	• Expanding our thinking from microgrid pilots to microgrids at scale • Do you really need a microgrid? • Focus on services and value, not technologies

Microgrids Policy: Forbidden Journey, Wizarding World, or Islands of Adventure?

Please complete the session survey in the meeting app

Session A4

Look under the "polls" button

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on behalf of

EMORY UNIVERSITY

Docket No. 42310

Exhibit 5

The New Frontiers in System Planning

Today's Speakers

- **Hon. Jeff Ackermann, Colorado**
- **Natalie Mims Frick, Lawrence Berkeley National Lab**
- **Hon. Nancy Lange, Minnesota**
- **Hon. Andrew McAllister, California Energy Commission**

The New Frontiers in System Planning

Hon. Jeff Ackermann

Colorado

NARUC – NASEO Task Force on Comprehensive Electricity Planning

NARUC
National Association of Regulatory Utility Commissioners

NASEO
National Association of State Energy Officials

Task Force Co-Chairs

Hon. Jeff Ackermann
Chairman
Colorado Utilities Commission

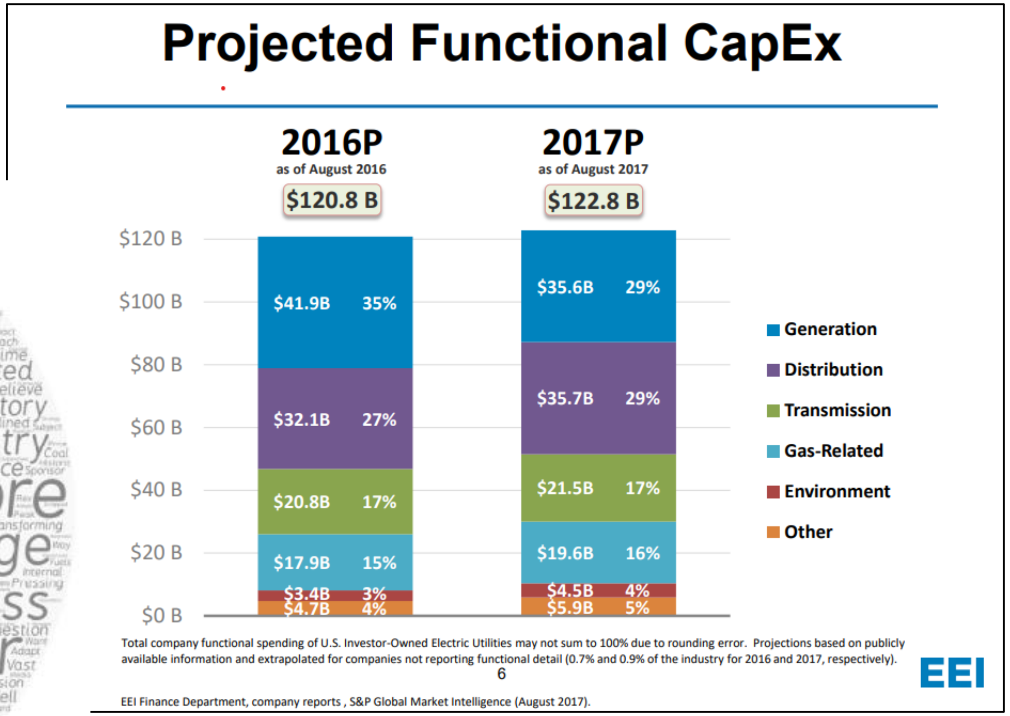
Dr. Laura Nelson
Director
Utah Office of Energy Development

Task Force Co-Vice-Chairs

Hon. Beth Trombold
Commissioner
Public Utilities Commission of Ohio

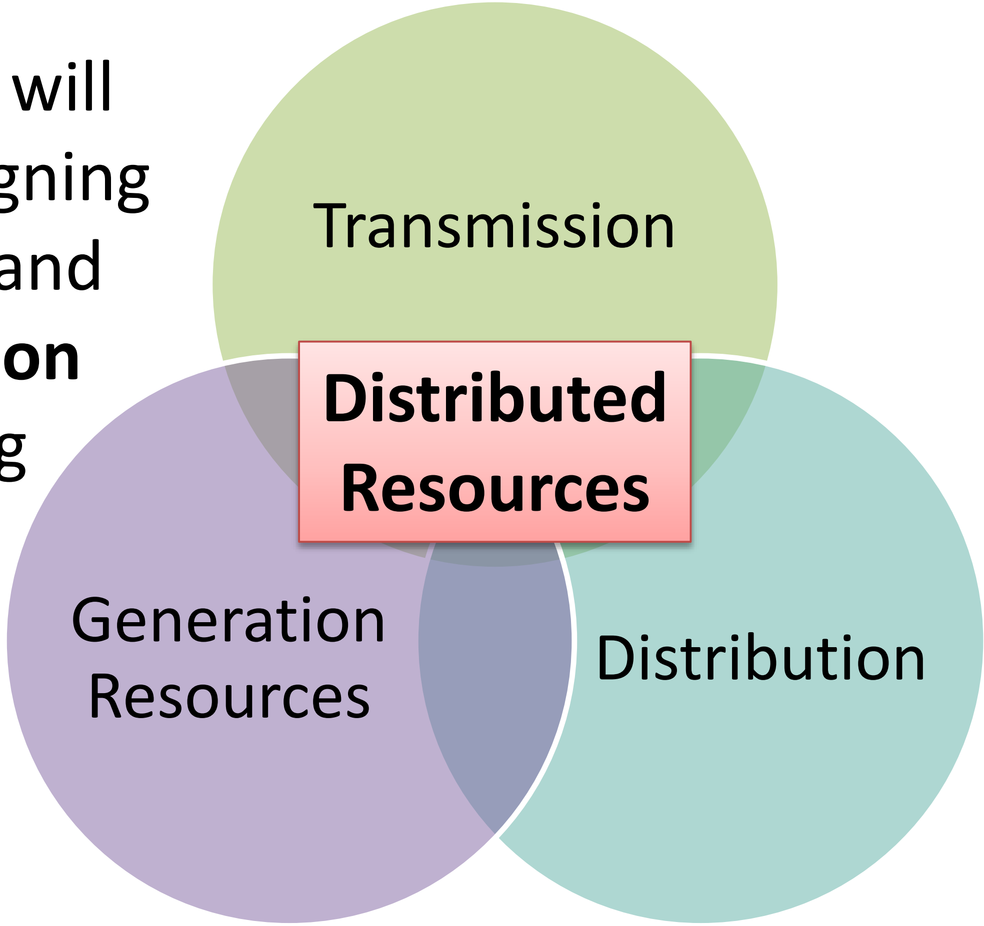
Dr. Andrew McAllister
Commissioner
California Energy Commission

What's Happening in the Electricity System Right Now?



Electricity Planning and Investment Decisions are Inter-Related

Task Force will focus on aligning **Resource** and **Distribution** planning



With greater alignment of electricity planning processes, states & utilities could:

- Improve reliability and resilience
- Optimize use of distributed and existing resources
- Avoid unnecessary costs
- Support state priorities
- Increase transparency of investment decisions

NARUC-NASEO Task Force

Purpose: Develop new pathways for aligned electricity planning

- **4 workshops over 2 years (start spring 2019)**
  - **Two member-only workshops**
  - **Two member-stakeholder workshops**
- **12 to 15 states**
  - **Commission and state energy office from each state working together**
  - **Participants TBA February 2019**

Targeted Outcomes

1. **Innovation**: Pioneer new tools and roadmaps for aligning planning to meet your state's needs
2. **Action**: Apply learnings to directly benefit your state
3. **Replication**: NARUC and NASEO publish templates to support all members

Participants will be supported by each other, technical experts, and facilitators

The New Frontiers in System Planning

Natalie Mims Frick

Berkeley Lab

BERKELEY LAB

LAWRENCE BERKELEY NATIONAL LABORATORY

U.S. DEPARTMENT OF ENERGY

The New Frontiers in System Planning

Presented by Natalie Mims Frick
Authors: Lisa Schwartz and Natalie Mims Frick

National Association of Regulatory Utility Commissioners
Annual Meeting – Nov. 14, 2018

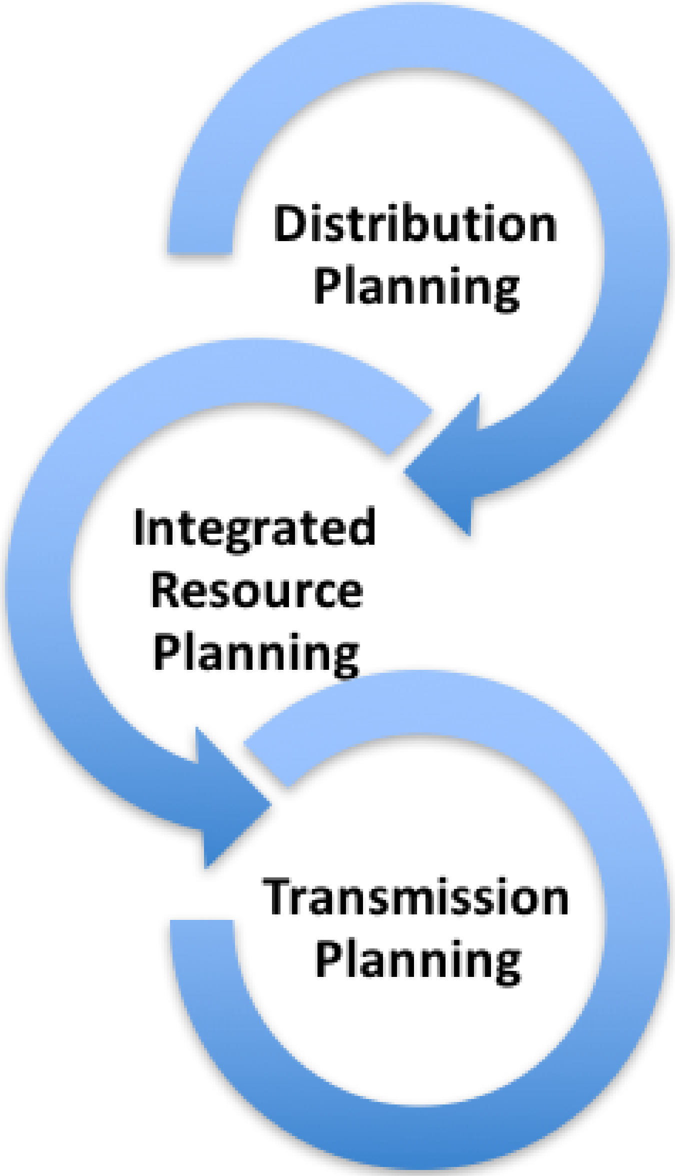
This presentation was supported by the U.S. Department of Energy's Office of Electricity, Transmission Permitting and Technical Assistance, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231

In this this presentation

- Electric grid planning activities
- Distribution system planning and integration with other processes
- Integrated resource planning
- Alignment across planning processes: opportunities and challenges
- Resources for more information

Electric grid planning activities (1)

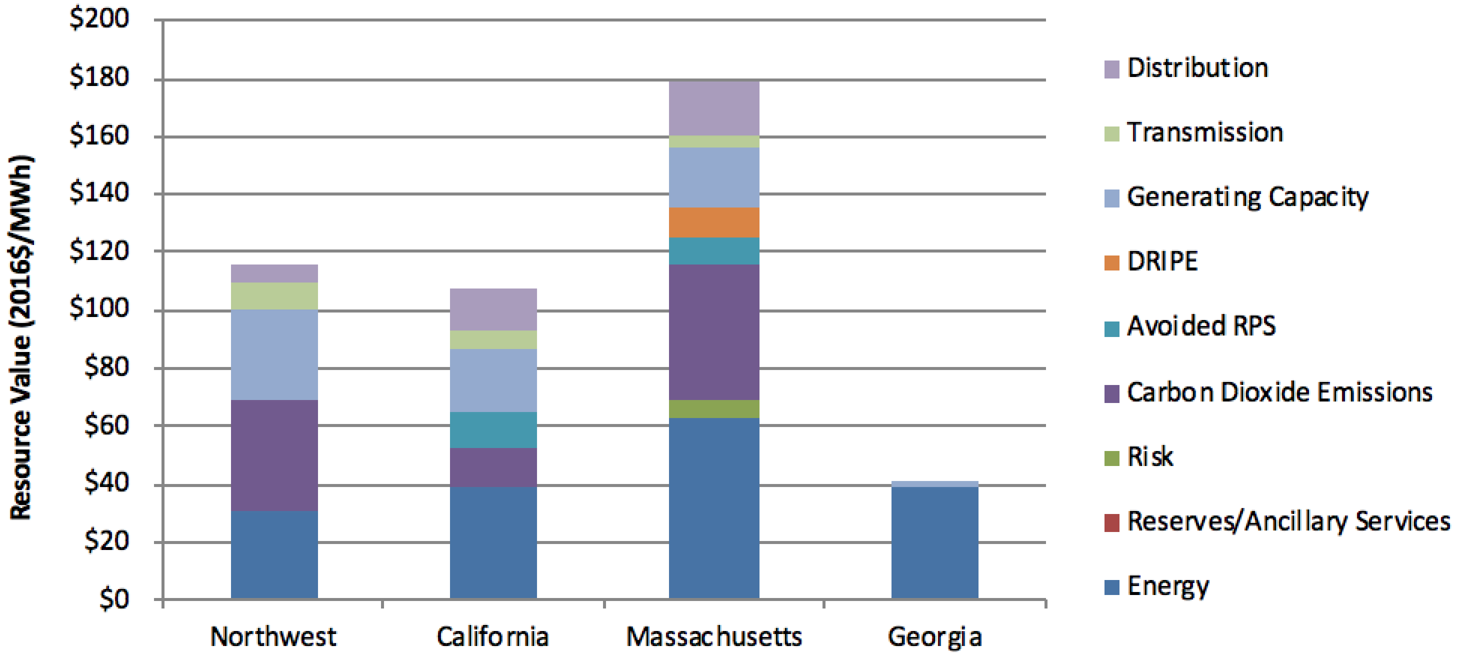
- ***Distribution planning***
  - Assess needed physical and operational changes to local grid
- ***Integrated resource planning*** (in vertically integrated states)
  - Identify future investments to meet bulk power system reliability and public policy objectives at reasonable cost
- ***Transmission planning***
  - Identify future transmission expansion needs and options for meeting those needs.



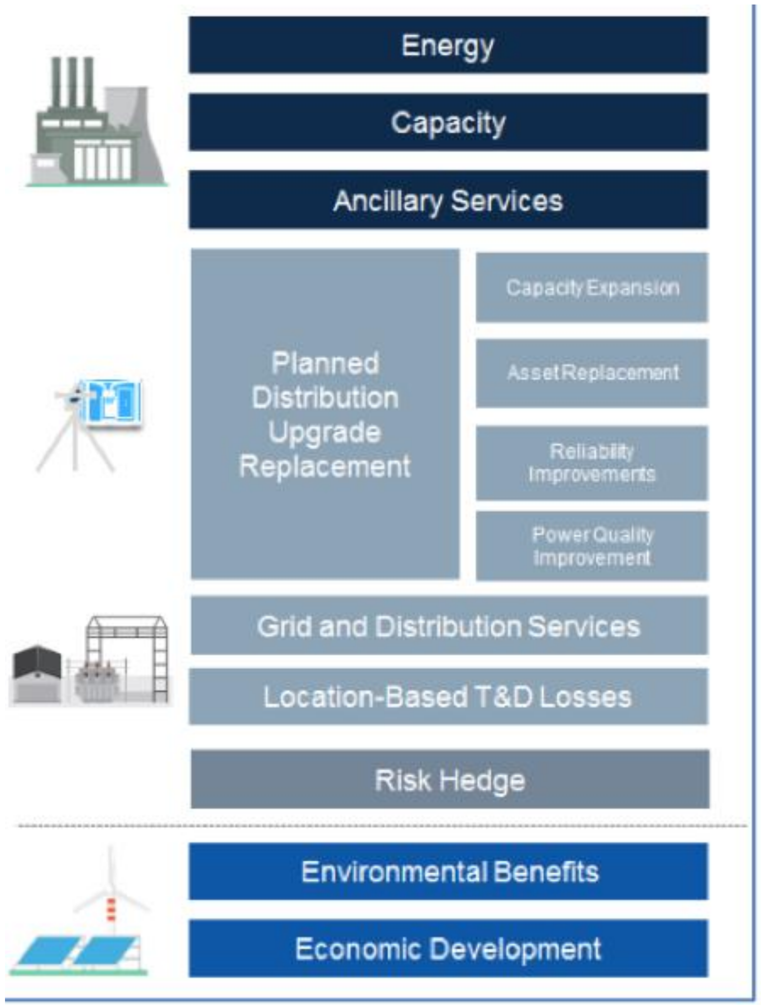
Electric grid planning activities (2)

- *Demand-side management (DSM) planning*
  - Identify opportunities to use energy efficiency and demand response to meet future energy and capacity needs

Time-varying value of efficiency



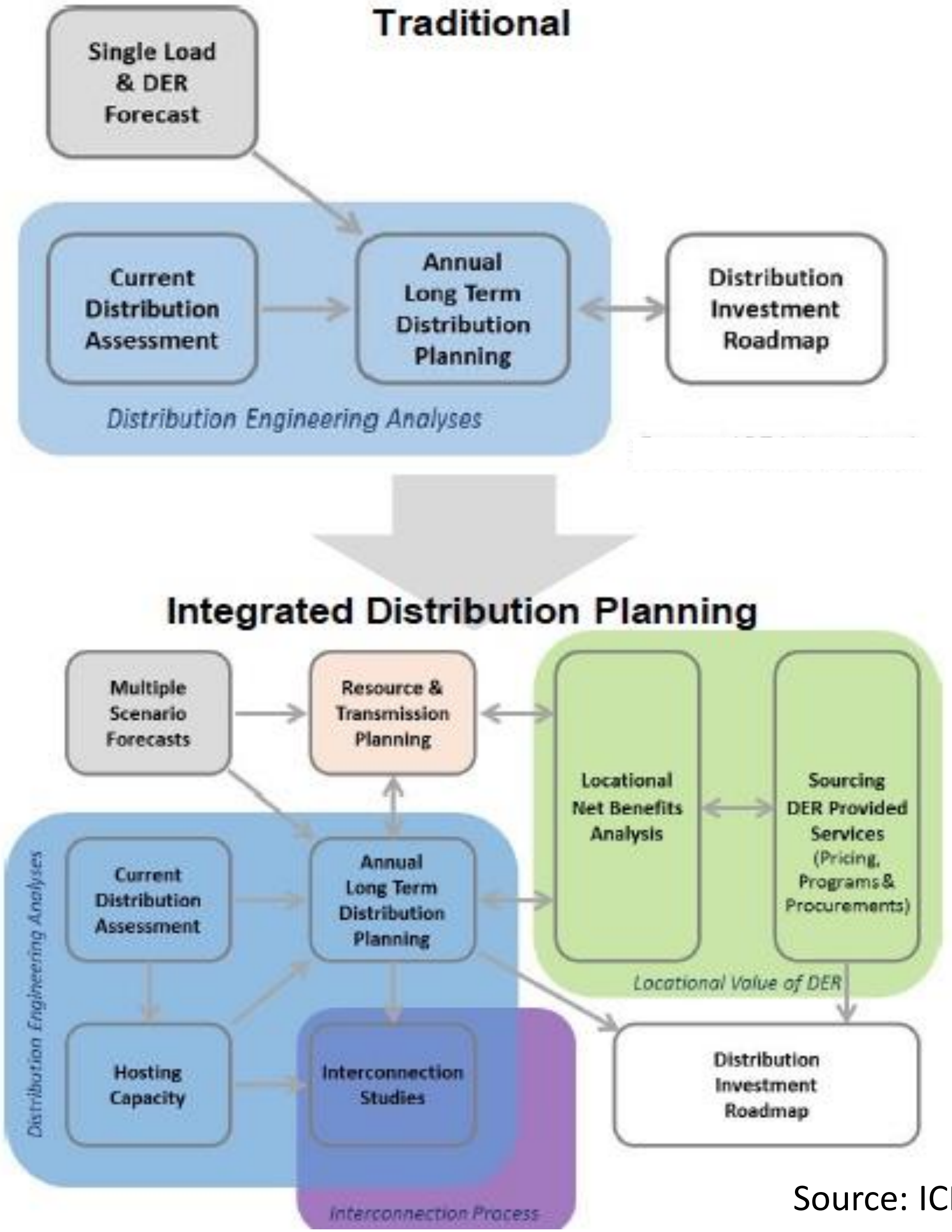
Locational value of efficiency



Integrated distribution planning

- Assesses **physical** and **operational** changes to the distribution system necessary to enable safe, reliable, and affordable service ***that satisfies customers' changing expectations and use of DERs, generally in coordination with resource and transmission planning***

- **Includes stakeholder-informed planning scenarios to support a reliable, efficient, and robust grid in a changing and uncertain future**



Source: ICF (2016)

Energy and grid-related services provided by DERs

Impact	DER Capability/Service	Key Function
Bulk Level Impact	Energy Production/Load Reduction	Produce electricity
	Generation Capacity	Meet extreme peak
	Frequency Regulation/Load Following/Balancing	Respond rapidly to balance supply and demand
	Spinning Reserve/Non-spinning Reserve	Reliability – provide ability to respond to unforeseen forces outages and/or changes in loads
Locational Impact	Locational Capacity for T&D	Provide or defer need for additional T&D peaking capacity
	Voltage Regulation	Maintain power quality/reduce losses

Adapted by Tom Eckman for Berkeley Lab from Smart Electric Power Alliance. *Beyond the Meter – Addressing the Locational Valuation Challenge for Distributed Energy Resources, Establishing a Common Metric for Locational Value*. September 2016.

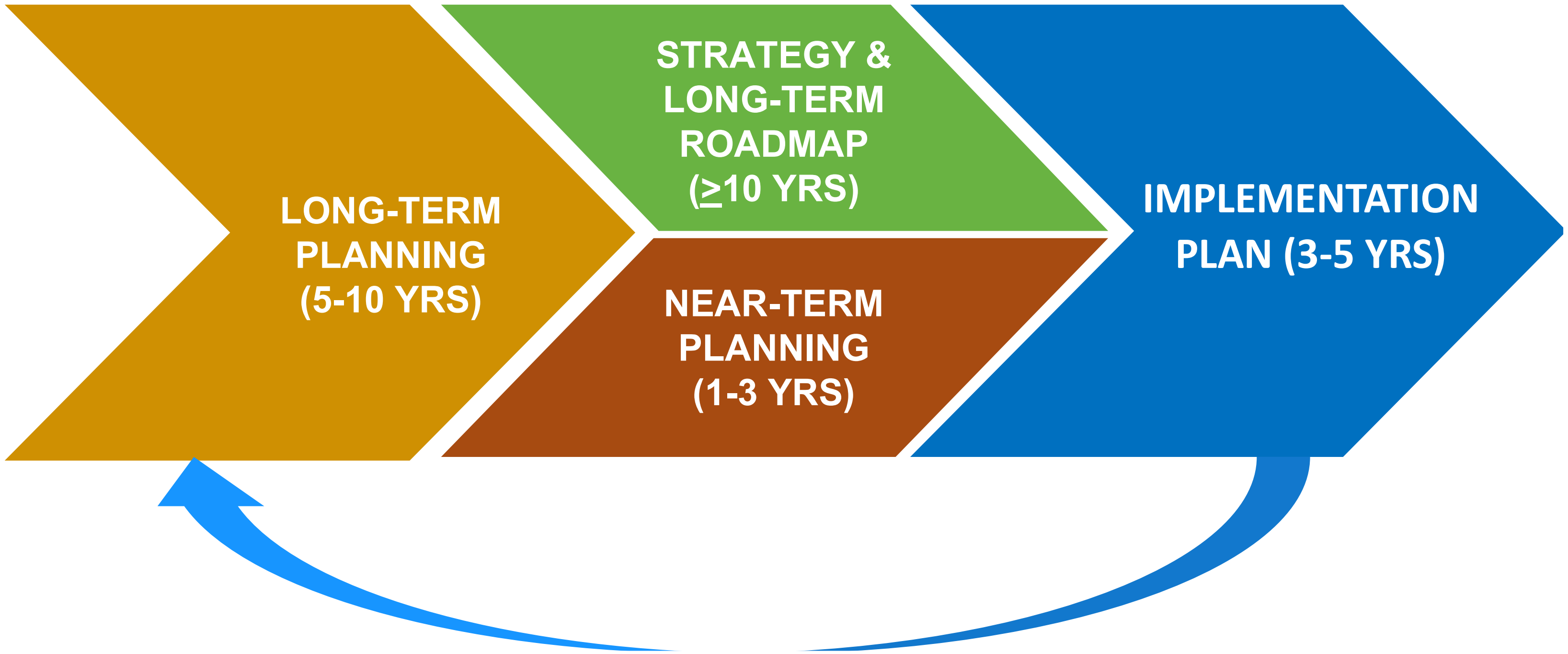
Foundational Elements of Distribution System Planning With DERs

Enabling Capabilities and Components	Analysis Areas
• Validated and calibrated feeder models • Data and grid state • Time-series power flow analysis (TSPFA)	• **Multiple scenario forecasts of load and DER projections** • **Hosting capacity analysis** • **DER interconnection studies** • **Cost-benefit analysis** • **Non-wires alternatives** • **Locational value analysis** • **Optimization of DER type, location and sizing**
Specific Components or System Modeling Considerations	**Advanced Capabilities**
• Smart inverters • Energy storage • Demand response • Transactive energy • Microgrids • Grid edge control	• Cloud computing • Advanced distribution management systems • Distributed energy resources management systems • Fast TSPFA • Convergence of planning and operations • Transmission and distribution co-simulation
Architecture, Communication Systems, Cybersecurity	**Process and Coordination**
• Architecture • Communication systems • Cybersecurity	• Coordination framework • Connecting physical system analysis to financial models • Prioritizing analyses

Homer et al., *Electric Distribution System Planning with DER and Grid Modernization - Tools and Methods* (forthcoming)

Integrated planning informs grid modernization strategy

Cyclical integrated distribution planning informs initial grid modernization strategy and updates.



Grid modernization strategy and implementation plans inform subsequent long-term and near-term integrated distribution planning.

Source: USDOE

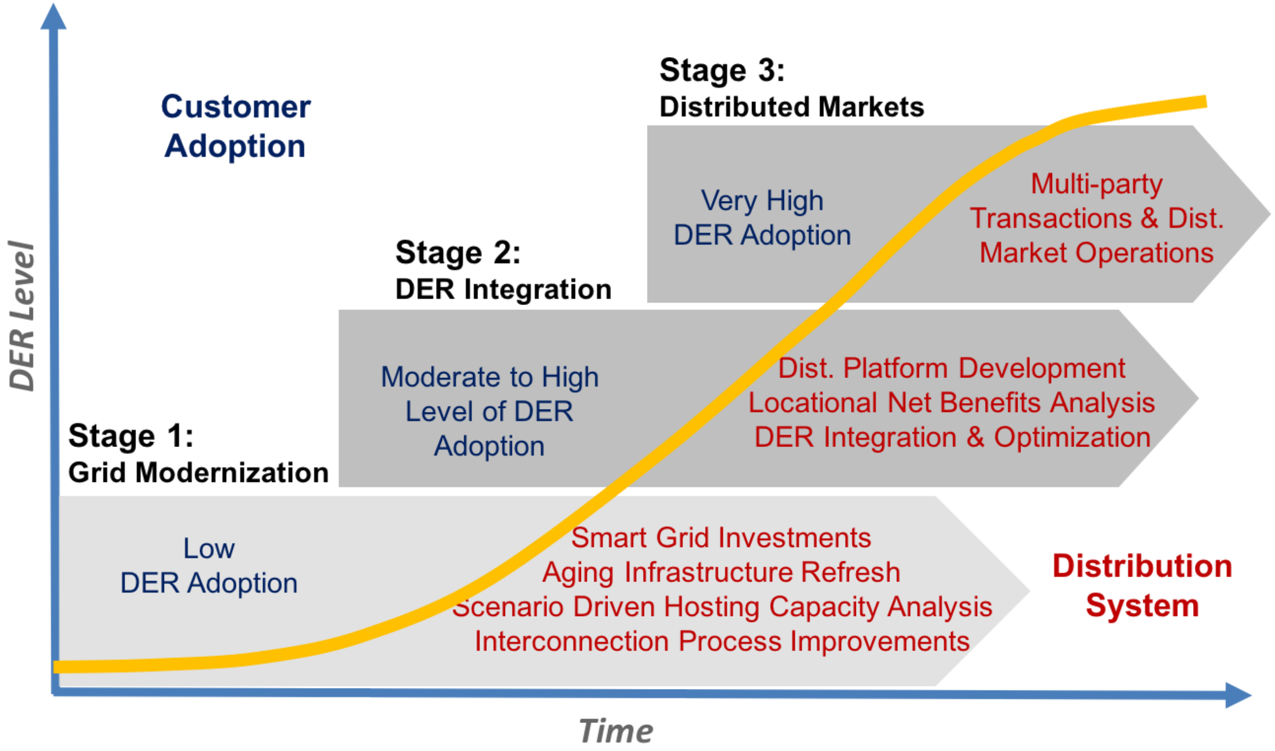
Drivers for improved distribution planning

- More DERs — cost reductions, policies, new business models, consumer interest
- Resilience and reliability
- Aging grid infrastructure and utility proposals for grid investments
- Need for greater grid flexibility in areas with high levels of wind and solar
- Interest in conservation voltage reduction and volt/VAR optimization
- Non-wires alternatives may provide net benefits to customers
- Utility investments: Distribution 29% ($35.7B) of 2017 EEI member investments*

*http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Documents/EEI_Industry_Capex_Functional_2018.07.17.pptx

State benefits from improved distribution planning

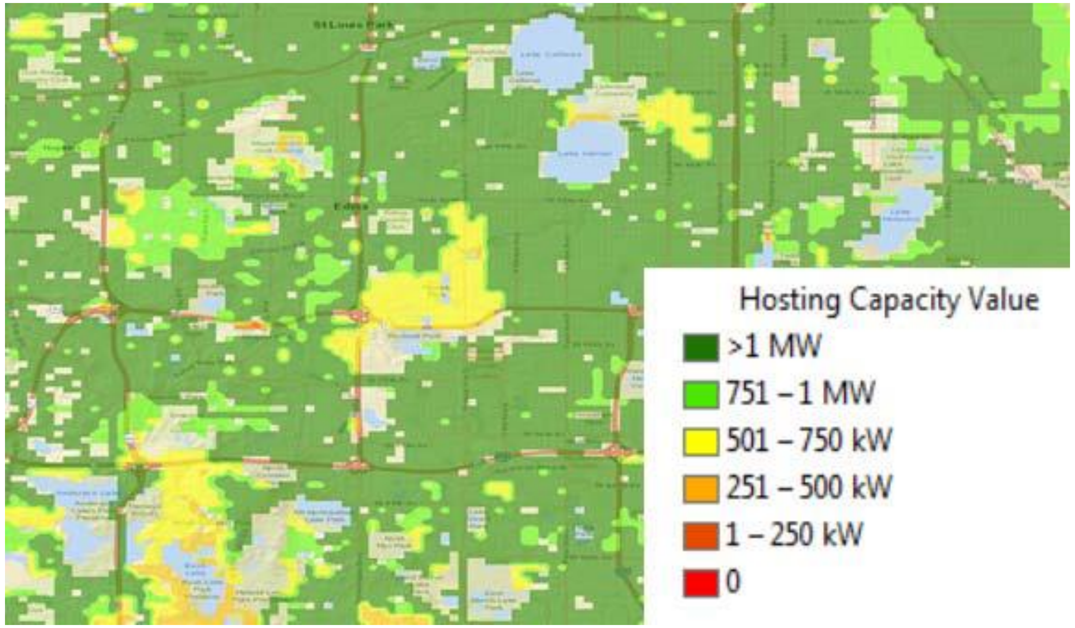
- Makes transparent utility plans for distribution system investments before showing up individually in rider or rate case
- Provides opportunities for meaningful PUC and stakeholder engagement
  - Can improve outcomes
- Considers uncertainties under a range of possible futures
- Considers all solutions for least cost/risk
- Motivates utility to choose least cost/risk solutions
- Enables consumers and service providers to propose grid solutions and participate in providing grid services



Graph from De Martini and Kristov for Berkeley Lab, 2015

Examples: States advancing distribution system planning

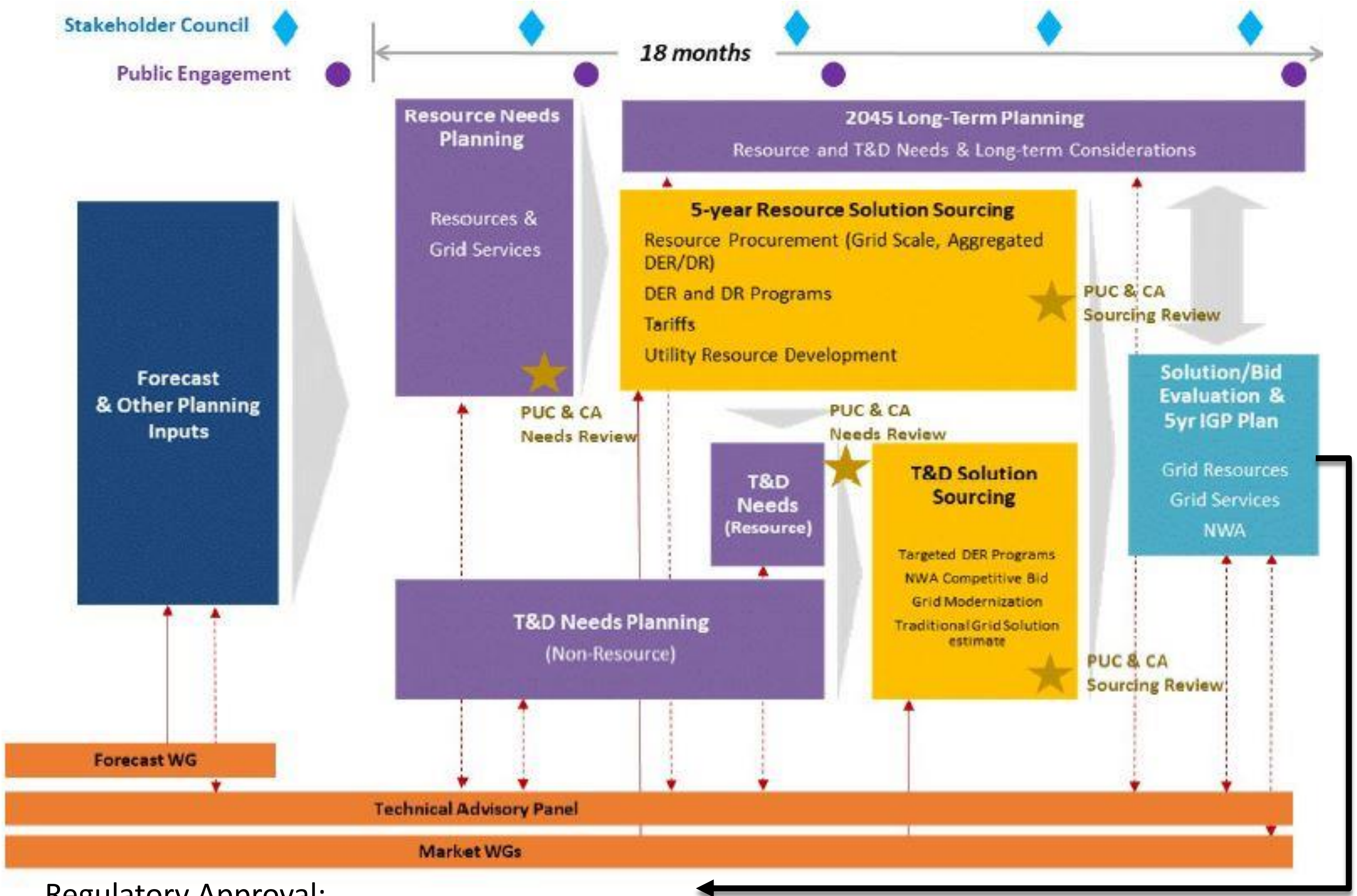
- Requirements for utilities to file distribution system or grid modernization plans (CA, HI, IN, MA, MD, MI, MN, NV, NY)
  - *Integrated* distribution planning is nascent.
- Consideration of cost-effective non-wires alternatives (CA, NY, RI)
- Requirements for hosting capacity analysis (CA, HI, IL, MN, NY)
- Locational net benefits analysis for DERs (CA, HI, NV, NY)
- DER procurement strategies (CA, HI, NY)
- Storm hardening, under-grounding (MD, FL)
- Requirements for utilities to report on poor-performing circuits and improvement plans (many states)



Xcel Energy, Hosting Capacity Study, 11/1/18

Example: Hawaii's integrated grid planning

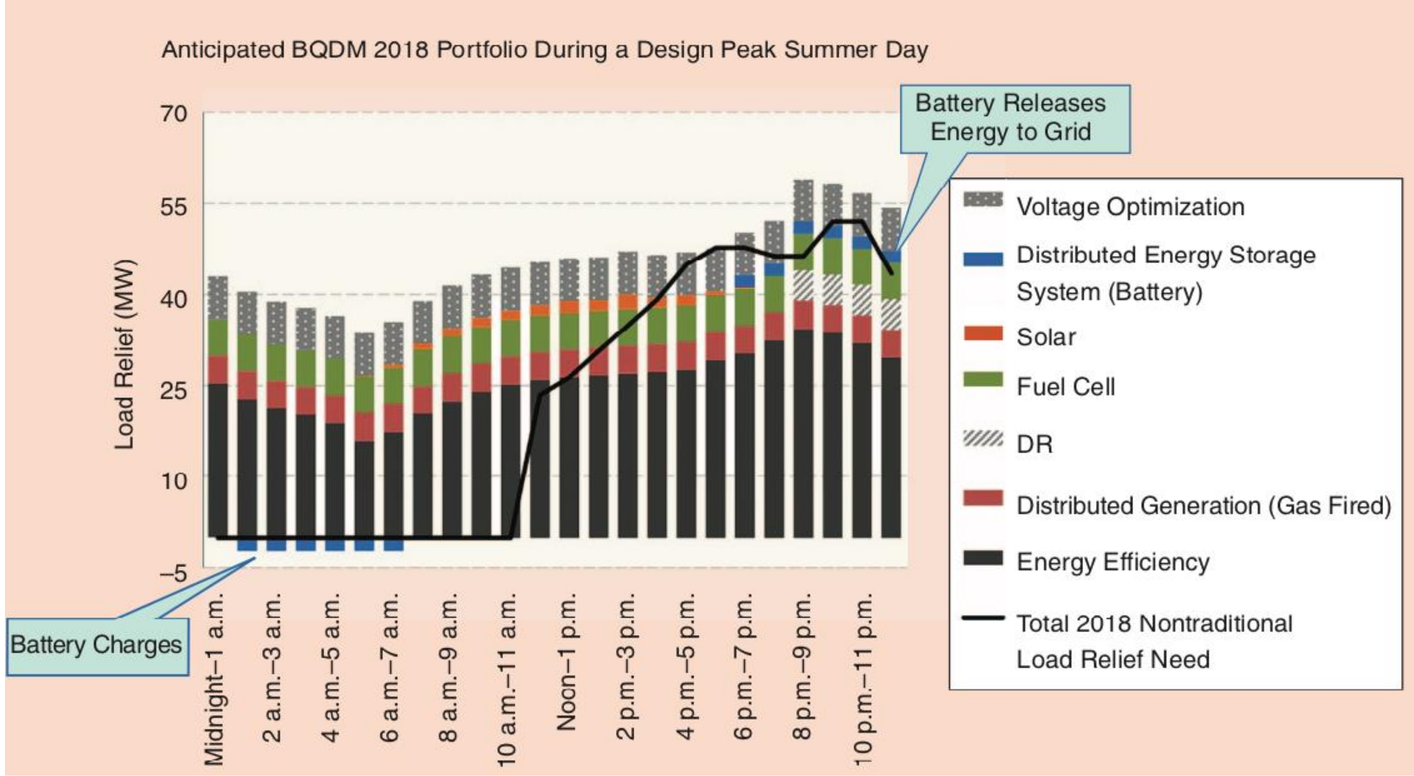
- Order No. 34281 (Jan. 2017) – PUC guidance for scenario-based grid modernization strategy to inform review of utility applications for grid modernization projects
- HECO filed final Grid Modernization Strategy on 8/29/17
  - PUC approved plan in Order No. 35268 (2/7/18)
- HECO issued *Planning Hawai'i's Grid for Future Generations: Integrated Grid Planning Report* on 3/1/18 (filed 7/12/18)
  - Proposed new "Integrated Grid Planning" process integrates customer, distribution, transmission, and bulk power resource levels of the system
    - Stakeholder involvement
    - Optimized solutions for resource adequacy and grid services, based on procurement processes including NWA solutions
    - Incremental deployment of grid modernization technology
- PUC investigating plan under Docket No. 2018-0165 (Order No. 35569)
- Objective: Identifying and procuring an optimal mix of distributed and grid scale resources to increase customer value and reduce risk



Regulatory Approval:
Seek PUC approval of Integrated Grid Plan’s 5-year plan & related applications

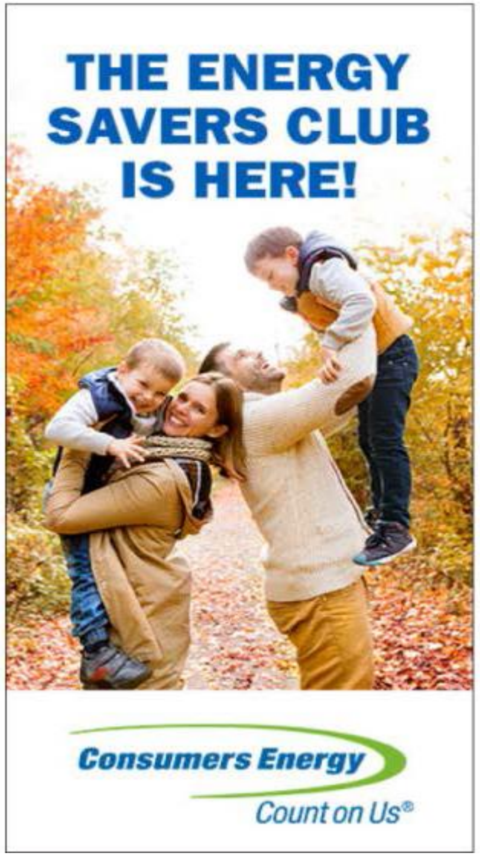
DERs in distribution planning: Non-wires alternatives

- Investments in energy efficiency, demand response, distributed generation and storage that provide **specific services** at **specific locations** to defer, mitigate or eliminate need for traditional distribution infrastructure
- Example: New York utilities provided suitability criteria (project type, timeline, cost) and described how the criteria will be applied to projects in capital plans



ConEd: Brooklyn-Queens project

Consumers Energy (MI): Energy Savers Club pilot program



DERs in distribution planning: Hosting capacity analysis

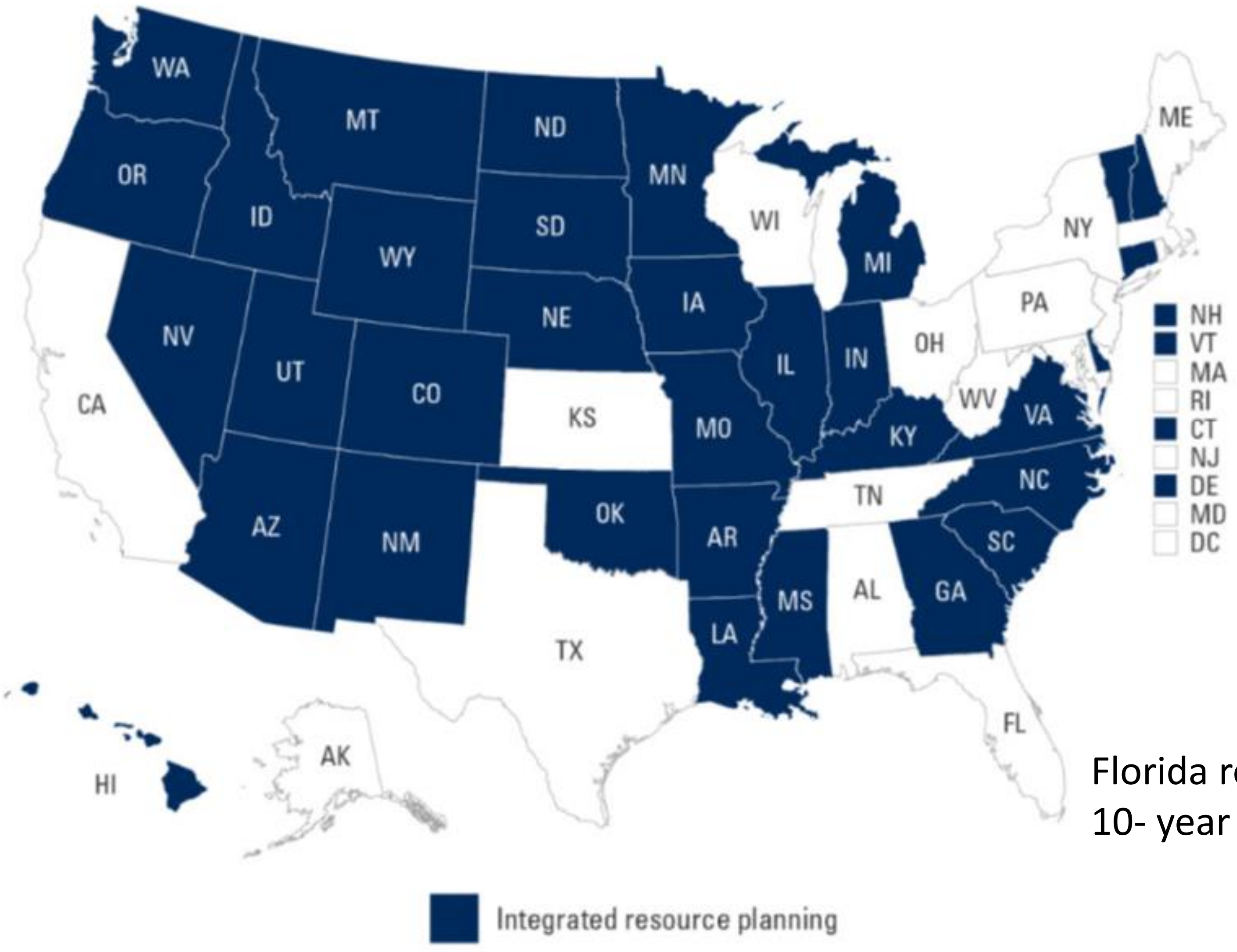
- Amount of DERs that can be interconnected without infrastructure upgrades
- Some states require regulated utilities to do it (CA, HI, MN, NY)
  - e.g., Minnesota statute requires Xcel Energy to conduct hosting capacity analysis; utility files annually - 2018 filing in Docket 18-684
- Some utilities do it on their own motion
  - e.g., Pepco
- Power system criteria to meet
  - Thermal
  - Power quality/voltage
  - Protection
  - Reliability/safety

Use Case	Capability
Development Guide	Identify areas with potentially lower interconnection costs
Interconnection Technical Screens	Augment or replace rules of thumb; determine need for detailed study
Distribution Planning Tool	Identify potential future constraints and proactive upgrades

Table adapted from ICF International, 2018

Integrated resource planning is required in most states

California now requires IRP



TVA Board requires IRP

Florida requires 10- year site plans

Source: EPA's Energy and Environment Guide, 2015

DERs in integrated resource planning

- Some regulators explicitly require utilities to consider at least one type of DER in IRP or other long-term planning.
- Examples:
  - Washington requires utilities to use identified DERs as inputs to IRP.
  - Oregon's order on Portland General Electric's 2016 IRP required the utility to "work with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process."
  - New Orleans requires Entergy New Orleans to consider storage and other DERs as potential supply-side resources in IRP.
  - New Mexico requires energy storage to be considered with other resource options in IRP.
  - Massachusetts issued an order that clarified the objective of including DERs to "facilitate the interconnection of distributed energy resources and to integrate these resources into the Companies' planning and operations processes."
  - California, Georgia, Iowa, Indiana, Kentucky, Michigan, Nebraska, Nevada, New Mexico and Oregon require consideration of combined heat and power in IRP.

Source: Berkeley Lab (forthcoming)

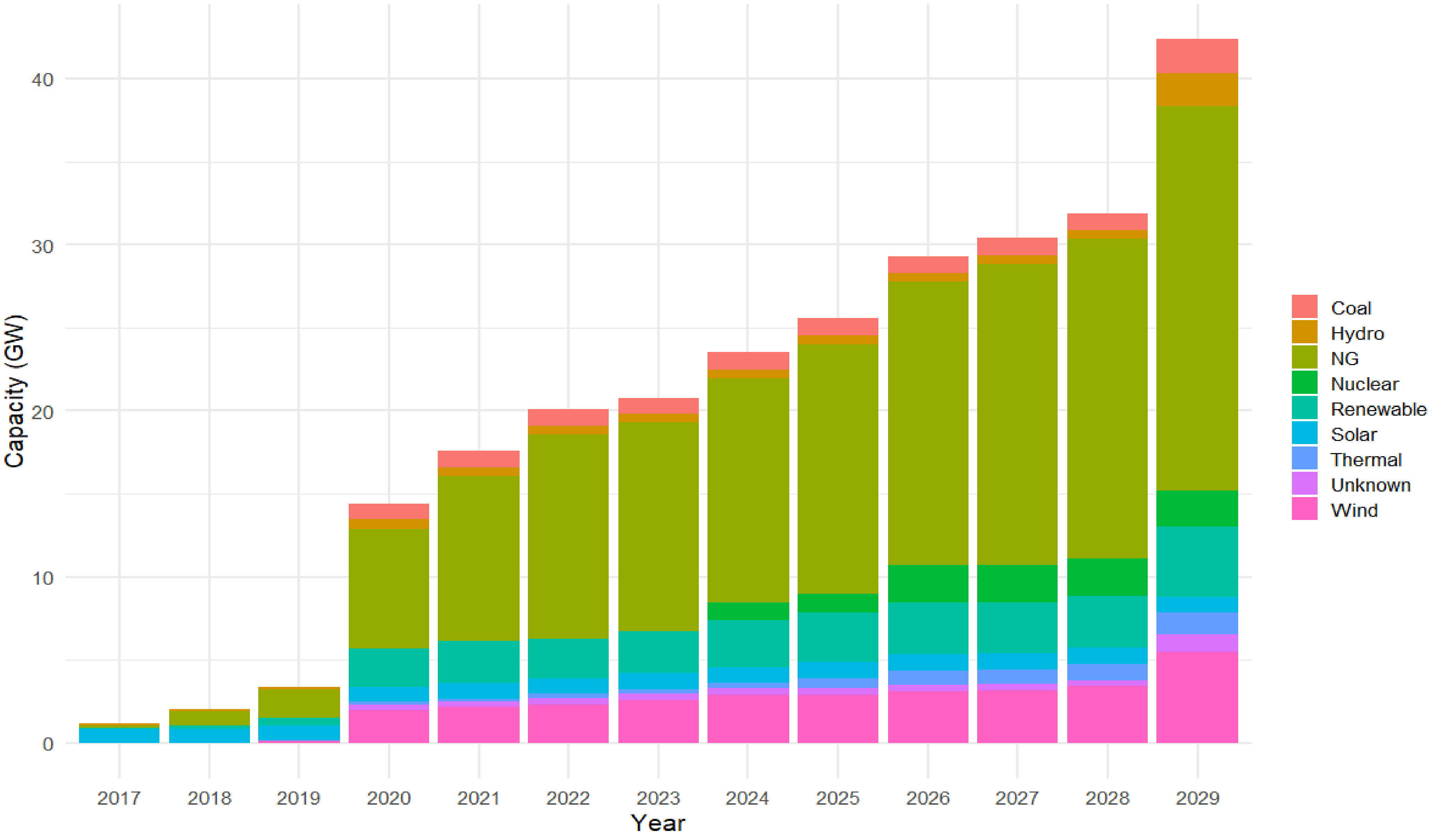
Berkeley Lab's Resource Planning Portal (1)

- Web-based tool that allows users to:
  - Input electric utility planning information in a consistent format
  - Benchmark planning assumptions across jurisdictions
  - Output results in a standardized format (e.g., maps, loads and resources tables)
- 39 western U.S. utilities (2003-17)
- 10 eastern U.S. utilities - adding now
- >117 electric resource plans and supplemental surveys
- ~1/3 U.S. installed capacity (>370 GW)

http://resourceplanning.lbl.gov/

Resource	**Capacity (GW)**
Natural Gas	123.7
Coal	73.6
Hydro	46.9
Unknown	43.7
Nuclear	31.4
Wind	18.7
Renewable	12.3
Solar	8.6
Thermal	4.1
Demand Response	8.8

Berkeley Lab's Resource Planning Portal (2)



Example output: Projected installed capacity

Steps toward aligning planning processes

- *Talk across planning groups within the utility*
- *Apply consistent inputs, scenarios and modeling methods where possible* across distribution planning, transmission planning, integrated resource planning and DSM planning
- *Account for all resources across planning processes*
  - Use customer adoption-based DER forecasting
  - Specify DER attributes needed to meet identified distribution needs
  - Incorporate NWA analysis into distribution system planning
- *Analyze multiple possible futures* – e.g., loads, DERs
- *Plan integration of utility assets and systems*
  - Specify how proposed investments will be used with legacy and future utility systems, for planning and customer benefit

Some challenges in aligning planning processes

- Disparate statutory and regulatory requirements
- Planning dimensions (following examples from Xcel's IDP, 11/1/18)
  - "Distribution planning is primarily concerned with location, and resource planning is primarily concerned with size, type and timing of resources – with transmission planning somewhere in the middle."
  - "Unlike IRPs, five-year plans are considered long-term in a distribution context...."
    - Unexpected loss of power plant often covered by RTO/ISO system; loss of distribution component often causes power outage to customers
  - "[D]istribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP."
- Planning tools
  - More accurate modeling tools are time-consuming, expensive and require data on the physical and electrical characteristics of distribution systems, spread across multiple utility business units.
  - Modeling tools must be able to capture both the individual and combined characteristics of DERs.

Resources for more information

- Alan Cooke, Juliet Homer, Lisa Schwartz, *Distribution System Planning – State Examples by Topic*. Pacific Northwest National Laboratory and Berkeley Lab, May 2018
- Juliet Homer, Alan Cooke, Lisa Schwartz, Greg Leventis, Francisco Flores-Espino and Michael Coddington, *State Engagement in Electric Distribution Planning*, Pacific Northwest National Laboratory, Berkeley Lab and National Renewable Energy Laboratory, December 2017
- Paul De Martini (ICF) for Minnesota Public Utilities Commission, *Integrated Distribution Planning*, 2016
- U.S. Department of Energy's (DOE) Modern Distribution Grid initiative and report (www.doe-dspx.org)
  - Volume I: Customer and State Policy Driven Functionality
  - Volume II: Advanced Technology Market Assessment
  - Volume III: Decision Guide
- *Summary of Electric Distribution System Analyses with a Focus on DERs*, by Y. Tang, J.S. Homer, T.E. McDermott, M. Coddington, B. Sigrin, B. Mather, Pacific Northwest National Laboratory and National Renewable Energy Laboratory, 2017
- J.S. Homer, Y. Tang, J.D. Taft, D. Lew, D. Narang, M. Coddington, M. Ingram, A. Hoke. *Electric Distribution System Planning with DER and Grid Modernization - Tools and Methods* (forthcoming)
- HECO, *Planning Hawai'i's Grid for Future Generations: Integrated Grid Planning Report*, March 2018
- ICF International, 2018 *Integrated Distribution Planning Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*, prepared for U.S. Department of Energy, July 2018
- National Association of State Energy Officials, Combined Heat and Power: A Resource Guide for State Energy Officials, 2013
- N.M. Frick, Schwartz, L., and Taylor-Anyikire, A. A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States. Berkeley Lab, forthcoming
- Several reports in Berkeley Lab's Future Electric Utility Regulation series
  - *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight*, by Paul De Martini (Cal Tech) and Lorenzo Kristov (CAISO)
  - *The Future of Electricity Resource Planning*, by Fredrich Kahrl (E3), Andrew Mills (Berkeley Lab), Luke Lavin, Nancy Ryan and Arne Olsen (E3)
  - *Value-Added Electricity Services: New Roles for Utilities and Third-Party Providers*, by Jonathan Blansfied and Lisa Wood, Institute for Electric Innovation; Ryan Katofsky, Benjamin Stafford and Danny Waggoner, Advanced Energy Economy; and National Association of State Utility Consumer Advocates

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The New Frontiers in System Planning

Hon. Nancy Lange

Minnesota

Powered Together
Tapping the Water–Energy Nexus
130th NARUC Annual Meeting and Education Conference

The New Frontiers in System Planning

Hon. Andrew McAllister
California Energy Commission

Audience Questions
(submit through the app)

More Information on NARUC-NASEO Task Force

Today
- See press release and charter
- Flyer

Soon
- Commissioners' Webinar week of December 10th – watch for announcement through Committee Lists

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B4 – The New Frontiers…

Look under the "polls" button

DIRECT TESTIMONY OF JOAN KOWAL

on behalf of

EMORY UNIVERSITY

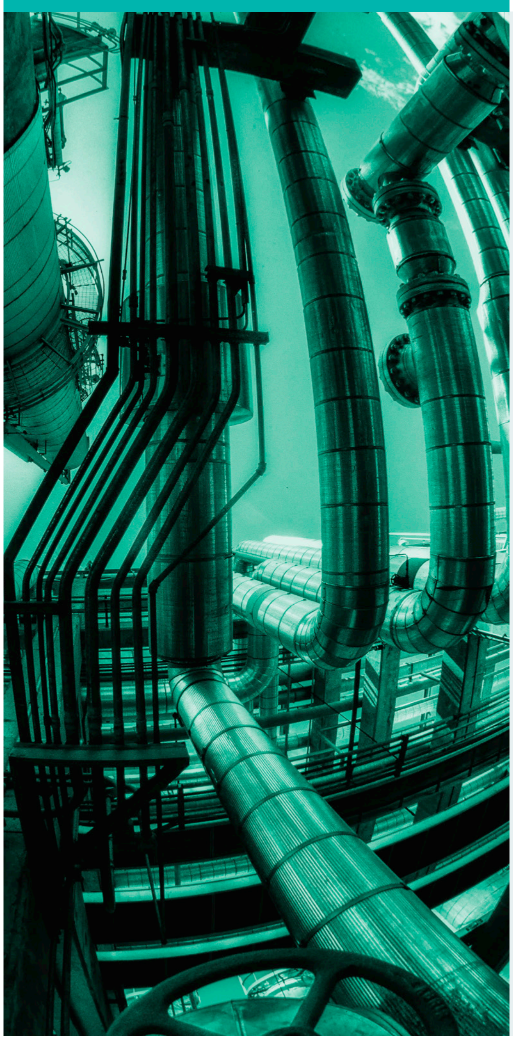
Docket No. 42310

Exhibit 6

White Paper

Utility Owned CHP—A Least-Cost Baseload Resource

ICF and Sterling Energy Group



Shareables

- Utility-owned combined heat and power (CHP) installations are an untapped efficiency resource of over 150 GW that can improve grid reliability while reducing operational costs.
- With thermal energy sales credited to fuel costs, utility-owned CHP systems can have the lowest Levelized Cost of Energy (LCOE) among base load supply options.
- Utility ownership of CHP means no lost revenues or subsidies, while unloading the transmission and distribution (T&D) system, lowering emissions, and strengthening the competitiveness of large customers.

Executive Summary

The relationship between electric utilities and their customers is changing. As distributed energy resource deployments grow, utilities are making efforts to modernize the grid, and customers are becoming more engaged in energy-saving solutions. Utility-owned CHP installations represent a large untapped least-cost, base load resource that can provide benefits on both sides of the meter while diversifying generation, increasing efficiency, lowering emissions and water use, reducing T&D losses and strengthening customer competitiveness.

Performance Benefits of CHP

- With thermal utilization, well applied CHP can be 50% more efficient than traditional power generation, leading to lower costs and reduced emissions
- CHP generates at the point of use, eliminating T&D losses, which average 7%, but often double during peak load hours
- CHP installations help increase the reliability and resiliency of power and steam supply for key utility customers, improving their competitiveness and supporting growth.

Economic Benefits of CHP

- Faster development, permitting, and commissioning of new utility generation in smaller MW increments helps match future load and supply
- Unloading the T&D system can help utilities avoid significant capital investment and high congestion costs
- CHP can help keep businesses competitive in their respective markets by improving reliability and lowering energy costs, supporting manufacturing expansion and job growth.

While many utilities understand and support CHP intellectually, they continue to consider CHP a *customer-owned* resource that competes with utility supply. Utilities have seldom explored CHP as a base load resource or included it as a supply option in their resource planning even though it is the most efficient method of generating baseload power. However, straightforward new business models are emerging with CHP as a key resource to help utilities transform towards a decentralized and highly resilient grid. Utility-owned CHP systems at customer sites can provide substantial benefits to utilities and the grid, and to a diverse array of customers with continuous thermal loads who are interested in reducing costs, expanding operations, and enhancing energy security.

While many facilities across the U.S. have already installed CHP on their own[1], there is still a large amount of technical potential for CHP remaining. According to a March 2016 Department of Energy report,[2] there is 151 GW of CHP technical potential for systems >5 MW at 4,000 industrial and commercial customer sites.

CHP Ownership Advantages for Utilities

By deploying CHP as a supply-side resource, utilities can realize significant benefits compared to investing in traditional central power stations.

- **Low Cost and High Capacity Factor –** CHP is the most efficient method of generating power, and well applied sites have been demonstrated to have the lowest LCOE among base load supply options when thermal credit is applied to fuel costs benefiting all customers. Base load CHP also has a higher annual capacity factor (95%) when compared to central station options such as natural gas combined cycle plants (averaging 40-80%) [3].
- **Less Risk –** The planning, permitting, and implementation process for CHP (2-3 years) is much shorter than that of a large capacity central station generator (6-10 years). Future utility loads are difficult to forecast – building smaller, high-efficiency CHP installations can reduce the risk involved with developing new power generation assets. With a utility-owned, rate-based CHP system, the utility does not lose power revenues from the CHP host site, who is secured with a long-term contract.
- **Locational Value –** Customer-sited CHP systems can provide locational value to utilities by relieving congestion, deferring the need for T&D investments and enhancing local reliability. CHP systems can also provide reactive power and other services to support grid operations.

[1] There is currently over 80 GW of CHP capacity from more than 4,300 installations according to the CHP Installation Database, https://doe.icfwebservices.com/chpdb/.

[2] "Combined Heat and Power Technical Potential in the United States". Prepared by ICF for the Dept. of Energy. March 2016. https://energy.gov/chp-potential

[3] The 2015 average capacity factor for combined cycle plants was 56% according to the Energy Information Administration.

Duke Energy's CHP Ownership Plans

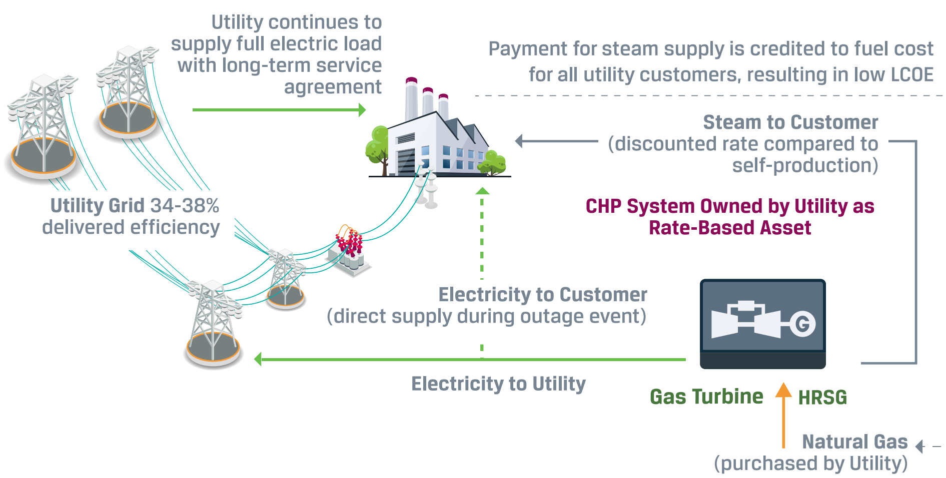
- Duke Energy has included base load CHP plants in their 2015 and 2016 integrated resource plans for the Carolinas and Indiana, demonstrating that distributed CHP is a least cost base load resource when compared to gas fired combined cycle and other central station technologies.
- The 16 MW CHP project is under development at Clemson University will be one of the first Duke Energy owned CHP plants which will provide for campus growth, added resiliency, increased efficiency and lower emissions for the campus and community.
- A similar 21 MW CHP project under development with Duke University will provide both steam and hot water for the campus, boosting efficiency to 80% HHV. The project will decrease CO2e emissions in North Carolina by a projected 100,000 tons/yr. The University is also procuring renewable biogas from NC swine industry projects doubling the emissions benefits. The University will own and retire the associated Renewable energy credits, while also helping catalyze the market for further methane reductions in the swine industry.
- Duke Energy is also working with select industrial manufacturing customers with suitable thermal loads to evaluate and pursue additional CHP opportunities that can be beneficial to the host, the utility, and all customers.

- **Increasing Value for Customers –** Being a CHP host can produce substantial operational and economic benefits for customers providing modern, highly efficient and reliable thermal (steam) energy systems without direct investment by customer. This can enable hosts to retire older boilers, reduce operating costs and still expand operations. The increased reliability and lower costs helps the host customer be more competitive in their market, protecting and even expanding production and local jobs.

Ownership Structure and Service Agreements

In many states, electric utilities can simply treat CHP investments as rate-based supply assets, the same as any other supply-side investment. With utility ownership of a CHP asset, the utility continues to serve the full customer electric load, without the loss of revenue that occurs when a customer invests in CHP. A long-term agreement is executed between the customer and utility, with guarantees for purchase of electricity service and steam or thermal energy from the utility. Thermal sales revenue is credited directly back to fuel costs, benefiting all customers by driving the net heat rate below central station generation. During utility outage events, the CHP system can provide resilience by continuing to serve the customer loads. This process is depicted in Exhibit 1.

EXHIBIT 1. UTILITY CHP OWNERSHIP BUSINESS MODEL



Benefits for Customers

Distributed energy resources are becoming economically competitive with traditional grid power and attractive to customers that are looking for more reliable, cleaner, and cost-effective sources of energy. Utility-owned CHP has several advantages compared to customer-owned CHP systems.

- **Lower Costs –** Utility-owned CHP equipment can provide lower-cost and more reliable thermal energy (steam, hot/chilled water) to customers, who may retire aging, high-maintenance equipment and apply the avoided costs into core business investments. Additionally, with the revenues from thermal sales being credited back to fuel costs for the entire rate base, electricity becomes less expensive for all customers.

- **Low Risk –** Customers can receive the benefits of high-efficiency on-site power and thermal production without a large capital investment in a non-core asset. Long-term steam contracts with utility suppliers can also reduce risk by providing a hedge against future price volatility.
- **Resiliency –** CHP has the ability to 'island' in the case of a grid outage, increasing resilience and providing benefits for the surrounding community. CHP can be integrated with existing plant systems, as well as nearby loads and resources, to create a microgrid that directly serves critical loads during outage events.

Example – Eight Flags Energy and Rayonier Advanced Materials[4]

Chesapeake Utilities subsidiary Florida Public Utilities (FPU) recently constructed a 21.7 MW, 200,000 lb/hr CHP project on Amelia Island. The project, named Eight Flags Energy CHP, supplies reliable base load power to FPU electric customers along with steam and hot water to the adjacent Rayonier Advanced Materials softwood cellulous specialty mill. It is one of the first in a new generation of CHP projects being developed by utilities that can beneficially use the waste heat of the power production process as part of their base load electric supply portfolio.

Photo Courtesy of: Florida Public Utilities, Cottle Communications

The $40 million project operates at 78% HHV efficiency, and has achieved an operating availably of 98.5% since it was commissioned in July 2016. The project supplies approximately 50% of electric supply to FPU customers on Amelia Island and uses 5,000 Dth/day of natural gas supplied via the FPU gas distribution system.

[4] FPU/Eight Flags Project Overview August 2016 - https://youtu.be/1UaNWrRBMpo

"We're continually looking for new ways to increase efficiencies, improve reliability, provide cost savings and add value to our customers and the communities we serve. That commitment has resulted in the development of this state-of-the-art CHP plant"

- Jeffry M. Householder, President of Florida Public Utilities Company.

The project was constructed in less than 12 months even though it is located on a challenging 1.5 acre site between the Rayonier mill and the Amelia River marsh only 8' above sea level. Amelia Island has been served by a single transmission line leaving it vulnerable to island-wide power outages. The CHP system was designed to withstand Category 4 winds and storm surge. Following a major storm, the CHP plant will be able to power an island-wide microgrid, supporting essential services and providing energy security for all customers.

Another important factor in planning the project was the collaboration with a key customer, Rayonier. The CHP system provides additional, competitively priced steam and hot water under a long term agreement permitting the mill to operate even when their boilers are down for maintenance. This expanded steam capacity was instrumental in the Rayonier site being approved for a $125 Million expansion scheduled to be operational in spring 2018. [5] The expansion will add 5 MW of electric load and substantial natural gas load to FPU.

Benefits for FPU and their Customers

- Reduction in power costs for all customers
- $28 million net present value for FPU
- Increased reliability by forming a regional generation microgrid on Amelia Island
- 78% overall efficiency leads to 80% lower NOx and 38% lower CO2 emissions than current supply

Benefits for Rayonier and the Community

- Increased steam capacity and electric reliability at the Rayonier plant – several more production days per year
- Rayonier expansion at site due to increased operational efficiency with CHP - resulting in 50 additional jobs and $20 Million annually to the NE Florida economy
- Increased the local tax base by $800,000

A Winning Combination

Utility-owned CHP can be a key asset in the current evolution of the electric grid, providing significant benefits to utilities, customers, and surrounding communities. Utilities can create new rate-based generation assets with locational value and additional revenue streams, while customers and local communities benefit from resilient on-site power and lower energy costs. Substantial growth potential exists for CHP given the transition towards a more robust, distributed energy system, and opportunities for utility ownership are also expanding.

By screening utility customers to identify good CHP candidates, utilities can begin to synthesize overall system benefits and target potential locations for CHP implementation. For utilities seeking to provide cleaner, reliable, and cost-effective base load power to their customers, CHP installations can offer a mutually beneficial solution.

[5] "Joint Venture LIngoTech Florida Plans Manufacturing Center in Fernandina Beach, Florida," 12/09/2016. http://www.areadevelopment.com/newsItems/12-9-2016/lignotech-fernandina-beach-florida.shtml

About ICF

ICF (NASDAQ:ICFI) is a global consulting and technology services provider with more than 5,000 professionals focused on making big things possible for our clients. We are business analysts, policy specialists, technologists, researchers, digital strategists, social scientists, and creatives. Since 1969, government and commercial clients have worked with ICF to overcome their toughest challenges on issues that matter profoundly to their success. Come engage with us at **icf.com**.

About Sterling Energy Group, LLC

Sterling Energy Group is a specialized energy engineering firm focusing on the efficient use of energy and combined heating and power for major industrial, institutional and utility clients throughout North America. We have unique experience in bringing engineering and economics together to identify, develop and optimize values on both sides of the meter through collaborative projects. Key values are Trust, Integrity, Respect and Environmental Responsibility in all we do.

About the Authors

Anne Hampson is a Principal at ICF with over 15 years of experience in market and policy analysis in the areas of power generation and energy efficiency. She leads ICF's efforts in the development and management of databases on installed CHP capacity as well as operational reliability of DG equipment. She has conducted analysis and research on market issues, regulatory policies, economic incentives, reliability issues, and performance characteristics of distributed generation equipment.

Dr. Bruce Hedman is a Fellow at ICF with over 35 years of experience in energy technology research, development and commercialization, and is a recognized authority on combined heat and power (CHP) and distributed generation technologies, markets and policies. He has worked extensively with public and private clients to analyze the opportunity for distributed generation technologies and identify regulatory and institutional hurdles to market development.

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