STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
____	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

RAJAN M. TELANG

DTE GAS COMPANY
QUALIFICATIONS OF RAJAN TELANG

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

A. My name is Rajan Telang. 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 Director, Regulatory Affairs.

Q. On whose behalf are you testifying?

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

Q. What is your education background?

A. I received a Bachelor of Science in Business Administration in 1990, with a major in accounting, from Wayne State University. In addition, I received a Master's of Business Administration degree from Michigan State University in 1997.

Q. What work experience do you have?

A. From 1990 to 1994, I practiced public accounting with the international accounting firm of Arthur Andersen & Co. In 1994, I joined Michigan Consolidated Gas Company (MichCon) to work in the Controller's organization and had several assignments of increasing responsibility in External Reporting and Financial Planning departments. In 1998, I was promoted to Director, Compensation and Benefits. In 2000, I transferred to MCN Energy Group, Inc (MCN), the parent company of MichCon, as Director of Accounting. In 2001, MichCon's parent, MCN, was acquired by DTE Energy, which is also the parent company for DTE Gas, where I assumed the position of Power Generation Controller within the Controller's organization. From 2005 to 2013 I held various accounting, budgeting, forecasting and reporting positions within the Controller's organization. In 2014, I transferred

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to my present position of Director, Regulatory Affairs where I have the responsibility for the development and implementation of regulatory strategy and administration for DTE Gas.

Q. Do you hold any certifications and are you a member of any professional organizations?

A. I am a Certified Public Accountant, a member of the American Institute of Certified Public Accountants and the American Gas Association.

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

A. No, I have not.

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Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Provide an overview of the Company's entire case;
- Review the overall methodology used to develop the Company's projected test year amounts in this case;
- Provide an overview of DTE Gas's affiliation with the NEXUS pipeline project;
- Address the ratemaking and policy considerations relative to the Company's proposed Revenue Decoupling Mechanism (RDM), Infrastructure Recovery Mechanism (IRM), and other policy proposals; and
- Introduce the Company's witnesses.

Q. Are you sponsoring any exhibits in this proceeding?

A. No, I am not.

Case Overview

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

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

Providing safe, reliable and cost-effective service to its customers means that DTE Gas: 1) provides quality customer service, 2) operates its system to ensure the safety of customers and employees, and 3) delivers natural gas service at a reasonable cost. The

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Company believes that providing our customers with quality 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 Gas's financial health requires that the Company has:

1) A reasonable opportunity to earn its cost of capital;
2) A well-balanced capitalization (no less than 52% equity to total permanent capitalization); and
3) The ability 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 Gas'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 Gas'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 to shareholders.

Q. What rate relief was provided by the Commission's Order in the Company's last rate case, Case No. U-17999?

A. The Company's last general rate case, Case No. U-17999, was filed on December 18, 2015 requesting $182.9 million in rate relief. On November 1, 2016, DTE Gas self-implemented a rate increase of $103 million. Self-implementation did not include

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$40.8 million of IRM surcharge revenue. The IRM surcharge was authorized to, and did, continue throughout the self-implementation period. Combined, the annualized self-implementation amounted to $143.8 million.

The Commission issued an order approving a $122.3 million rate increase on December 9, 2016. This order also approved the Company's IRM for the meter move out, main renewal, and pipeline integrity programs. The IRM plan and surcharge approved in Case No. U-17999 began in January 2017.

Q. What actions has the Company taken to delay the need for a rate case filing for two years?

A. DTE Gas continues to focus on efforts to control and, where possible, reduce costs through sustainable and on-going Continuous Improvement efforts. These activities have allowed the Company to partially mitigate the impact of increasing routine operating costs without reducing the quality of service to customers. Furthermore, the Commission's approval of the IRM surcharge in Case No. U-17999 allowed the Company to recover the cost of service for approximately $28 million in capital expenditures spent during 2017 and 2018, thereby helping to offset the need to file a general rate case to recover these incremental costs not included in the projected test year of U-17999.

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

A. The Company has carefully considered the necessity of 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 Gas's current authorized base rates are no longer expected to provide DTE Gas with a reasonable opportunity to earn a fair return on equity beginning in October 2018. The primary reason DTE Gas's costs will exceed its revenues is the extensive infrastructure investments, beyond the costs recovered through the IRM, made to ensure the reliability of its system, the safety of its customers, and compliance with State and Federal requirements. The only way that DTE Gas can adequately provide the required service levels and safety that our customers expect and require is by being financially healthy.

To attract the capital necessary to ensure safe and reliable system operations, the Company must be able to demonstrate its ongoing financial health. Inadequate rates will likely result in higher financing costs and have a significant negative impact on DTE Gas's ability to adequately serve its customers and maintain the integrity of its gas distribution, transmission, and storage assets. This negative impact will occur because more dollars are required to support DTE Gas's financing costs, and therefore will not be available for system maintenance or customer service. Similarly, inadequate funding for capital and maintenance programs, over time, will result in the deterioration of DTE Gas's distribution, transmission, and storage infrastructure, ultimately resulting in reduced system reliability.

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

A. Yes. DTE Gas has an important positive economic impact on the communities it serves. DTE Gas is a large employer with over 1,600 employees throughout the State of Michigan; and through the Pure Michigan Business Connect campaign, the

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Company utilizes the services of numerous local contractors and vendors. DTE Energy companies, as a whole, spent over $1.3 billion with Michigan-based companies in 2016. In addition, through property taxes, DTE Gas contributes to the financial health of the communities it serves. In the 2016 historical test year, DTE Gas paid over $50 million in property taxes. These taxes directly benefit Michigan communities. Further, to maintain facilities and comply with various regulations, DTE Gas continues to make major capital investments in the communities where it serves and operates. Thus, DTE Gas's financial health supports additional job growth opportunities and provides incremental tax revenue for the communities it serves.

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

A. Yes. DTE Gas 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 Gas has, and continues to, aggressively pursue opportunities to reduce costs. O&M expense of $414 million in DTE Gas's projected test year reflects the savings resulting from sustainable cost reductions achieved through Continuous Improvement efforts. DTE Gas has proactively engaged in numerous efforts throughout the company 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, this level of cost savings could not eliminate the need for rate relief by the end of 2018.

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

A. As Company Witness Ms. Suchta summarizes, DTE Gas expects a revenue shortfall of $85.1 million for the October 1, 2018 through September 30, 2019 projected test year. The key factors contributing to this shortfall are the revenue requirement associated with increased investments made in net plant, including the associated depreciation and property tax increases, and an increase in O&M expense.

Q. Will the $85.1 million revenue shortfall result in a $85.1 million rate increase for customers?

A. No. A portion of the $85.1 million revenue deficiency is due to the inclusion of IRM related capital investments made through 2018. These IRM capital investments are currently being recovered through a separate IRM surcharge. However, as I describe later in my testimony, the current IRM surcharge will end when new base rates are established in this proceeding. As supported by Company Witness Mr. Slater, the current IRM surcharge will recover $28.1 million for IRM related investments through December 2018 of the projected test period. When the current IRM surcharges terminate, the $28.1 million recovered through the surcharges will now be included as part of base rates. Excluding the current $28.1 million IRM surcharge revenue, which is already a part of customers' bills, the Company's actual revenue shortfall is $57 million rather than $85.1 million.

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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 Gas has used actual historical data as the starting point in determining most estimated cost levels for the projected test year. Historical costs were then adjusted for the impact of inflation. As has been DTE Gas's practice in prior cases, certain other costs adjustments reflect specific estimates or projections where general impacts of inflation alone would not be appropriate. For example, these include, but are not limited to, capital expenditures, uncollectible expense, injuries and damages, pension and other post-employment benefits. These cost components are supported by other Company witnesses.

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

A. The historical test year being used by DTE Gas is the calendar year ended December 31, 2016. 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 October 1, 2018 through September 30, 2019 projected test year.

NEXUS

Q. What is the NEXUS pipeline project?

A. The NEXUS pipeline project ("NEXUS" or "the Project") is approximately 255 miles of 36" diameter pipeline providing service from eastern Ohio into existing pipeline system interconnects in southeastern Michigan. DTE Gas's affiliate, DTE Gas

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Storage & Pipelines (wholly owned by DTE Energy) and Enbridge Inc. are 50/50 partners in the Project. NEXUS will transport Appalachian shale gas, including Utica and Marcellus shale gas, to customers in Ohio and Michigan, and to customers in Ontario, Canada. These additional natural gas supplies will support customers' day-to-day gas needs and provide cleaner power generation fuels, thereby meeting a growing environmental need. The Project will provide these regions with additional access to natural gas supplies to help meet the growing environmental need for cleaner fuels for power generation and for industrial and commercial customers, as well as home heating and domestic use. The service commencement date for the NEXUS pipeline is currently targeted for late in the third quarter of 2018.

Q. What is DTE Gas's affiliation with the NEXUS project?

A. There are two main transactions into which DTE Gas has entered with NEXUS:

First, DTE Gas has signed a 15-year Capacity Lease Agreement with NEXUS to deliver natural gas on DTE Gas's system from the Willow Gate Station in Ypsilanti Township, Washtenaw County, Michigan to Vector-Milford Junction, Vector-Belle River, or Union-St. Clair stations, with an option to extend the service for up to an additional 30 years. Also, as part of this agreement and discussed in more detail by Company Witness Ms. Sandberg in this case, DTE Gas will add additional compression to its facilities at Willow Run and Milford stations to enable the additional gas to flow on the DTE Gas system. As I discuss later in my testimony, this agreement lowers the Company's future revenue requirement and, thus, its customers' rates.

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Second, DTE Gas entered into a Precedent Agreement with the NEXUS pipeline to secure long-term firm transportation service on the NEXUS pipeline for 75,000 Dth per day. DTE Gas has included these NEXUS transportation expenses in its GCR plans beginning sometime late in the third quarter of 2018. NEXUS costs have been included in the following GCR Plan filings:

1) 2015-2016, Case No. U-17691;
2) 2016-2017, Case No. U-17941; and
3) 2017-2018, Case No. U-18152

Since the Precedent agreement is related to gas supply cost, and therefore will be recovered through the Company's Gas Cost Recovery (GCR) process, this agreement will not be addressed in detail in this proceeding. Rather it will be addressed in the Company's next GCR plan case, Case No. U-18412, by Company Witness Mr. Lawshe to be filed in December 2017. In Case No. U-18412 Witness Lawshe will further describe the terms of the agreement between DTE Gas and NEXUS. In addition, he will discuss the evaluation that led to DTE Gas contracting with NEXUS for long term firm transportation service.

Q. Are there any other transactions between DTE Energy affiliates and the NEXUS pipeline project?

A. Yes, DTE Electric, an affiliate of DTE Gas, has also entered into a Precedent Agreement with the NEXUS pipeline to purchase natural gas supply transportation capacity. In DTE's Electric's 2018 Power Supply Cost Recovery Case (PSCR), Case No. U-18403, DTE Electric is seeking recovery of NEXUS transportation expenses that are expected to be incurred starting in the third quarter of 2018. In Case No. U-18403, Company Witness Mr. Pratt, describes the terms of the agreements between

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DTE Electric and NEXUS. In addition, he discusses the evaluation that led to DTE Electric contracting with NEXUS for gas transportation capacity.

Q. In its last rate case order, in Case No. U-17999, what specific issue did the Commission direct DTE Gas to address related to NEXUS in its next general rate case filing?

A. In its order in Case No. U-17999, the Commission directed DTE Gas to provide a complete revenue requirement calculation for the capital investments that DTE Gas is making to support the gas volumes that NEXUS will flow on DTE Gas's system. Witness Suchta has included this revenue requirement calculation using all related project costs in her testimony, which is detailed in Exhibit A-23, Schedule M3.

Q. What benefits will DTE Gas's Agreements with NEXUS provide to its customers?

A. Several benefits will be realized by DTE Gas's customers due to DTE Gas's Agreements with NEXUS, including:

1) Reduced distribution rates resulting from NEXUS revenues exceeding the related costs to provide the service;
2) Lower gas commodity costs, and therefore GCR rates, because DTE Gas will have increased access the most prolific and low-cost producing gas basins in the nation;
3) Future stability of gas commodity supply and pricing through access to the diversity of gas supply that NEXUS provides; and
4) Increased flexibility and reliability of DTE Gas's transmission system through the addition of 50,000 HP of new compression.

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Q. How will DTE Gas's Agreements with Nexus reduce customer rates?

A. As mentioned earlier, DTE Gas signed a 15-year Capacity Lease Agreement with NEXUS to deliver natural gas on DTE Gas's system. Transportation sales resulting from the lease agreement will generate approximately $30 million of incremental revenue for DTE Gas annually. The average annual NEXUS related revenue requirement is $24 million over the same 15-year period, resulting in an average net benefit of $6 million per year. The average annual net benefit of $6 million provides customers approximately $90 million of financial benefits over the 15-year period by reducing the Company's future rate relief needs.

Q. How will DTE Gas's agreements with NEXUS lower gas commodity rates charged to GCR customers?

A. As discussed in DTE Gas's GCR Plan case filed in December 2015, Case No. U-17941, the addition of NEXUS to the DTE Gas transportation portfolio is expected to lower the cost of gas for DTE Gas customers by approximately $375 million over the 15-year lease agreement per an analysis performed by ICF International, an independent consultant.

Q. How will DTE Gas's Agreements with NEXUS help to ensure the future stability of gas commodity supply and pricing in Michigan?

A. The stability of natural gas supply and pricing in Michigan is enhanced by DTE Gas's agreements with NEXUS, which will bring in 1.3 Bcf of gas per day to DTE Gas's system from the Utica and Marcellus shale gas reserves. These reserves are some of largest, fastest-growing and most cost-effective sources of natural gas supply in North America. This additional gas supply will improve Michigan's security of supply,

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thereby mitigating price volatility and potential price run ups in the future such as those occurring during the two winters of 2013-14 and 2014-15 at each of the major Midwest city-gate market locations, including DTE Gas.

This gas supply will also position DTE Gas to meet the projected increase in demand in the region over the next several years, as new gas-fired electric generation comes on line as part of the transition away from coal to a lower carbon sources of energy. For example, DTE Electric stated in its July 31, 2017, Certificate of Necessity filing (Case No. U-18419) that it expects to increase gas-fired electric generation through the addition of combined cycle gas turbine (CCGT) power plants totaling 2,100 MW by 2030.

Q. How will DTE Gas's Agreements with NEXUS increase the flexibility and reliability of DTE Gas's transmission system?

A. As described by Witness Sandberg, DTE Gas will be completing its investment of approximately $200 million to add 50,000 horsepower of compression to the Company's system to accommodate the gas flow expected from NEXUS. Additionally, as explained by Company Witness Ms. Aud, the modular design of this additional compression will optimize system operating flexibility and are being made at facilities that are currently at capacity on a summer design day.

In addition, as discussed by Witness Aud, this additional compression investment effectively extends the life of some of DTE Gas's existing compressor units and provides DTE Gas with more flexibility to strategically plan maintenance outages at these stations during non-design days and shoulder months. This flexibility will reduce the chance of unplanned outages affecting system reliability and service to DTE Gas's customers.

<u>Revenue Decoupling Mechanism (RDM)</u>

Q. What is Revenue Decoupling?

A. Revenue decoupling is a regulatory mechanism that removes the link between energy sales and utility revenues. Revenue differences are trued-up on a periodic basis and flowed back to customers as adjustments to rates so that the utility's revenues match the allowed revenue requirement as established in the utility's last general rate case. A well designed RDM removes the utility's disincentive to encourage Energy Waste Reduction (EWR). RDM eliminates the negative financial impact from the loss of energy sales resulting from EWR programs.

Q. What is DTE Gas's current RDM?

A. The Company's current RDM was approved by the Commission in its December 9, 2016 order in Case No. U-17999. The current RDM is designed as a "simple revenue tracker" reconciling Case No. U-17999 distribution revenue with actual weather normalized distribution revenue (both excluding GCR revenues, surcharges and the customer charges). The RDM is limited by a revenue cap set at 150% of the legislated EWR targets, resulting in a current RDM cap of 2.25%. The current RDM will terminate when DTE Gas implements new rates by Commission order.

Q. Are sales revenues from all customer types or classes included in the current RDM?

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A. No. The current RDM excludes large general service customers (General Service Rate, GS-2) and End-User Transportation (EUT) customers from the RDM calculation; as a result, GS-2 and EUT customers are not subject to RDM surcharges or credits. The RDM does not function well for these rate schedules and may produce inappropriate results due primarily to the movement of customers among rate schedules, plant closings, and load additions. This result clearly conflicts with the desired alignment of Company and customer interests relative to energy waste reduction.

Further, revenues from new customer attachments and off-system services are also excluded from the RDM reconciliation calculation.

Q. How is the revenue shortfall or excess determined and the resulting credit or surcharge calculated?

A. The calculation of any revenue shortfall or excess, and the resulting customer credit or surcharge, is determined on a rate schedule basis. This calculation provides the benefit of aligning recovery of any short-fall, or refund of any excess, with the approved rate design.

Q. Is the Company proposing an RDM in this proceeding similar to the current RDM approved in Case No. U-17999?

A. Yes. DTE Gas is proposing to continue the RDM approved in Case No. U-17999 as a “simple revenue tracker” that reconciles Case No. U-17999 distribution revenue (excluding GCR revenues, surcharges and customer charges), with actual weather normalized distribution revenue (excluding GCR revenues, surcharges and the customer charges).

Q. When will the reconciliation period for the proposed RDM begin?

A. The Company proposes that the first reconciliation period begin October 1, 2019, which is the first month following the end of the projected test year in this case.

Q. What should the RDM caps be for years one and two?

A. Similar to the RDM caps approved in both Case Nos. U-16999 and U-17999, the RDM is limited by a revenue cap to reflect a reasonable estimate of the maximum qualifying revenue shortfall (or excess) that could be experienced by the Company, assuming that DTE Gas generates EWR credits at a level equal to 150% of the statutory minimum. With respect to the first annual reconciliation period, the qualifying revenue shortfall, by rate schedule, should be capped at 1.125% of the rate case qualifying revenue. With respect to the second and succeeding reconciliation periods, the qualifying revenue shortfall, by rate schedule, is capped at 2.25% of the rate case qualifying revenue.

Q. When would the proposed RDM terminate?

A. The proposed RDM would terminate when DTE Gas implements new rates by receiving a Commission order approving new rates based on an updated test year. The Company proposes that the reconciliations be filed annually, beginning three months after the end of the first reconciliation period, consistent with the current process.

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Infrastructure Recovery Mechanism (IRM)

Q. What is the Company's current IRM?

A. In Case No. U-17999, the Commission granted approval of DTE Gas's IRM to recover the predetermined incremental revenue requirement for infrastructure investments made in the Company's Main Renewal Program (MRP), Meter Move-out Program (MMO), and Pipeline Integrity Program (PI) for the five-year period of 2017 – 2021. Capital expenditures used to calculate the IRM are made on a calendar-year basis. The IRM surcharge is calculated on a calendar-year basis for each year of the five-year investment period. The surcharge is based on the predetermined cumulative incremental revenue requirement associated with the incremental capital investment. The Company files an annual reconciliation in the first quarter of the year for the capital spend in the prior year for Commission review. If the amount spent does not meet the required minimum, the IRM surcharges are adjusted downward in July of each year.

Further, Case No. U-17999 established that all capital invested as part of the IRM would be rolled into rate base, and recovery would continue through base rates, when DTE Gas files its next general rate case. Additionally, the IRM surcharge would expire upon a Commission order establishing new rates in a rate case superseding the current IRM.

Q. How has DTE Gas included the net invested IRM capital into rate base in this proceeding?

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A. As supported by Company Witness Ms. Uzenski, DTE Gas has included all invested IRM capital through December 31, 2018, which includes the first three months of the projected test period, into rate base in this case.

Q. Why is DTE Gas proposing to include only the planned IRM capital from October through December 2018 in the projected test year in this case?

A. As I will describe later in my testimony, DTE Gas is proposing to establish a new IRM surcharge beginning on January 1, 2019 to recover the incremental revenue requirement associated with invested IRM capital made on a calendar year basis; beginning for calendar year 2019. Therefore, it will be administratively simpler to include all invested IRM capital through December 31, 2018 in rate base in this case and begin the new IRM surcharge for 2019 IRM capital beginning on January 1, 2019. However, absent an IRM surcharge, all invested IRM capital through September 30, 2019 should be incorporated into the projected test year in this case. Of course, such a revision would require an increase to the Company's revenue requirement.

Q. What is the Company's proposed IRM?

A. In general, DTE Gas is proposing to recover the incremental revenue requirement associated with the MRP, MMO, and PI programs for the five-year period, 2019-2023 through a new IRM surcharge consistent with the Company's current IRM. Company Witness Harris provides further detail on the specific IRM capital investments proposed. Company Witness Suchta then calculates the revenue requirement for the relevant future periods. DTE Gas is proposing to increase rates due to the operation of the IRM on a fixed schedule, as described by Company Witness Slater, over the next five years.

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Q. Over what period is DTE Gas proposing to utilize the IRM to recover the incremental revenue requirement related to this capital spending?

A. DTE Gas is proposing to start the recovery mechanism effective January 1, 2019 with the first recovery period going through December 2019, for investments made in 2019. Thereafter, DTE Gas will phase in additional increases annually each January and continue through 2023 unless new base rates are established before that date. If DTE Gas does not file a rate case and have an order authorizing new base rates before December 2023, then DTE Gas will continue the IRM surcharge at the same monthly rates in effect in December 2023 until new base rates are established in its next general rate case. Continuing the IRM indefinitely at the December 2023 level, adjusted for any reductions from the last reconciliation filing, may allow DTE Gas to remain out of a rate case until costs other than IRM result in the need for rate relief.

Q. How does DTE Gas propose to reconcile its actual infrastructure-related expenditures with the expenditures reflected in the proposed IRM rates?

A. Consistent with the reconciliation process for the current IRM approved by the Commission in Case No. U-17999, DTE Gas will file a report by the last day of February of each year for the previous calendar year. This report will detail the amounts spent under the mechanism within the following parameters:

1. The annual spend will be the total of the targeted cost estimates for each of the three programs. The overall annual total costs start at $223.5 million in 2019, increasing to $247 million in 2020 and to $289 million in years 2021-2023. The breakout by program by year is shown on Company Witness Ms. Harris's Exhibit A-12, Schedule B6. Each year the Company will have the flexibility to increase or decrease the expenditures for each of the programs by up to 3.2% of each year's

target spend. The amounts applicable would be: 2019, $7.2 million; 2020, $7.9 million; 2021 through 2023, $9.2 million. Expenditures within $7.2 million in 2019, for example, of a program's target will not result in a reduction in the IRM surcharge if the total IRM spend equals or exceeds the year's target spend with no more than 3.2% increase ($7.2 million in 2019) in any one program.

2. As calculated by Witness Suchta, if DTE Gas's actual spend in any one of the programs is more than 3.2% below the target level, the IRM surcharges will be reduced by $0.013 per $1 million of shortfall exceeding $7.2 million in 2019, for example. Any such reduction will occur in July immediately following the February filing. This reduction applies to each program for which spending is below its target.
3. If none of the individual IRM programs' spending shortfalls exceed the tolerance amount but DTE Gas's actual total IRM spend is <u>below</u> the annual target, the IRM surcharges will be reduced by $0.013 per $1 million of the amount that the total actual spend is below the annual target. Any such reductions will be implemented in July of the year when the reconciliation is completed.
4. If both the total spend and one or more of the IRM programs would trigger a reduction in the IRM, the reduction will be based on the greater of the absolute value of 1) the total actual spend compared to the target, 2) the sum of the amount by which the spending shortfall of each of the programs exceeds 3.2% of their individual program targets.

Q. If the IRM expenditures in any one year exceed the target spend, how is the surcharge modified?

A. If DTE Gas's IRM capital expenditures exceed the target level in any given year, there is no adjustment to the mechanism and no recovery of the overspend via the IRM.

Excess expenditures not recovered the via IRM may result from the overall IRM program or the component three programs, MMO, MPR, and PI. For individual programs, overspend will be adjusted, within 3.2%, to reflect offsetting underspend in another program(s). IRM capital expenditures exceeding the target spend in total, or in any one program would remain unrecovered until the Company's next general rate case proceeding.

Q. If DTE Gas does not meet or exceed targeted IRM expenditures, what is the impact to the IRM surcharge?

A. Any spending shortfall, (either in total or due to not hitting the target level less 3.2% of the total IRM capital expenditure) will reduce the IRM surcharges in July of the year of the reconciliation, subject to Commission order in its reconciliation filing. The IRM surcharge will decrease at a rate of $0.013 per $1 million of actual spending shortfall. This fixed rate was developed by Witness Suchta on Exhibit A-18, Schedule H5. The rate reduction will be reflected to all future IRM surcharges until terminated due to a final rate order in a rate case proceeding.

Q. How are the proposed IRM surcharges calculated?

A. The monthly IRM surcharge for each rate class is calculated for each year of the five-year IRM program in Witness Slater's Exhibit A-18, Schedule H3. The resulting surcharges are included in a table included in proposed Sheet D-2.01, in exhibit A-18, Schedule H5. If there is an adjustment to the surcharges due to underspend in any year, this table on Sheet D-2.01 will be updated to reflect the change for that year and the following years. Witness Slater supports the IRM surcharge calculation in his testimony.

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Q. When will the new IRM surcharge begin?

A. DTE Gas is proposing to implement the new IRM surcharge on January 1, 2019 to recover the cost of service associated with the IRM capital invested during the 2019 calendar year. In subsequent years of the program, DTE Gas will implement new IRM surcharges annually on January 1, as detailed on pages 1-6 of Exhibit A-18, Schedule H3, to recover the cost of service on the incremental IRM capital invested from that calendar year. For example, the IRM surcharge beginning on January 1, 2020 will recover the cost of service for new IRM capital expenditures in calendar year 2020, reflecting the half year convention for 2020, plus a full year cost of service for IRM capital expenditures from 2019.

Q. Why is January 1 the optimal start date for the IRM surcharge implementation?

A. A January 1 implementation results in a match between when costs are incurred and recognized and when revenues are received. It is an optimal outcome, allowing the IRM to operate under the matching principle. Additionally, since depreciation expense for the first year of a capital investment is based on the half year convention, starting the surcharge in January will provide the appropriate level of revenue requirement recovery in the first year without causing regulatory lag in the subsequent years.

Q. What would be the status of the IRM surcharge if DTE Gas files a rate case during the five-year period the IRM surcharge is in place?

A. U-18999 IRM surcharges cease when new base rates are implemented in the Company's next general rate case. At that time, all capital invested as part of the IRM in this filing would be rolled into rate base and recovery would continue through base rates as a part of a base rate case filing. As part of any future rate case, DTE Gas

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may propose to implement an updated IRM to address recovery of future infrastructure investment. Absent a rate case, the U-18999 IRM surcharge would continue indefinitely at the final rate established after the fifth year of the program (capturing all invested IRM capital through December 31, 2023). Again, once new base rates including the capital expenditures recovered via the U-18999 IRM surcharge are implemented in a general rate case, these IRM surcharges would be terminated. Because IRM surcharges are implemented on a billed basis, the IRM surcharges would terminate 1) after the final billing cycle of the month new rates are in effect or 2) with the last billing cycle of the month prior to new rates, if new base rates are in effect on the first business day of the month.

Other Policy Proposals

Q. Is DTE Gas proposing to recover costs associated with the Company's incentive compensation programs?

A. Yes. DTE Gas uses incentive compensation to: 1) attract and retain employees with the requisite skills and experience to ensure quality customer service delivery; 2) ensure that DTE Gas's employees' total compensation, which is comprised of both base and variable components, is externally competitive and internally equitable; and 3) differentiate total rewards based on organizational and individual contributions. Given DTE Gas's need to provide adequate total compensation and to drive performance that ultimately benefits our customers, incentive compensation is an essential component of the Company's total compensation package. In Case No. U-17999, the Commission disallowed the Company's request for recovery of incentive compensation costs related to financial performance measures and approved the recovery of expenses associated with incentive compensation programs tied to operational metrics. The Commission's finding was that while financial metrics largely benefit shareholders, operational metrics and the resulting improvements benefit customers directly and, therefore merit customer funding. In the current proceeding, Witness Cooper fully supports the recovery of these costs and is supporting a comprehensive cost-benefit analysis.

Q. Is the Company proposing any changes to low-income rates and tariffs in this proceeding?

A. Yes. DTE Gas is proposing to continue its Low-Income Assistance (LIA) credit piloted in case U-17999, as well as to continue the Residential Income Assistance Service Provision (RIA) credit available to Residential Service Rate A customers. In addition, the Company proposes to increase enrollment and funding for the LIA credit as discussed in more detail by Company Witness Mr. Johnson. The proposed increase will allow DTE Gas to best serve the needs of our most vulnerable low-income customers.

Q. How does DTE Gas propose to recover costs associated with the 50,000 Dth per day of capacity under the ANR Alpena transport contract that is used and useful for delivering GCR purchased gas supply to the DTE Gas system?

A. Since 50,000 Dth per day of capacity under the ANR Alpena transport contract is now primarily used and useful for delivering GCR purchased gas supply to the DTE Gas system, DTE Gas believes that it is more appropriate to recover those costs as part of the cost of gas in the GCR. However, consistent with the Commission order in DTE Gas Rate Case No. U-17999, DTE Gas has included $3.5 million per year for those costs in the projected test year in this proceeding. Should the Commission agree that those costs should be recovered as part of the cost of gas in the GCR, then the Company would rescind its request for $3.5 million per year recovery of those costs in this proceeding.

Q. Why does DTE Gas believe that $3.5 million per year of costs under the ANR Alpena transport contract should be recovered as part of the cost of gas in the GCR in lieu of base rates?

A. The Commission initially approved the recovery of costs under the ANR Alpena transport contract in base rates because its primary function at that time was to provide system integration by connecting the DTE Gas storage fields with the DTE Gas Alpena system. However, the initial contract has since been replaced and the primary use of the new ANR Alpena transport contract is to deliver GCR purchased gas supplies into the DTE Gas system. Therefore, the Commission should approve recovery of these costs as part of the cost of gas in the GCR in the same way the costs for all other interstate transportation contracts that deliver GCR purchased gas supplies to the DTE Gas system are recovered.

<u>Introduction of Other Witnesses</u>

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

A. The Company proposes to present its case through 17 witnesses, including myself, as described below (in alphabetical order).

1) Ms. Jennie Aud, Director – Gas Control and Planning, will support: overall lost and unaccounted for (LAUF) gas and gas used by Company (Company Use) volumes for the twelve months-ending September 30, 2019 projected test

period; transmission LAUF gas as it relates to DTE Gas's primary transmission system; the overall summary of LAUF and Company Use cost of service and the allocation of these costs to GIK related and base distribution customers; the operational requirements driving the facility expansions requirements for transporting Nexus volumes; and support for DTE's use of a design peak day and the variables used to develop design peak day volumes.

2) Mr. George Chapel, Manager – Market Forecasting, will support the customer counts and normalized customer consumption for 2016, 2017, and will support DTE Gas's forecasted customer counts and customer consumption for the October 2018 - September 2019 test year, by total and by customer class. Mr. Chapel will also discuss the assumptions relating to the Exelon Easement Agreement and the resulting adjustments to DTE Gas's customer counts and usage projections, including adjustments to consumption such as Energy Waste Reduction and the changing heating value of natural gas on DTE Gas's system. Finally, Mr. Chapel will support DTE Gas's cost of gas forecast and the ANR Pipeline agreements for transportation service to Grand Rapids and the Alpena pipeline transmission system to serve connected markets.

3) Mr. Michael Cooper, Director – Compensation, Benefits & Wellness, will present: an overview of benefit expense for DTE Gas for the 2016 historical test year and the projected test year for the twelve months ending September 30, 2019. Mr. Cooper will provide support for the Company's pension costs, OPEB, active employee healthcare 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 support the inclusion of the incentive plan costs based on the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

4) Mr. Henry J. Decker, Director – Energy Gas Sales and Marketing, will support the Company's proposed gas-in-kind percentages for all rate classes. Further, Witness Decker will support the Company's projected test year forecast of transportation volume, revenue and customer count forecasts relating to End-Use Transportation (EUT) customers. In addition, Witness Decker will support our proposal to recover the transportation rate discounts provided to AK Steel and Ford Motor Company, two of DTE Gas's largest EUT customers, in base rates. Witness Decker will also support DTE Gas's proposed EUT monthly customer charges, rate schedule break-even points for rate design purposes, the minimum and maximum EUT optional rates, and modifications to DTE Gas's Rate Book for EUT customers. He will further discuss the Company's projected test year forecast of Off-System (Midstream) Storage, and Transportation Revenue, Other Operating Revenues and the Transmission and Compression of Gas Costs by Others. Finally, Witness Decker will discuss DTE Gas's appliance service program revenue, gas customer choice supplier revenues, and other gas revenues. Witness Decker will also support projected earnings impact of the Company's Blue Lake Storage investment, and

miscellaneous service revenues. In addition, he will request recovery of natural gas research and development expenses pursuant to the standards set-out in the Commission's Order in Case No. U-14561.

5) Ms. Joi Harris, Vice President – Gas Operations, will support the Company's request to increase the IRM capital expenditure levels to achieve a 15-year renewal to completion of the Main Renewal Plan and expand the Meter Move Out program to address overdue Meter Assembly Checks. Witness Harris will discuss why the accelerated removal of unprotected mains is reasonable and prudent to ensure the continued safety and reliability of our gas system. In addition, she will discuss how the proposed expansion of the MMO program will help to address the Company's inability to access inside meters for purposes of atmospheric corrosion control, continuing surveillance and leak surveys as referenced by the MPSC Staff in Case No. U-17999.

6) Mr. Mark Johnson, Director – Revenue Management and Protection, will support the Operation and Maintenance (O&M) expenses of DTE Gas's Customer Service and Regulated Marketing organizations for the projected test year for the twelve months ending September 30, 2019. Witness Johnson will support historical costs and projected related O&M expenses for the period October 1, 2018 through September 30, 2019. Further, Mr. Johnson will discuss the inflationary impact on forecasted costs, provide an update on DTE Gas's level of uncollectible expense, and discuss Customer Service and Marketing performance and areas of improvement. Finally, Mr. Johnson will show that the low-income assistance credit (LIA), whose initial pilot was approved in the

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Company's last rate case (Case No. U-17999), fills a need or extends assistance to customers in a way unique from or complementary to the Company's other assistance programs, including the Low-Income Self-Sufficiency Plan and RIA.

7) Ms. Diane Martino, Principal Engineer – Environmental Management and Resources, will describe and explain DTE Gas's Manufactured Gas Plant (MGP) remediation projects.

8) Ms. Alida Sandberg, Director – Engineering Services, will support the actual routine capital expenditures for 2016 and the projected test year for the 12 months ending September 30, 2019; other capital expenditures through September 2019, including the top 25 capital projects; and Infrastructure Recovery Mechanism (IRM) capital expenditures through December 2018, including an additional non-IRM Pipeline Integrity expenditure of $3.0 million through September 30, 2019.

9) Mr. Robert Sitkauskas, Manager – Advanced Metering Infrastructure, will support DTE Gas's Advanced Metering Infrastructure (AMI) project. He will provide a brief background on AMI efforts at the Company, explain the expected benefits to utility ratepayers, and provide a detailed utility cost/benefit analysis as required by the MPSC's Order in Case No. U-15985.

10) Mr. Kenneth Slater, Manager – Revenue Requirements, will support DTE Gas Company's jurisdictional cost of service studies (by rate schedule) for the projected test year ending September 30, 2019 (projected test year) for both

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sales and end-user transportation; jurisdictional rates for each rate schedule that includes a monthly service charge and a commodity distribution charge based on the results of the jurisdictional cost of service studies; the development of an unbundled rate covering off-system transportation; a second cost of service study analysis to support the recovery of the AK Steel and Ford Motor Company discount in rates; the proposed IRM monthly charges; and proposed tariff changes relating to modifications applicable to its various rate schedules.

11) Mr. Edward Solomon, Assistant Treasurer and Director – Corporate Finance, will support DTE Gas's projected capital structure and the cost of its long and short-term debt to be used in the determination of DTE Gas's overall rate of return.

12) Ms. Margaret Suchta, Consultant – Regulatory Economics, will support DTE Gas's 2016 historical test year revenue sufficiency, balance sheet classification, rate base determination, adjusted Net Operating Income (NOI), overall rate of return (ROR) percentage, and the revenue multiplier. Further, Witness Suchta will sponsor the NOI adjustments for interest synchronization and income tax savings. She will also sponsor DTE Gas's projected revenue deficiency, classification of the projected 13-month average balance sheet, rate base determination, as well as the revenue multiplier, interest synchronization adjustment, income tax savings adjustment, and overall rate of return. In addition, Witness Suchta will support the calculation of the incremental revenue requirements for DTE Gas's Infrastructure Recovery Mechanism (IRM) as well as calculate a fixed rate reduction for each $1 million of under spend of IRM capital, if DTE Gas incurs such an under spend. Further, Witness Suchta will

sponsor a complete revenue requirement calculation for the NEXUS project, including evidence on the project's costs and revenues for DTE Gas. Finally, Witness Suchta will sponsor a revenue deficiency calculation excluding AK Steel and Ford Motor Co. as DTE Gas customers.

13) Ms. Renee Tomina, Director – Gas Operations, will support and describe Gas Operations O&M expense; the status of DTE Gas's leak backlog; and Meter Assembly Check (MAC) activities for the projected test year.

14) Ms. Theresa Uzenski, Manager – Regulatory Accounting, will support DTE Gas's financial statements for the historical test year ended December 31, 2016, the interim forecast period and a twelve-month projected test year ending September 30, 2019, including a 13-month average balance sheet. Witness Uzenski will support the development of the projected test year adjusted gas operating income based on forecasted changes from the normalized historical gas operating income and the inflation rate used to develop projected O&M and Capital related costs. She will also support the Corporate Staff Group (CSG) expenses for the historical and forecasted periods and explain the function of this group and the method for allocating costs to DTE Gas and the other DTE subsidiaries. Witness Uzenski will also support that costs recovered from other mechanisms are excluded from the financial statements in this case (EWR, IRM, GCR Mechanism, and RDM) and explains the accounting for the IRM. Further, Witness Uzenski is requesting deferral accounting for certain Pension and OPEB costs.

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15) Dr. Michael Vilbert, Principal – The Brattle Group, will estimate the cost of capital for the Company. Specifically, Dr. Vilbert will provide return on equity (ROE) estimates derived from a sample of comparable risk, regulated gas local distribution utility companies ("gas LDCs"). Dr. Vilbert will also consider the relative risk of the Company's proposed capital structure ratio to arrive at his recommendation for the allowed ROE.

16) Ms. Sherri Wisniewski, Director – Tax Accounting, will support the DTE Gas Federal Income Tax (FIT), Michigan Corporate Income Tax (MCIT), municipal income tax, property tax and other general taxes for the 2016 calendar year historical period and the twelve months ending September 30, 2019 projected test period.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
______________________________________	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JENNIE A. AUD

DTE GAS COMPANY
QUALIFICATIONS OF JENNIE A. AUD

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

A. My name is Jennie A. Aud. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Gas Company (DTE Gas or Company) and hold the position of Director, Gas Control and Planning.

Q. What is your education and business experience?

A. I received a Bachelor of Science Degree in Mechanical Engineering from Lawrence Technological University, Southfield, Michigan, in 1991. I was employed by ANR Pipeline Company from 1990 to 1994 as a Facility Planning Staff Engineer, after which I accepted employment at Michigan Consolidated Gas Company (MichCon) as a Senior System Planning Engineer. From 1996 to 1998, I was Manager, System Planning and Asset Optimization; from 1998 to 1999, I was Manager, System Planning and Gas Planning; and from 1999 to 2001, I was Manager, System Planning and Gas Control. From 2002 to January 2011, I was Manager, Gas System Planning. In 2011, I accepted the position of Manager, Gas Renewal Program and held that position until April of 2015 when I accepted my current position as Director, Gas Control and Planning.

Q. What are your current duties and responsibilities with DTE Gas?

A. In my current position as Director, Gas Control and Planning, for DTE Gas, I am responsible for the following functions: Gas Control which involves the 24/7/365 monitoring and control of gas volumes, pressures and alarm conditions on DTE Gas's transmission and major distribution system; Measurement and Control Maintenance which involves installation and maintenance of communication, instrumentation and electronic gas measurement equipment throughout DTE Gas's

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system; Gas Measurement which manages the gas measurement function to ensure completeness and quality for receipt/delivery volumes and energy quantities, along with maintaining the Supervisory Control and Data Acquisition (SCADA) system used by Gas Control; Gas Nomination Services which administers all inbound scheduling/nomination activity on DTE Gas's pipelines, schedules all outbound transportation nominations on third party pipelines and allocates wellhead production gas to producers based on ownership interest; and Project Planning and Asset Prioritization, which include, among other things, managing and optimizing DTE Gas's transmission, storage and compression assets.

Q. Have you previously sponsored testimony before regulatory bodies?

A. Yes. I have provided testimony in a gas quality case filed by ANR Pipeline Company before the Federal Energy Regulatory Commission (FERC) in Docket No RP04-435-000. I have filed testimony with the Michigan Public Service Commission (MPSC) in Case No. U-14800, seeking ex parte approval of the sale of excess system gas supply and related accounting changes resulting from enhancements made to DTE Gas's storage system. I have also provided testimony with the Michigan Public Service Commission (MPSC in Case No. U-17999, a DTE Gas Rate Case.

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PURPOSE OF TESTIMONY

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

A. I am sponsoring testimony addressing the following areas:

1. Overall lost and unaccounted for (LAUF) gas and gas used by Company (Company Use) volumes for the 12 months-ending September 30, 2019 projected test period;
2. Transmission LAUF gas as it relates to DTE Gas's primary transmission system;
3. The overall summary of LAUF and Company Use cost of service and the allocation of these costs to GIK related and base distribution customers;
4. The operational requirements driving the facility expansions requirements for transporting Nexus volumes; and
5. Support for DTE's use of a design peak day and the variables used to develop design peak day volumes.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-15	E8	Summary of Lost and Unaccounted for Gas, Gas Used by Company and Cost Recovery – Projected Test Year
A-15	E9	Actual Lost and Unaccounted for Gas, 12 months ended August – Five Year Average
A-15	E10	Lost and Unaccounted for Gas and Gas Used by Company – Cost Recovery Calculation

A-15	E11	Gas Used by Company – Historical 5-year Average and Projected Test Year
A-15	E12	Transmission System Lost and Unaccounted For Summary - 5 Years ended August 31, 2017 - Average
A-15	E13	Primary Gas Transmission System Map (schematic)
A-22	L12	Alternative Summary of Lost and Unaccounted for Gas, Gas Used by Company and Cost Recovery – Projected Test Year
A-22	L13	Alternative Lost and Unaccounted for Gas and Gas Used by Company – Cost Recovery Calculation

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

A. Yes, they were.

LOST AND UNACCOUNTED FOR GAS

Q. What do you mean by the term LAUF gas?

A. LAUF gas is the difference between booked sources of gas and booked disposition of gas. Sources of gas include gas purchases made by DTE Gas, receipts from, and re-deliveries to, off-system transporters, receipts for end-use transportation customers, and storage injections and withdrawals. The disposition of gas includes the metered and estimated consumption of distribution sales, end-use transportation customers and gas used by the Company. As in most, if not all, gas pipeline and storage systems, the sources of gas will not equal the disposition of gas on an annual or monthly basis. This difference is LAUF gas. Sources of gas greater than the disposition of gas for a pipeline system represent losses, and sources of gas less than the disposition of gas represent gains. The LAUF gas can either be permanent or temporary.

Q. What are the major causes of LAUF gas?

A. There are a number of contributors to LAUF gas including:

1) Metering inaccuracy, specifically, losses that occur when receipt meters overstate or when delivery meters understate, or gains that occur when receipt meters understate or delivery meters overstate;
2) Leaks and theft, both of which are losses and occur almost exclusively in distribution piping systems; and
3) Other metering and billing issues that result in under-recording of deliveries.

Q. How does DTE Gas calculate LAUF gas?

A. DTE Gas breaks LAUF gas into three categories and calculates a monthly loss (or gain) estimate based on these categories:

1) Transmission (determined on a daily basis on the primary transmission system; caused by cumulative metering inaccuracy)
2) Leaks (calculated based upon known leaks, estimating undetected leaks and applying a leakage factor per leak)
3) Theft and Other (all other issues and any net inaccuracy in estimates of losses due to leaks; the percentage of this category that is made up of theft losses is also estimated based on known theft activity)

Some of these categories are difficult to quantitatively identify, or at least separately identify. For example, since most leaks and theft occur within the distribution system and are not measured, their individual contribution to distribution system losses can only be estimated.

Q. Are there any temporary situations that cause LAUF gas to fluctuate between months and over annual cycles?

A. Yes. Temporary situations include:

1) Preliminary to final accounting entries,
2) Unbilled revenue calculation,
3) Unrecorded transactions captured in a subsequent month,
4) Actual meter reads following a previous estimated read, and
5) Rebilling a settlement billing of customers who stole gas in a previous period or an adjustment for meters not registering accurately.

Q. What are DTE Gas's key initiatives to control and reduce the level of LAUF gas in each of these areas?

A. For transmission LAUF, DTE Gas employs the use of check metering at large interconnects, continuous condition monitoring of ultrasonic meters (USMs), physical meter inspections, and audits of the configuration/functionality of the meter installations. For leaks, repairs are used as the short-term mitigation method, with the long-term solution being the renewal of poor performing distribution mains and services. Several theft detection methods are used including analysis of usage and billing data, field activities involving inspection of sites without customer agreements, and ongoing meter inventory efforts.

DTE Gas continuously analyzes usage and billing data to determine sources of unmetered, unbilled or under-estimated volumes. For example, meters that stop registering or indicate significantly less usage than historical volumes are investigated for equipment malfunction or theft. In the long-term, DTE Gas's Meter Move Out activities, as described by Company Witness Ms. Harris, will significantly reduce the number of inside meters. This program will improve DTE Gas's ability to safely and efficiently detect and remediate theft and other metering / billing issues complicated by the inability to easily access meters located inside customers' homes.

Q. Has DTE Gas applied any specialized resources to detect and analyze potential locations and causes of LAUF gas?

A. Since 2010, DTE Gas has utilized contractors to perform scheduled leak survey activities on distribution mains and services and to acquire meter inventory data. Since 2012, DTE Gas has contracted with an outside firm (Metroscale Analytics) to provide technical resources to support activities within the Gas Revenue Analytics group, which is responsible for efforts to monitor and improve processes to reduce LAUF gas. Meter data is used to confirm billing system data on meter type and serial numbers. This same data can also detect instances of stolen meters relocated to affect the theft of gas. Meter data is used to confirm billing system data on meter type and serial numbers. It can also detect instances of stolen meters relocated to affect the theft of gas.

Metroscale Analytics provided data on potential usage at sites that did not have an active customer and at sites with non-registering meters. This effort enhanced the ability to detect the elevated risk of potential theft, including instances of hazardous piping modifications. Each year the list of idle services checked by Metroscale Analytics is selected from our Customer Service and Billing (CSB) system (and now Customer Relationship and Billing (CRM&B) system) and reflects active service lines without a customer of record or a non-registering meter with a customer of record.

Metroscale Analytics uses thermal imaging to determine which locations appear heated. The homes with an apparent heat source but no active customer are referred to Revenue Management and Protection (RM&P) for investigation of possible theft or for non-registering meters, to Field Operations to replace the meter.

Q. What is the proposed LAUF gas volume for the projected test period?

A. DTE Gas is supporting 4,566 MMcf of LAUF gas for the projected test year. (Exhibit A-15, Schedule E9). This volume is based on five-year September 1, 2012 to August 31, 2017 average. To minimize the impact of swings in the unaccounted-for nature of LAUF gas, the Commission and Staff have supported the use of a five-year average in DTE Gas's last four fully litigated general rate cases. (Cases Nos. U-15985, U-13898, U-10150, and U-17999). Staff also supported a five-year calculation for LAUF in U-16999, which was subsequently settled.

TRANSMISSION SYSTEM LOSSES

Q. What part of DTE Gas's gas transmission and distribution system is included in what is described as the primary transmission system?

A. The primary transmission system, illustrated schematically in Exhibit A-15, Schedule E13, is defined as pipelines operating at 20% or greater of its specified minimum yield strength (SMYS) and generally consists of the largest diameter and highest pressure pipelines within DTE Gas's integrated transmission and distribution system. The primary transmission system provides access to much of the large pipeline interconnect, storage and production meters on DTE Gas's system. The primary transmission system also provides direct feeds to the distribution systems supplying the Southeast Michigan market areas, and secondary transmission systems providing supply to the Ludington-Muskegon and Traverse City-Petoskey-Mt. Pleasant market areas.

Q. Which DTE Gas customers utilize the primary transmission system?

A. The primary transmission system is the portion of the transmission system that all DTE Gas customers utilize. They are as follows: Gas Cost Recovery (GCR), Gas Customer Choice (GCC), end-use transportation (EUT), off-system transportation and storage service customers.

Q. How do these DTE Gas customers utilize the primary transmission system?

A. DTE Gas customers utilize the primary transmission system as follows:

1) Access to pipeline and production supplies for DTE Gas's GCR, GCC and EUT customers, even those not able to receive supply directly from the primary transmission system, such as those in the Upper Peninsula or Grand Rapids;

2) Access to storage for GCR, GCC and end-use transportation customers;
3) Off-system transportation and storage services; and
4) Transportation of supplies and storage for the DTE Gas market areas.

Customers that utilize DTE Gas's storage either directly or indirectly require the use of DTE Gas's primary transmission system to transport their supply to and from storage.

Q. What sources of gas are physically metered on DTE Gas's transmission system?

A. All gas received by DTE Gas at (1) interconnecting points with third party pipelines, (2) storage facilities connected to its system, and (3) interconnecting production points on its system is physically metered. The Company has custody transfer quality meters in place at each of these locations allowing DTE Gas to accurately measure the actual gas flow.

Q. What redeliveries of gas are physically metered from DTE Gas's primary transmission system?

A. All gas volumes redelivered by DTE Gas at (1) interconnecting points with third party pipelines, (2) storage facilities connected to DTE Gas's system, (3) transmission-distribution transfer points within the DTE Gas system, and (4) for Company Use fuel, are physically metered.

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Q. Why are transmission system losses relevant when DTE Gas has already identified the overall LAUF volumes to be recovered in this proceeding?

A. Transmission system losses and distribution system losses occur on different parts of DTE Gas's system that are used in different proportions by the various classes of customers. As described in Company Witness Mr. Decker's testimony, DTE Gas's off-system transporters and the largest end-use transportation customers are extensive users of DTE Gas's transmission system with little or no utilization required on DTE Gas's lower pressure distribution system. DTE Gas can determine the losses or gains that occur on its primary transmission system separately from the losses that occur on the remainder of its system, the distribution system.

Q. How much of DTE Gas's total throughput is handled by the primary transmission system?

A. Based on historical volumes, the throughput on the primary transmission system comprises approximately 80% of the total throughput on DTE Gas's entire system, with most of the remaining throughput entering from other pipelines into either a regional transmission system or directly into a distribution system in areas like Grand Rapids and Sault St. Marie.

Q. How will the Nexus pipeline interconnect affect the total throughput on the DTE Gas primary transmission system?

A. With Nexus's supply gas, the primary transmission system will handle approximately 85% of the total DTE Gas system throughput.

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Q. Why is it important that DTE Gas have an accurate means of measuring flow activity and LAUF on its primary transmission system?

A. It is important for two reasons. First, it helps the Company understand a major component of its Company-wide LAUF gas. Since approximately 80%-85% of the total source volumes entering DTE Gas's entire pipeline system flow onto the primary transmission system, errors in metering these large volumes can greatly impact Company-wide LAUF. Second, it identifies a major cost component of LAUF associated with users of DTE Gas's primary transmission pipeline system. DTE Gas has an extensive transmission pipeline operation because of its geographically diverse service territory and large gas storage capacity. The ability to isolate losses on the primary transmission system helps to explain, in part, total natural gas losses to the Company.

Q. Can DTE Gas isolate the losses occurring on its primary transmission facilities from those on the balance of its system?

A. Yes. DTE has installed custody transfer quality measurement at transmission-to-distribution transfer locations connected to the primary transmission system. These installations provide DTE with the ability to definitively identify primary transmission losses. DTE Gas has meter installations that permit daily balancing of the primary transmission system to determine transmission LAUF gas. The Company also prepares a comparison of the monthly LAUF gas on the primary transmission system with the Company-wide LAUF gas volumes.

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Q. Has there been a significant change in the level of primary transmission gains/losses over the last five-year period ending August 2017?

A. Yes. The Company has experienced both losses and gains in the five-year period. The Company filed in Case No. U-17999 an actual primary transmission loss percent of 0.27% based on the five-year historical period ended 2015. For the five-year period ended August 2017, the Company's actual primary transmission gain is 0.03% as calculated on Exhibit A-15, Schedule E12.

Q. To what do you attribute the transmission gains recorded in 2016 and 2017?

A. As stated previously in my testimony, one of the contributors to LAUF gas is metering inaccuracy, specifically gains that occur when receipt meters understate or delivery meters overstate.

Q. How does transmission LAUF impact total Company wide LAUF?

A. For the five-year period ended August 31, 2017, the primary transmission-only losses and gains have averaged a 0.03% gain of physical primary transmission system deliveries. This gain offsets approximately 3.31% of Company-wide LAUF gas. See Exhibit A-15, Schedule E12. The ability to isolate primary transmission system LAUF gas from Company-wide LAUF gas, has allowed a better understanding of where losses or gains were occurring on DTE Gas's system.

Q. Does DTE consider the gains recorded in 2016 and 2017 due to metering inaccuracies to be significant?

A. No. In each year where transmission gains were observed, Exhibit A-15, Schedule 12, column (d) and lines 4 and 5 show that the gains were 0.13% and 0.44%, which

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are both below the 2% threshold for metering inaccuracy that is considered significant, as defined by the Company's tariff.

COMPANY USE

Q. What is Company Use volume?

A. Company Use volume is predominantly fuel that is used to operate and maintain DTE Gas's transmission and storage facilities. Company Use includes, among other things, fuel used for compressors, gas processing at storage fields and gate station heaters. Company Use also includes gas the Company provides to various third party pipeline companies necessary for the efficient operation of DTE Gas's system. An example would be fuel provided to ANR Pipeline Company (ANR) pursuant to the Trufant transportation arrangement to transport gas supply to market areas that are non-contiguous with our primary transmission and storage system. The Company also uses natural gas to heat Company facilities.

Q. What is the Company Use volume for the projected test year?

A. DTE Gas is supporting 3,570 MMcf of Company Use fuel in the projected test year. Exhibit A-15, Schedule E11 summarizes the major components of Company Use.

Q. Has the Company identified any known and measurable changes to the Company Use volume?

A. Yes, the Company has identified two changes to the Company Use volume. The first change adjusts for the increasing Btu heating value content of gas deliveries and receipts. Company Witness Mr. Chapel explains the expected change from historical Btu factors to those used in the projected test year. Because the Btu

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content is expected to be higher, less natural gas volume will be required to operate DTE Gas's compression and other equipment. The historical Company Use was lowered by 5 MMcf for this effect, as shown in Exhibit A-15, Schedule E11.

As an example, if a piece of equipment is rated at 100,000 Btu per hour, it will burn 100,000 Btu per hour regardless if you have a gas with 950 Btu/cf or 1,100 Btu/cf. So, if this equipment burns 100,000 Btu per hour, and the Btu content increases from 950 Btu per cubic foot to 1,100 Btu per cubic foot, the piece of equipment will use fewer cubic feet of the higher Btu content gas to burn its 100,000 Btu per hour. The second change results from anticipated transportation of Nexus volumes on the DTE Gas transmission system. The historical Company Use was increased by 1,114 MMcf for transportation of Nexus gas across the system, as shown in Exhibit A-15, Schedule E11. These two changes to historical Company Use result in the Company Use volume of 3,570 MMcf in the projected test year, which is a 1,109 MMcf (or 69%) increase from the 5-year historical average year level of 2,461 MMcf.

Q. Why does the Company Use volume for the projected test year increase by 69%?

A. Throughput for the 12 months ended August 2017, from Schedule E12, line 5 column (c) is 411,051 MMcf. With the addition of Nexus volumes of 240,000 MMcf, the total projected test year physical throughput (as supported by Witnesses Chapel and Decker), is an increase in throughput of just over 58%. This increased volumetric throughput requires compression which increases the Company Use volume needed for the projected test year.

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GAS-IN-KIND CALCULATION

Q. How does the isolation of transmission LAUF gas impact the ability to allocate overall LAUF gas costs?

A. Isolating transmission loss gives DTE Gas the information necessary to determine appropriate allocations of these costs.

Q. Given the high level of accuracy in measuring the inputs and outputs of DTE Gas's transmission system, is it reasonable to conclude that the remaining LAUF volume and cost is related to DTE Gas's distribution system?

A. Yes. Losses on the distribution system are dominated by leaks and theft. Both types of losses occur almost exclusively in the small diameter, low pressure parts of the distribution system. These losses are associated with activity by distribution customers and, to a lesser extent, are a result of theft.

Q. Are there any classes of customers who have limited impact on distribution system LAUF?

A. Yes. DTE Gas's off-system transporters and the largest end-use transportation customers use little or none of DTE Gas's lower pressure distribution system. Off-system customers are served almost exclusively from the primary transmission system.

Q. How do off-system transporters and large volume end-use transportation customers contribute to the amount of LAUF and gas used by Company?

A. These customers contribute to LAUF and Company Use as follows:

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1) Primary transmission LAUF volumes are based on the average percentage of transmission LAUF times projected test year off-system transportation, storage and end-use transportation volumes, and

2) Company Use volumes are based on the average percentage of Company Use volumes divided by total throughput for the projected year. Witness Chapel supports the GCR, GCC and aggregate (GCR / GCC) volumes for the projected test year used in the calculation while Witness Decker supports the off-system transportation, storage and end-use transportation volumes for the projected test year.

Q. What is the average company use percentage on a system wide basis?

A. Based on 3,570 MMcf Company Use volumes (Exhibit A-15, Schedule E11) and 704,071 MMcf projected test year physical throughput provided by Witness Decker Exhibit A-15, Schedule E14, the average Company use is 0.51% of gas used by the Company.

Q. What is DTE Gas projecting for Transmission LAUF for the projected test year for GCR, GCC, Aggregates, DIG Transportation, XXLT Transportation, 3rd Party and Exelon 3rd Party customers?

A. DTE is projecting a gain of 0.03% based on the 5-year historical average LAUF on DTE Gas's transmission system experienced from September 1, 2012 – August 31, 2017, excluding incremental NEXUS volumes.

Q. What is DTE Gas projecting for Transmission LAUF for NEXUS volumes being transported on DTE Gas's system?

A. For the incremental volumes delivered by NEXUS, DTE Gas is projecting no incremental losses or gains.

Q. Why is DTE Gas projecting no losses or gains for transporting NEXUS volumes?

A. Until DTE Gas transports NEXUS volumes on its transmission system, it is uncertain what impact these incremental volumes will have on transmission LAUF. If the system experiences losses or gains, then data will exist for future projections.

Q. What is DTE Gas projecting as a weighted average Transmission LAUF rate, taking into consideration all customers that transport gas on DTE Gas's transmission system?

A. Utilizing the projection of a 0.03% Transmission LAUF gain for GCR, GCC, Aggregates, DIG Transportation, XXLT Transportation, 3rd Party and Exelon 3rd Party customers and a Transmission LAUF projection of 0% for Nexus, the weighted average Transmission LAUF is calculated as a 0.02% gain.

FACILITY EXPANSION REQUIREMENTS FOR NEXUS

Q. What impact is NEXUS having on DTE Gas facilities?

A. To accommodate 1.3 Bcf per day of additional receipt volumes from NEXUS, the Milford Compressor Station, Willow Run Compressor Station and Willow Gate Station are being expanded.

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Q. Why is DTE Gas expanding facilities at Milford Compressor Station, Willow Run Compressor Station and Willow Gate Station?

A. The Milford Compressor, Willow Run Compressor, and Willow Gate facilities are being expanded to accommodate increased receipts to DTE as a result of the NEXUS Capacity Lease. The DTE/NEXUS Capacity Lease Agreement, increases receipts onto the DTE Transmission system at Willow Station by 1.3 Bcf per day throughout the year. The expanded facilities are required because currently, on a summer design day, both Willow Run and Milford compression are at capacity.

Q. What incremental facilities are needed at Milford Compressor Station?

A. The incremental facilities required at the Milford Compressor Station are three (3) 10,915 HP Solar Taurus 70 units and their ancillary equipment along with associated valves and station piping. These facilities are required at Milford Compressor Station to accommodate the increase in volumes requiring compression on summer design days.

Q. What incremental facilities are needed at Willow Run Compressor Station?

A. The incremental facilities required at Willow Run Compressor Station are two (2) 2,500 HP Caterpillar 3608 units, one (1) 5,000 HP Caterpillar 3616 unit, and one (1) 7,700 HP Solar Taurus 60 unit and their ancillary equipment along with associated valves and piping. These additional facilities are required at Willow Run Compressor Station to increase the pressure of PEPL and ANR volumes received at Willow Gate Station to match the NEXUS volume delivery pressure received at Willow Gate Station. NEXUS is required to provide a delivery pressure that matches DTE Gas's prevailing pressure of up to 858 psig, which matches the existing MAOP of DTE Gas's K Line and Willow Gate Station. The additional compression at Willow Run Compressor Station was sized to compress the ANR and PEPL volumes to a pressure of 858 psig.

Q. What incremental facilities are needed at Willow Gate Station?

A. The proposed incremental facilities installed at the Willow Gate Station are heaters, piping and valving required to interface with the new and existing Willow Run Compressor Station units.

Q. Do the new facilities at Milford Compressor Station and Willow Run Compressor Station provide any additional benefits to DTE Gas beyond accommodating NEXUS volumes?

A. Yes. Adding additional compressor units at Willow Run and Milford Compressor stations provides DTE Gas with additional flexibility to strategically plan maintenance outages at these stations during non-design days and shoulder months. This flexibility will help minimize any impacts to DTE Gas's customers and reduce the chance of unplanned outages effecting system reliability. At present time, all units at Milford are close to 40 years old and require extensive maintenance to keep them in optimum running condition. These aging compressor units require additional lead time to acquire replacement parts for maintenance and repair. This additional lead time lengthens the required outage. The new Milford Compressor Station compressor units will provide additional flexibility, allowing DTE to more strategically schedule and perform routine maintenance on the older units. It will also provide back-up for unexpected maintenance during the shoulder months of April to May and September to November.

PEAK DAY DESIGN

Q. Are there any other items that you are supporting in this proceeding?

A. Yes. Company Witness Mr. Slater is supporting the use of the design peak day methodology for cost of service allocation purposes. My testimony supports DTE Gas's use of a design peak day and the variables used to develop design peak day volumes.

Q. What are the key variables in developing design peak day volumes?

A. The design peak day volume calculation is determined annually for gas cost recovery purposes to ensure DTE Gas's retail customer (GCR, GCC and end-user transportation) markets can be physically served even with the coldest historical temperatures that have been experienced in its service areas. The design peak day is defined as the consumption expected on a day with an average temperature of -4 degrees Fahrenheit. Customer mix impacts the design peak day volume as each class has a different sensitivity to temperature. In the GCR process, key operational factors are considered to ensure the Company's ability to reliably serve its customers. These variables include retail market size, storage capability, contractual obligations, flowing supply, and potential weather effects. Given these factors, the Company calculates the optimal operating plan for the worst possible weather conditions to ensure supply reliability. This plan constitutes the Company's design peak day calculation.

Q. Why does DTE Gas use a design peak day rather than a historical peak day?

A. The design peak day reflects a consumption level consistent with the design of the utility's system. A historical peak day may not reflect consumption expected in severe cold weather because, on that peak day, temperatures may have been above the design conditions.

IMPACT OF LOSS OF AK STEEL AND FORD-ROUGE VOLUMES

Q. What information are you providing regarding the loss of AK Steel and Ford-Rouge?

A. Witness Slater requested both the impact on peak day load and exhibits reflecting a scenario where AK Steel and Ford Rouge are no longer customers on DTE Gas's system. I have created exhibits adjusting my Exhibit A-15, Schedules E8 and E10 to reflect the outcome of AK Steel and Ford Rouge left DTE Gas's system. Exhibit A-22, Schedules L12 and L13 reflect the impact of no longer having to plan for or provide service to AK Steel and Ford Rouge. The impact of no longer having to plan to provide service to AK Steel and Ford Rouge resulted in a reduction in load of 71.5 MMcf/d on a peak day.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
______________________________________	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

GEORGE H. CHAPEL

DTE GAS COMPANY
QUALIFICATIONS OF GEORGE H. CHAPEL

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Q. What is your name, business address, and occupation?

A. My name is George H. Chapel. My business address is DTE Gas Company (DTE Gas or Company), One Energy Plaza, Detroit, Michigan. I am employed by DTE Gas as Manager, Market Forecasting.

Q. What is your educational background and business experience?

A. In December 1985, I earned a Bachelor of Science degree from Central Michigan University with a major in mathematics. In April 1988, I was hired by Michigan Gas Company (MiGas) as a Rates and Gas Supply Analyst. There I performed various duties of increasing responsibility arising out of the regulation of MiGas as a public utility. In 1993, the assets of MiGas were rolled in amongst those of affiliate Southeastern Michigan Gas Company and Battle Creek Gas Company. These companies were combined to form what is known today as SEMCO Energy Gas Company (SEMCO). My duties with SEMCO included demand forecasting, supply planning, supply purchasing, nominating, and pipeline capacity management.

In May 1998, I was hired by DTE Gas as a Gas Supply Analyst. My duties with DTE Gas in that capacity included supply purchasing and market analysis. In October 2000, I was promoted to Manager, Gas Supply. I assumed my current position on January 1, 2003.

Q. What are your responsibilities with DTE Gas as Manager, Market Forecasting?

A. I am responsible for projecting DTE Gas's rate schedule customer growth/decline and its natural gas supply requirements. I provide gas demand forecasts in support of the Company's regulatory proceedings as well as support for supply planning and financial forecasts. Further, I perform analyses of the various components that contribute to gas demand forecasts such as studies that focus on weather dynamics and studies that focus on gas demand consumption dynamics.

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

A. Yes. I sponsored testimony on behalf of SEMCO and its subsidiaries in a variety of cases before the Commission. These cases include two general rate cases, two Michigan Residential Conservation Surcharge cases, and a number of Gas Cost Recovery (GCR) Plan and Reconciliation proceedings. I have also provided testimony in many regulatory proceedings for DTE Gas, including GCR Plan and Reconciliation proceedings, as well as DTE Gas's four most recent general rate cases: Case Nos. U-13898, U-15985, U-16999, and U-17999.

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PURPOSE OF TESTIMONY

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

A. My testimony will cover the following subjects:

1) **Historical Test Year Customer Count** – I will support the customer count for the historical test year and will explain how a customer is defined.

2) **Customer Count Forecast –** I will discuss the derivation of DTE Gas's customer count forecast. I will describe the seven demand regions across which DTE Gas serves customers. Further, I will describe the reasons that DTE Gas gains or loses customers, how these gains or losses will impact the change in DTE Gas's customers, and how these gains or losses impact the forecasted total number of DTE Gas's customers.

3) **Historical Test Year Customer Usage –** I will support DTE Gas's weather normalized total sales on an unbilled basis for 2016.

4) **Weather Normalization Adjustment** – I will support DTE's weather normalization adjustment which adjusts actual consumption from past periods to eliminate the impact of warmer than normal or colder than normal weather temperatures (measured in Heating Degree Days or HDDs) that occurred during that time.

5) **Customer Usage Forecast** – I will describe usage factors and how these factors, combined with weather, are applied to projected customer count to arrive at projected usage.

6) **Exelon** – I will discuss the volume assumptions related to the Exelon Easement Agreement, executed to mitigate concerns raised by the Staff of the Federal Trade Commission in their review of the acquisition by DTE Energy Company of MCN Energy Group.

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7) **Gas Cost Forecast** – I provide a forecasted cost of gas that is used by Company Witnesses Ms. Uzenski and Ms. Aud in testimony when the cost of gas is a component of the subject matter of their testimony.

8) **ANR Transport Contract No. 122065 for Service to the Alpena System and ANR Transport Contract No. 112110 for Service to Grand Rapids –** I describe $2.8 million in known and measurable increase in costs under these contracts from the historical test year 2016 to the projected test year October 2018 through September 2019.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-5	E1	Annual Service Area Sales by Major Customer Classes and System Output
A-15	E1	Annual Service Area Sales by Major Customer Classes and System Output
A-15	E1.1	Forecasted Deliveries and Customers by Rate Schedule
A-15	E2	Market Outlook: 2018 – 2022 Volumes and Average Number of Customers
A-15	E3	Comparison of Historical and Projected Number of Residential and Commercial Heating Customers
A-15	E4	Consumption per Customer Trend – Rate GS-1 & Rate A
A-15	E5	Monthly Normal Degree Days: Monthly 15-Year Normal (2002-2016) and 30-Year Normal (1987-2016)

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

A. Yes, they were.

HISTORICAL TEST YEAR CUSTOMER COUNT

Q. What was the 2016 total customer count?

A. On average for 2016, DTE Gas had approximately 1.2 million rate schedule customers, as shown on Exhibit A-15, Schedule E1.1, page 2 of 2, line 8, column (f). In this case, I define a customer as a service charge rendered by the Company for rates A, AS, 2A, and GS-1. Because service charges are rendered on a per meter basis for these rates, a customer can also be thought of as a meter. There may be instances where a single service address may have more than one meter and may receive more than one service charge. If a service address receives two gas bills, I count them as two customers, even if they are paid by the same individual. For Rates GS-2, S, and all transportation classes, a customer is a "meter or Contiguous Facility" and the customer charge is assessed on that basis.

CUSTOMER COUNT FORECAST

Q. What is the customer count forecast for the projected Test Year?

A. The adjusted projected Test Year customer count is 1,286,917. See Exhibit A-15, Schedule E1.1, page 2 of 2, line 8, column (o). It reflects forecasted customer gains across the rate schedules for the projected Test Year of 4,119 and new construction customer attachments for the Test Year of 9,072.

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Q. How is the customer count forecast by rate class derived?

A. A forecast of the number of customers by class, by month, is prepared using a recent three-year historical average growth/loss rate calculated for each of DTE Gas's seven demand regions. For this forecast, the historical three-year historical period was 36 months ended November 2016. The seven demand regions are: Detroit/Ann Arbor, Grand Rapids, Muskegon, Traverse City, Alpena, Sault Ste. Marie, and Iron Mountain.

Once this base forecast is developed, incremental customer growth and losses are projected. Incremental growth through projected attachments and other positive Event Codes from April 2016 through March 2017 are added to the growth/loss rate, while projections of customer losses via meter lock and cut & cap programs, as well as other negative Event Codes, based on activity from April 2016 through March 2017, are subtracted from the growth/loss rate.

Q. What is an "Event Code?"

A. An Event Code is a function of the Company's billing system that identifies historical changes to customer count. Each time a customer is added to or leaves the Company's customer rolls, an Event Code is generated. For instance, if a customer moves into a house in the Company's service territory and requests service, a positive Event Code results, since this action increases the overall customer count by one. Alternatively, if a customer moves out of a house in the Company's service territory and requests a service shutoff, then a negative Event Code results, since this action decreases the overall customer count by one.

Q. What is the impact on DTE Gas's projected customer count as a result of its meter lock and cut and cap programs?

A. Based on the information provided to me by Company Witness Mr. Johnson, locked meters are expected to reduce customer count by 25,000-30,000 customers in each year of the five-year forecast period. DTE Gas expects that approximately 61% of these locked customers (approximately 16,600-18,300 per year) will return to an active service state.

Cutting & capping the meters of customers that have a long history of arrears is projected to reduce customer count by approximately 500-1,000 customers in each year of the five-year forecast period, including 2017. DTE Gas expects a renewal rate of approximately 60% (approximately 450-600 per year) of these cut & capped customers being returned to an active service state. These reconnect and renewal rates are consistent with the rates that DTE Gas has observed in the past several years.

HISTORICAL TEST YEAR CUSTOMER USAGE

Q. What were 2016 actual sales?

A. DTE's unadjusted total 2016 sales were 146.6 Bcf. See Exhibit A-15, Schedule E1.1, page 1 of 2. Unadjusted total sales are a combination of billed and unbilled GCR, GCC, and Aggregate sales volumes. DTE Gas's recorded billed and unbilled GCR and GCC sales volumes in 2016 were 144.9 Bcf. Aggregate customer sales volumes were 1.7 Bcf. DTE's unadjusted total 2016 sales, including end use transportation customers, were 293 Bcf. See Exhibit A-5, Schedule E.1.

Q. Did you make any adjustments to the historical test year's total sales volumes?

A. Yes. The weather in 2016 was warmer than normal. For this forecast, I used a 15-year weather normalization methodology, calculated from 2002-2016 (the most recently completed 15-year calendar period), to calculate an adjustment for this warmer weather. Actual 2016 total sales volumes were increased by 10.5 Bcf to arrive at weather normalized total sales of 157.1 Bcf. See Exhibit A-15, Schedule E1.1, page 1 of 2.

Q. What are the anticipated 2017 normalized actual sales?

A. The anticipated 2017 normalized actual sales totaling 157.3 Bcf are shown on Exhibit A-15, Schedule E1.1, page 1 of 2 in column (e), line 16. This total includes actual sales through August 2017, weather-normalized using 2002-2016 15-year normal weather, plus forecasted sales for the months of September through December 2017. At the time of the preparation of this exhibit, only actual sales through August 2017 were available.

WEATHER NORMALIZATION ADJUSTMENT

Q. What is weather normalization and how is it used?

A. Weather normalization adjusts actual consumption from a past period to compensate for the impact of warmer than normal or colder than normal weather temperatures (measured in Heating Degree Days) that occurred during that time. Normal weather is one of the key components for forecasting future consumption. Forecasted consumption, in turn, is used to design rates.

Line No.

Q. What is a Heating Degree Day?

A. A Heating Degree Day (or HDD) is a measure of how temperature relates to natural gas usage for heating purposes; HDDs give an indication of a customer's likelihood of turning on their furnace to heat their home or facility. Basically, the greater the HDDs, the greater the heating demand. Mathematically, HDDs are defined as the greater of A) zero, or B) 65 – average daily temperature (in degrees Fahrenheit). For instance, if the daily high temperature is 30 degrees and the daily low temperature is 20 degrees, then the daily average temperature is 25 degrees. The HDDs for that day then, are: 65 – 25 = 40 HDDs.

If, on the other hand, the daily high temperature is 90 degrees and the daily low temperature is 70 degrees, then the daily average temperature is 80 degrees. The HDDs for that day then, are: 0, since 65 – 80 results in a negative value.

Q. Why is it important to normalize weather when forecasting consumption?

A. Weather is one of the primary determinants of natural gas demand. The more accurately the Company can project HDDs, the more accurately it can project customer consumption. Accurate consumption projections result in customers paying the correct rates designed to recover the utility's costs. Inaccurate consumption forecasts will result in customer rates that are either too high or too low.

Q. What weather normalization method is DTE Gas using for its forecast in this case?

A. For this case, DTE Gas is presenting normal HDDs based upon 15-year normal weather calculated from calendar year 2002 through calendar year 2016. In Case No. U-15985, the Commission approved 15-year normal weather based upon 1994-2008, in Case No. U-16999, the Commission approved 15-year normal weather based upon 1997-2011, and in Case No. U-17999, the Commission approved 15-year normal weather based upon 2000-2014. In this case, I have updated the normalization to reflect the most recently completed 15 calendar years.

CUSTOMER USAGE FORECAST

Q. How are rate schedule sales volumes projected?

A. Rate schedule volumes are projected by taking the weather normalized 2016 rate schedule volumes and adjusting them to reflect expected volume changes. There are three main issues that are expected to affect sales volumes into the projected Test Year of October 2018 – September 2019. First, DTE Gas is experiencing changes in the number of customers it serves through 2017 and expecting it to continue into 2018; sales volumes will vary directly with the number of customers served. Second, DTE Gas expects changes in overall rate schedule consumption per customer due to variances in the Company’s gas heating value, demographic changes in the Company’s customer base, and energy waste reduction on an ongoing basis through 2017 and into the projected test year. Third, using a 15-year normal weather forecast will capture weather-related effects impacting customers’ usage.

Q. What is the customer usage forecast for the projected Test Year?

A. The normal rate schedule forecast volumes for the projected Test Year are 153.7 Bcf. Please see Exhibit A-15, Schedule E1.1, page 1 of 2. From the historical period to the projected Test Year, DTE Gas is projecting losses of 3.4 Bcf due to reductions in usage per customer, driven primarily by the Company's Energy Waste Reduction (EWR – Formerly known as Energy Optimization) program and by variances in the Company's system-weighted heating value.

2017 Weather Normal Volumes

For 2017, DTE Gas forecasts slight volumetric gains from the weather normalized 2016 Base Year together with a slight increase of 0.3 Bcf due to attachments in 2017. These adjustments result in a normal weather forecast of 157.3 Bcf.

2018 Bridge Period Weather Normal Volumes

Into the January through September 2018 nine moth bridge period, volumes are expected to be reduced by 52.8 Bcf from the 12 month 2017 forecast. These losses are offset slightly by volumetric additions due to customer attachments of 0.6 Bcf resulting in Jan-Sep 2018 rate schedule volumes of 105.1 Bcf. The rather significant drop is due largely to the fact that this January-September 2018 transition period between the historical and the projected Test Year is only nine months long (i.e. it is not a full year owing to the omission of October through December 2018, which are reflected in the projected test year). This seemingly large reduction is simply because volumes from October through December are in the projected Test Year, but not in the transition period.

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October 2018 through September 2019 Test Year

Forecasted volumetric changes across the rate schedules to arrive at the projected Test Year forecast total an addition of 46.9 Bcf (reflecting the October through December volumes included in the projected Test Year, but not in the January – September 2018 nine-month transition period), which are increased by an attachment volume of 1.6 Bcf. These adjustments result in projected Test Year normal rate schedule forecast volumes of 153.7 Bcf (column (k)). The reduction from the weather normalized total sales of 157.1 Bcf in the historical period to the 153.7 Bcf in the projected year is due to conservation and increased heating values, offset by gains in the number of customers.

Q. What is DTE Gas's forecast for 2018 through 2022 by rate schedule?

A. Exhibit A-15, Schedule E2, entitled "Market Outlook: 2018 – 2022," provides a summary of DTE Gas's market projections for rate schedule (i.e., non-EUT) gas deliveries for 2018 through 2022. Forecasted gas sales volumes by customer class and the forecasted number of customers by rate revenue class are detailed on pages 1 and 2, respectively.

HEATING VALUE OF GAS

Q. What is the heating value of natural gas?

A. Heating value of natural gas is defined by the ratio of Btu to a cubic foot (cf). The more Btus per cf of gas, the higher the heating value will be.

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Q. What is a Btu?

A. A Btu is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. Gas that has a higher Btu content will be able to generate more heat (i.e. "boil more water") per cf than a cf of lower Btu content gas.

Q. How does heating value affect natural gas consumption?

A. As mentioned previously, gas with a higher heating value generates more heat per cf than gas with lower heating values. Given that, natural gas customers require a lower volume of high heating value gas to generate the same heating requirements as they would if that gas was of a lower heating value. In other words, all other things being equal, customers consume lower volumes of high heating value gas than they do of comparatively low heating value gas.

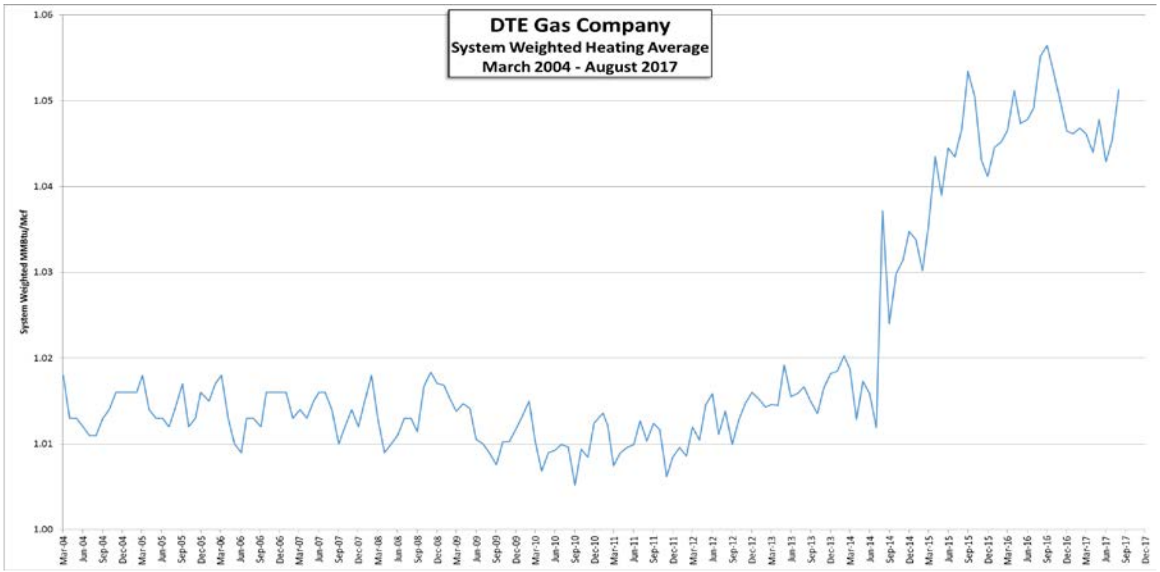
Q. Has the Company determined that higher system-average heating values lead to lower volumetric consumption?

A. Yes. Evidence of this relationship has to do with a quality known as the interchangeability of gas for purposes of combustion. Interchangeability is the ability to substitute one gaseous fuel for another (natural gas with varying levels of heating value, for instance) in a combustion application without materially changing operational safety, efficiency, performance, or materially increasing air pollutant emissions. The DTE Gas laboratory has determined that, should system-average heating values increase to as high as 1,100 Btu/cf as a result of increased levels of ethane, then natural gas with heating values at this level would combust as efficiently as lower heating value gas and would not have a measurable impact on burning characteristics or efficiencies of customers' gas appliances on the DTE Gas system. This means that a 90% efficient furnace will extract 90% of the heat out of one cf of gas whether the heat content is 1,000 Btu/cf or 1,100 Btu/cf; an 80% efficient furnace will extract 80% of the heat out of one cf of gas whether the heat content is 1,000 Btu/cf or 1,100 Btu/cf. In other words, higher heating value gas will lead to commensurately lower volumetric consumption regardless of whether that gas has a heating value of 1,000 Btu/cf, 1,100 Btu/cf, or any heating value in between.

Q. What has the Company's system-average heating value been in recent years?

A. The graph below shows the DTE Gas system-average heating value from March 2004 through August 2017. From 2004 to July 2014, the Company's monthly system-average heating value fluctuated from a low of 1,005 Btu/cf in September 2010 to a high of 1,020 Btu/cf in February 2014. In August 2014, however, the system-average heating value increased to 1,037 Btu/cf. Beginning in August 2014, the Company's system-average heating value began a steady rise, ultimately reaching a value as high as 1,056 Btu/cf in September 2016. See the chart below:

Chart 1



Q. What is the impact of the heating value in making a forecast?

A. Increases in the system-average heating value would, all other things being equal, lead to lower consumption of Mcf (i.e. volumetric) among the Company's 1.2-1.3 million customers. The regression period used to calculate the usage factors in this forecast is August 2014 to July 2016. The system-weighted-average heating value of that period, and thus the heating value implicit in the usage factors themselves, was 1,040 Btu/cf. Any volumetric analysis, including a forecast, based on these periods must consider potential changes in heating value and how future volumetric consumption would be affected by these changes.

Q. Does the Company expect further changes to occur in its system-average heating value from the level in the August 2014 / July 2016 base regression period?

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A. Yes, the Company expects heating values to be higher in the projected Test Year than it was in the 2014-16 base regression period.

Q. How does the Company expect its system-average heating value to change?

A. The Company has made a projection of its system-average heating value for the projected Test Year. The Company's forecast assumes that the latest 12-month system heating value (at the time the forecast was prepared) from August 2016 through July 2017, adjusted for expected changes due to incremental supply coming from the Nexus Pipeline, to be appropriate in calculating all forecasted demand. The August 2016 through July 2017 heating value is 1,048 Btu/cf. With the change in the supply mix expected from the Nexus Pipeline beginning in 2018, the Company expects the system-average heating value to increase to a value of 1,051 Btu/cf. This value is then used as a component in the calculation of forecasted company demand. The regressed usage factors have in effect then been adjusted by a factor of 1,040 / 1,051 = 0.9895. (Note: 1,040 Btu/cf is the base regression period heating value and 1,051 Btu/cf is the Projected Test Year heating value.)

Q. How did the Company arrive at the figure of 1,051 Btu/cf as the appropriate system-average heating value for the Projected Test Year?

A. The Company expects that it will receive a significant amount of supply from Nexus Pipeline over the course of the Projected Test Year. The production basins from which Nexus Pipeline receives its supply are found in the relatively high Btu Utica and Marcellus shale regions of Ohio, West Virginia, and western Pennsylvania. Recent supply data from the Energy Information Administration suggests that gas from these regions has been roughly in the range of 1,070 Btu/cf to 1,090 Btu/cf over the past couple of years. As such, the Company expects that the supply it will receive from Nexus Pipeline will be in this range.

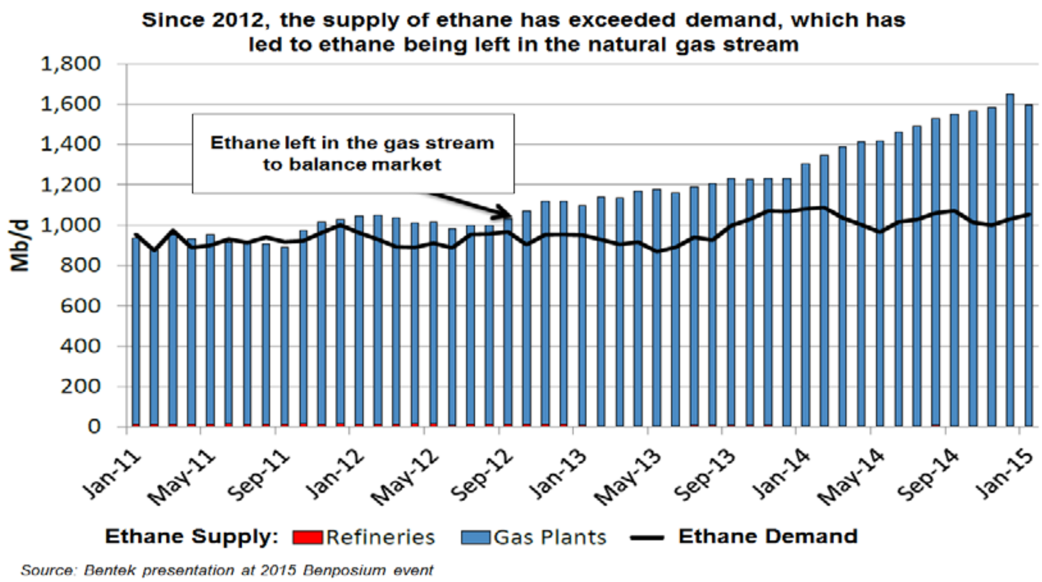
A Company system supply allocation study suggests that with the inclusion of supply coming from Nexus Pipeline, the system-weighted average supply will be expected to increase from 1,048 Btu/cf (the system-weighted average supply from August 2016 to July 2017) to 1,051 Btu/cf in the Projected Test Year.

Q. Why has the heating value of gas increased in recent years on DTE Gas's system, as opposed to the period prior to 2014?

A. The heating value of natural gas has increased on DTE Gas's system because levels of higher heating value ethane have not been processed out of produced natural gas that the Company receives at some of its main pipeline interconnects. Leaving ethane in the gas stream rather than processing it out increases the heat content of the natural gas stream as a result of ethane's higher heat index versus methane. Methane (chemically CH_4 and the primary molecule in natural gas) has a heating value of approximately 1,010 Btu/cf, while ethane (chemically C_2H_6 and a subsidiary molecule in natural gas) has a heating value of approximately 1,770 Btu/cf. A natural gas mix that contains higher levels of ethane relative to methane will have a higher heating value.

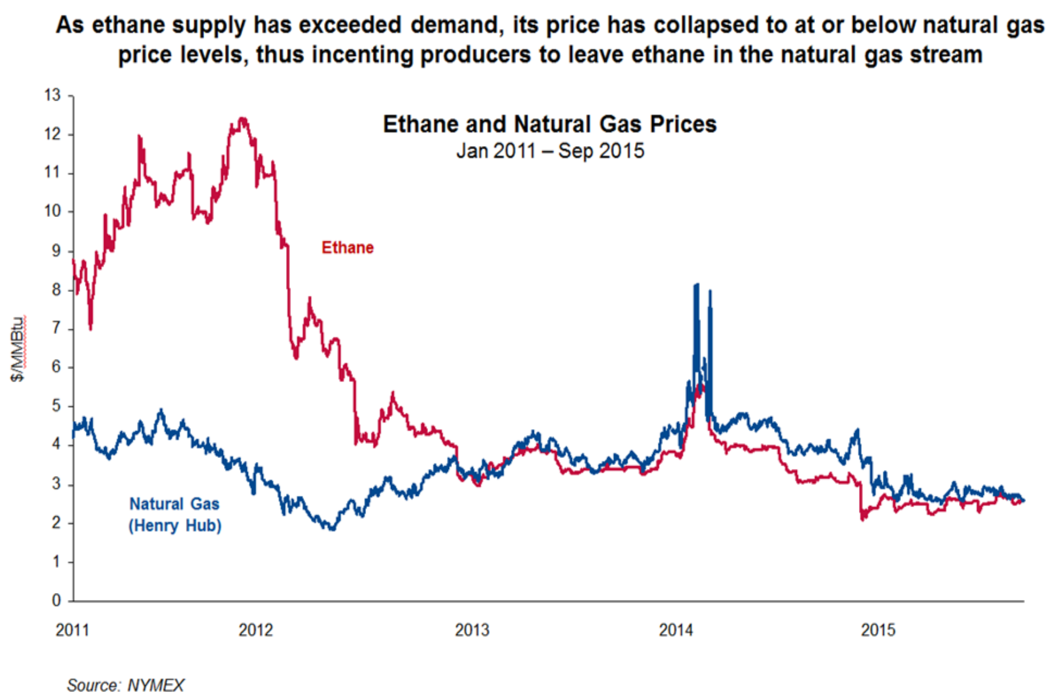
Large increases in higher BTU natural gas production from shale basins have resulted in significant ethane supply increases. From 2012 to 2015, ethane supply grew by ~60%. See Chart 2 below.

Chart 2



Since demand has not been able to keep pace with supply, the price of ethane has dropped from ~$12/MMBtu in 2012 to below the price of natural gas from 2013 to 2015. See Chart 3 below.

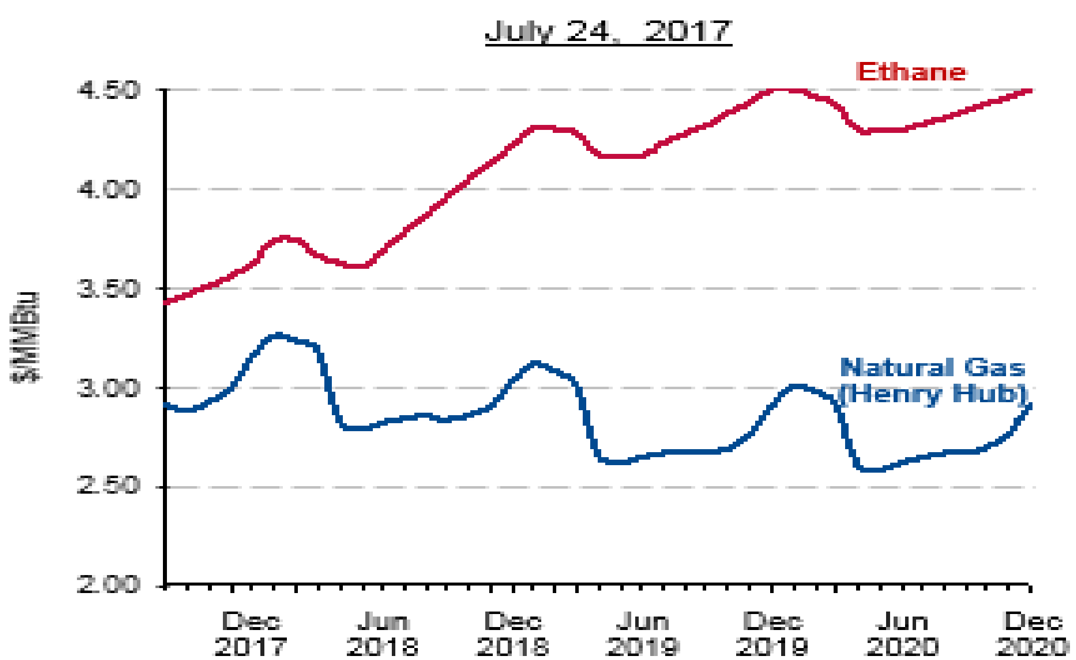
Chart 3



Since 2015, the price of ethane has rebounded to be higher than natural gas, although far short of the pre-2013 levels. As of July 2017, the ethane forward market has been trading at roughly $0.50-$1.75 per Dth higher than the natural gas forward market. The transportation costs to get the Marcellus/Utica ethane to its Gulf Coast markets, however, has an equivalent cost of nearly $3.50/Dth which erodes any price advantage of the cost of the ethane itself. Chart 4, below, illustrates that the highest price spread during the Projected Test Year in the forward curve between ethane and natural gas is only $1.60/Dth. The $1.50 per Dth is well below the transport costs needed to cost effectively bring ethane to market.

Chart 4

Comparison of Monthly Natural Gas (Henry Hub) and Ethane Forward Prices



Because of the low price of ethane, many natural gas processors have chosen to leave ethane in the natural gas stream rather than strip it out for sale as a separate product. Leaving ethane in the gas stream has led to the continuing higher levels of the heating value in natural gas.

The Marcellus and Utica shale production basins are in Pennsylvania, West Virginia, and Ohio, and these states have a much higher heat content in their gas than Michigan. According to the Energy Information Administration, in 2016, Pennsylvania had a heating value of 1,041 Btu/cf, Ohio had a heating value of 1,070 Btu/cf, and West Virginia had a heating value of 1,088 Btu/cf while Michigan had a heating value of 1,041 Btu/cf. As more gas from the Marcellus and Utica shale production basins has flowed to the Midwest and into Michigan, the heat content of gas delivered to Michigan has also gone up.

Q. Will the heat content in gas continue to stay at these higher levels through the DTE Gas test year (October 2018 – November 2019)?

A. Yes. While the ethane futures market continues to show higher prices than the natural gas futures market, the transport costs to get ethane from the Marcellus/Utica shale to Gulf Coast markets remains cost prohibitive. Therefore, it is expected that producers will continue to leave ethane in the natural gas stream for deliveries out of the Marcellus/Utica supply region. Much of this supply is expected to continue to flow into Midwestern and Michigan markets, keeping the heating value of supply into Michigan at these higher levels.

Q. What is the longer-term outlook for the Marcellus and Utica production basins?

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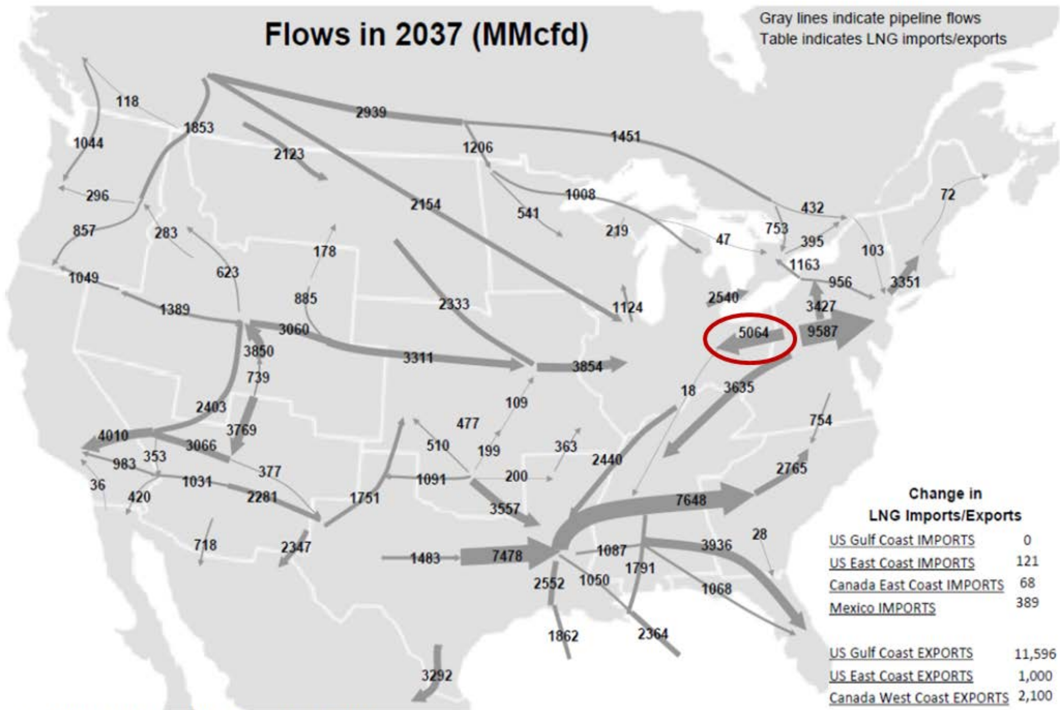
A. Chart 5, below, show that longer term, ~5.1 Bcf/day of gas (circled in red) from the Marcellus and Utica shale production basins should flow to the Midwest, including Michigan.

Chart 5



Source: ICF GMM® CPP Case, August 2015

When pipelines bringing gas from the Marcellus and Utica shale production basins, such as the Rover and NEXUS pipelines, go into service, the heating values of gas delivered to Michigan at higher levels will remain high and possibly grow higher. These pipelines are expected to go into service in 2017 and 2018.

Q. What is the projection of the Company's system-weighted average heating value for the October 2018 – November 2019 Test Year?

A. The projection of the Company's system-weighted average heating value for the October 2018 – November 2019 projected Test Year is an average of 1,051 Btu/cf based upon the system average heating value of the most recent 12-months at the time of the preparation of the forecast (August 2016 through July 2017) and adjusted for the higher heating value gas expected from the Utica and Marcellus shale regions.

SALES FORECASTS

Residential Sales Forecast

Q. How are residential sales forecasted?

A. There are five key elements used in projecting volumes in the residential sales market. The first element is the projection of normal weather HDDs by region.

The second element is the forecast of the number of customers, by month, in the seven different market areas that DTE Gas serves. DTE Gas's seven different service regions are: Detroit/Ann Arbor, Grand Rapids, Muskegon, Traverse City, Alpena, Sault Ste. Marie, and Iron Mountain.

The third element is an analysis of the usage per customer per HDD at varying temperatures. The Company uses a three-step linear factor model that determines the monthly demand for all rate classes based on HDDs and customer counts.

The fourth element reflects the Company's Energy Waste Reduction (EWR) program initiated in 2009. This program provides education, incentives and weatherization material to the Company's customer base and is designed to encourage customers to take steps to reduce energy consumption in their home or business. As part of the Company's most recent EWR Plan filing (Case No. U-18262), the Company projected annual demand reductions due to EWR to be one percent annually. I have included this level of projected savings in my demand forecast.

The fifth element used to project volumes is an observed increase in the Company's system-weighted heating value in Btu/cf. This increase in heating value has continued to stay relatively high over the past several years and has reduced demand, as discussed earlier in this testimony.

The combination of these five elements (normal HDDs, customer count, three-step linear heat load factor, EWR, and higher heating value levels) for each respective market area yields the residential sales market forecast.

Q. How does the three-step linear methodology work?

A. The three-step linear equation consists of three components: a base load component and two linear components. The base load component determines how much gas a customer is expected to use every single day, regardless of the weather. The two linear components determine how much gas a customer is expected to use depending on how many HDDs are present on any given day. The three-step linear equation is described mathematically with the following equation:

$$\text{Customer's Demand} = BL + ax_{\Delta} + bx_{55}$$

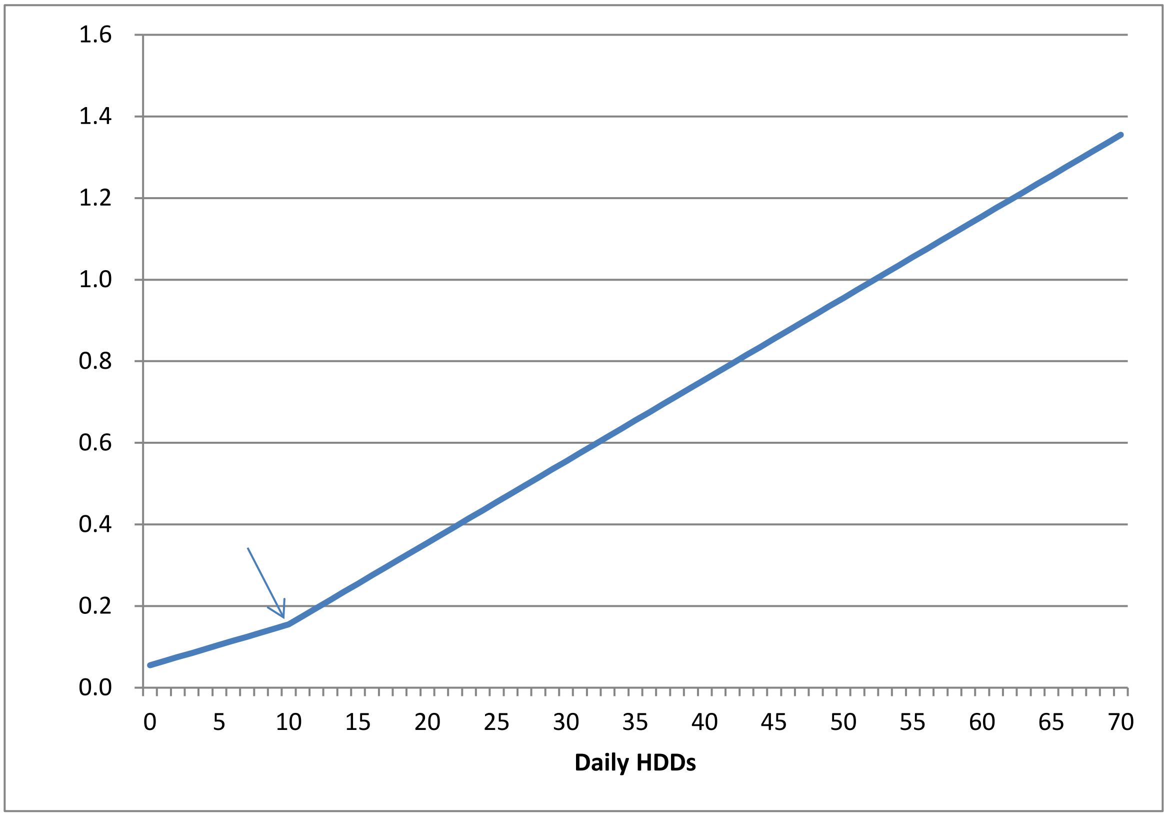
where BL = base load, x_{Δ} = HDDs between 55 and 65 degrees, and x_{55} = HDDs below 55 degrees. Further, a and b represent coefficients unique to each rate class in each demand region. The “a” coefficient is generally a lower value than the “b” coefficient because the “a” coefficient represents typical customer usage at average temperatures between 55 and 65 degrees Fahrenheit, which are levels at which some, but not all, of DTE Gas’s customers will turn on their furnace. This has the impact of dampening the demand calculation in the spring and fall months by weighting the lesser “a” coefficient more heavily during mild weather. Conversely, it has the impact of calculating higher demand in the winter months by weighting the higher “b” coefficient more heavily during colder weather. The “b” coefficient represents typical customer usage at average temperatures below 55 degrees Fahrenheit, levels at which nearly all of DTE Gas’s active space heating customers will turn on their furnace.

For the purposes of example, I have included Chart 6 below that depicts this equation.

This graph shows the daily consumption pattern of a typical space heating customer. At relatively low HDDs (<10), on the left side of the graph, the slope of the graph is upward, but gradual. At higher levels of HDDs (>10), the slope of the graph gets steeper, indicating higher consumption per HDD the colder it gets.

Line No.

Chart 6



Q. How were the number of residential customers, including both GCR and GCC, forecasted?

A. Monthly customer additions and losses in each of DTE Gas's seven service regions over a three-year period were analyzed to develop a trend factor for the number of residential customers. The historical data used is the actual monthly billing data for each of the approximately 1.2 million DTE Gas customers across its service territory. Customer growth and loss, by month, is then projected for each region and projected forward for five years to develop the demand forecast.

The forecast also reflects marketing initiatives within the Company that, beginning in 2017, are expected to add 8,500-9,100 customers annually from 2018 through 2022.

The Company also expects offsetting customer count reductions over the ensuing five years due to continued efforts at locking and cutting & capping customers because of theft or non-payment, as discussed previously.

Q. What changes does DTE Gas forecast in the number of residential customers for 2018 through 2022?

A. DTE Gas experienced overall growth in its residential customer market until 2006. DTE Gas's total residential heating customer count then experienced a period of decline in the several following years bottoming out in 2011, due largely to difficult economic conditions and declining population in DTE Gas's service territory. Since that time, however, DTE Gas's residential customer counts have once again been growing. See Exhibit A-15, Schedule E3. The number of DTE Gas's residential heating customers peaked in 2006 at a level of 1,158,586 customers. Customer count then declined by over 57,000 through 2012, to 1,101,255. Since that time, residential customers have grown to a total of 1,129,690 as of 2016. Annual net total customer growth, beginning in 2017 and into the five-year 2018 - 2022 forecast period is projected to be approximately 15,000 annually, totaling roughly 77,000 over the five years.

Q. Why have normalized residential sales declined over the past several years?

A. Although the customer count, in total, increased from 1983 to 2006, the sales increases associated with this increased customer count were mitigated by a reduction in average consumption per customer during that period. As noted above, since 2006 customer counts declined but have been on the rebound since 2012.

Average customer consumption, however, has continued to decline in general, albeit at a slower rate over the past several years.

As represented on Exhibit A-15, Schedule E4, line 17, column (b) for the period ending August 2004, DTE Gas's average Rate A residential space heating customer utilized 117.5 Mcf per year, normalized using 2002-2016 15-year normal weather. Over the next two years, normalized consumption per customer dropped significantly, to 105.1 Mcf per year by the period ending August 2006. This significant reduction can largely be attributed to a lagged price-related conservation reaction to the high natural gas prices that struck the entire country following the 2005 hurricane season. This conservation, though initially driven by prices, has resulted in persistent load reduction. I believe this reduction has sustained because even as prices have moderated, usage per customer has continued at these lower levels. For example, the 12-month period ending August 2007 saw average annual residential space heating consumption further reduced by 0.8 Mcf per year to 104.4 Mcf per year. Continuing this trend, for the period ending August 2008, average annual residential space heating consumption was down yet again to 103.6 Mcf per year, a further per customer reduction of 0.8 Mcf per year. Steady declines in usage per customer were observed through 2009 (100.7 Mcf), 2010 (98.6 Mcf) and for the period ending August 2011, when average annual residential space heating consumption was down yet again to 97.6 Mcf per year, resulting in a per customer reduction of another 1.0 Mcf per year. A brief rebound in normalized consumption per customer was observed in 2012 (98.5 Mcf) and 2013 (99.6 Mcf), likely attributable to improving economic conditions and relatively stable and low gas prices.

Despite a continuation of improving economic conditions and low natural gas prices, normalized consumption again began to drop in 2014 (98.6 Mcf) and 2015 (96.6 Mcf). In particular, 12 months ended August 2015 is precisely the period in which higher heating values began, likely contributing to this further reduction in normalized consumption per residential heating customer. Through 2017, normalized consumption per residential space-heating customer is down slightly to 96.4 Mcf.

Q. What are some other reasons why you believe customer usage has generally declined even as gas prices have moderated?

A. The 2005 era hurricanes triggered an increase in natural gas prices (and hence GCR rates). That customer consumption declined significantly following this price spike is also true. That customer consumption did not return to previous levels after natural gas prices abated, too, is a fact. These facts indicate that our customers likely put into place permanent measures such as insulation, windows, and higher efficient furnaces that lead to permanent load loss. These more recent declines can be explained by the continual energy efficiency efforts of DTE Gas's customers, including upgrades of windows, insulation, the replacement of older, less fuel-efficient appliances, and use of thermally efficient building materials, due in some part to DTE Gas's EWR program, which began in 2009. Further reasons that normalized consumption has decreased in recent years are higher levels of energy efficiencies required in building codes as well as newer appliances being more energy efficient.

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Q. Do you project a continued decline in consumption per Rate A residential customer?

A. Yes. In Calendar 2017, normalized average annual consumption is down to 96.4 Mcf per year, a per customer reduction of 0.2 Mcf per year from 12-month ended August 2015 levels. By Calendar 2018, normalized average annual consumption is projected to be down to 91.9 Mcf per year, a further per customer reduction of 4.5 Mcf per year. The average Rate A consumption in the Projected Test Year is expected to be 91.0 Mcf/customer. This reduction reflects a continuation of normalized demand destruction. This demand destruction includes 1) continued conservation measures, which are assumed to compound annually at a rate of 1% in conjunction with the Company's Commission approved EWR program, and 2) continued loss of volumetric consumption due to the expected higher levels in the Company's system-average gas heating value.

Commercial Sales Forecast

Q. How did you forecast gas sales for the commercial market?

A. The methodology used for forecasting sales in the commercial market is similar to that used for the residential market. Like the residential process described above, the process involves forecasting the number of customers, the 2002-2016 15-year weather normalized usage per customer for the forecast period, and further reductions due to the EWR program and increased heating values.

Q. What changes have been occurring in the number of commercial customers in DTE Gas's territory?

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A. Similar to the residential class, the numbers of DTE Gas's commercial rate class customers generally increased from 1981 through 2006. See Exhibit A-15, Schedule E3, page 2 of 2. Over this period, DTE Gas gained approximately 900 to 1,000 commercial customers annually. Between 2007 and 2013, however, DTE Gas's commercial customer base saw a decline driven by the economic downturn, losing approximately 4,500 customers during that time. In 2014, however, this seven-year trend snapped and DTE added 135 customers. This growth continued through calendar year 2016 and is expected to grow, driven largely by continued economic improvements, through 2022.

Q. What trends has DTE Gas observed in commercial market normalized use per customer?

A. As observed in the residential markets described earlier, DTE Gas has experienced a similar pattern in normalized use per customer in the commercial market, as shown on Exhibit A-15, Schedule E4. Beginning following the 12-month period ending August 2004, DTE Gas's average Rate GS-1 commercial space heat customer's utilization decreased steadily through 2010, with a one-year increase in 2008. Since the 12-months ending August 2011, usage increased significantly in one year, 2013 while experiencing nominal net changes through 2015. As with the residential customers, however, normalized consumption reversed trend as of August 2015, resulting in annual customer consumption of 428.1 Mcf per customer and continuing through 2017 with normalized per customer consumption down to 422.3 Mcf. This reversal coincides with the recent increases noted in system-average heating value.

The overall historical decline in usage by the commercial customers is largely related to technology and customer awareness of the variety of conservation measures that can be implemented. Commercial customers can reduce energy usage, while maintaining acceptable comfort levels, mainly through basic and cost-effective changes in their heating and ventilating systems, including the use of electronic energy management systems. I believe that increases observed over the past five years, however, can likely be attributed to improvements in the economic environment as well as continued low gas prices. The reversal to lower normalized consumption seen in the past several years may likely be caused by the observed increased system-average heating value.

Q. What actions do commercial customers take to reduce their gas usage?

A. Many of the actions available to commercial customers are similar to those available to residential customers. Conservation techniques available to commercial customers to reduce gas usage include the installation of additional insulation, dialing down temperature settings (and even shutting down their heating systems during nights and weekends), changing hours of operation so that less heating is required, shutting off heat to areas not in use, installing weather-stripping, installing energy efficient windows or insulating and boarding up windows, installing insulation on steam lines, and reducing losses by simply keeping doors closed. In addition to such simple techniques, customers can reduce ventilation losses by reducing the amount of air exhausted, installing self-closing doors, and installing heat exchangers to extract heat from the air that is vented to the outdoors. More sophisticated techniques include the elimination of standing pilots, installation of economizers on the boilers, reducing boiler steam pressure, replacing faulty steam traps, installation of additional duct work to increase air flow efficiency, making air/gas adjustments on boiler controls for optimum combustion, installing ceiling fans in strategic locations, and performing routine maintenance on heating equipment. Customers can also utilize devices that optimize combustion efficiency by monitoring and analyzing the products of combustion, devices that monitor solar heat gain and compensate boiler operation and fully automated electronic energy management devices. Boiler replacement with a new more efficient boiler and replacement of steam heating systems with forced air and infra-red heating are other examples of more capital intensive, yet very effective conservation techniques.

<u>Industrial Sales Forecast</u>

Q. How did you forecast gas sales for the industrial market?

A. The methodology used for forecasting sales in the industrial market is similar to that used for the residential and commercial markets. The process involves forecasting the number of customers, the 15-year weather normalized usage per customer for the forecast period, further reductions due to the EWR program and increased heating values, and using such data to calculate sales.

Q. Has DTE Gas seen the same declines in the number of customers and use per customer in the industrial market that it has seen in the commercial and residential markets?

A. No. DTE Gas's rate schedule industrial classes have remained relatively small and unchanged. The majority of DTE Gas's larger industrial customers take End-User Transportation (EUT) service from DTE Gas.

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Q. What is DTE Gas forecasting for its rate schedule industrial markets?

A. DTE Gas is forecasting distribution volumes to be approximately 0.3 in 2018, decreasing to 0.2 Bcf per year, for rate schedule sales to industrial customers through 2022, as shown on Exhibit A-15, Schedule E2, page 1 of 2, line 19.

EXELON ASSUMPTIONS

Q. What is the Exelon Easement Agreement?

A. DTE Gas and Exelon Energy Company (Exelon) filed a joint application for approval of a special contract granting Exelon certain rights and interests in DTE Gas's gas transportation and storage system. This agreement was executed to mitigate concerns raised by the Staff of the Federal Trade Commission in their review of the acquisition by DTE Energy Company of MCN Energy Group, DTE Gas's current and former parent companies, respectively.

Q. What rights does this easement agreement give Exelon?

A. This contract grants Exelon rights to annual transportation and storage capacity on DTE Gas's distribution system to provide energy sales (supply and delivery) in a specific part of DTE Gas's service territory where DTE Gas and DTE Electric overlap. The Exelon Easement Agreement states that an initial block of 5 Bcf of annual transportation capacity ("Initial Capacity") was to be made available to Exelon on the effective date of June 1, 2001. Exelon may purchase up to 15 Bcf of additional annual transportation capacity ("Supplemental Capacity") in one Bcf increments as this load becomes available. On May 1, 2005, Exelon exercised its right to purchase 1 additional Bcf of supplemental capacity.

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Q. What assumptions have you made regarding the forecast of Exelon volumes?

A. As mentioned earlier, Exelon has 5 Bcf of Initial Capacity, plus Supplemental Capacity up to 5 Bcf. Based upon past experiences with load loss from Exelon, the Company expects them to fully sign up current/former DTE Gas Rate GS-1 customers at 8 Bcf through 2019. Exelon volumes are not reflected in Exhibit A-15, Schedule E1.1 or Exhibit A-15, Schedule E2.

Q. Why were Exelon customers removed from the forecasted volumes?

A. Exelon customers (formerly served by DTE Gas) are removed from the sales forecasts because Exelon, and not DTE Gas, provides gas distribution service to these customers.

COST OF GAS FORECAST

Q. Why is it necessary to calculate a cost of gas rate forecast in this case?

A. The cost of gas rate is used by several of DTE Gas's witnesses for an array of purposes, such as pricing company use and lost and unaccounted for gas and for developing and supporting assumptions for expected customer impacts and costs where the cost of gas is an important component for those assumptions.

Q. What is the projected cost of gas rate for the GCR periods included in the projected Test Year?

A. For the October 2018 – September 2019 projected Test Year, I project a $3.22 per Mcf jurisdictional cost of gas.

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Q. How did you calculate the projected Test Year cost of gas rate?

A. I derived my cost of gas projection based on New York Mercantile Exchange (NYMEX) close prices for natural gas contracts on September 27, 2017. More specifically, I applied those NYMEX prices to DTE Gas's non-fixed price supply in its updated supply portfolio as of that date to calculate the projected Test Year cost of gas rate for purposes of this case. The calculation of this cost of gas includes costs associated with DTE Gas's pipeline transportation portfolio and supply under contract as part of its fixed price plan, discussed fully in its GCR Plan filing.

ANR TRANSPORT CONTRACT NO. 112110 FOR SERVICE TO GRAND RAPIDS AND CONTRACT NO. 122065 FOR SERVICE TO THE ALPENA SYSTEM

Q. What were the O&M costs incurred under ANR Transport Contract No. 112110 and Contract No. 122065 during the historical test year of January 2016 through December 2016?

A. ANR Transport Contract No. 112110 had $1.3 million of costs charged to O&M during the historical test year and Contract No. 112065 had $2.2 million of costs charged to O&M, for a total of $3.4 million (note: total does not match due to rounding of individual components).

Q. What are the projected costs to be incurred under these ANR transport contracts during the projected test year October 2018 through September 2019?

A. Assuming the same level of volumetric usage in the projected test year as occurred in the historical test year, the costs under ANR Grand Rapids Transport Contract

No. 112110 are expected to increase by $1.3 million to a total of $2.5 million (note: total does not match due to rounding of individual components), and the costs under ANR Alpena Transport Contract No. 112065 are expected to increase by $1.6 million to a total of $3.7 million (note: total does not match due to rounding of individual components). Combined, the costs under these contracts are expected to increase by $2.8 to a projected test year total of $6.3 million (note: total does not match due to rounding of individual components).

Q. Why are the costs under these ANR transport contracts expected to increase by $2.8 million?

A. The capacity under ANR Grand Rapids Transport Contract No. 112110 will double from 100,000 Dth/day to 200,000 Dth/day effective November 1, 2017. Consequently, the costs under this discounted rate contract will double, increasing the costs by $1.3 million. This increase in capacity was identified in the original contract dated November 15, 2005, and was contracted for at that time to provide long-term capacity needed to serve the projected growth in peak-day markets in the Grand Rapids area. Regarding ANR Alpena Transport Contract No. 112065, the ANR transport rates have increased under this maximum tariff rate contract effective August 1, 2016, pursuant to the Federal Energy Regulatory Commission approved rate increase. That rate increase was the result of the ANR general rate case in Docket No. RP16-440-000. Applying these new ANR tariff rates to the same volumetric usage in the projected test year as occurred in the historical test year results in an increase in costs of $1.6 million.

Q. Why are the costs of these transport contracts charged to O&M for recovery through base rates and not charged to GCR cost of gas?

A. Both contracts provide system integration services by connecting the DTE Gas storage facilities to EUT, GCR, and GCC markets in certain DTE Gas service territories. ANR Contract No. 112110 provides service to the Grand Rapids markets and ANR Contract No. 112065 provides service to markets on the Alpena transmission system. Consequently, the Commission approved recovery of these costs in base rates in the DTE Gas Rate Case No. U-17999. However, since the primary receipt point under ANR Contract No. 112065 for service to Alpena was relocated to the ANR interconnect with Alliance Pipeline near Chicago, Illinois, this contract is now primarily used to transport purchased gas supply to serve GCR, and GCC customers as supplier of last resort. Consequently, DTE Gas uses the full 50,000 Dth/day of transport capacity at a projected cost of $3.5 million for its GCR supply portfolio. Alternative recovery of this $3.5 million through the GCR mechanism in lieu of base rates is more fully addressed by Company Witness Mr. Telang.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL S. COOPER

DTE GAS COMPANY
QUALIFICATIONS OF MICHAEL S. COOPER

Line
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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 (DTE LLC).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Gas Company (DTE Gas 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 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 Position 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.

Q. What are your responsibilities as Director of Compensation, Benefits & Wellness?

Line
No

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 Gas or DTE Electric Company 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). In addition, I provided support to the compensation and benefits witness in the following cases:

U-16999	2012 DTE Gas General 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

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PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony will present an overview of benefit expense for DTE Gas for the 2016 historical test year and the October 1, 2018 through September 30, 2019 projected test year. 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, including an analysis of salaries for non-represented positions at December 31, 2016 relative to the market medians for such positions;
- 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 at DTE Gas.

Q. Are you sponsoring any exhibits?

A. Yes, I am supporting information on the following exhibits:

Exhibit	Schedule	Description
A-13	C5.9	Projected Operation & Maintenance Expenses - Employee Pensions and Benefits
A-13	C5.9.1	Aon Hewitt Healthcare Trend
A-13	C5.9.2	Price Waterhouse Coopers 2018 Medical Cost Trend
A-13	C5.9.3	Wells Fargo Insurance Healthcare Claim Trend for 2018
A-13	C5.10	Projected Operation & Maintenance Expenses - Pension Costs - Qualified
A-13	C5.11	Projected Operation & Maintenance Expenses - Other Post-Employment Benefits (OPEB)
A-19	I1	2018 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Gas
A-19	I2	2018 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Energy Corporate Services LLC
A-19	I3	2018 Long-Term Incentive Plan Metrics
A-19	I4	Incentive Compensation Cost/Benefit Analysis
A-19	I5	Employee Compensation Market Analysis
A-19	I6	Aon Hewitt Review of Compensation Benchmarking Practices

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 Gas provides to most of its employees. Pension costs are recognized under U.S. GAAP Accounting Standard Codification (ASC) section 715-30 (ASC 715-30) and include defined benefit pensions. Costs for the Company's Savings Plan and other defined contribution benefits are recognized separately.

Q. What pension plans are included in the Company's pension costs?

A. The Company has two qualified pension plans that cover eligible employees of DTE Gas. One is for eligible employees covered by collective bargaining agreements, referred to as the DTE Gas Union Plan (Union Plan) and another is for all eligible employees of DTE Gas not covered by collective bargaining agreements, known as the DTE Gas Non Union Plan (Non Union Plan). The pension costs reflected on Exhibit A-13, Schedule C5.10 reflect the sum of these two pension plans.

Q. What are the components of pension costs?

A. Pension costs, as measured at the beginning of each fiscal year under ASC 715-30, 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 4.25% was applied in determining the PBO at the end of the historical test year as well in the projected test year for the Non Union Plan whereas a discount rate of 4.45% was used in measuring the PBO for the historical period as well as in the projected test year for the Union Plan. The discount rate used in measuring interest costs during the 2016 historical test period for the Non Union Plan was 4.50% and was 4.70% for the Union Plan, based on the interest rate environment at the end of 2015. The discount rates used in determining interest during the projected test year reflect the assumption that high-quality corporate bond interest yields at the end of 2018 will remain essentially unchanged from the yields prevailing in December 2016.

Expected return on assets: 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 trusts at the beginning of the year plus any planned funding for the year and reduced for planned disbursements. 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. The annual expected rate of return was 7.75% for the historical test year and is assumed to be 7.50% in the projected test year. The reduction in the assumed investment return to 7.50% reflects lower overall market expectations.

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Amortizations: 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 impact 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 plan assets resulting from experience different from that assumed in the actuarial assumptions. Most notably, since discount rates and return on assets assumptions are based on estimates, differences arise whenever discount rates change 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 C5.10, the Company's pension costs are projected to decrease by $2.9 million, from $16.2 million in the historical test year to $13.3 million in the projected test year. The decrease in pension costs between the two periods is caused primarily by an increase in the projected return on assets arising from an increase in assets, partially offset by a reduction in the expected annual rate of return on assets.

Q. What is the level of pension contributions reflected in the projected pension costs?

A. DTE Gas is projecting pension contributions of $25 million annually in 2017, 2018 and 2019 for the DTE Gas Union Plan. The planned contributions are based primarily on minimum pension funding requirements, as prescribed by Employee Retirement Income Security Act of 1974 (ERISA), the Pension Protection Act of 2006 (PPA) and the Highway and Transportation Funding Act of 2014. Additional contributions are made, as necessary, to keep the pension plans funded to at least 80% on a non-stabilized basis to avoid funding based benefit restrictions under ERISA and PPA.

Q. What is the net pension expense for the projected test year?

A. The total projected pension cost of $13.3 million is adjusted for the portion of pension costs capitalized to produce a projected pension expense of $8.4 million.

Q. Is the net pension expense of $8.4 million reflected in the Company's proposed revenue requirement?

A. No. Pursuant to the Commission's Order in Case No. U-13898, the Company has been accruing a regulatory liability for the negative pension expense. Since the Company has a pension related regulatory liability resulting from previous year's deferrals of negative pension costs, the projected net pension expense will be a reduction to that liability and therefore is not included in the Company's projected revenue requirement, as explained by Witness Uzenski.

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OTHER POST-EMPLOYMENT BENEFITS (OPEB)

Q. What are OPEB Costs?

A. For DTE Gas, 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. The costs described below exclude those related to VEBA contributions for non-represented new hires effective January 1, 2012 and certain other represented new hires.

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.

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 4.25% at the end of the historical test year as well as during the projected test year.

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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 qualified trusts. The expected annual rate of return was 8.00% during the historical test year and is assumed to be 7.75% during the projected test year. Similar to the pension expected return assumptions, the reduction in the expected annual rate of return on assets is based on overall lower market expectations.

Amortizations: This cost component includes the amortizations related to prior service costs and unrecognized gains and losses. 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. Gains and losses, outside a similar 10% corridor described for pension expense, are amortized over the current estimated remaining service lives of active participants.

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, the Company's OPEB costs are projected to increase from a negative $44.0 million in the historical test year to a negative $18.0 million during the projected test year for an increase in OPEB costs of $26.0 million. The increase in OPEB costs between the two periods is primarily due to a $27.6 million reduction in the amortization of Prior Service Costs.

Q. Why is the amortization of Prior Service Costs decreasing between 2016 and the projected test year?

A. In 2012 and 2013 the Company implemented significant changes in the medical and related benefits it provides to its current and future retirees. These changes substantially reduced the Company's APBO. The benefits of this reduction were deferred as Prior Service Costs that were amortized as negative Prior Service Costs over four years. These Prior Service Costs will be completely amortized by the end of 2017.

Q. What medical cost escalation assumptions are reflected in the projected test period OPEB costs?

A. The projected test year OPEB costs assume retiree health care costs will increase by 6.50% annually for retirees less than 65 years old and 6.75% annually for retirees 65 years and older. These rates of increase are projected to trend downward to an ultimate annual increase of 4.50% in 2030 for all retirees.

Q. Has DTE Gas externally funded its OPEB liability?

A. Yes. DTE Gas has generally funded the OPEB costs included in the Company's revenue requirement adopted by the Commission in previous orders through a Voluntary Employees' Beneficiary Association (VEBA) trust and an Internal Revenue Code Section 401(h) trust.

Q. Is the Company intending to externally fund the OPEB?

A. No. Since the Company's assets at December 31, 2016 exceed the APBO, the projected OPEB costs are expected to remain negative in future years and any contributions would likely not be tax deductible, the Company is not intending to externally fund OPEB costs as measured under ASC 715-60.

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 to a regulatory liability the Company's net negative OPEB expense, and accordingly, the net negative OPEB expense is excluded from 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 line 4 of Exhibit A-13, Schedule C5.9 reflects the costs of the plans described above that are offered in lieu of the traditional retiree healthcare plan for eligible employees. The increase in New Hire Retiree VEBA expense from \$0.9 million in the historic test year to \$2.0 million in the projected test year is premised on increased plan participants arising from the hiring of new employees.

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% for all employee groups. In addition, employees hired after the defined benefit pension plan was closed to new hires receive an additional 4% employer contribution. The Employee Savings Plan costs are projected to increase from \$6.6 million in the historic test year to \$7.9 million in the projected test year based on projected annual wage increases as well as the impact of the increased employer contributions for newly hired employees.

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ACTIVE EMPLOYEE BENEFIT PROGRAMS

Q. What are the other benefit programs 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, life insurance and long-term disability coverage. The components of these benefits are summarized on Exhibit A-13, Schedule C5.9. These costs are projected to increase from $15.9 million for the historic test year to $19.2 million in the projected test year. The largest component in this category is the cost of healthcare plans consisting of medical, dental and vision benefits for active employees, which are projected to increase from $13.2 million in the historic test year to $16.3 million, as reflected on Exhibit A-9, Schedule C5.9, based on projected annual healthcare trend factors provided by Aon Hewitt, as described below.

Q. What is the basis for your future trend factor in active healthcare costs used for the projected periods in this proceeding?

A. Annual cost trend factors of 8.0% for 2017 and 8.5% for both 2018 and 2019 were applied to the Company's actual 2016 active healthcare expense. These escalation assumptions were provided by the healthcare experts at Aon Hewitt, as reflected in Exhibit A-9, Schedule C5.9.1

Q. How were these trend factors determined?

A. Aon Hewitt's Allowed Trend is based on its internal guidance, which represents a consensus expectation for medical and prescription drug costs the Aon Health and Benefits practice developed across all 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 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 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 because 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. This practice recognizes that union employee benefits are set by collective bargaining agreements and can only be changed through agreement between the Company and the unions and that further significant changes in plan design or employee contribution are not anticipated for non-represented employees in the near future.

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. Are you aware of any active healthcare projections that corroborate the reasonableness of the Company's 8.0% annual escalation for 2017?

A. Yes. In 2017, two studies available in the public domain issued by Price Waterhouse Coopers, LLP (PWC) and Wells Fargo Insurance (Wells Fargo) predict a Medical Plan Trend comparable to the 8.0% escalation assumption for 2017 supplied by Aon Hewitt. PWC projects 2018 Medical Plan Trend to be 6.5% while Wells Fargo projects Medical Plan Trend to be between 6.9% and 9.5%, depending on the nature of the healthcare benefits. The PWC study is included on Exhibit A-9, Schedule C5.9.2 and the Wells Fargo study is included on Exhibit A-9, Schedule C5.9.3.

Q. Did the Company's managed care carriers increase their premiums in 2017?

A. Yes. The Company's three managed care providers increased their premiums by a simple average of 14.5% in 2017 compared to 2016. Specifically, HAP's premiums were increased by 9.8%, Priority Health's premiums were increased by 15.8% and Blue Care Network's premiums were increased by 17.8%.

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' actual active healthcare premium increases for non-represented employees in 2018 compared to 2017 by 7.6% for HAP, 7.5% for Priority Health and 5.5% for Blue Care Network.

Q. Has the Company experienced increases in its active healthcare expenses in 2017?

A. Yes. Through September 30, 2017, the Company's active healthcare expenses have increased by over 19% compared to the first nine months of 2016. Moreover, annualized active healthcare expenses have increased by almost 23% relative to calendar year 2016. This experience reflects the impact of the increases in managed care premiums, the required redesign of the Company's wellness programs due to regulations issued by the Equal Employment Opportunity Commission in 2016 and significant increases in healthcare services utilization in 2017. It further highlights

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the year to year sensitivity of active healthcare expenses to unpredictable volatility.

Q. Based on these factors, what is the most reliable measure of the Company's expected levels of active healthcare expense?

A. The annual trend factors of 8.0% for 2017 and 8.5% for 2018 and 2019, as provided by Aon Hewitt and reflected on Exhibit A-13, Schedule C5.9.1, reflect the most rigorous analysis of future healthcare cost trends and, thus, should be applied in projecting the Company's active healthcare expense for the projected test year. Aon Hewitt's projected trends are based on national market trends. Market trends are a more reliable predictor of the future than the experience at any individual company because of the impact of short-term changes in utilization and specific plan design changes on annual expenses. While the Company's experience in 2017 suggests that its actual active healthcare expenses will increase faster than the Aon Hewitt trend rate, it is reasonable to expect the long-term trend will remain in the 8.00% to 8.50% annual rate of change. Indeed, to the extent the 2017 year to date active healthcare expense level is indicative of permanent trends in pricing and utilization, the Company's projection of active healthcare expenses it will incur in the projected test period is conservative.

Q. What are Other Employee Benefits Costs?

A. The costs of the Company's Other Employee Benefits are also reflected on Exhibit A-13, Schedule C5.9. These costs include a variety of other benefits, including Accrued Vacation, Supplemental Severance Plan costs, Long-Term Disability claims, costs associated with the Affordable Care Act (ACA) and the Company's

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Wellness Program, that are projected to increase from the $4.0 million expense in the historic test year to a $4.9 million expense in the projected test year.

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 Gas'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 C5.9 is based on the average of the recorded expense for the most recent five years, which is then escalated by the projected 3.0% 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. The Supplemental Severance Plan, which was implemented on July 1, 2016, is designed to address the differences in full benefit eligibility retirement ages between the DTE Traditional Pension Plan and the MCN Energy Group, Inc (MCN) Traditional Pension Plan. As a severance plan, in accordance with the regulations of the U.S. Department of Labor, it is not subject to participation, vesting and funding requirements of ERISA. Eligible employees will receive a lump sum payment equal to the present value of the difference between the DTE Pension Plan and the MCN Pension at the termination of employment. Aon Hewitt developed the projected cost of this plan. Certain employees of both DTE Gas 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 acquisition of MCN. The cost of this supplemental severance plan is allocated to DTE Gas to the extent the labor costs for eligible employees are recognized by DTE Gas.

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 2016 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 at the end of 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 costs reflect an increase in the Company's matching contributions based on 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 7.50%, 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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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 7.50%. 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 and a Supplemental Retirement Plan for employees whose annual earnings or benefit accumulation exceed various Internal Revenue Code limitations. 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 $34.0 million is adjusted for the impact of the portion of these costs to be transferred and capitalized and the elimination of costs allocated to the Company's Energy Optimization program to produce a projected test period expense of $31.7 million.

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 the existing Collective Bargaining Agreements with Local 223 of the Utility Workers Union of America and Local 799 of the International Chemical Workers Union, the Company is obligated to increase base pay rates by 2.50% in 2017 and 2.95% in 2018 and 2019. Further, existing contracts with bargaining units representing DTE Gas's employees in Greater Michigan provide for base wage increases of 2.75% in 2017 and 3.00% in both 2018 and 2019. In addition to scheduled base wage rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions. In total, it is expected that labor increases for employees covered by collective bargaining agreements will increase by at least 3.0%.

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 pay adjustment programs in March 2017 that resulted in overall pay increases for non-represented employees of 3.0%. In addition to the annual pay adjustment program, employees also receive pay increases in connection with any promotions.

Based on the above, I have determined that annual escalations of 3.0% for 2017, 2018 and 2019 are a conservative estimate of the Company's expected increase in its labor rates.

EMPLOYEE COMPENSATION

Q. What is DTE Gas's compensation philosophy and framework for non-represented, non-executive employees?

A. Non-represented employees are those employees not covered by any Collective Bargaining Agreements with DTE Gas's union organizations whereas Non-executive employees are generally defined as those below the Vice President level. DTE Gas's compensation philosophy is to provide pay programs that: a) attract, retain and motivate employees, b) ensure that pay is externally competitive (paid near the market median) and c) differentiate total rewards based on both organizational unit and individual contributions and results.

At DTE Gas, total annual compensation for non-represented employees has two primary components: base 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 customer, Company, departmental and individual results. Variable pay is made up of both short-term incentive plans and a long-term incentive plans.

Q. How does DTE Gas'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 exempt 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 represented by these two components that is the benchmark that prospective employees use to gauge whether DTE Gas's compensation is competitive with other potential employers. If the Company chose to reduce or eliminate the opportunity for employees to earn the variable pay component, it would then need to consider whether it would be appropriate to increase base salaries to attract and retain a highly skilled workforce. This elimination of variable pay in turn would have the effect of increasing the cost of benefits, such as 401(k) and life insurance, which are tied solely to base salaries. Thus, at Target performance levels, the Company's total costs would be higher if base pay for employees was set at the market levels.

Q. How does DTE Gas's non-represented compensation philosophy and framework provide benefits to customers?

A. DTE Gas's compensation philosophy and framework provides a benefit to customers and shareholders 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. 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 non-executive 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 reservoir engineer consists of companies 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 competitive 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, and demonstrated performance. The ranges are reviewed periodically to help ensure they remain competitive in the external market.

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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.

Q. Could DTE Gas increase its base pay levels to the market levels for total compensation instead of providing variable pay opportunities to stay competitive?

A. Yes, it could, but as mentioned above, such an increase would result in a higher level of fixed costs tied to base salaries such as 401(k) matching contributions, life insurance, disability insurance and other employee benefits. Moreover, given the recognized motivational value of variable pay compensation programs, as described below, delivering employee compensation solely in salary would diminish the motivational incentive for employees to provide superior service to customers and the other constituencies that DTE Gas serves. Annual incentives ensure that individuals have an element of “at risk” compensation that allows DTE Gas to differentiate pay based on performance and allocate compensation to those employees that are most deserving. In my opinion, incentive-based compensation is an important tool to drive performance improvement and effectively manage compensation costs, particularly in a service-based industry like the utility industry.

Q. What are the components of the Company’s non-executive incentive compensation program?

A. Payouts for the Company’s incentive compensation programs are dependent upon the achievement of customer, Company, departmental and individual goals. Payouts under the Performance Shares of the Long-Term Incentive Plan (LTIP) for eligible participants are dependent upon the achievement of specific financial goals over a three-year performance period.

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 resources companies and significant non-energy related companies selected on the basis of revenues, financial performance, geographic location and availability of compensation information.

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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.

COMPETITIVE COMPENSATION ANALYSIS

Q. Has the Company prepared an analysis of whether its compensation practices are competitive with the market medians?

A. Yes. DTE Gas has preformed an analysis of virtually all incumbent salaries as of December 31, 2016 showing that DTE's compensation practices are competitive with market medians. Exhibit A-19, Schedule I5 reflects a summary of the market median for all DTE Gas positions for which corresponding positions have been identified, other than those employees covered by collective bargaining agreements. In addition, Exhibit A-19, Schedule I5 reflects those positions at DTE Energy Corporate Services LLC that primarily support DTE Gas. Exhibit A-19, Schedule I5 reflects employee compensation information organized based on Career Family classifications used by DTE Gas. A Career Family is a grouping of jobs based on similar skill requirements

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and job content in a specialized discipline (i.e. Finance, Engineering, Information Technology, etc.) that may or may not fit into a business unit organizational structure. For example, Engineering or Finance Career Families could exist in several organizational units.

Q. How is an analysis of a competitive pay strucure performed?

A. In simplest terms, an analysis of market based pay structure is performed by identifying comparable positions and determining the compensation ranges paid by similar employers in relevant locations. A more expansive description of the means of assessing a competitive pay structure is provided in an article published by Salary.com, entitled Understanding Market Pricing (August 2008).

Q. Is the Company's use of a market pricing approach to employee compensation consistent with others?

A. Yes. According to a survey performed by World at Work, entitled Job Evaluation and Market Pricing Practices (November 2015), up to 74% of companies use a market pricing model for setting compensation levels.

Q. Why have you excluded from this analysis employees covered by collective bargaining agreements?

A. Compensation levels for unionized employees are determined through a negotiated process, which involves a variety of work rules and benefit related issues, rather than determined strictly through market analysis. Moreover, the specialized skills and expericence required by many of the positions are not readily comparable to other positions in the local market. Thus, a comparison of pay levels for those employees covered by collective bargaining agreements is not useful in this context.

Q. What conclusions do you draw from Exhibit A-19, Schedule I5?

A. In summary, Exhibit A-19, Schedule I5 demonstrates that the weighted average of the annual base compensation for all positions with incumbents at December 31, 2016 with available position matches was 0.8% higher than the average of median market base compensation. Plus, such analysis further demonstrates that total cash compensation for all positions with incumbents at December 31, 2016 with available position matches was 0.7% higher than the average of median market for total cash compensation. This analysis concludes that the Company's total compensation is insignificantly different from the market medians, and confirms that the Company's compensation practices are consistent with the Company's compensation policy to pay employees near the market median for comparable positions on a total cash compensation basis.

Q. How was the market median for the positions determined?

A. As described above, the Company subscribes to several compensation survey providers that create comprehensive databases of job descriptions that enables the Company to match the job requirements, including education, expertise and experience of existing positions with market surveys. After matching job positions are identified, actual base and total compensation ranges are developed from the salary survey database. The information on Exhibit A-19, Schedule I5 was derived from the Company's compilation of the compensation for positions with an incumbent as of December 31, 2016.

Q. Why have you limited your analysis to positions with incumbents as of December 31, 2016?

A. December 31, 2016 represents the end of the historical test period used by the Company in this filing. Although throughout the course of any year employees may leave the Company and new employees may be added, any comparison of actual compensation must be based on the actual pay levels of existing employees. Since it is impractical to identify the actual compensation and market median comparisons for each former and newly hired employee throughout the year, the only meaningful analysis of the Company's overall compensation practices is for incumbents in positions at a fixed point in time. Accordingly, the analysis reflected on Exhibit A-19, Schedule I5 is as of December 31, 2016.

Q. What proportion of DTE Gas's total employee population as of December 31, 2016 is reflected in this analysis?

A. Over 99% of the employee population as of December 31, 2016 at DTE Gas, as well as DTE Corporate Services, LLC employees that provide supporting services to DTE Gas, but exclusive of those employees represented by collective bargaining agreements is reflected in this analysis.

Q. Why aren't all incumbents included in this analysis?

A. Although the Company is able to find job matches for the 99.1% of its positions, it is simply unrealistic to expect matches for every single position. In those circumstances in which a comparable job description is not identified, the Company compares the compensation of similar internal jobs for which an external match was identified. Since only 0.9% of the positions as of December 31, 2016 were unmatched with external job descriptions and the reasonableness of the compensation for those unmatched positions was validated by comparision to similar positions within the Company, the analysis provided on Exhibit A-19, Schedule I5 is as comprehensive as is practically possible to create.

Q. What is included in the total cash compensation amounts?

A. Total cash compensation reflects base pay as of December 31, 2016 and the Target payout levels for those employees eligible to participate in the Company's short-term incentive compensation programs. Although the analysis on Exhibit A-19, Schedule I5 does not reflect the value of the Company's Long-Term Incentive Plan, as it is primarily for executive level positions, a separate analysis of executive compensation, inclusive of long-term plans, shows that total compensation is slightly less than the median of the Company's peer group, as discussed in more detail below.

Q. Has the analysis of pay relative to market medians reflected on Exhibit A-19, Schedule I5 been reviewed by an independent expert on compensation?

A. Yes. Exhibit A-19, Schedule I6 reflects a report prepared by Aon Hewitt regarding its review of the data and techniques used by the Company in preparing its comparison of Company compensation levels to market compensation levels. The independent assessment by Aon Hewit concludes that the Company has deployed best practices in sourcing the market pay data and developing estimated market values, among other things.

Q. Do the total compensation levels inherent in Exhibit A-19, Schedule I5 agree with payroll costs incurred in 2016 for non-represented employees?

A. No. Since the comparison of compensation levels to market was measured as of December 31, 2016, it would necessarily not agree with the actual compensation costs for the twelve months ending December 31, 2016 due to changes in the number and mix of employees throughout the year as well as the impact of any changes in employees' compensation arising from promotions or other pay increases that occurred during the year. In addition, the labor costs on Exhibit A-19, Schedule I5 reflect the total cash compensation of those employees at DTE Energy Coprorate Services LLC that support DTE Gas while only the portion of the labor costs allocated to DTE Gas are included in DTE Gas's recorded payroll costs. Moreover, the computation of total cash compensation on Exhibit A-19, Schedule I5 is based on the achievement of Target performance levels in the incentive compensation plans whereas total cash compensation costs recognized in 2016 reflects actual 2016 performance levels.

INCENTIVE COMPENSATION PROGRAMS

Q. What is the purpose of your testimony regarding the Company's incentive compensation programs?

A. My testimony will begin with an explanation of the Commission's recent actions on the treatment of incentive compensation expense and then I will explain the components of the incentive compensation expense the Company is seeking to include in its revenue requirement.

Q. Has the Commission previously addressed the issue of the inclusion of incentive compensation in the Company's revenue requirements?

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A. Yes, it has. In the Commission's Order in the Company's most recent general rate case (Case No. U-17999), 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 return on equity and cash flow may seem to be exclusively focused on creating increased value to shareholders, such a conclusion ignores the role that cost effectiveness and a focus on continuous improvement have on a company's financial metrics that also benefit customers through lower revenue requirements and higher quality customer service. That is, when 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. Financial based measures motivate employees to improve their work processes to use fewer resources while also producing improved performance. While cost efficiencies that contribute to improved financial performance result in temporary shareholder benefits, when new rates are established incorporating these lower costs the benefits to customers

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become a permanent benefit. By setting revenue requirements based on costs, the long-term benefits to customers can 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 Gas's O&M expense levels from 2007 through the 2016 historical test period increased by less than the rate of inflation. Indeed, the Company's 2016 O&M expenses are $26.3 million less than they would have been had the Company's O&M increased by the Consumer Price Index. This historical record of being able to keep increases in the Company's O&M less than the rate of inflation indicates the Company has realized significant improvements in operating efficiencies through the deployment of a Continuous Improvement campaign throughout the Company as well as other initiatives to reduce the Company's costs.

Q. Are there other customer benefits from 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. Higher credit ratings result in lower cost of capital to the Company and, thus reduced revenue requirements. Moreover, a financially strong company will have greater access to capital markets, which is especially important in light of the Company'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 motivate improved organizational performance. An effective incentive compensation plan provides a "pay-for-performance" environment intended 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 lead 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 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 awards ensure that individuals have an element of "at risk" compensation allowing 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, in 2011. This study indicates that variable pay programs are increasingly prevalent among the vast majority of companies (Incentive Pay Practices Survey: Publicly Traded Companies, WorldatWork and Deloitte Consulting, February 2014).

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 its peers, inclusive of the variable component related to incentive compensation. These benchmarks establish a mid-point salary range based on the median market level. Based on a recent analysis of executive compensation prepared by Aon Hewitt, the target total compensation of DTE Energy's executives is about 4% less than the average of its peers, inclusive of both short and long-term incentive compensation at target levels. The Company's variable pay programs are a component of the total compensation policies required for the Company to be competitive with its peers, rather than a supplement. 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.

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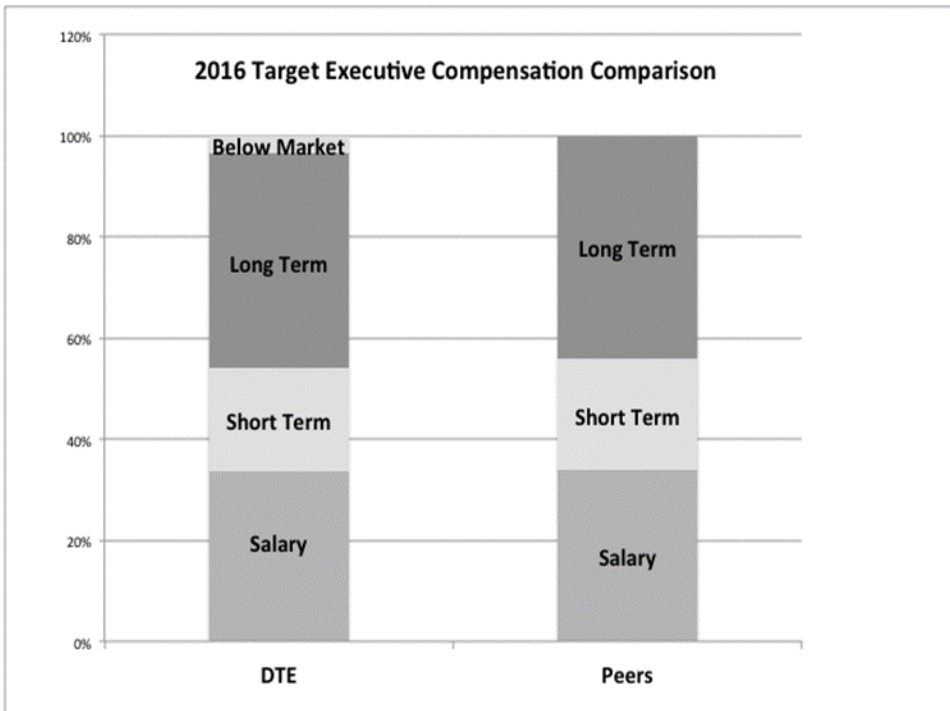
Q. How do the components of the Company's total compensation practices compare to the Company's peers?

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 to the 50th percentile of its peers are reflected in the table below.

Chart 1



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 delivered through the Long-Term Incentive Plan (LTIP).

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Q. What is the AIP?

A. The AIP is a short-term variable pay vehicle available to senior management level employees to motivate performance. The defined measures and weightings in this plan include financial performance (40%), customer satisfaction (20%), employee engagement (20%) and operating excellence (20%). The specific 2018 measures and performance Targets for DTE Gas are reflected on Exhibit A-19, Schedule I1. For each measure, a Target is set for which a "normal" payout will be earned. Performance less than Target but above a minimum Threshold results in a payout between 25% of Target and Target, and performance up to a Maximum may result in a payout of up to 175% of Target. Actual payouts to individual employees are based on the performance against the Targets but also may be modified by a factor of 0% to 150% based on individual performance.

Q. What are the financial measures included in the AIP?

A. Three financial measures for DTE Gas employees are designed to create a clear line of sight for all employees to focus on operating excellence by rewarding employees when the Company is successful.

1) DTE Gas's Operating Earnings objective is the Company's 2018 budget.
2) DTE Gas's Adjusted Cash Flow is similarly the Company's 2018 budget. A cash flow measure reflects the importance of maintaining a high credit rating allowing access to capital markets at reasonable costs and terms.
3) DTE Energy's Earnings per Share measure is based on the midpoint of current 2018 earnings guidance.

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 incorporates the key drivers of customer satisfaction, as measured by J.D. Power. The 2018 Target is to close half of the gap between the Company's actual performance in 2017 and top decile results for the J.D. Power National Peer Set.

2) The first Customer Satisfaction Improvement Program measure relates to unsatisfactory customer service based on the number customer complaints collected through the operation of the DTE Cares program as determined by use of a 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 is to achieve an 8.0% reduction in the DPMO from 2016 actual results.

3) The second Customer Satisfaction Improvement Program measure relates to the measurement of how successful the Company is increasing the proportion of delighted customer interactions based on call center activity as well as field and self-service interactions. The 2018 Target for this measure, also called +1PMO, is a 5.0% improvement in the number of highly satisfied customer interactions compared to 2017 actual 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 Target is to achieve an 8.0% reduction in the number of complaints made to the MPSC in 2016.

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Q. What are the measures related to employee engagement and safety?

The three employee engagement measures encompass the areas of employee engagement and three employee safety 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 and is premised on the continuation of top decile performance compared to Gallup's overall database of participating companies. Employee Engagement is a statistically significant measure of the level of commitment employees have to an organization's success and should not be confused with a measure of mere employee satisfaction.

The Company has two safety 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 .88 Target for 2018 represents top decile performance based on the Company's peers.
2) OSHA Days Away, Restricted or Transferred (DART) rate. Target performance in 2018 will require a DART rate of .33 per 100 employees divided by the actual number of hours worked.

Line No

Q. What are the Operating Excellence measures for 2018?

A DTE Gas has six Operating Excellence measures that are specific operating priorities for 2018 and are included as AIP measures to motivate the achievement of certain operating objectives important to the Company, its customers and the Commission.

1) Gas Distribution System Improvement: This measure relates to the number of priority three leaks at year-end. The Target for 2018 is 973 leaks, which represents top decile performance relative to our peers

2) Leak Response Time: This measure reflects the elapsed time, as measured in minutes, between when a customer reports potential leaks to the Company and when a Field Service employee arrives at the site. This measure is designed to provide a leadership focus on the importance of responding to all potential leaks as quickly as possible. The Target in 2018 is to achieve an average response time of 22.8 minutes.

3) The Lost and Unaccounted for Gas: This measure is designed to encourage the Company's leaders and employees to focus on maintaining system integrity and the efficient operation of the gas distribution system. The 2018 Target is an annual volume of Lost and Unaccounted for Gas of 3.3 Bcf.

4) Gas Compression Reliability: This is a measure of total available horsepower hours divided by total annual horsepower hours. The purpose of this measure is to focus leaders and employees on the importance of a strategic emphasis on compression reliability and thus deploy the optimum maintenance work on a timely basis to achieve high levels of equipment reliability while achieving lower overall life cycle costs. The 2018 gas compression availability Target is 90%.

5) The Gas Damage Prevention Effectiveness: This measure relates to the number of third-party damages to the Company's distribution and service lines per

thousand staking requests received from 811 (Miss Dig). The purpose of this measure is to enhance public safety, reduce leaks and prevent the disruption of natural gas service by reducing the number of damage incidences to the Company's system from excavations. The 2018 Target is to realize only 3.3 third party damages per thousand staking tickets.

6) Installation of Remote Control Valves (RCV) on the gas transmission system in High Consequence Areas, as defined by the United States Department of Transportation regulations. While the 2018 Target has not been established pending actual results in the number of RCV's installed in 2017, the 2018 Target will reflect an improvement over the number of installations in 2017.

Q. Which employee classification is eligible to participate in the AIP?

A. All Officer level employees, typically 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 results in a 50% payout of target while maximum performance payout is 150%. In addition, the measure related to the Gallup survey of employee engagement is eliminated in recognition that the Company's leadership is responsible for providing an environment conducive to a high level of employee engagement and the weightings for the two safety related measures are both increased from 5.00% to 7.50% and the weighting for Operating Excellence measures is increased from 20% to 25%.

Q. Are there other AIPs and REPs that impact DTE Gas's expenses?

A. Yes. In addition to the DTE Gas measures described above, there are also AIPs and REPs in place for corporate staff employees at DTE Energy Corporate Services LLC that provide services to all DTE Energy business units, including DTE Gas. The measures and weightings for DTE Energy Corporate Services LLC are reflected on Exhibit A-19, Schedule I2.

Q. What is the Company's Long-Term Incentive Plan?

A. The Long-Term Incentive Plan (LTIP) provides the opportunity for certain individuals to receive retention-oriented or performance-based rewards delivered via shares of DTE Energy common stock, either through Restricted Stock or Performance Shares, which are based on the achievement of multiyear performance objectives. Currently 30% of the value of awards is through Restricted Stock and 70% through grants of Performance Shares for executives while 100% of the awards to non-executives 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 used in the 2018 LTIP?

A. The measures used in 2018 are shown on Exhibit A-19, Schedule I3.

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 Gas, 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 enables continued access to the debt markets at reasonable terms and conditions. The third measure that contributes 20% to the weighting is the actual DTE Gas Average Return on Equity for 2018 through 2021. The focus on DTE Gas'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 costs of the Long-Term Incentive Plan?

A. The LTIP costs incurred in 2016 pertain to the grants of Performance Shares and Restricted Stock. While the expense related to the Restricted Stock is not conditional on any Company performance measures, Performance Shares expense is based on the achievement of the Target levels of performance. Both the Restricted Stock and Performance Shares costs 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

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the adjustments to the actual 2016 LTIP expense to normalize for the impact of actual awards for the Performance Shares to Target performance and the elimination of the impact of changes in DTE Energy's stock price recognized in 2016.

Q. What is the net expense of the variable pay programs if the Company achieves its Financial and Operating Targets?

A. The net expense if DTE Gas achieves its Financial and Operating Targets for the short-term and long-term plans, exclusive of the expense associated with the top five officers, is $12.6 million. The table below summarizes the expense by the nature of the plans, the classification of the employees eligible and differentiated between the Financial and Operating measures.

Table 1

	LTIP	AIP (000's Omitted)	REP	Total
Financial				
DTE Gas	$991	$161	$1,061	$2,212
DTE LLC	2,514	795	1,639	4,948
	3,504	956	2,700	7,160
Operating				
DTE Gas	0	241	1,592	1,833
DTE LLC	0	1,193	2,458	3,651
	0	1,434	4,050	5,484
Total				
DTE Gas	991	402	2,653	4,045
DTE LLC	2,514	1,988	4,097	8,599
	$3,504	$2,390	$6,750	$12,644

Q. Why are the expenses for DTE Energy Corporate Services LLC 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 Gas and DTE Electric for which the costs are billed to the operating companies, as explained by Witness Uzenski. In addition, DTE Energy Corporate Services LLC employs all the officers of DTE Energy, including the officers of DTE Gas.

Q. How have you reflected the Operating Excellence measures related to DTE Electric included in the DTE Energy Corporate Services LLC AIP and REP?

A. While the AIP and REP costs allocated to DTE Gas in the historic test period from DTE Energy Corporate Services LLC include measures related to DTE Electric, almost 75% of the AIP and REP costs are allocated to DTE Electric. Since the AIP and REP costs related to DTE Electric are not allocated to DTE Gas, the AIP and REP weightings for DTE Energy Corporate Services LLC have been adjusted to exclude the measures related to DTE Electric. Accordingly, the weightings for the AIP and REP costs at DTE Energy Corporate Services LLC for the Operating Excellence measures, as reflected in the table above, are identical to the Operating Excellence measures for DTE Gas.

Q. Are all 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.

Accordingly, $814,000 of incentive compensation expense related to Restricted Stock is not variable and is excluded from the table above.

Q. Is the Company requesting recovery for all executive compensation expenses?

A. No. While the Company believes that all its compensation expenses are reasonable, the Company has excluded $2.8 million of variable compensation expense for DTE Energy's top five executive officers. This exclusion is reflected on Exhibit A-3, Schedule C16, which is supported by Witness Uzenski. The impact of this elimination in expense is also reflected in 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 its recent Orders addressing variable pay programs that recovery of such expenses was dependent on a showing that the variable pay plans provided benefits to customers in excess of the costs to be included in the company's revenue requirements.

Q. Are the Commission's criteria for recovery of the costs of variable pay programs consistent with the policies of other utility rate setting agencies in the Midwest?

A. Partly. While some State utility commissions may disallow all costs of variable pay programs without regard to any assessment of reasonableness (i.e., Wisconsin), the more prevalent regulatory practice allows recovery of variable pay program costs when there are some identifiable operational benefits of such programs (i.e., Illinois and Indiana). Indeed, the Indiana Utility Regulatory Commission (IURC) has in place a long-standing policy of allowing the recovery of costs of variable pay programs. Specifically, the IURC has consistently allowed the recovery of incentive compensation costs, based both on financial and operating measures when, 1) the incentive compensation is not a pure “profit-sharing plan” driven exclusively by financial results, 2) the incentive compensation does not result in excessive levels of total compensation, and 3) when shareholders absorb a portion of the cost of the incentive compensation programs.

Q. Has the Company performed an analysis of the customer benefits of the Company’s variable pay programs?

A. Yes. The Company has 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 costs. This analysis, as reflected on Exhibit A-19, Schedule I4, demonstrates that the expected aggregate benefits will significantly exceed the costs of these programs. While certain individual measures, such as customer satisfaction and certain safety related objectives provide benefits that defy precise quantification, there should be little serious dispute as to the qualitative value of such metrics. The Company is aware of the frustration experienced by customers when customer service issues are not promptly resolved, even though the value of the elimination of that customer frustration is not readily estimated. The inability to precisely quantify the customer benefit in no way diminishes its value. The greatest benefits achieved through improved safety performance are the avoided injuries or property damage made possible through an increased emphasis on safe work habits and conditions.

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 variable pay program expense within the Company's revenue requirement.

Q. Are you sponsoring an exhibit that quantifies the extent to which the customer benefits exceed the expense of the Company's variable pay programs?

A. Yes. Exhibit A-19, Schedule I4 contains a recap of the quantified benefits relative to the costs of the incentive plans. This exhibit demonstrates that the total calculated customer benefit of $24.6 million exceeds the total variable pay program expense of $12.6 million by $12.0 million.

Q. How are the Financial Measures benefits 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. One benefit is the focus of the metrics related to DTE Gas earnings (as measured through DTE Gas's Average Return on Equity and DTE Gas Operating Earnings). Another benefit is avoided interest costs arising from the maintenance of the Company's existing 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 measuring financial performance produced cost savings for customers?

A. Yes. As a natural gas distribution company, DTE Gas has little direct control over its revenue because the Commission sets its rates and the Company's sales volumes

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are largely dependent on regional economic activity and weather. Because the Company can't control either of these factors, DTE Gas's primary ability to improve its financial performance is its ability to control its costs; and 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 2016 O&M expense is $26.2 million less than if the Company's O&M expense incurred in 2007 had increased by the rate of inflation, or an annual O&M expense savings of $2.6 million ($26.2 million/10 years).

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 BBB+ debt rating from Standard & Poor's and comparable ratings by the other major debt rating firms. The yield spread between utility bonds rated BBB+ compared to BBB- is 52 basis points. Based on the long-term debt included in the capital structure sponsored by Company Witness Mr. Solomon, a downgrade to BBB- would increase the Company's annual interest costs by $7.8 million. The benefit of this avoided cost is allocated to the cash flow related measures of the variable pay expenses similar to the earnings-related benefits.

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Q. How are the benefits of the operating measures 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 in measuring customer benefits are, in most instances, based on comparisons relative to the Company's performance in 2016. In those circumstances where 2016 performance was unrepresentative of long-term trends, a five-year average of actual performance was used in measuring the value of achieving Target performance levels in 2018. Unless specifically identified, the benefits of achieving Target performance are allocated between the AIP and REP components based on the relative AIP and REP costs for the related measure.

Q. How did you quantify the benefit of improvements in the Customer Satisfaction measures?

A. While the Target of closing half the gap between the Company's actual performance in 2017 and the top decile ranking relative to the Company's J.D. Power's National Peer Set is an ambitious Target, there is insufficient comparative data to derive a quantified customer benefit of achieving such objective in 2018.

The benefits of attaining Target performance in the customer satisfaction improvement program is based on the Company's avoided cost based on an 8.0% reduction in defects per million opportunities plus avoided customer costs for a total customer benefit of $63,100. Since the +1PMO measure is a new measure in 2018, the customer benefits of achieving a 5% increase in this measure compared to 2017 actual results is not quantifiable.

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No

The benefits of achieving Target performance of an 8.0% reduction in the number of customer complaints to the MPSC is similarly based on the Company's and customer avoided costs of the time spent resolving complaints for a total benefit of $8,600. Although the total quantified benefits of the measures related to customer satisfaction amount to only $71,700, 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 customers and the Commission, as well as the Company.

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. Gallup has determined that a 0.1 improvement in the grand mean will result in a median improvement of 3.1% in absenteeism, a 1.8% increase in productivity and a 3.8% reduction in safety incidents. Based on a five-year average of the Company's performance in 2011 through 2016, achievement in 2018 of Target Gallup survey results will generate O&M savings at DTE Gas of $7.3 million inclusive of savings allocated from DTE Energy Corporate Services 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 RIR 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 $136,000 per incident, as adjusted for inflation. Thus, based on Target level performance, the net O&M savings relative to the five-year average of the Company's recent experience are estimated to be $585,000 inclusive of savings allocated from DTE Energy Corporate Services LLC and net of the savings 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 measure.

Q. What are the benefits related to Gas Distribution System Improvement?

A. Although not specifically quantifiable, the benefits of the reduction in the number of year-end gas leaks relate to a reduction in Lost and Unaccounted for Gas volumes, as separately described below.

Q. How did you quantify the benefits of achieving the Target reductions in Gas Distribution Response Time?

A. The savings that arise from the achievement of the improvements in leak response time is based on the reduction of 0.87 full time equivalent employees, which results in an annual savings of $130,900. Although the quantifiable savings of a reduction in leak response time is less than the related expense, clearly all customers realize a non-quantifiable benefit of the Company being able to promptly respond to leak calls.

Q. How were the savings from meeting the 2018 Target volume of Lost and Unaccounted for Gas quantified?

A. The benefits of achieving the Target performance regarding Lost and Unaccounted for Gas result from a reduction in the average annual Lost and Unaccounted for Gas

Line No

volumes over the last five years of 4.6 Bcf compared to the 2018 Target of 3.3 Bcf. At the projected 2018 average cost of gas of $3.22/Mcf, the savings from the reduction in Lost and Unaccounted for Gas volumes would be $4.3 million. The benefit of this reduction in Lost and Unaccounted for Gas volumes would be realized by customers as the reduced volumes are reflected in the updated five-year average of Lost and Unaccounted for Gas volumes in subsequent rate cases, as per the Commission's traditional practice.

Q. What are the identified benefits of the improvement in Gas Compression Reliability?

A. The benefits from increased availability of gas compression relate to the ability to increase off-system transportation service. Based on the Target increase in availability it is expected the Company would be able to increase off system transportation revenue by over $150,000.

Q. What are the savings created by achieving the Gas Damage Prevention Effectiveness measures?

A. The savings from achieving a reduction in the third-party damage claims is based on the avoided costs of $3,000 per claim. A reduction in the number of claims per thousand Miss Dig calls from 5.2 in 2016 to the 2018 Target of 3.3 results in savings of almost $1.7 million.

Q. How did you quantify the benefits of the Gas Transmission Reliability measure?

A. While not quantifiable, the benefits of achieving the increased number of installations of remote control valves ("RCV") in high consequence areas could be significant if

Line No

the installation prevents a major incident in a populated area. The installation of additional RCV's reduces the probability of catastrophic damages and is made possible by decreasing the time required to close a gas transmission valve if an incident occurs through enabling personnel to stop gas flows remotely.

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 above the variable pay expense of the measure, it is clear that in aggregate the customer benefits of the Company achieving Target performance levels are substantially greater than the variable pay program expense. Thus, the Company's incentive compensation expense should be included in the revenue requirements adopted by the Commission in this proceeding as reasonable and prudently incurred 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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

HENRY J. DECKER

DTE GAS COMPANY
QUALIFICATIONS OF HENRY J. DECKER

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

A. My name is Henry J. Decker and I am currently employed at DTE Gas Company (DTE Gas 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 Gas.

Q. What is your educational background?

A. I graduated from The Georgia Institute of Technology in 1995 with a Bachelor's degree in Mechanical Engineering. I also earned a Masters of Business Administration degree from Carnegie Mellon University Tepper School of Business (formerly known as the Graduate School of Industrial Administration) in 2002.

Q. What work experience do you have?

A. From 1995 to 2000, I worked at BOC Gases, now part of Linde AG, as a plant engineer where I worked at various air separation plants in the United States and traveled extensively across the world trouble-shooting operational difficulties at other air separation plants. I left that industry in 2000 to pursue my MBA, where I focused on strategy and finance. Upon earning my MBA in 2002, I worked as a Financial Analyst for International Business Machines in White Plains, New York. After approximately one year, I accepted a position with Taro Pharmaceuticals in Hawthorne, New York as a Senior Financial Analyst. In 2005, I left Taro Pharmaceuticals to work for Rothschild, Inc. as an investment banker where I focused on mergers and acquisitions and corporate restructurings, primarily in the

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power and utility industries. After five years with Rothschild, I joined Moelis & Company, another investment bank, where I also focused on the power and utility industry. As an investment banker, I advised many different clients including electric and natural gas utilities, independent power producers, and private equity firms on various transaction types including mergers, acquisitions, divestitures, capital market transactions and corporate restructurings (e.g. bankruptcies). In 2013, I joined DTE Energy as a Director of Strategy and Corporate Development, where I was responsible for leading various strategy and commercial development assignments. In 2014, I joined DTE Electric as the Director of Strategy and Planning responsible for leading the development of DTE Electric's long-term generation strategy and associated integrated resource planning activities.

Q. What is your current position?

A. I became a DTE Gas employee in September of 2016 as Director, Gas Sales and Marketing.

Q. Have you previously provided testimony to the Commission?

A. No, I have not.

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PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to:

- Discuss proposed gas-in-kind percentages for all rate classes;
- Discuss future test year projections of transportation volume, revenue and customer count forecasts relating to End-Use Transportation (EUT) customers;
- Seek authorization to recover the transportation rate discount provided to AK Steel and Ford-Rouge, two of DTE Gas's largest EUT customers, in customer rates;
- Support DTE Gas's proposed EUT monthly customer charges, rate schedule break-even points for rate design purposes, and the minimum and maximum EUT optional rates;
- Discuss modifications and/or clarifications to DTE Gas's Rate Book – Sections C, D, and E;
- Discuss the Company's future test year projections of Off-System (Midstream Services) Storage and Transportation Revenue;
- Discuss customer benefits associated with the NEXUS pipeline project;
- Discuss other Operating Revenues;
- Discuss Costs for Transmission and Compression of Gas for Others;
- Discuss DTE Gas's appliance service program revenue, gas customer choice supplier revenues, and other gas revenues;
- Support projected earnings impact of the Company's Blue Lake Storage investment, and miscellaneous service revenues;
- Request recovery of natural gas research and development expenses pursuant to the standards set forth in the Commission's Order in Case No. U-14561; and

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- Discuss marketing related operating and maintenance (O&M) expenses.

Q. How is your testimony organized?

A. My testimony is organized into twelve sections as follows:

SECTION 1 – Gas-in-kind: I describe full system and transmission-only gas-in-kind (GIK) percentages and cost of service credit.

SECTION 2 - End-Use Transportation: I describe the various EUT service categories, the historical test year and projected test year EUT volumes, EUT customer count, and EUT revenues.

SECTION 3 – Recovery of Transportation Rate Discounts for AK Steel and Ford-Rouge: I support the proposal that DTE Gas recover the rate discounts for AK Steel and Ford-Rouge, both major EUT customers.

SECTION 4 – Midstream Services: I describe projected test year revenue for Midstream Services storage, transportation, and other various components, plus the transmission and compression gas costs. In addition, I describe customer benefits of the NEXUS pipeline project.

SECTION 5 – Other Operating Revenue Components: I explain the development of the appliance service program revenue, gas customer choice (GCC) supplier revenue, miscellaneous service revenue, and other gas revenues.

SECTION 6 – In Section 6, I present DTE Gas's proposed monthly customer charges, the rate schedule economic break-even points, and the minimum and maximum optional rates under the EUT rate schedules for rate design purposes.

SECTION 7 – Tariff Changes for All Customers: I discuss modifications to Section C of the DTE Gas Rate Book including the elimination of the Connection Fee.

SECTION 8 – Tariff Changes for Sales Customers: I discuss modifications to Section D of the DTE Gas Rate Book.

SECTION 9 – Tariff Changes for EUT Customers: I discuss modifications and clarifications to Section E, Part I of the DTE Gas Rate Book.

SECTION 10 – Tariff Changes for Contract Rate Customers including the General Service Rates, EUT Rates, and Off-system Storage and Transportation Rates: I discuss modifications to Sections C, D, and E of the DTE Gas Rate Book.

SECTION 11 – Gas Technology Institute: I support the proposal that DTE Gas recover natural gas research and development expenses, specifically costs to participate in the Gas Technology Institute Utilization Technology Development program.

SECTION 12 – Gas Marketing: I discuss O&M expenses as they relate to DTE Gas Marketing.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-13	C3.2	Projected EUT Revenue
A-13	C3.3	Projected Off-System Storage and Transportation Revenue
A-13	C5.5	Projected Operating and Maintenance Expenses--Marketing
A-15	E6	Projected EUT Customers
A-15	E7	Projected EUT Volumes
A-15	E14	Proposed Gas In Kind Percentages
A-22	L1	AK Steel Alternate Fuel Supply Cost Comparison
A-22	L14	Alternative Proposed Gas in Kind Percentages
A-22	L15	Alternative Comparison of Historical and Projected EUT Revenue
A-22	L16	Alternative Comparison of Historical and Projected EUT Customers
A-22	L17	Alternative Comparison of Historical and Projected EUT Volumes
A-22	L18	Alternative Off System Storage and Transportation Revenue
A-23	M1	NEXUS Capacity Lease Agreement
A-23	M2	NEXUS Lease Revenue

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

A. Yes, they were.

SECTION 1 – GAS-IN-KIND

Q. What is Gas In Kind (GIK)?

A. GIK is gas (expressed as a percentage of throughput) that is supplied by customers to offset Company Use gas and Lost and Unaccounted For (LAUF) gas. Company Use gas is created by fuel consumed by the Company in the provision of storage and transportation services. LAUF is comprised of transmission system losses (metering) and distribution system losses (theft, metering and leaks). Reference Company Witness Ms. Aud's testimony for detail and background on Company Use and LAUF.

Q. Why is it important to distinguish transmission system losses from distribution system losses?

A. Determining loss rates for transmission and distribution systems separately is important in determining appropriate GIK rates for customers based on cost causation. As explained in Witness Aud's testimony, LAUF can be categorized as either transmission system losses or distribution system losses. Off-system storage and transportation customers ("off-system customers") and large volume end-use transportation customers (also referred to as XXLT transport customers) are extensive users of DTE Gas's transmission system with little or no utilization of the distribution system. Losses on the distribution system are primarily a result of leaks, metering and theft. It is important to note that theft has never been identified with EUT customers that utilize the distribution system.

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Q. Is DTE Gas recommending any changes to GIK rates for off-system customers and EUT customers?

A. No. DTE Gas recommends maintaining GIK rates that were approved by the Commission in DTE Gas's last rate case, Case No. U-17999. These GIK rates are set forth below.

Table 1

Rate Schedule	GIK
ST, LT, XLT	1.41%
XXLT	1.00%
Off System	1.00%

See Exhibit A-15, Schedule E14, line 18, columns (d), (f), and (g) for details of GIK calculations.

Q. Why is the Company maintaining GIK rates approved in Case No. U-17999 for off-system and EUT customers?

A. DTE Gas is not recommending any changes to the GIK rates for the following reasons:

1. These GIK rates support the current off-system and end-use transportation competitive business environment without additional risk to load and revenue loss;
2. These GIK rates provide a contribution to the recovery of LAUF for all other rate classes including Commission-approved special contracts; and
3. Significant uncertainty exists with respect to NEXUS volumes being placed on DTE Gas's transmission system, which may result in additional transmission losses not currently observed in our historical averages.

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Q. What GIK rate does DTE Gas forecast sales rate customers will experience in the test period?

A. Based on the GIK rates proposed above, the GIK rates for sales rate customers is the equivalent of 1.63%. GIK in base rates. See Exhibit A-15, Schedule E14, line 17, column (c) for details of GIK calculation.

Q. How were GIK percentages established for existing special contracts?

A. In each of the special contracts not covered by a tariff GIK percentage, the Company used the GIK percentage in the special contracts previously approved by the Commission. This is the same methodology used in DTE Gas's previous rate cases (Case Nos. U-13898, U-15985, U-16999) and is consistent with the order received in DTE Gas's last rate case U-17999.

SECTION 2 – END-USE TRANSPORTATION

Q. What are the characteristics of DTE Gas's EUT class of customers?

A. End-Use Transportation (EUT) customers are DTE Gas's largest Commercial and Industrial (C&I) customers. These customers purchase their natural gas from third-party gas suppliers and then contract with DTE Gas to transport and balance the customers' nominated gas supplies on the DTE Gas system for delivery to the customers' facilities. EUT customers range in size from commercial buildings and schools consuming 10,000-15,000 Mcf of natural gas per year to very large industrial operations such as a steel mill, petroleum refinery, and merchant power plants consuming more than 9.0 Bcf per year. Many EUT customers have alternative energy options including coal, oil, propane, local gas wells, electricity, waste fuels, bio-fuels, by-pass interconnections to interstate and intrastate pipelines, third-party steam providers, and steam utilities.

Q. What are the various EUT rate schedules?

A. DTE Gas's Rate Book includes four EUT rate schedules: ST (Small Transportation), LT (Large Transportation), XLT (Extra Large Transportation), and XXLT (Extra Extra Large Transportation). The Company also has three customers taking transportation service under Commission approved special contracts. EUT customers typically select the rate schedule most suited for their needs based on their annual natural gas consumption utilizing the economic break-even points between each of the EUT rate schedules. The economic breakeven points are detailed further in Section 6 of my testimony.

Q. What types of customers take EUT service under rate schedule ST?

A. The ST rate applies to customers consuming less than 100,000 Mcf per year and encompasses every type of commercial and industrial operation. Customers served under Rate ST include schools, community colleges, state and federal office buildings, municipalities, community hospitals, commercial bakeries, food processors, automotive parts suppliers, distribution and warehousing, light and heavy industrial inclusive of assembly, fabricators, finishing and painting, and small foundries. In the projected test year, DTE Gas projects that the Rate ST customer group will include 461 EUT customers with approximately 17.5 Bcf of associated transportation sales. As a point of reference, the ST rate schedule accounts for 79% of the total number of EUT customers and only 13% of the EUT

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projected total gas transportation sales volume. The average annual throughput for the ST rate schedule is approximately 38,000 Mcf per account.

Q. What types of customers take EUT service under rate schedule LT?

A. Customers served under the LT rate schedule consist of the larger commercial and industrial operations such as universities, regional hospitals, municipal power and water departments, automotive companies and Tier 1 parts suppliers, furniture manufacturing, metals extrusion, forging and casting, forestry and building products, and power generation peaking facilities. LT rate customers consume between 100,000 and 700,000 Mcf annually. These customers have competitive alternate fuel options including taking service directly from nearby, interstate natural gas pipelines. In fact, one large power generation plant taking LT rate service bypassed the Company to take service from an interstate pipeline in late 2012. That power generation plant remains directly connected to the interstate pipeline. During the projected test year, the LT rate class will include 97 customers with approximately 20.5 Bcf of transportation sales. The LT rate schedule accounts for 17% of the EUT customers by count and 16% of the EUT projected gas transportation sales. The average annual throughput for the LT rate schedule is approximately 211,000 Mcf per account.

Q. What type of customers take EUT service under rate schedules XLT and XXLT?

A. Customers served under the XLT and XXLT rate schedule consist of the largest EUT customers including major universities, a regional water and sewer operation, power plants, utility steam plants, automotive assembly operations, pulp and paper mills, chemical plants, and a steel mill. Rate XLT and XXLT customers typically require high delivery pressure for their natural gas-fired processes and are likely to take transportation service directly from the Company's transmission system. During the projected test year, these 24 largest EUT customers will consume approximately 93.2 Bcf; or stated in percentages, 4% of the largest EUT customers account for 71% of the EUT projected total gas transportation sales. The average annual throughput for these largest customers is 3.9 Bcf per year.

Q. What is the purpose of the XXLT rate schedule?

A. The cost based XXLT transportation rate schedule, previously approved in the Commission's Orders in Case Nos. U-15985 and U-17999, provides a gas transportation rate which is determined primarily by allocating only transmission system costs. By basing XXLT rates primarily on transmission system costs, the rates reflect the costs that these customers impose upon the Company. These rates are designed to retain the very largest EUT customers that would otherwise bypass DTE Gas's system and take service from interstate transmission pipelines, which are not regulated by the MPSC. Their size, energy consumption, and location near interstate pipelines afford these customers the opportunity and means to make an investment to bypass DTE Gas's system.

The cost based XXLT rate, determined by allocating only transmission system costs, has not remained competitive for two EUT customers. The Company has discounted transportation rates with one XXLT customer and one XLT customer. These customers maintain a direct interconnect to an interstate gas pipeline. The Company is seeking to recover the cost of the rate discounts for these two EUT customers as discussed further in Section 3 of my testimony. Absent approval to recover the discounts provided under these two contracts from other customers, the Company will be required to reduce its projected test year sales and revenue forecast by 13.0 Bcf and $3.7 million (based on current rates), respectively. The Company would not need to reduce its projected test year sales and revenue forecast if the Commission authorizes the Company to recover the cost of the rate discounts for these two EUT customers as discussed further in Section 3 of my testimony.

Q. What type of service considerations warrant DTE Gas and the EUT customers seeking Special Contract approval from the MPSC?

A. The MPSC has approved Special Contracts between DTE Gas and three of its EUT customers. These three special contract customers operate very large natural gas fired equipment that require high delivery pressures only available from DTE Gas's transmission system and high pressure systems connected to the transmission system. These three customers, absent the special terms and conditions of service reflected in their unique contracts, would have bypassed DTE Gas's system and taken service directly from interstate pipeline companies that are not regulated by the Commission and are based outside the State of Michigan. These three Special Contract customers are projected to consume 36 Bcf per year. DTE Gas sought Commission approval of these special agreements as the terms within the agreements included rates and performance provisions that warranted special contract consideration. These Special Contract customers sought Commission approval with the desire to have fixed rates and firm gas transportation services, to mitigate state regulatory risk in recognition of the substantive facility investments these customers made to their operations, and to replicate the alternate natural gas supply options that exist in the form of interstate pipeline bypass. Special contract revenues from these customers contribute toward the recovery of DTE Gas's fixed system costs, which is beneficial to all DTE Gas's customers. In summary, it is in the mutual interest of the Company and its entire customer base to have the competitive ability to seek and receive endorsement for special contracts that increase system utilization for the benefit of all customers.

Q. Is the Company seeking recovery of the discounted rates provided under the three special contracts?

A. No. The Company is not seeking recovery of the discounted transportation rates provided in the three special contracts as the Commission has not historically recognized special contract rate discounts when calculating and approving DTE Gas's rate schedules and revenue deficiencies.

Q. Why are the rate schedules XLT, XXLT, and special contracts customers critical to the Company and the Company's other customers?

A. The XLT and XXLT rate schedules and special contract customers, consisting of just 24 customers, consume significant volumes of natural gas and are projected to provide more than $24 million annually (at current rates) in revenues covering the Company's fixed costs. These customers are very sophisticated energy buyers having alternate fuel choices and interstate pipeline bypass options, but also have competing enterprise facilities located in other states or countries. Large enterprises can relocate their energy intensive production out of DTE Gas's service territory. This multitude of alternatives means DTE Gas must offer competitive rates to the

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largest EUT customers to: 1) retain existing large customers, 2) attract new large customers; or 3) re-connect large energy consumers that previously bypassed DTE Gas. DTE Gas must continually assess, modify and create service distinctions. The very largest of DTE Gas's EUT customers consume a quantity of gas that warrants an EUT service category tailored to its needs, discounted rates, or special contracts when the cost based service categories cannot provide the flexibility necessary to retain them as customers.

Q. Why is it specifically important to have flexible and negotiable rates when DTE Gas has the option to negotiate and seek Commission approval of a Special Contract that could provide a competitive service offering?

A. There are two primary reasons why flexible and negotiable rates are the preferred option over seeking Special Contract approval, especially with the customers that qualify for rate schedules XLT and XXLT. First, the very largest EUT customers desire flexible and negotiable rate terms since it allows them to determine the economics of their DTE Gas transportation option without having to submit a proposal for regulatory review and endorsement. Regulatory review increases risk to the customer because the special contract's terms and conditions may not be approved. Second, the Commission has not historically recognized special contract rate discounts when calculating and approving DTE Gas's rate schedules and revenue deficiencies. Therefore, it is DTE Gas's desire to seek Special Contract approval from the Commission only after DTE Gas has attempted every option within the terms of the approved cost based or optional rate schedules to retain and/or attract large commercial or industrial customers.

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EUT Volumes and Customer Count

Q. What EUT customer counts were recorded during the 2016 historical test year and are projected in the test year ending September 2019?

A. During the historical test year, DTE Gas had 596 EUT customers. DTE Gas projects it will have 582 EUT customers during the projected test year. See Exhibit A-15, Schedule E6 for details by rate class.

Q. What EUT volumes were recorded during the 2016 historical test year and are projected in the test year ending September 2019?

A. During the historical test year, EUT customers transported 149.0 Bcf. DTE Gas is projecting EUT customers to transport 131.1 Bcf during the projected test year. See Exhibit A-15, Schedule E7, for details by rate class.

Q. What is the overall methodology used to develop the EUT volumes and customer counts for the projected test year forecast?

A. The projected test year EUT volume and customer count forecast was developed using the 12-months ended 2016 actual volumes as a base, adjusted for known and measurable changes resulting from:

1. The most recent natural gas consumption, and production and energy projections based on customer dialogue;
2. The five-year average use for all utility and merchant power plant operations;
3. Permanent facility closures and load reductions, including reductions due to energy waste reduction, previously called energy optimization;
4. Adjustment for the heat content of the gas supply;
5. Rate switching between rate classes;

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6. Known load expansions and new facility additions;
7. Allocation of special contract volumes to the applicable cost based rate, XLT or XXLT; and
8. Allocation of all volumes billed under an optional transportation rate to the applicable cost based rate with the exception that the AK Steel and Ford-Rouge volumes remain on the respective XXLT optional rate and XLT optional rate volumes (Exhibit A-15, Schedule E7, column (h), lines 4 and 6).

Q. Why did the Company's EUT volumes decline from the historical test year to the projected test year?

A. The Company projects test year EUT volumes will fall about 18 Bcf from the 2016 historical test year. This reduction is primarily due to an expected 19.7 Bcf reduction in consumption from utility and merchant power plants. The remainder of the volume changes are due to 1) a 1.4 Bcf reduction due to energy efficiency; 2) 0.6 Bcf of permanent volume reduction due to EUT facility closings or customers no longer taking service under an EUT rate; offset partially by; 3) 1.9 Bcf increase from new EUT customers; plus 4) 1.7 Bcf net impact of EUT customer volume increases and decreases during the projected year compared to 2016 consumption as depicted in Exhibit A-15, Schedule E7, page 2 of 2.

Q. Why are power generation customers' 2016 EUT sales volumes higher than those projected for the test year?

A. There are three main drivers that led to 2016 power generation sales decreasing during the projected test year. These drivers are:

- Natural gas prices: The forward-looking natural gas pricing indicators during the projected test year show that natural gas prices will be approximately 15% higher than they were during the historical test year based on NYMEX (Henry Hub) historical pricing and forwards as of October 24th, 2017.
- Warmer-than-normal summer temperatures: DTE Gas expects the summer temperatures to be at 15-year weather-normalized temperatures during the projected test year.
- Level of power plant outages: In addition to the above factors, DTE Gas's utility and merchant power plant customers also saw increased utilization due to a number power plant outages (both planned and unplanned) during the historical test year.

Q. Is the historical test year a reasonable forecast for EUT power generation volumes during the projected test year?

A. No. The historical test year does not provide a reasonable forecast for the power generation volumes due to the one-time events discuss above.

Q. Why does the historical five-year average provide a reasonable forecast for EUT power generation volumes during the projected test year?

A. The power generation customers operating behind the Company's gas system operate primarily as peaking plants that run intermittently. The plants typically run on extreme weather days (hot or cold), and during times when base load plants are experiencing outages, voltage support, and maintenance. Finally, the plants run when they are selected by the regional electric system operator to operate during any given day. In recognition of the high degree of variability in the operations of these facilities, using the five-year average is an appropriate methodology to forecast power generation volumes.

Q. What are the EUT power generation volumes over the past five years?

The EUT power generation volumes over the past five years are depicted in Table 2 below. During the five years ending with the historical test year, the power generation volumes were volatile year to year ranging from a low of 29.6 Bcf to a high of 61.9 Bcf, representing a variance of 32.3 Bcf. The five-year average power generation volumes ending 2016 is 42.3 Bcf annually. Volatility during the five-year period is distributed significantly above and below the five-year average. The 2017 power generation sales forecast, which includes actual sales through August 2017, shows that the power generation sales for 2017 have declined to levels comparable to the five-year average used in the Company's forecast.

Table 2 – Power Generation Volumes

Year	Actual (Bcf)	Variance (Bcf) to 5-Year Average
2012	42.1	(0.2)
2013	29.6	(12.7)
2014	32.6	(9.7)
2015	45.4	3.1
2016	61.9	19.6
5-year Average – used for Projected Test Year	42.3	---
2017*	45.5	3.2

* Includes actual sales through August 2017

Given the highly volatile nature of the power generation sales and the lack of a reliable means to forecast the variability of the peaking and intermittent operations

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of the Company's power generation customer operations, the five-year average is the most likely outcome during the projected test year.

Q. What new EUT customer volume increases are included in the Company's projected test year?

A. The Company included six new EUT customers that will increase EUT volumes by 1.9 Bcf as shown in Exhibit A-15, Schedule E7, page 2, line 2. The largest addition is a new particle board plant currently under construction and forecasted to be operational during the projected test year. This new particle board plant will consume 1.7 Bcf of the 1.9 Bcf associated with new EUT customer additions.

Q. What additional EUT customer volume increase is included in the Company's projected test year?

A. Exhibit A-15, Schedule E7, page 2, line 6 shows an increase of 1.7 Bcf. This line is the net result of the EUT customer operational change in volumes (increases and decreases) from the historical year to the projected year. These operational volume changes include new or lost loads, increases or decreases in production, and partial facility expansions or closures.

<u>EUT Revenue</u>

Q. What were EUT revenues for the 2016 historical test year?

A. The Company's EUT transportation, monthly customer charge, standby charges, and minimum commitment revenues for 2016 were $77.1 million. See Exhibit A-13, Schedule C3.2, column (b) for details.

Q. What is your forecast for EUT revenue amounts for the projected test year?

A. The projected EUT Revenue is $87.4 (at current rates), consisting primarily of distribution, monthly customer charge, and standby charge revenues. See Exhibit A-13, Schedule C3.2, column (c) for details.

Q. What methodology was used to develop the EUT projected test year revenues?

A. The projected test year EUT revenue forecast was developed by using the projected test year EUT volumes, the customer count previously discussed in my testimony and detailed in my exhibits, and then applying the EUT transportation rates (except for AK Steel and Ford-Rouge where the discounted transportation rates were applied; see Section 3 of my testimony) and customer charges approved in DTE Gas's last rate case, Case No. U-17999.

Q. Why did the Company's EUT revenues increase from the historical test year to the projected test year?

A. The increase in EUT revenues from the historical test year to the projected test year is primarily due to the rate increases approved in Case No. U-17999 and the allocation of special contract volumes to the applicable cost based rate XLT and XXLT category.

Q. What are Standby Charge Revenues?

A. Standby Service and associated standby charges are billed to customers that have installed natural gas fired equipment that, for example, operates intermittently, operates a limited number of hours per year, or operates on an alternate fuel and the customer desires to retain natural gas service in the event the alternate fuel source is unavailable or not operating. The Company has customers taking standby service under both the EUT rate schedules and the non-EUT general service rate schedules.

Q. What methodology was used to develop the EUT and non-EUT projected test year standby charge revenues?

A. The projected year EUT and non-EUT standby charge revenues are based on the contracts currently in place and the associated level of contracted standby service during the projected test year.

Q. What were standby charge revenues for the EUT customers for the 2016 historical test year?

A. The Company's EUT standby charge revenues for 2016 were $1.7 million. See Exhibit A-13, Schedule C3.2, column (b), line 18.

Q. What is your forecast for EUT standby charge revenue amounts for the projected test year?

A. The projected EUT standby charge revenue is $1.8 million. See Exhibit A-13, Schedule C3.2, column (c), line 18.

Q. What were standby charge revenues for the general service rate customers (non-EUT) for the 2016 historical test year?

A. The Company's non-EUT general service rate schedule standby charge revenues for 2016 were $0.8 million. See Exhibit A-13, Schedule C3.2, column (b), line 24.

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Q. What is your forecast for the general service rate customers (non-EUT) standby charge revenue amounts for the projected test year?

A. The projected non-EUT general rate service schedule standby charge revenue is $1.0 million. See Exhibit A-13, Schedule C3.2, column (c), line 24.

Q. What are Minimum Revenue Commitments?

A. Minimum Revenue Commitments are a way for DTE Gas to ensure revenue, generally to offset nonvolumetric costs, regardless of a customer's level of consumption. Such commitments are necessary when DTE Gas negotiates fixed price transportation services, and/or construction of gas facilities in exchange for minimum revenue commitments by the customers. DTE Gas would not have offered these customers a fixed price contract or made the investment in the required gas facilities without future revenue certainty through these revenue commitments. Minimum revenue commitments are in alignment with the Company's tariff regarding new attachments, which ensure that no subsidy for new customers is provided from current customers.

DTE Gas reconciles the revenues paid on these agreements with the revenues committed for the time period specified in the agreement. If a customer does not meet the minimum revenue terms of the agreement, the customer remits a payment equal to the difference between the minimum requirement revenue and the actual revenue paid during the prior period. These remittances are captured in line 17 of Exhibit A-13, Schedule C3.2; line 17 does not include any other amounts.

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Q. How has DTE Gas accounted for minimum revenue commitments in the 2016 historical test year and the projected test year?

A. The historical test year revenues depicted in Exhibit A-13, Schedule C3.2 include minimum commitment revenues. The projected test year revenues do not include minimum revenue commitments.

Q. Why are minimum commitment revenues not included in your projected EUT revenues?

A. The test year revenues are calculated assuming minimum commitment revenues are achieved and thus do not require separate payments. This treatment is the same methodology used in DTE Gas's previous rate cases (Case Nos. U-13898, U-15985, and U-17999). In each of these cases, all transportation volumes, except for volumes forecasted for AK Steel and Ford-Rouge (See Section 3 of my testimony), were priced at cost based rates making no other revenue adjustments, such as the inclusion of minimum volume commitments, necessary when calculating the projected test year revenues for EUT customers. If minimum volume commitment revenues were included, then revenues would be double counted; once from the inclusion of cost based revenue and once for the volume commitment revenues. The methodology shown on Exhibit A-13, Schedule C3.2 under column (c) is consistent with this approach.

SECTION 3 – RECOVERY OF TRANSPORTATION RATE DISCOUNT FOR AK STEEL AND FORD-ROUGE

Q. Why does DTE Gas provide service to AK Steel and Ford-Rouge at a discounted rate?

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A. DTE Gas serves AK Steel (AK) and Ford Motor Company's Rouge Complex (Ford-Rouge) at discounted rates to retain them as DTE Gas EUT Customers; otherwise, these two customers would bypass to an interstate pipeline provider that is interconnected with both customers. Retaining AK Steel and Ford-Rouge as EUT customers on discounted rates behind the Company's system provides annual revenues that exceed the cost of the discounts. Retaining these two customers on discounted rates benefits all customers by reducing the cost of service for all other customers; therefore, the discount should be recovered through base rates.

Q. What is the value of the rate discounts provided to AK and Ford-Rouge in order to retain these two customers?

A. The Company has discounted AK and Ford-Rouge's rates by a combined total of $0.7 million per year. After the rate discounts are applied, AK and Ford-Rouge will provide a combined $3.7 million in annual revenue during the projected test year at current rates.

Q. How would you describe AK Steel Corporation and its Dearborn Works?

A. AK is a leading provider of steel products for the automotive, infrastructure, manufacturing, construction, and power generation and distribution markets. AK is a significant employer, operating steel mills in Kentucky, Pennsylvania, Ohio, Indiana and Michigan. In Ohio, AK operates four mills. AK's Dearborn Works steel mill, currently served by DTE Gas, is an integrated steel mill producing hot and cold rolled steels, hot dip galvanized products, and advanced high strength steels for the automotive industry. AK's numerous steel making operations provide many locational choices for production other than the Dearborn Works. AK

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acquired the Dearborn Works from Severstal North America, Incorporated in December 2014.

Q. How would you describe Ford Motor Company and its Rouge Complex?

A. Ford Motor Company is a major employer and manufacturer having its world headquarters based in Dearborn, Michigan. Ford's Rouge Complex is also located in Dearborn, MI and is serviced by DTE Gas Company. Ford assembles the Ford F-150 truck at the Ford Rouge Complex and at its assembly operations located in Kansas City, Missouri.

Q. Why are AK's Dearborn Works and Ford's Rouge Complex important customers to DTE Gas?

A. AK is DTE Gas's second largest EUT customer by volume, consuming 11.7 Bcf of natural gas resulting in $2.9 million of revenue (monthly charge revenue plus transportation revenue) during the historical test period. AK's end-use transportation service is rendered under the Company's Rate Schedule XXLT.

Ford, as a whole, is one of DTE Gas's top ten EUT customers by volume with multiple DTE Gas accounts serving its Dearborn, Michigan area automotive operations. The Ford-Rouge account consumed 1.3 Bcf resulting in $0.6 million of revenue during the historical test period. Ford-Rouge purchases transportation service under the Company's Rate Schedule XLT.

Q. How does DTE Gas provide AK's Dearborn Works and Ford's Rouge Complex gas transportation service?

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A. The site AK's Dearborn Works and Ford's Rouge Complex occupy was once known as "The Rouge." The Rouge, built by Henry Ford during the early part of the 20^{th} century went through numerous transformations during its first century of operations up until Ford's steel mill assets were divested in 1989. These steel mill assets are now owned by AK.

Because of the expansive size of The Rouge, DTE Gas serves the site with two large high-pressure metering stations. These two metering stations measure gas transported to both AK and Ford-Rouge; subtraction meters are installed within The Rouge to measure the quantities of gas delivered to the Ford-Rouge operations. DTE Gas invoices Ford-Rouge on the quantities measured by the subtraction meters, and AK's consumption is measured by calculating the difference between the quantities measured at the two meter stations less the quantities measured by the subtraction meters.

Q. Why is it important to explain how DTE Gas delivers natural gas to AK and Ford at The Rouge?

A. It is important to understand that AK and Ford-Rouge cooperatively operate the utility infrastructure at The Rouge, including receipt of transported supplies of natural gas. DTE Gas must therefore negotiate with AK and Ford-Rouge knowing that both customers have identical competitive options with respect to natural gas service.

Q. Do AK and Ford-Rouge have alternative fuel supply options at The Rouge?

A. Yes. The Rouge complex has a compelling alternative fuel supply due to the proximity of an interstate pipeline owned by Panhandle Eastern Pipeline Company (PEPL). In 2006 - 2007, AK's predecessor, Severstal, constructed a bypass interconnection with PEPL's interstate pipeline; AK Steel continues to maintain this direct interconnect with PEPL.

Q. Has AK's predecessor, Severstal, and Ford-Rouge ever taken natural gas service from PEPL?

A. Yes. Upon completion of the interconnect bypass construction in early 2007, both Severstal (now AK) and Ford-Rouge commenced taking natural gas service directly from PEPL. In this same time-period, Severstal installed a powdered coal fuel system which displaced additional natural gas use at its steel mill operations. Severstal went from transporting more than 20 Bcf per year from DTE Gas to less than 2 Bcf per year due to the use of these two alternative fuel supplies.

For simplicity, I will refer to Severstal and AK Steel collectively as AK from this point forward in my testimony.

Q. What rate schedule were AK and Ford-Rouge on prior to bypassing to PEPL?

A. Both AK and Ford-Rouge were taking service from DTE Gas under the cost based XLT rate prior to connecting to and taking service from PEPL's interstate pipeline and terminating service agreements with DTE Gas.

Line No.

Q. Why did AK and Ford-Rouge construct and utilize a bypass to PEPL's interstate pipeline?

A. By directly interconnecting with PEPL and bypassing the Company's transmission and distribution system, these two companies significantly reduced their transportation costs. The Company estimates that these two companies reduced their gas transportation costs by as much as 40% compared to the cost-based XLT rate in effect at that time.

Q. Why did AK and Ford-Rouge return to EUT service with the Company?

A. AK returned to the Company's EUT service in 2009 when DTE Gas negotiated an $0.11 per Mcf discount, which made the Company's discounted rate XLT service competitive with AK's alternative fuel supply with PEPL at the time. Then in 2010, AK switched to the then newly approved cost based Rate Schedule XXLT until March 2013. The cost based XXLT rate was competitive with AK's bypass alternative when originally approved in Case No. U-15985 in 2010.

Similarly, Ford-Rouge returned to service with DTE Gas when DTE Gas negotiated a discounted rate XLT contract. Ford-Rouge is currently taking service from DTE Gas under a discounted rate XLT contract with an expiration on December 31, 2018. The current discounted rate XLT contract between Ford-Rouge and DTE Gas includes a $0.1468 per Mcf discount providing Ford-Rouge an annual discount of $194,000.

Q. What occurred after the cost based XXLT rate contract with AK expired in March 2013?

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A. By the expiration of the cost based XXLT rate contract between DTE Gas and AK in 2013, AK's alternate fuel supply source from PEPL had become more competitive than the cost based XXLT rate. To retain AK as a customer, DTE offered a four-year contract (for the period April 2013 to March 2017) with a discounted XXLT rate. This contract provided AK with an effective $0.056 per Mcf discount from the cost based XXLT rate.

Q. Why did the cost based XXLT rate become less competitive in 2013 for AK?

A. There were two reasons the Company's cost based XXLT rate became less competitive in 2013:

1. The Commission's order in Case No. U-16999 increased the cost based XXLT rate effective January 1, 2013, and
2. AK had natural gas transportation prices with PEPL that were affirmed to be less than the cost based XXLT rate at the time of their negotiations.

Q. What occurred when the contract between DTE Gas and AK expired in March 2017?

A. During contract extension negotiations in early 2017, AK maintained that it needed a discount of approximately $0.05 per Mcf to remain a DTE Gas customer; otherwise, AK would utilize its bypass option with PEPL, whose rates were more competitive. DTE Gas calculated that the cost based XXLT rate was as much as $0.13 per Mcf higher in cost than AK's alternate fuel supply option from PEPL (See Exhibit A-22, Schedule L1, line 5). In March of 2017, DTE Gas agreed to a three-year discounted transportation agreement with AK that provides a $0.0423 per Mcf discount to the prevailing cost of service XXLT transportation rate. This

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contract rate results in an annual discount of approximately $0.5 million on the AK contract.

Q. Are you proposing that DTE Gas be allowed to recover the amount of the annual discounts for both AK and Ford-Rouge?

A. Yes. I am proposing that DTE Gas be permitted to recover the full amount of the discounts on the AK and Ford-Rouge contracts totaling $0.7 million in accordance with Section 6a of Public Act 3 of 1939, as amended by 2016 Public Act 341, MCL 460.6a(7).

Q. What does MCL 460.6a(7) state?

A. MCL 460.6a(7) states the following:

> The commission shall, if requested by a gas utility, establish load retention transportation rate schedules or approve gas transportation contracts as required for the purpose of serving industrial or commercial customers whose individual annual transportation volumes exceed 500,000 decatherms on the gas utility's system. The commission shall approve these rate schedules or approve transportation contracts entered into by the utility in good faith if the industrial or commercial customer has the installed capability to use an alternative fuel or otherwise has a viable alternative to receiving natural gas transportation service from the utility, the customer can obtain the alternative fuel or gas transportation from an alternative source at a price that would cause them not to use the gas utility's system, and the customer, as a result of their use of the system and receipt of transportation service, makes a significant contribution to the utility's fixed costs. The commission shall adopt accounting and rate-making policies to ensure that the discounts associated with the transportation rate schedules and contracts are recovered by the gas utility through charges applicable to other customers if the incremental costs related to the discounts are no greater than the costs that would be passed on to those customers as the result of a loss of the industrial or commercial customer's contribution to a utility's fixed costs.

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Q. Why should the Commission approve recovery of the discounts provided to AK and Ford-Rouge?

A. The Commission should approve recovery of the AK and Ford-Rouge discounts consistent with MCL 460.6a(7) for the following reasons:

1. AK and Ford-Rouge are industrial customers having transportation volumes greater than 500,000 dekatherms on DTE Gas's system;
2. The contracts between DTE Gas and AK and Ford-Rouge were agreed upon in good faith through iterative negotiations;
3. AK and Ford-Rouge have installed the capability to use an alternative gas transportation service via the interconnect with PEPL and can obtain this alternative gas transportation service at a price that would cause each customer to not use DTE Gas's system. Exhibit A-22, Schedule L1 depicts the calculations the Company made during negotiations with AK determining the viability of AK bypassing to PEPL for lower cost natural gas service.
4. At current rates, AK and Ford-Rouge make a significant contribution ($3.7 million) to DTE Gas' fixed costs in the projected test year. At projected rates, this contribution increases to $4.7 million ($4.4 million plus $0.3 million of IRM revenue in 2019).

The incremental costs resulting from providing a discounted rate to AK and Ford-Rouge ($0.7 million) are significantly less than the contribution these customers make to covering DTE Gas's fixed costs. If AK and Ford-Rouge no longer received service from DTE Gas, costs currently allocated to them would be shifted to the remaining customers ($4.7 million). AK's and Ford-Rouge's contribution to DTE Gas's fixed costs is calculated as the total revenue ($4.8 million) net of any

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costs and potential other revenues directly attributable to this revenue ($0.1 million). If the contribution from these two EUT customers to DTE Gas's fixed costs is removed from the cost of service model, revenue from other customer classes will increase. Specifically, revenue from the Residential customer class will increase by $1.9 million, revenue from General Services will increase by $0.7 million, and revenue from all other customer classes and EUTs will increase by $2.1 million. If these two customers leave the system, it will impact IRM surcharges as well. Approximately $279 million IRM costs, previously allocated to AK and Ford-Rouge, will be allocated to other customers. Company Witness Mr. Slater has run two cost of service models; one with the AK and Ford-Rouge volumes and revenues included at a fixed discount (Exhibit A-16, Schedule F1); and one without the AK and Ford-Rouge volumes and revenues (Exhibit A-22, Schedule F3). The comparison of the shift in costs is depicted in Witness Slater's testimony and Exhibit A-22, Schedule L10. I have created Exhibits A-22 Schedules L14 through L18 to provide Witness Slater with the information he needed to develop a cost of service. These schedules provide the same information as my Exhibit A-13, Schedules C3.2 and C3.3 and Exhibit A-15, Schedules E6 and E7 but assume AK Steel and Ford Rouge no longer take service from DTE Gas.

Q. What will occur if the Commission does not authorize DTE Gas to recover the discounts provided to AK and Ford-Rouge?

A. If the Commission does not authorize the Company to recover these discounts, then per the terms and conditions of the contract between DTE Gas and AK:

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- DTE Gas will terminate the rate discount provided AK under the current contract, effectively increasing AK's transportation rate to the then approved cost based XXLT transportation rate.
- AK then has the option to continue to take service from DTE Gas under a newly negotiated cost based rate contract, or
- AK may terminate service with DTE Gas and commence taking service from PEPL.

AK has advised DTE Gas that it will exercise its option to cease transportation service with the Company and switch to PEPL if the rate discount is terminated. Similarly, DTE Gas's discounted contract with Ford-Rouge expires after December 2018, three months following the Commission's expected Order in this general rate case. Absent a Commission order approving recovery of discounts, DTE Gas will negotiate a cost based XLT rate contract with Ford-Rouge effective January 2019 which is likely to motivate Ford-Rouge to switch to service with PEPL.

SECTION 4 – MIDSTREAM SERVICES

Q. What are Midstream Services?

A. Midstream Services (Midstream) represent the sale of storage and transportation services to off-system customers. These services maximize the utilization of DTE Gas's rate base assets. The revenue and the associated GIK collected from the sale of Midstream Services is an offset to the overall DTE Gas revenue requirement. This enhanced optimization of assets helps to mitigate rate increases for all customers.

Q. What are off-system customers?

A. Off-system refers to customers who transport gas from a Receipt Point into the Company's storage and transmission system to a Delivery Point that is interconnected to another local gas distribution company or a pipeline not owned by DTE Gas. These customers ultimately consume gas outside the DTE Gas service territory. Conversely, DTE Gas's GCR, GCC and EUT customers are collectively referred to as 'on-system customers'.

Q. What is included in Midstream Revenue?

A. Midstream Revenue has two components:

1) Revenue collected by invoicing off-system customers for storage and transportation services; and
2) GIK collected from off-system customers for the utilization of DTE Gas's storage and transmission system.

Q. How does Midstream Services generate revenue?

A. Midstream Services generates revenue by selling the following services:

1) Storage Services, which include:
   a. Contract Storage Services; and
   b. Park and Loan Services.
2) Transportation Services, which include:
   a. Off-System Transportation Services; and
   b. Exchange Services.

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Q. What is the Midstream revenue contribution for the projected future test period starting in October 1, 2018?

A. The forecasted Midstream revenue contribution for the projected future test period is $102.4 million.

Q. How does this compare to the 2016 calendar year historical test period?

A. Midstream generated $79.5 million in revenue during the historical test period.

Q. How did you determine the Midstream Revenue contribution for the projected future test year?

A. The majority of DTE Gas's Midstream storage and transportation assets are currently contracted under long-term, fixed-price arrangements. DTE Gas determined its projected Midstream revenue of $102.4 million by including known revenues from these contracts and adding projected revenues associated with unsold storage and transmission assets, based on the anticipated market value of these uncommitted assets.

Q. How does the projection for Midstream revenue in this case compare to the Midstream revenue approved in DTE Gas's last rate case (Case No. U-17999)?

A. Midstream revenues approved in Case No. U-17999 were $74.4 million. In this filing, the Company is projecting Midstream revenues to be $102.4 million or $28.0 million more than the Company's last rate case. A comparison of the changes in Midstream revenues between the two cases are set forth in the table below:

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Table 3

Storage Revenue:

Rate Case	Storage Capacity	Storage Revenue
U-17999	51.7 BCF	$35.0 Million
U-18999	63.4 BCF	$38.9 Million
Variance	11.7 BCF	$3.9 Million

Transportation Revenue

U-17999	$39.4 Million
U-18999	63.5 Million
Variance	$24.1 Million

Total Storage and Transportation Revenue

	Storage Revenue	Transportation Revenue	Total Revenue
U-17999	$35.0 Million	$39.4 Million	$74.4 Million
U-18999	$38.9 Million	$63.5 Million	$102.4 Million
Variance	$3.9 Million	$24.1 Million	$28.0 Million

Q. Why is storage capacity available for sale to off-system customers increasing since Case No. U-17999?

A. For the projected future test period, there will be 63.4 Bcf available for sale to off-system customers. This storage includes approximately 52 Bcf of allocated capacity and 11.4 Bcf resulting from the Settlement Agreement between ANR Pipeline Company, DTE Gas Company and Blue Lake Gas Storage Company, dated February 1, 2016. (Reference FERC Docket RP13-743-000).

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Q. How much revenue is expected from the sale of Blue Lake storage to off-system customers?

A. The 11.4 Bcf of Blue Lake storage is forecasted to generate $4.2 million of incremental revenue.

Q. Why is Midstream storage revenue increasing since U-17999?

A. Storage revenue is forecasted to increase by $3.9 million, from $35.0 projected in U-17999 million to $38.9 million. This increase is the result of two factors:

1. $4.2 million increase is due to the incremental storage capacity available for sale to off-system customers; and
2. $2.4 million increase is due to a higher forecast for Park and Loan Services revenue from $5.1 million to $7.5 million. The $2.4 million revenue increase results from using a 5-year average for Park and Loan revenue versus the 3-year weather normalized average used in Case No. U-17999.

These gains are partially offset by a $2.7 million decrease in the average value of the contract storage portfolio resulting from expiration of long-term contracts at higher rates. The net result yields an increase of $3.9 million of storage revenue over the period.

Q. Why is Midstream transportation revenue increasing since Case No. U-17999?

A. Transportation revenue is projected to increase by $24.1 million, from $39.4 million projected in Case No. U-17999 to $63.5 million. The Capacity Lease Agreement with NEXUS Gas Transmission (NEXUS), in which NEXUS is leasing 1.1 Bcf/d of capacity on the DTE Gas system, results in a $32.1 million increase to Off-System Transportation revenue. This revenue increase is partially offset by the expiration of long-term transportation contracts that will not be renewed and a reduction in forecasted exchange volumes. The net result yields an increase of $24.1 million. (Reference Exhibit A-23, Schedule M1 – Capacity Lease Agreement).

Midstream Services Revenue - Storage

Q. What storage services does DTE Gas Midstream offer?

A. DTE Gas owns and operates four natural gas storage reservoirs that provide 135.1 Bcf of cyclable storage capacity. A portion of these assets are used for the benefit of DTE Gas's on-system customers by allowing for the procurement and storage of lower cost natural gas supplies during the lower demand period of April through October (Summer) and for use during the future higher cost and higher demand period of November through March (Winter). Excess capacity not allocated for on-system customers is made available for sale to off-system customers.

Storage services have three main characteristics: 1) storage capacity, 2) daily injection entitlements, and 3) daily withdrawal entitlements. The capacity available for Midstream varies from year to year depending on the needs and actual utilization of the capacity by DTE Gas's on-system customers. Storage service offerings can be short-term, which is less than two years, or long-term, which is greater than two years, and can be offered as either firm or interruptible service.

Q. What is the total storage revenue that is included in the projected future test period?

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A. Total projected storage revenue included in the future test period is $38.9 million. This revenue includes $31.4 million Contract Storage and $7.5 million of Park and Loan revenue. (Reference Exhibit A-13, Schedule C3.3, lines 1, 2, 3, column (d)).

Q. What determines the value of Contract Storage services?

A. Pricing for Contract Storage services is dictated by the market at any given point in time, and generally reflects the price differential or spread between the projected prices during the withdrawal period, and the projected prices during the injection period, discounted for the cost of financing inventory and injection fuel costs. Off-system customers typically procure gas supplies during the lower demand summer period, inject these supplies into their storage accounts, and then make withdrawals during the higher demand winter period.

Q. Are there specific considerations for valuing Contract Storage on the DTE Gas system?

A. Yes. Before offering any services, DTE Gas must first ensure deliverability of natural gas to our on-system customers. This requirement means DTE Gas may have limited excess winter deliverability available to sell to off-system customers when the storage spread values are the greatest. In the event there is excess deliverability for off-system customers, the storage DTE Gas will offer is generally of lower quality than typical winter and peak day storage services.

Q. How was the Contract Storage revenue projection calculated?

A. Midstream has currently sold and has under contract 45.2 Bcf of the 63.4 Bcf allocated storage capacity available to it through March 31, 2019. 33.7 Bcf is sold and under contract through the test period. These longer-term contracts will contribute $22.6 million in revenue. The additional 18.2 Bcf of storage capacity available for sale in the 2018/19 cycle (i.e. starting April 1, 2018) and 11.5 Bcf available for sale in the 2019/20 cycle (i.e. starting April 1, 2019) is forecasted to contribute an additional $8.8 million to the test period revenue for a total of $31.4 million of storage revenue. (Reference Exhibit A-13, Schedule C3.3, line 1, column (d)).

Q. How does the Contract Storage revenue projection compare to the historical test period?

A. In the historical test period, Midstream earned $30.8 million of storage revenue compared to $31.4 million of storage revenue in the projected period. (Reference Exhibit A-13, Schedule C3.3, line 1, columns (b) and (d)).

Q. Why is Midstream Contract Storage revenue increasing compared to the historical test period?

A. Contract Storage revenue is forecasted to increase by $0.6 million. As stated earlier in my testimony, 11.4 Bcf of Blue Lake storage capacity is expected to contribute an incremental $4.2 million. This contribution is partially offset by a $3.6 million decrease in the average value of the remaining 52 Bcf contract storage portfolio, from approximately $0.59 per Mcf to approximately $0.52 per Mcf, resulting from expiration of long-term contracts at higher rates. The net result yields an increase of $0.6 million of storage revenue over the projected test period.

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Q. How did DTE Gas project how much GIK would be collected from off-system customers' utilization of Contract Storage services?

A. To project GIK collected, DTE must project storage cycling. DTE has calculated the five-year average (using periods 2012/13 – 2016/17) of storage cycling to project the expected cycling during the projected test year. The five-year average is 53%, which means that over the last five years about half of the stored gas has been withdrawn and then injected the following summer. Weather has a significant impact on the degree to which storage is cycled.

For the projected future test period, Midstream expects to sell 63.4 Bcf of storage capacity of which 53% of this gas will be cycled. This cycling will generate a total of 33.6 Bcf (63.4 Bcf times 53%) of storage injections on which Midstream will collect 1.00% GIK, as approved by the Commission in Case No. U-17999.

Q. Is DTE Gas proposing to change the 1.00% GIK collected on Contract Storage Services?

A. No. The collection of GIK from off-system customers serves as a mechanism for DTE Gas to recover the costs of transmission LAUF (i.e. Lost And Unaccounted For) and Company Use volumes to provide Contract Storage Services.

The current GIK rate of 1.00% is both fair and equitable as it covers the actual cost of providing the service and will continue to provide a subsidy to DTE Gas distribution customers. (Reference Exhibit E-15, Schedule E-14, line 18, column (g)).

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Q. What are Park and Loan Services?

A. In addition to selling the 63.4 Bcf allocated storage capacity as a service to off-system customers, Midstream utilizes unused storage capacity and deliverability for park and loan services. The service consists of ratable injection over a specified period for ratable withdrawal over a different specified period. For instance, if there is excess storage capacity in January then Midstream may sell a service for ratable injection (park) or withdrawal (loan) during the month of January for ratable withdrawal (park) or injection (loan) during the month of May. Park and Loan Services enable DTE Gas to optimize the amount of revenue from its storage complex.

Q. What determines the value of Park and Loan Services?

A. Pricing for Park and Loan services is dictated by the market at any given point in time, and generally reflects the price differential or spread between the projected prices during the withdrawal period, and the projected prices during the injection period, discounted for the cost of financing inventory.

Q. How was the Park and Loan revenue projection calculated?

A. Midstream is projecting $7.5 million in Park and Loan revenue for the test period. As described above, DTE Gas used 2012 through 2016 average annual revenue to arrive at this projection. (Reference Exhibit A-13, Schedule C3.3, line 2, column (d)).

Q. How does the Park and Loan revenue projection compare to the historical test period?

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A. In 2016 Midstream earned $7.9 million for Park and Loan services compared to $7.5 million included in the projected test year. Exceptionally warm winter weather in winter 2015/16 resulted in low storage withdrawals and thus high storage balances. High storage balances led to limited storage space for the summer 2016 injection season and higher rates for Park and Loan Services. The Midstream forecast is based on normal weather in the test period; therefore, using a five-year average is a more appropriate indicator of outcome than single year. (Reference Exhibit A-13, Schedule C3.3, line 2, columns (b), (c) and (d)).

Q. How did DTE Gas project how much GIK would be collected from off-system customers' utilization of Park and Loan Services?

A. Midstream does not charge GIK on Park and Loan Services. It is industry practice not to charge GIK on Park and Loan Services as the GIK value is embedded in the Park and Loan Service rate. Therefore, GIK is not collected.

Midstream Services Revenue - Transportation

Q. What are transportation services?

A. DTE Gas provides transportation services to off-system customers that want to transport gas across DTE Gas's transmission system from a specified receipt point location to a different delivery point location. For example, a customer may want to move gas from ANR Pipeline Company through DTE Gas's system for delivery to Great Lakes Gas Transmission. DTE Gas charges the off-system customer a fee for utilizing the DTE Gas transmission system from the receipt point to the delivery point for the transportation of their gas.

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Q. How much total transportation revenue is included in the projected future test period?

A. Midstream is projecting $63.5 million in transportation revenue for the projected future test period. This revenue includes $57.5 million in Off-System Transportation revenue and $6.0 million in Exchange revenue. (Reference Exhibit A-13, Schedule C3.3, lines 5, 6, and 7, column (d)).

Q. What determines the value of Off-System Transportation Services?

A. The value of Off-System Transportation Services is determined by the natural gas markets, and more specifically, by the difference in gas prices at the receipt point and the delivery point. If the price of natural gas at point A (receipt point) is $2.50 per Mcf and the price of natural gas at point B (delivery point) is $2.60 per Mcf, this results in a total value of transporting gas from point A to point B of $0.10 per Mcf. This value is collected in two components: a demand/commodity charge plus a GIK charge. For the $2.50 per Mcf example above: At the GIK rate of 1.00%, the $0.10 per Mcf transportation value could be collected as $0.075 per Mcf demand charge plus $0.025 per Mcf of GIK ($2.50 multiplied by 1.00% GIK).

Q. Are there specific considerations for valuing Off-System Transportation Services on the DTE Gas system?

A. Yes. DTE Gas must ensure that it reserves sufficient transportation assets to deliver natural gas to its on-system customers. DTE Gas may have limited capability to provide transportation services to its Midstream customers when transportation values are their highest (i.e., highest transportation values generally occur when the physical ability to provide transportation services are at their lowest).

Q. How was the Off-System Transportation revenue projection calculated?

A. Midstream has $57.5 million of Off-System Transportation revenue sold and under contract, including $32.1 million for the NEXUS Capacity Lease Agreement. The forecast of Off-System Transportation revenue is defined by assets available for sale and the market demand for services. Currently, we do not anticipate demand for beyond what is already under contract. (Reference Exhibit A-13, Schedule C3.3, line 5, column (d)).

Q. How does this Off-System Transportation revenue projection compare to the historical test year?

A. In the historical test year, Midstream earned $31.6 million compared to $57.5 million in the projection. As described earlier in my testimony, $32.1 million of the increase is due to the Capacity Lease Agreement with NEXUS. This increase is offset by $1.7 million of revenue directly attributable to the capacity lease agreement with NEXUS and the expiration of other long-term transportation contracts that are not expected to be renewed; the net result yields an increase of $25.9 million. (Reference Exhibit A-23, Schedule M1 – Capacity Lease Agreement and Exhibit A-13, Schedule C3.3, line 5, column (b), (c) and (d)).

Q. How did DTE Gas project how much GIK would be collected from utilization of Off-System Transportation Services?

A. DTE Gas analyzed the trend of customers' utilization of Off-System Transportation Services over the last five years to project that off-system customers would transport 137.1 Bcf across the DTE Gas system in the future test period. In addition, NEXUS volumes are expected to be 240.5 Bcf, based on contracts

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included in the FERC Docket No. CP16-22-000, dated August 25, 2017. Therefore, GIK would be applied to a total of 377.6 Bcf of Off-System Transportation volumes.

Q. Is DTE Gas proposing a change to the 1.00% GIK collected on Off-System Transportation Services?

A. No. As discussed above, DTE Gas is proposing to maintain a 1.00% GIK rate as it covers the actual cost of providing the service and will continue to provide a subsidy to DTE Gas distribution customers.

Q. What are Exchange Services?

A. Exchange Services are transportation services that facilitate a contemporaneous exchange of gas on a Gas Day. In an exchange, DTE Gas agrees to deliver a quantity of natural gas to an interstate or intrastate pipeline interconnection. In exchange, the Off-System customer agrees to nominate an equal quantity of gas to DTE Gas at a DTE Gas city gate or storage facility location. These transport routes may include pipelines such as ANR Pipeline, Panhandle Eastern Pipeline, Vector Pipeline, and Great Lakes Gas Transmission. Since these services rely on the availability of gas at both the delivery and re-delivery points, the transfer of gas between the locations is a non-physical event, requiring no incremental fuel or losses to achieve the transaction.

Q. How are Exchange rates derived?

A. The value of an Exchange Service is calculated similarly to the value of a transportation service. It is the difference in price of gas at point A and the price of

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gas at point B. For example, if the price of gas at point A (receipt point) is $2.50 per Mcf and the price of gas at point B (delivery point) is $2.60 per Mcf, then the total value of exchanging gas between points A and B is $0.10 per Mcf. This value is collected as a demand charge and since no physical gas was transported, no GIK is applicable to this service.

Q. How was the Exchange revenue projection calculated?

A. Midstream is projecting $6.0 million in Exchange revenue for the test year, based on a volume of 55.9 Bcf and an average rate from 2012-2016 of $0.108 per Mcf.

Q. How does this Exchange revenue projection compare to the historical test year?

A. In the historical test year, Midstream earned $9.2 million. In the projected test year the Exchange revenue is forecasted to be $6.0 million. The $3.2 million difference is a result of lower market opportunities for exchanging gas with volumes from NEXUS and Rover pipelines entering the Dawn market (Reference Exhibit A-13, Schedule C3.3, line 6, columns (b), (c), and (d)).

<u>NEXUS Pipeline Project</u>

Q. What is the NEXUS pipeline project?

A. NEXUS Gas Transmission is an approximately 255-mile pipeline to transport Utica and Marcellus shale gas to Ohio, Michigan and Ontario markets. DTE Energy owns a 50% interest in NEXUS Gas Transmission. DTE Gas is party to a 15-year capacity lease agreement with NEXUS for the transportation of natural gas.

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Q. What are the terms of the capacity lease agreement?

A. DTE Gas will deliver NEXUS a fixed lease quantity of 1.1 Bcf per day to Vector-Milford Junction, Vector-Belle River, and to Union-St. Clair at a blended rate of approximately $0.08 per Mcf per day. All actual volumes delivered will be charged a GIK rate of 1%. The term of the agreement is 15 years, with an option to extend the service for up to 30 additional years. (Reference Exhibit A-23, Schedule NI – Capacity Lease Agreement).

Q. Will DTE Gas need to make infrastructure investments to supply NEXUS?

A. Yes. DTE Gas will invest approximately $200 million in its system to add over 50,000 horsepower of compression for the NEXUS pipeline. NEXUS will compensate DTE Gas for its investments through the NEXUS capacity lease agreement.

Q. How much revenue will be generated for DTE Gas from the NEXUS capacity lease agreement?

A. The lease agreement allows DTE Gas to charge NEXUS a firm volume for 15 years, which will provide $32.1 million of annual revenue.

Q. What if NEXUS doesn't need/take all the pipeline's capacity on any given day?

A. The lease agreement is a firm contract allowing DTE Gas to charge the full reservation charge of $32.1 million per year regardless how much actual capacity NEXUS uses. NEXUS will only be charged GIK on actual volumes.

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Q. What is the revenue requirement associated with NEXUS?

A. As supported by Company Witness Ms. Suchta, over the 15-year lease term, the annual revenue requirement averages approximately $24.3 million. The average annual revenue requirement includes O&M costs, depreciation, property taxes, and return on capital. Refer to exhibit A-23, Schedule N2 - NEXUS Lease Revenue.

Q. How does the NEXUS arrangement benefit DTE Gas customers?

A. The annual revenue of $32.1 million will more than offset the average revenue requirement of $24.3 million to provide the transportation service and the foregone transportation revenue of $1.7 million directly attributable to the capacity lease agreement with NEXUS; providing a customer benefit of over $90 million over the 15-year contract. This benefit offsets DTE Gas's costs and reduces the overall revenue requirement for DTE Gas' base rates.

SECTION 5 - OTHER OPERATING REVENUE COMPONENTS

Q. Are you sponsoring any components of other operating revenue?

A. Yes. I am sponsoring the following other operating revenue components that are included on Company Witness Ms. Uzenski's Exhibit A-13, Schedule C3:

1. Appliance service programs (also known as Home Protection Plus) (line 11);
2. Gas choice supplier revenues (line 13);
3. Other gas revenues (line 15); and
4. Blue Lake Investment Income (line 17).

Appliance service programs

Q. What services are provided by the Home Protection Plus program?

A. DTE Gas's main service offering under its Home Protection Plus (HPP) appliance service program are Heating, Ventilation, and Air Conditioning (HVAC) appliance repair services to customers as performed by DTE Gas field service employees and selected vendors. The appliance repair offerings include the repairs of furnaces, air-conditioners, water heaters, ranges/ovens, refrigerators, dishwashers, clothes washers and clothes dryers. The HPP programs offered by the Company are subject to a one year service agreement between the Company and residential customers that require DTE Gas to repair gas and electric equipment and appliances installed in the customer's home. The covered repairs are performed at no additional cost to the customer other than the contract service charge that is prepaid or paid monthly.

Q. What are the benefits to DTE Gas and its retail customers from the HPP programs?

A. DTE Gas customers receive several benefits from the HPP program:

1. First, the services offered by DTE Gas provide peace of mind to its customers as they have confidence that the appliance repair service will be completed safely and reliably. The program also provides customers with an affordable monthly payment option to help customers manage their personal finances eliminating the need for costly unplanned repair bills.
2. Secondly, DTE Gas's pricing structure for the services results in revenue which exceeds the inherent costs for the programs, thus reducing the overall cost of service to DTE Gas' customers.

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3. Thirdly, across Greater Michigan, this program helps balance the Company's workload between seasons and provides DTE Gas the ability to maintain and fully utilize skilled field technicians at the Company. By retaining a workforce to service these programs in Greater Michigan, DTE Gas has retained additional resources that are available to respond to emergency gas leak calls or other immediate needs, as necessary.

Q. What is the Company's projected test year revenue from the appliance service programs?

A. The revenues associated with these programs in the projected test year are included as a reduction in the overall cost of service to customers. In the projected test year, the Company expects to maintain its enrollment levels and revenues consistent with the historical test period of approximately 208,000 customer enrollments and $70.7 million in gross revenue. This can be seen Exhibit A-13, Schedule C3, line 11.

Gas Choice Supplier Revenue

Q. What are Gas Choice Customer (GCC) customers?

A. GCC customers consist of residential and business customers that wish to purchase their natural gas commodity from a diverse group of Alternative Gas Suppliers (AGS) rather than purchase GCR supply from the Company. The GCC customer typically desires fixed gas commodity pricing or a competitive alternative to GCR supply.

Q. In general, how does the GCC program work?

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A. In 2002, DTE Gas voluntarily implemented the current GCC program. Under this program, all of DTE Gas's customers have the option to purchase their natural gas supply from a third-party AGS rather than the utility. The AGSs are responsible for delivering gas supply on behalf of their customers while DTE Gas retains responsibility for the gas distribution, including maintaining facilities, responding to leaks and other emergencies, reading customer meters, performing all billing, remittance and collection activities, and responding to all customer inquiries other than those related to the AGS's natural gas supply service offering.

Q. What items are included in the GCC revenue?

A. This revenue consists of administrative billing fees DTE Gas charges the participating AGSs, as well as switching fees that DTE Gas bills directly to customers.

Q. What administrative billing fees does DTE Gas assess the AGSs?

A. As previously noted, DTE Gas performs all functions associated with the billing, remittance, and collection activities associated with customers who participate in the GCC program. Pursuant to Sections F1.6 and F1.11 of DTE Gas's Rate Book, DTE Gas charges the AGS nominal monthly fees associated with these services. These fees include a monthly charge of $0.30 per GCC account, and a $100 per month Pricing Category fee. GCC suppliers direct DTE Gas to create Pricing Categories for them. Pricing Categories provide DTE Gas with the rate and customer information necessary to bill customers for their GCC natural gas supply.

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Q. What is the customer-switching fee?

A. Pursuant to Section F6. of the Rate Book, GCC customers may change AGS's one time in any 12-month period at no cost. Customers are charged a $10 switching fee for each additional change during that same 12-month period.

Q. Are you forecasting any changes in the gas choice supplier revenue?

A. No. DTE Gas projects revenue for this category of $1.4 million as shown on Exhibit A-13, Schedule C3, line 13.

<u>Other Gas Revenue</u>

Q. What is other gas revenue?

A. This revenue is driven by miscellaneous charges and services provided to third parties. The primary components are receipt point revenue, Michigan tax revenue, City of Detroit tax revenue, and non-cash customer credits, as described below:

Receipt point revenues: Revenues that DTE Gas receives related to dry receipt point interconnections between the Company's transmission system and various production locations. Dry receipt points are unique in that gas located behind these points flows directly into DTE Gas's transmission system without first being transported through gathering lines or processing facilities. Dry Receipt Point fees are set forth in agreements between the Company and producers operating at these locations. In general, these fees cover a fixed amount associated with operating and maintaining the interconnection or metering equipment, plus any costs incurred by Company personnel for unscheduled or non-routine service work. Receipt point revenues are offset by the operations, maintenance and materials related to performing the work at the receipt points.

Michigan and City of Detroit tax revenue: The Company is a tax collection agent for both the State of Michigan and the City of Detroit. The Company receives payments and discounts by filing state sales or use taxes early or timely and for collecting Detroit Utility Users Tax. These tax related payments, discounts, and collections fees are booked as revenues.

Non-cash customer credits: Revenues derived from applying a credit or debit to customer residential bills for miscellaneous adjustments. The adjustment can be for a fast meter correction, switched meter correction, customer satisfaction remedy, theft change reversal or charge, and agency payments for utility bill assistance. The non-cash credit revenues are booked to various general ledger revenue accounts.

Q. Are you forecasting any changes in other gas revenue in your projected test year, when compared to the 2016 historical test year?

A. No. DTE Gas does not expect any significant changes in these services or related revenues. The Company's projected test year revenues for this category is $0.3 million as shown on Exhibit A-13, Schedule C3, line 15.

<u>Blue Lake Investment Income</u>

Q. What is Blue Lake Investment Income?

A. Blue Lake Investment Income results from DTE Gas's 25% equity ownership in Blue Lake Gas Storage Company (Blue Lake). Blue Lake is a 48 Bcf storage

Line No.

facility in Northern Michigan that is jointly owned by Blue Lake Holdings (DTE Gas Company) and ANR Blue Lake Company (Transcanada Corporation).

Q. Are you forecasting any changes to Blue Lake Investment Income in your projected test year as compared to the historical test period?

A. Yes, DTE Gas is forecasting an income reduction of $4.8 million per year. As described in Company Witness Mr. Feldmann's testimony in Case No. U-17999 and as stipulated in the Settlement Agreement between ANR Pipeline Company, DTE Gas Company and Blue Lake Gas Storage Company, dated February 1, 2016, Blue Lake's rate, and therefore its revenues, have decreased. As a result, we are projecting Blue Lake investment income of $0.8 million in the projected test year as shown on Exhibit A-13, Schedule C3, line 17. (Reference FERC Docket RP13-743-000).

SECTION 6 – PROPOSED MONTHLY CUSTOMER CHARGES, RATE SCHEDULE ECONOMIC BREAK-EVEN POINTS, AND MINIMUM AND MAXIMUM OPTIONAL EUT TRANSPORTATION RATES

Q. How were the various rates and charges for each rate schedule developed?

A. DTE Gas utilized the total allocated cost of service for each rate schedule or group of rate schedules as developed by Witness Slater.

Monthly Customer Charges

Q. What factors were considered in establishing the proposed monthly customer charges?

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A. There are several factors that were considered in determining the appropriate monthly customer charges for DTE Gas's rate schedules. As an example, the recommendation for changes to the monthly customer charges considers the:

1. Social concerns that the Commission has expressed in previous rate cases;
2. Historically approved economic break-even points between the various rate schedules;
3. Time elapsed since customer charges were last adjusted; and
4. Volatility of customers' bills, especially the financial impact of colder-than-normal winters on customers' bills.

Q. What monthly customer charges, applicable to its sales and transportation rate schedule customers, is DTE Gas proposing?

A. Based on the considerations listed above, the Company's proposed monthly customer charges are shown on Witness Slater's Exhibit A-16, Schedule F2, pages 2 and 3. That exhibit shows the current monthly customer charges (column (b)) and the proposed monthly customer charges (column (c)) applicable to DTE Gas's rate schedule customers.

Q. What monthly customer charges are you proposing for the residential rate schedules and the general service rate schedule?

A. The proposed monthly customer charges for residential and general service rate schedules are shown on Witness Slater's Exhibit A-16, Schedule F2, page 2; DTE Gas is proposing that the monthly customer charge for Rate A be changed to $15.00. The value of $15.00 is less than one half of the value of the fixed charges that could apply to a Rate A account and it reflects a gradual movement towards the establishment of a fixed rate that approximates non-volumetric charges that are attributable to serving this class of customers. To maintain historical consistency, DTE Gas proposes that the monthly customer charge for Rate 2A-Meter Class I be set identical to residential Rate A at $15.00 and the monthly customer charge for Rate 2A-Meter Class II and Rate GS-1 be set at $35.00.

Q. What monthly customer charges have you proposed for the remainder of the sales and transportation rate schedules?

A. By working with Witness Slater, I determined the monthly customer charges for the remaining rate schedules by using the economic break-even points and the Rate GS-1 monthly customer charge proposed in my testimony. The monthly customer charges for the remaining rate schedules are shown on Exhibit A-16, Schedule F2, pages 2 and 3, column (c); the proposed Rate GS-2 monthly customer charge is $600.00, the Rate S monthly customer charge remains at $200.00 and the monthly customer charges for EUT Rates ST, LT, XLT, and XXLT are $2,400.00, $4,775.00, $14,500.00, and $137,750.00, respectively.

<u>**Rate Schedule Economic Break-even Points**</u>

Q. Why is it important to retain the economic break-even points between the various rates?

A. Maintaining the economic break-even points is important for several reasons:

1. It provides transparency for customers so they know which rate is most economically viable for their operations;
2. It stabilizes and minimizes rate switching between the various rate schedules;

3. It stabilizes and minimizes rate switching between the sales and EUT rate schedules;
4. It retains the historical break-even points familiar to customers, customers' energy agents, and the Company;
5. It reduces administrative and contractual actions for both the customers and the Company upon issuance of the Commission's Final Order;
6. It provides an accepted balance by both the Commission and customers, whereby small customers are charged lower monthly charges and higher volumetric charges, while larger customers are charged significantly higher monthly charges and lower volumetric charges; and
7. It provides a rate design with a higher monthly charge and lower volumetric rate that significantly aids in the retention of the very largest transportation customers that retain competitive energy alternatives.

Q. What are the economic break-even points between the various rate schedules proposed in this case?

A. The proposed economic break-even points between the various rate schedules are as follows:

GS-1 to GS-2	14,000 Mcf per year
GS-1 to S	2,200 Mcf per year
GS-1 to ST	14,500 Mcf per year
ST to LT	100,000 Mcf per year
LT to XLT	700,000 Mcf per year
XLT to XXLT	3.9 Bcf per year

The economic break-even points listed above were determined by including the proposed monthly customer charges, distribution charges, and the IRM surcharge for the various rate schedules.

EUT Cost Based Rates and Minimum and Maximum Optional Rates

Q. What is your proposal regarding the cost based rates under the EUT rate schedules?

A. Witness Slater's Exhibit A-16, Schedule F2, page 3, shows the proposed rates for the various EUT rate schedules.

Q. What is your proposal regarding the range for the optional rates under the EUT rate schedules?

A. The Commission has historically approved a cost based transportation charge for each of the EUT rate schedules. In addition, the Commission has historically approved a minimum and a maximum transportation charge for each of the EUT rate schedules and defined as optional rates in the Company's Rate Book. Witness Slater's Exhibit A-16, Schedule F2, page 3, shows the proposed range of rates for the various EUT rate schedules. I am proposing that the minimum optional rate under rate schedules ST and LT remain at \$0.23 per Mcf and the minimum optional rate under rate schedule XLT and XXLT remain at \$0.18 per Mcf and \$0.05 per Mcf, respectively.

Q. How did you determine the maximum optional rates for the EUT rate schedules?

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A. In respect to rate schedules ST, LT, and XLT, I calculated the maximum optional rate for each EUT service category as depicted on Witness Slater's Exhibit A-16, Schedule F2, page 3 by calculating the difference between the minimum optional rate for each of the rate schedules and the cost of service rate determined by Witness Slater. I then added that difference to the cost of service rates to determine the maximum rates.

Consistent with the Commission orders in Case Nos. U-15985, the U-16999 settlement, and U-17999, I recommend setting the maximum rate for rate schedule XXLT equal to the rate calculated for rate schedule XLT.

Q. Why is it important to have the maximum option rate for EUT customers set at the proposed levels?

A. The maximum option rate is sometimes used when negotiating with industrial customers, to the benefit of DTE Gas and the customer, to facilitate paying for a portion of the gas facilities construction and enhancements needed to extend facilities to the industrial customer. These facilities and their construction, including the large main extension, service installation and metering assembly, can be costly. The maximum optional rates provide the Company and customers a negotiable option to cover some, or all, of the construction cost of large capital projects by amortizing a portion of the cost of the gas facilities construction into the gas rate over the length of a long-term agreement in lieu of the customer paying a higher up-front contribution in aid of construction.

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Q. Do you believe that DTE Gas's proposed cost base rate design meets the objectives to attract and retain customers having an interstate bypass option?

A. Not entirely. The Company has been required to discount the cost based rates to keep AK Steel and Ford-Rouge from bypassing to the interstate pipeline. The Company will need to discount the XLT and XXLT rates proposed in Witness Slater's Exhibit A-16, Schedule F2, page 3 and be also allowed to recover the cost of the discounts from other customers to retain AK Steel and Ford-Rouge.

Q. Are there any other examples where the cost based XXLT rate was not competitive with an energy consumer's interstate pipeline alternative?

A. Yes. During 2011, and then again during late 2013, DTE Gas had the opportunity to compete for the business of another very large energy consumer (approximately 9 Bcf per year) that is interconnected to an interstate pipeline. In each of these cases, the cost based XXLT rate was not competitive enough to persuade this heavy industrial manufacturer to purchase transportation service from DTE Gas. This industrial company stressed that the regulatory risk and uncertainties attributed to charges like the IRM charge, energy waste reduction surcharges, and potential increases in the transportation rate and GIK percentage were critical in its decision to stay with its interstate pipeline provider. It is evident that this potential XXLT customer would need Commission relief from certain regulatory risk prior to investing several million dollars to interconnect with DTE Gas's system. The Company's best opportunity to compete for this potential customer's natural gas transportation business would be to discount the XXLT rate to a competitive level. The Company would also need recovery of the discount similar to the Company's request for discount recovery requested in Section 3 of my testimony. The Order in

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this rate case will play a significant role in determining whether future negotiations with this potential large gas transportation customer will be successful.

Q. Based on your experience and customer negotiations, what recommendations are you proposing pertaining to the XXLT rate design?

A. The XXLT rate (including the DIG rate class) should not be allocated any of the distribution mains plant cost or distribution operating expenses consistent with Company's allocation in Case Nos. U-15985 and U-17999 as authorized by the Commission.

Q. Why are distribution costs not allocated to the XXLT and DIG (Dearborn Industrial Generation, LLC) rate classes?

A. The EUT customers forecasted to take service under the XXLT rate during the projected test year, including DIG, primarily take delivery of their gas supplies directly from the Company's transmission system and high pressure systems directly connected to the Company's transmission system. Therefore, and from a cost allocation basis, these customers should not be assigned any distribution costs.

SECTION 7 - TARIFF CHANGES FOR ALL CUSTOMERS

Q. What changes is DTE Gas proposing to its tariff pages under Section C of DTE Gas's Rate Book?

A. DTE Gas is proposing changes to the Company's tariff pages under Section C8.4. The tariff sheet modifications are reflected, in their entirety, in Witness Slater's Summary of Proposed Tariff Changes (Exhibit A-16, Schedule F5) and Witness Slater's Proposed Tariff Changes (Exhibit A-16, Schedule F5.1).

Q. What changes are you proposing for Section C8.4 of the Rate Book?

A. We propose to eliminate Section C8.4 - Connection Fee - and its associated references in Section C8.

Q. What is the intent of Section C8?

A. Section C8 of the tariff, in its entirety, addresses the Customer Attachment Program (CAP), and how costs associated with new gas mains and/or service lines will be calculated and recovered from the requesting customer through a Customer Contribution.

Q. Mechanically, how is the Customer Contribution calculated?

A. Simplistically, the Customer Contribution is calculated such that the customer will pay the positive difference, if any, between the net present value (NPV) of all costs associated with the new service, less the NPV of the anticipated revenue stream. For a residential customer, a twenty-year revenue stream is used in the calculation. Then, a minimum $300 Connection Fee is added. Thus, even if the NPV of the anticipated revenue exceeds the NPV of the associated costs, the customer is still required to pay a minimum of $300.

DTE Gas employs a CAP cost model to calculate the Customer Contribution. Variable information such as the length and size of the required piping (main and/or service) is entered in to the model, along with an estimate of the customer's expected annual usage. Costs embedded in the model include, among other things, materials, direct and indirect labor, depreciation, property taxes, O&M, and carrying charges on plant investment. The model also includes a calculation used to derive the NPV of the customer's anticipated future annual usage. Once the variable information is manually input, the model calculates the Customer Contribution.

Q. Why do you propose to eliminate the $300 Connection Fee in Section C8 of the Rate Book?

A. In 1995, when the CAP was incorporated into the tariff, the CAP cost model did not include administrative and meter expenses. Rather, those expenses were recovered through the Connection Fee. Over time, as the model evolved, administrative and meter expenses were included in the CAP model and the Connection Fee was used to reduce the associated costs required to serve the customer. Mechanically, this was accomplished within the CAP model by offsetting the NPV of the costs by the $300 Connection Fee. Thus, the customer is currently required to pay the Connection Fee even if the NPV of the anticipated revenue exceeds the NPV of the associated costs. Under our proposal, this will no longer be the case. Rather, the $300 offset currently embedded in the CAP model will be eliminated, and the Customer Contribution will be zero for situations where the NPV of the anticipated revenue exceeds the NPV of associated costs. Likewise, under our proposal, in instances where the NPV of the revenue is less than the associated project costs, the customer will pay the deficiency, which includes administrative and meter fees as part of the Customer Contribution. As such, the $300 Connection Fee should be eliminated as the CAP model that is currently in place already accounts for the recovery of all costs associated with new customer attachments.

Q. Are there other reasons for eliminating the $300 Connection Fee in Section C8 of the Rate Book?

A. Yes. The $300 Connection Fee, at times, deters customers from converting from propane, or other alternate fuels, to natural gas. Customers who are converting have to consider other conversion costs, such as plumbing changes and the installation of new appliances. The addition of the $300 fee, which is paid upfront and out-of-pocket, in addition to these related costs, can be burdensome to customers.

SECTION 8 –TARIFF CHANGES FOR SALES CUSTOMERS

Q. What are the changes that DTE Gas is proposing to its tariff pages applicable to its sales customers under Section D of DTE Gas's Rate Book?

A. The changes to these tariff pages include the Company's proposed Monthly Customer Charges and Distribution Charges for each rate schedule and as shown on Witness Slater's Exhibit A-16, Schedules F5 and F5.1.

SECTION 9 –TARIFF CHANGES FOR EUT CUSTOMERS

Q. What are the changes that DTE Gas is supporting to its tariffs for transportation and storage customers under Sections E1 through E14 of DTE Gas's Rate Book?

A. DTE Gas is proposing the following changes to its tariffs under Sections E1 through E14 of the Company's Rate Book, which are reflected in Witness Slater's Exhibit A-16, Schedules F5 and F5.1:

1. Clarify the use of the term "sales service" and modify the standard contract extension from Month-to-Month to Year-to-Year in Section E14-Availability, Sheet E-14.00;
2. Clarify how Gas-in-Kind is applied on injected quantities in the Load Balancing Storage and Charges, Section A, Sheet E-18.00;

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3. Reflect the Company's proposed Monthly Customer Charges and Transportation Charges for each EUT rate schedule in Section E14; and
4. Incorporate the Company's proposed GIK percentages under Section E14.

The tariff sheet modifications are reflected, in their entirety in Witness Slater's Summary of Proposed Tariff Changes (Exhibit A-16, Schedule F5) and Witness Slater's Proposed Tariff Changes (Exhibit A-16, Schedule F5.1).

Q. What changes are you proposing to the Availability provision in Section E14, Sheet E-14 in the Company's Rate Book?

A. I am recommending one clarification and one modification to the Availability provision listed in Section E14, Sheet E-14 of the Company's Rate Book. For the benefit of EUT customers and their gas suppliers and agents, I am proposing to clarify the Availability provision in Section E-14 by replacing the words "sales service" with the words "a non-Transportation Service Rate."

Q. What additional modification are you proposing to the Availability provision in Section E14, Sheet E-14 in the Company's Rate Book?

A. I am proposing to modify the Availability provision in Section E14, Sheet E-14 in the Company's Rate Book by replacing the extension term provision from a Month-to-Month period to a Year-to-Year extension period.

Q. Why are your proposing to change the extension period from Month-to-Month to Year-to-Year?

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A. The Company's standard transportation contracts have included a Year-to-Year extension term provision for many years. This proposed change aligns the Rate Book with the typical contract negotiations executed by the Company and its EUT customers. The Availability provision in E14 retains the verbiage that states "unless otherwise agreed upon between Company and Customer" so that the contract term, including the extension term, may be negotiated.

Q. What changes are you proposing to the Load Balancing Storage and Charges portion of the Company's Rate Book?

A. In Section E14, Load Balancing Storage and Charges, sub-section B, I am proposing to clarify how Gas-in-Kind is applied on injected quantities in the Load Balancing Storage and Charges, Section A, Sheet E-18.00. The clarifications are intended to align the tariff language with the Company's long-standing method of assessing GIK on excess Load Balancing Storage injections. This change is a clarification only; GIK and billing practices will be unchanged.

Q. Have you reflected DTE Gas's proposed customer charges and transportation rate changes in your exhibits?

A. Yes. DTE Gas's revised customer charges and revised transportation rates are shown as part of the revised tariff pages included Witness Slater's Exhibit A-16, Schedules F5 and F5.1.

Q. Is DTE Gas proposing to revise how it charges EUT customers for GIK fuel costs in this case?

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A. No. DTE Gas proposes to retain the GIK rate applicable to EUT service rates ST, LT, and XLT at 1.41%, and the GIK rate applicable to XXLT service rates at 1.00% as discussed in Section 1 of my testimony.

SECTION 10 –TARIFF CHANGES FOR CONTRACT RATE CUSTOMERS INCLUDING THE GENERAL SERVICE RATES, EUT RATES, AND OFF-SYSTEM STORAGE AND TRANSPORTATION RATES

Q. What is the Company proposing to clarify in its Rate Book pertaining to Contract Rate Customers?

A. The Company is proposing to clarify the contract signature authority required to execute or amend gas service contracts for certain general service rates, end-use transportation rates, and off-system storage and transmission rates.

Q. What contract signature authority is currently stated in the Company's Rate Book?

A. The Company's Rate Book currently designates an officer of the Company, typically the President or a Vice President, or a designated representative, as those who may approve and execute gas service contracts for certain general service rates, end-use transportation rates, and off-system and storage and transmission rates.

Q. What clarifications is the Company proposing to its Rate Book when approving and executing gas service contracts?

A. To add clarity, the Company is proposing to modify Rate Book sections C1.2, C1.7, D7, D8, E14, E25, E26, E27, E28 to be consistent with the Company's enterprise

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policies regarding signature authority for contracts and financial transactions, establishment of contracts, record retention, and contract management and administration. If approved, these changes would authorize, under current Company enterprise policy, that a President, Vice President, Director, Manager or Principal Supervisor would have approval and execution authority of gas service contracts based on the signing authority of the respective leadership position granted by Company policy.

Q. Are there any other proposed changes to the Company's Rate Book provisions?

A. Yes:

1. Clarify the last sentence of Section C1.2 of its Rate Book pertaining to contracts.
2. Incorporate the Company's proposed not to exceed rate under Sections E25 and E26.

Q. What clarification is the Company proposing in Section C1.2?

A. The last sentence of Section C1.2 of the Company's Rate Book specifies contract forms shall be first approved by the Commission. Currently, the Commission does not approve the Company's contract forms. However, the Company is required to maintain its contract forms on the Company's website. The Company is proposing to delete the reference to the Commission approving contract forms, replacing the words with a provision stating that contract forms will be listed on the Company's website.

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The tariff sheet modifications proposed in SECTION 10 of my testimony are reflected, in their entirety, in Witness Slater's Summary of Proposed Tariff Changes (Exhibit A-16, Schedule F5) and Witness Slater's Proposed Tariff Changes (Exhibit A-16, Schedule F5.1).

Q. What rate changes are being proposed by DTE Gas relating to the off-system transportation (TOS-F and TOS-I) rates?

A. DTE Gas is proposing to slightly increase the TOS-F (Section E25) and TOS-I (Section E26) not to exceed rate from $0.375 per MMBtu to $0.376 per MMBtu as supported by Witness Slater on Exhibit A-16, Schedule F6.

<u>SECTION 11 – PROPOSAL TO RECOVER GAS RESEARCH AND DEVELOPMENT COSTS</u>

Q. Are you proposing any other programs or services?

A. Yes. I am proposing that DTE Gas be permitted to recover natural gas technology research and development (R&D) expenses by becoming a member of the Gas Technology Institute's Utilization Technology Development (GTI-UTD) program. The Gas Technology Institute (GTI) is a leading gas technology-based R&D organization with the history, science, and engineering capability to support the development of technology-based solutions for industry, government, and consumers.

Q. Why is DTE proposing to support a R&D program?

A. DTE Gas is one of the largest gas utilities in Michigan and North America. Moreover, DTE Gas is an industry leader in customer satisfaction, safety, and energy efficiency, and is striving to be the best operated gas utility. As such, DTE Gas should also be a leader in directing natural gas technology research, development and efficiency improvements that ultimately provide cost savings and increased customer satisfaction for DTE Gas's Michigan-based residential, commercial and industrial customers.

Q. Why is DTE proposing to support the GTI-UTD program?

A. DTE Gas and its customers would immediately benefit from the GTI-UTD program's body of knowledge in natural gas technologies once becoming a member. Others in the industry recognize this value as well, as is evidenced by GTI-UTD membership growing from 5 utility members in 2004 to 18 utility member companies currently. Furthermore, GTI-UTD has been successful in leveraging approximately $4 million of annual member funding more than 4:1 from governmental and industry partners. For example, in 2016, each $1.00 in new UTD funding from utilities was leveraged by an additional $4.71 of direct funding from government and industry partners for related end-use R&D. By investing in the GTI-UTD, DTE Gas and its gas customers would benefit from this R&D leverage and the related outcomes.

Q. What types of R&D projects has GTI-UTD facilitated?

A. The GTI-UTD program currently involves a wide-ranging portfolio of R&D on end-use equipment and appliances for the residential, commercial, industrial and transportation customer segments. GTI-UTD and its members are actively managing R&D projects inclusive of water heating, cooking, space conditioning, commercial foodservice, gas heat pumps and desiccants and humidity control, industrial processes, combined heat and power, and transportation. The GTI-UTD's recent report on research project summaries for 2016-2017 include 24 residential applications, 16 commercial applications, two distributed generation technology applications, 13 industrial and 15 transportation applications.

Q. What technology advancements and commercialized projects have been realized by the GTI-UTD programs?

A. Residential technology advancements and commercialized products include a solar-assisted natural gas water heating system, a gas-fired absorption heat pump water heater, a combination space/water heating and air handling unit, and a self-powered gas appliance control valve. Commercial and Industrial products include heat recovery systems, high efficient condensing rooftop heating units, a gas heat pump system, a gas-fired energy star commercial dryer, and ultra-low NO_x gas burners. Food service product examples include a low-oil-volume fryer, high efficiency conveyor oven, convection oven broiler, and a steamer. Transportation market segment technologies include a cost-effective natural gas home refueling system, and three new natural gas engines.

Q. How do the new technologies described above benefit DTE's natural gas customers?

A. These new technologies help gas consumers lower their energy costs, reduce equipment costs and emissions, and improve efficiencies. By investing in the GTI-UTD, DTE will help its customers be early adopters of new gas technologies, partner with its customers in developing demonstration sites and piloting technologies, develop pro-active responses to regulatory challenges, help customers meet emission-reduction goals, identify consumer energy preferences, and develop renewable energy integration opportunities.

Q. Are there any other areas of research in the DTI-UTD program?

A. The GTI-UTD program also develops unbiased, credible technical information for public stakeholders to consider when codes and standards are being developed, including energy comparisons that consider source energy impacts.

Q. Do customers of DTE Gas already benefit from the GTI-UTD program even though DTE Gas is not a GTI-UTD member?

A. Yes; however, it is an indirect benefit as no other Michigan gas utility is a GTI-UTD member and none of the current GTI-UTD members are working specifically to support the technology interests of customers located in Michigan. DTE Gas's participation and funding in GTI-UTD would be directed toward natural gas technologies that benefit our DTE Gas residential, commercial and industrial customers pertinent to the Michigan economy, energy plans, and climate.

Q. What level of R&D expenses is DTE Gas proposing to recover?

A. Membership in the GTI-UTD costs $350,000 per year. DTE Gas is proposing to recover this annual cost in its base rates. The cost would be approximately $0.00125 per Mcf if applied volumetrically, or $0.30 per meter per year on a per customer basis.

Q. Has the Commission previously ruled on utility participation in R&D?

A. Yes. The Commission issued an Order in Case No. U-14651 on this topic.

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Q. What did the Commission's Order in Case No. U-14651 find?

A. The Commission's Order in Case No. U-14561 found that:

- Local distribution companies (LDCs) should be permitted to seek recovery of R&D expenses through general rate case proceedings;
- A request for recovery of R&D expenses up to $0.0174/Mcf would be reasonable at that time;
- LDCs should be permitted to select which R&D organizations and projects, if any, to support;
- LDCs should track R&D expenses in Account 930.2 of the Uniform System of Accounts; and
- Any excess R&D amounts recovered in one year should be carried forward for spending on R&D projects during the following year.

Q. Would DTE Gas's participation as a member of the GTI-UTD program comply with the Order in Case No. U-14651?

A. Yes. DTE Gas is requesting permission to recover R&D expenses through this general rate case proceeding. The proposed request for recovery of R&D expenses is significantly lower than the $0.0174/Mcf approved in Case No. U-14651, and DTE Gas has selected a reputable R&D organization focused on natural gas technologies. The Company would track its R&D expenses in Account 930.2 of the Uniform System of Accounts. The GTI-UTD program provides that any excess R&D amounts payed to GTI-UTD in one year would be held in the Company's account with the GTI-UTD and carried forward for spending on R&D projects during subsequent years.

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Q. When would DTE Gas propose to join as a member of GTI-UTD?

A. The Company would join the GTI-UTD immediately following an order in this general rate case proceeding authorizing the Company to recover R&D expenses.

SECTION 12 - O&M EXPENSES FOR DTE GAS MARKETING

Q. What O&M expense is included in the projected test year for DTE Gas Marketing?

A. DTE Gas Marketing projects $42.4 million of O&M expense during the projected test period. This amount is equal to the actual 2016 annual expense of $39.3 million, plus an adjustment for inflation. See Exhibit A-13, Schedule C5, line 7.

Q. What are the primary costs included in DTE Gas Marketing's O&M during the projected test year?

A. The primary costs for DTE Gas Marketing O&M forecast include, among other items, labor, marketing, and advertising expenses, and vendor expenses for the appliance service program.

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 GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority	)))))))	Case No. U-18999

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JOI M. HARRIS

DTE GAS COMPANY
QUALIFICATIONS OF JOI M. HARRIS

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

A. My name is Joi M. Harris. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Gas Company, (DTE Gas or Company) as Vice-President, DTE Gas, Gas Operations.

Q. What is your educational background?

A. I have a Bachelor of Science in Industrial Engineering and a Masters of Business Administration from Wayne State University.

Q. What is your work experience?

A. I joined DTE Gas in 1991 where I held various positions including Control Maintenance Technician, Supervisor - Gas Measurement and Manager - Transmission and Storage Operations. In 2007, I was promoted to Director of Transmission and Storage Operations. In 2010, I assumed the responsibilities of Director of Gas Control and Planning and in 2011, I transitioned to Director of Southeast Michigan Gas Operations. In 2013, I was promoted to Vice-President of Gas Operations.

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

A. In my current position as Vice-President, Gas Operations for statewide gas operations, I am responsible for all areas of operations including field service, distribution, construction planning and drafting.

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

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A. Yes. I provided testimony in DTE Gas Company's General Rate Case, Case No. U-16999 regarding the Company's gas distribution system's operations and in DTE Gas Company's Infrastructure Recovery Mechanism case, Case No. U-17701 regarding expansion of the Company's Main Replacement Program and related increase in the Infrastructure Recovery Mechanism surcharge.

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Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Company's request to increase the Infrastructure Recovery Mechanism (IRM) capital expenditure levels to achieve completion of the Main Renewal Plan in 15 years and expand the Meter Move-Out (MMO) program to address overdue Meter Assembly Checks (MACs). In support of this request, my testimony explains:

1. DTE Gas' proposal to increase the IRM capital expenditures by $85.1 million in 2019, $108.4 million in 2020 and $150.6 million in 2021 above the approved $127.6 million for 2017;
2. Why the accelerated removal of unprotected mains within the Company's distribution system is prudent; and,
3. How the proposed expansion of the MMO program addresses the Company's inability to access inside meters for purposes of atmospheric corrosion control, continuing surveillance and leak surveys referenced by Staff in Case No. U-17999.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.2	Infrastructure Recovery Mechanism Capital
A-12	B6	Infrastructure Recovery Mechanism Capital – Summary
A-12	B6.1	Main Renewal Program History
A-12	B6.2	Incremental Resource Requirements
A-12	B6.3	Capital Expenditures – Main Renewal Program

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A-12	B6.4	Inside Meter Move-Out History
A-12	B6.5	Leaks on Mains and Services – 2010 - 2016
A-12	B6.6	Overdue MACs by Aging
A-12	B6.7	Actual Capital Cost of IRM compared to targeted levels 2014, 2015, 2016
A-12	B6.8	Map of MAC MMO Pilot Area
A-12	B6.9	Historic Corrosion Leak Rates

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

A. Yes, they were.

<u>Infrastructure Renewal Mechanism</u>

Q. What is the IRM?

A. The IRM is the program name for a series of capital expenditures that support the long-term improvements to DTE Gas's infrastructure. The three processes making up the IRM capital expenditures are: Pipeline Integrity (PI), Meter Move Out, and Main Renewal Program (MRP). The individual processes are discussed in more detail later in my testimony. DTE Gas is currently making substantial investments in these areas and will continue to make substantial expenditures beyond the Company's projected test period in this proceeding. As part of this proceeding, the Company seeks to recover its cost using a new IRM surcharge related to IRM capital expenditures from 2019 through 2023.

Q. Why does DTE Gas have infrastructure programs?

A. IRM programs are necessary to assure the safety of DTE Gas's customers and the public and to allow it to provide reliable utility service. The Commission has clearly stated that assuring safe and reliable utility service is an obligation it takes seriously (page 25, Commission order in U-16999, April 15, 2013). The Commission has repeatedly shown its dedication to achieving these safety and reliability goals by encouraging and approving the programs making up DTE Gas's IRM. The IRM proposed in this case continues supporting DTE Gas's and the Commission's goal of safe and reliable service by continuing and expanding the IRM programs. These expansions will allow DTE Gas to complete these programs even more quickly than projected in past cases.

Q. What does the Company seek to recover in this proceeding related to IRM capital expenditures?

A. The Company has included all IRM capital invested through December 31, 2018 in base rates, as supported by Company Witness Ms. Uzenski. All the IRM capital beginning January 1, 2019 is included in calculating the new IRM surcharge. This approach is administratively simple because the IRM capital is incurred and can then be reconciled on a calendar year basis.

The Company expects to invest increasing amounts in MMO, MRP, and Pipeline Integrity from 2017 through 2021.

Table 1

Year	**Proposed Spend** ($ Millions)
2017	$161.2
2018	$183.1
2019	$220.5
2020	$243.9
2021	$286.0

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These amounts are used by Company Witness Ms. Suchta in her development of the IRM revenue requirement and Company Witness Mr. Slater in his cost of service. The annual capital spending by component for the IRM is included on Exhibit A-9, Schedule B6, Infrastructure Recovery Mechanism Capital Expenditures 2013-2021.

Q. What are DTE Gas's recent historical IRM expenditures?

A. The spending levels in the below table demonstrate DTE Gas's commitment to improving its infrastructure with the prudent capital spending levels proposed in this application.

Table 2

	IRM Spend ($ Millions)	
	Approved	**Actual**
2015	$77.4	$86.8
2016	$93.0	$122.0
2017F	$127.6	$161.8

Q. In what programs will the Company focus the incremental capital expenditure?

A. DTE Gas proposes to increase spending levels in both the MRP and MMO programs. The increase will further reduce the cycle-time for the retirement of cast iron and unprotected steel distribution main from current expenditure levels. It will also address the declining trend of inside meter impacted through routine work, which will also reduce the cycle-time to relocate all inside meters in the DTE Gas system.

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Main Renewal Program

Q. What is the MRP?

A. DTE Gas's MRP is a focused effort that has accelerated the upgrade of DTE Gas's distribution system. The program focuses on DTE Gas's main renewal and retirement efforts on poor performing mains. DTE Gas has implemented a long-term strategy to reduce the Company's level of incoming leaks and lost and unaccounted for gas resulting from gas leaks. The program resulting from this focus and strategy is concentrated in Southeast Michigan where most of DTE Gas's cast iron and non-protected steel mains are located. The program includes renewals and retirements in the Greater Michigan service area as well.

In its order, dated September 13, 2011 in Case No. U-16407, the MPSC found that DTE Gas should implement its proposed capital spending for removing cast iron and unprotected steel mains effective with the issuance of that order. The Commission supported the MPSC Staff's position in this MRP case stating, "that the safety and reliability of DTE Gas's gas distribution system is not a goal but rather a necessity, and the Commission is charged with enforcing gas safety standards." (U-16407 Order, page 7)

Q. How has the current MRP evolved from the original MRP approved in Case No. U-16407?

A. In Case No. U-16407, DTE Gas originally contemplated main renewal and retirement efforts totaling $17.1 million in 2012 and $17.4 million in 2013 that would target 30 miles of annual retirement. At this pace, DTE Gas would retire the cast iron and unprotected steel in its distribution system in about 133 years. To address the

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persistent rate of incoming leaks, the Company has since increased its level of investment in MRP to further accelerate the retirement of its poor performing main. Through a series of stepped expansions using continuous improvement methodologies, DTE Gas reduced the time span of its replacement efforts by nearly 100 years as shown in the chart below.

Table 3

	U-16407	**U-16999**	**U-17701**	**U-17999**
Proposed Miles	30 miles	54 miles (2012) 66 miles (2013)	82 miles (2016) 103 miles (2017)	92 miles (2016) 123 miles (2017)
Proposed Dollars	$17.4MM	$46.9MM	$62.5MM (2016) $78.3MM (2017)	$70.4MM (2016) $93.8MM (2017)
Program Completion	133 Years	60 years	35-40 years	30-35 Years
Other		Surcharge Implemented	MGA	

Q. Why is DTE Gas seeking to increase the capital spending level and the miles of main being renewed from the level in Case No. U-17999?

A. Several factors have led the Company to propose additional main renewal expenditures beginning in 2019. The factors supporting the increase proposed in this case are essentially the same as those leading to the Company's initial MRP proposal and subsequent expansions.

1) Experience: After five and a half years of MRP operation, DTE Gas has gained a tremendous amount of operational experience and, consistent with the MRP plan approved by the Commission and expansions granted in Case Nos. U-17701 and U-17999, has put processes in place to allow it to complete more distribution main remediation per year than in the initial years of the MRP. By the 2019 construction season, DTE Gas is confident that more renewals can be completed

through a mix of additional Company resources and increased contractor assistance.

2) Leak elimination: The Company's existing MRP has been effective in eliminating leaks in the target areas, but more can be accomplished. Supported by Company Witness Ms. Tomina, DTE Gas continues to see a sizeable number of distribution main and service line leaks across the balance of system. For 2016, benchmarking data showed that the Company ranked 10th (third quartile) for incoming leaks per mile of main and service line when compared to 15 similar natural gas utility companies.

3) Risk reduction: Every increase in the number of miles renewed and the speed of renewal reduces the risk of a major leak situation.

4) Customer affordability: The MRP effort is paramount in maintaining a safe and reliable natural gas system. Still, whenever rate increases are contemplated, it is imperative to consider the impact on customer's bills. Current natural gas costs, at historic and continuing lows, reduce the impact of MRP costs on customer bills.

Q. Does accelerating the removal of unprotected mains fit the objectives of the MPSC?

A. Yes. The Commission has found repeatedly that the safety benefits, cost savings and environmental benefits from replacing poor performing main are in the public interest. In its April 16, 2013, order in Case No. U-16999, the Commission noted that the MRP program was critical to the Commission's mission to ensure safe and reliable utility service. In its November 23, 2015 order in Case No. U-17701, the Commission reiterated its commitment to DTE Gas's main replacement program.

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MPSC Chairman John Quackenbush stated in the Associated Press release[1], "Replacing higher risk and poorer performing gas mains will continue the MPSC's focus on enhancing safety and reliability for customers and reduce the risk of failures or leaks." As recently as July 2017, the Commission approved Consumers Energy's Enhanced Infrastructure Replacement Program. DTE Gas believes that expansion of its MRP supports the Commission's mission to ensure safe and reliable utility service in Michigan.

Q. Has the MRP been effective in preventing leaks?

A. Yes. DTE Gas has evaluated areas that have been subject to main replacement under the MRP to determine their leak levels. A 2017 review of 359 cast iron and unprotected steel main segments that were replaced in 2016 showed no leaks during the Company's 2017 leak survey. Prior to their replacement in 2016, there were 131 leaks identified during the prior survey on these same gas main segments.

Q. Why hasn't the number of incoming leaks moderated since the MRP was implemented?

A. The remaining cast iron and unprotected steel distribution main is deteriorating at a pace greater than originally forecasted. For this reason, the Company is seeking to increase the level of capital expenditures to eliminate the poor performing main from its distribution system over the next 15-20 years. When corrosion leaks per one-hundred miles of metallic main are trended as shown in Exhibit A-12, Schedule B6.9 Historic Corrosion Leak Rates, the Company continues to experience an increasing amount of leaks on metallic main due to corrosion and exceeds the statewide rate. In 2016, DTE

[1] November 23, 2015 press release: http://www.michigan.gov/som/0,4669,7-192-47796-369861--,00.html

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Gas's system experience corrosion leaks at a rate of 33.8 leaks per 100 miles of metallic main compared to all distribution systems statewide at a rate of 12.8 leaks per 100 miles. Excluding DTE Gas, the statewide average is 2.1 leaks per 100 miles. See Exhibit A-12, Schedule B6.5. This reflects a compound annual growth rate of 11.9% for DTE Gas since 2010, and -4.2% for the statewide average excluding DTE Gas. Historically, Staff has supported the expansion of the MRP due to these factors as shown in U-16999 where Staff Witness Chislea states, "Given the amount of higher risk metallic material in MichCon's system and MichCon's corrosion leak rate, this increase in the size of the program is justified. MichCon's commitment to a program of this size will help to improve the safety and reliability of the distribution system."

Q. Has DTE Gas demonstrated the ability to ramp up the spending levels for the MRP over the last several years?

A. Yes. Exhibit A-12, Schedule B6.7 Actual Capital Cost of IRM compared to targeted levels, summarizes the significant ramp-up of spending from 2014 ($47.0 million), to 2015 ($53.1 million), to 2016 ($86.3 million). This continual increase in MRP spending demonstrates DTE Gas's commitment to its MRP proposal in this proceeding and ability to deliver on that commitment.

Q. Has DTE Gas experienced any safety incidents related to the Main Renewal Program since expanding in 2016?

A. Yes. During 2017 there were 19 damages by contractors performing MRP work on behalf of DTE Gas (second party) or the general public (third party). Twelve (12) of these were in Grosse Pointe and the remaining were scattered across DTE's territory. The root causes were documented and countermeasures implemented for all

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damages.

Q. What countermeasures were implemented in response to these incidents?

A. In response to the incidents, which garnered significant attention from the community and the media, the Company halted all work in the target area for one week and conducted a safety stand down. During the stand down, the Company reviewed safe digging practices, provided contract personnel with tools to document leading indicators and findings in the field, and assigned dedicated safety and quality assurance personnel for all work. Leading indicator scorecards are reviewed weekly to mitigate safety precursors. Additionally, the Company's primary construction contractors have adopted industry best practices in excavation safety with an emphasis on continual training, root cause analysis and metric reporting.

Q. Has the Company's response been effective in reducing the number of incidents?

A. Yes. Since June 16, 2017, four damages have occurred in Grosse Pointe; all of which were quickly remediated by DTE Gas personnel. Contractors have identified and mitigated 18 safety precursors using the leading indicator scorecards. Year-to-date, the Company has experienced a 15% reduction in damages compared to 2016's performance statewide.

Q. Will the incremental $316.5 million MRP investment in years 2019-21 create full time employee (FTEs) requirements?

A. Yes. The Company will require additional resources (FTEs) to complete the additional work. These resources will be comprised of both Company and outside contractors.

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Exhibit A-12, Schedule B6.2, Incremental Resource Requirements, summarizes by resource type the work force needed to complete an additional $271 million of MRP work for years 2019-21.

Q. How many additional miles of main does DTE Gas expect to renew or retire with the incremental $316.5 million of MRP investment for years 2019-21?

A. The miles of main addressed in any given year are expected to be a function of many factors including the specific construction conditions on the streets being renewed. Based on approximate units, unit costs and the lack of new retirement candidates, DTE Gas estimates that it will renew an average of 44 additional miles in 2019, 2020, and 2021; bringing its total target level of main renewal and retirement to about 254 miles per year. This estimate is calculated in Exhibit A-12, Schedule B6.3, Capital Expenditures – Main Renewal Program. The units and cost per unit data have been revised to reflect updated cost assumptions based on DTE Gas's experience in recent years.

Q. Does the Company intend to allow for flexibility in the capital expenditure of the IRM based on economic conditions and customer rate affordability?

A. Yes. The Company intends to maintain the IRM capital expenditure as ordered in Case No. U-17999 as the minimum spend for the program and the proposed additional $271 million for years 2019-21 as the maximum spend. The Company will meet with the Commission Staff annually to review the plan for the following year.

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Q. Does the Company propose to follow the same capital expenditure variability approved by the Commission in its last rate case related to the IRM?

A. Yes. From a capital expenditure standpoint, the Company's goal is to manage each of the individual components of the IRM to the levels put forth in this proceeding. DTE Gas recognizes that some project variability and uncertainty exists. Including all three projects (MRP, MMO, and PI) under one larger funding mechanism helps reduce the risk and provides DTE Gas the opportunity to address the most pressing issues within the three project groups. As approved by the Commission in the Company's last rate case, DTE Gas proposes that each year it has the flexibility to increase or decrease the expenditures for each of the programs by up to 3.2% of the total IRM capital expenditures. In 2019, total spend will be $220.5 million resulting in a flexibility among the programs of $7.1 million per year.

Q. Is the Company proposing any changes to the MRP aside from the level of expenditures and the related surcharge amount?

A. Yes. There are modest changes to the retirement candidate selection criteria. Each calendar year, DTE Gas uses the outputs of a main replacement prioritization model and a meter move out prioritization model to rank leak survey areas and develop a prioritized three-year plan to replace mains and services and move inside meters outside based on risk. The main replacement prioritization model has five major factors including: risk scores, main and service pipe material, pending and repaired leaks per mile, service density, and other consequence factors. The meter move out prioritization model has six major factors including: overdue meter assembly checks, meter set abnormal operating conditions, location of meters, service operating pressure, inside meter density, and other consequence factors. The output of these

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prioritization models is combined with equal weighting to create a combined prioritization score that identifies the leak survey areas with the highest risk pipe and percentage of inside meters. In general, the order of replacement is dictated by the combined prioritization score. However, other factors including gas flow analysis, coordination with municipalities, other infrastructure projects, and constructability considerations may impact the order in which areas are scheduled for replacement.

Q. Has the Modified Grid Approach (MGA) provided cost synergies for the MRP?

A. Yes, while executing the 2016 and 2017 work, the Company realized the expected savings through the deployment of the Modified Grid Approach. Based on a conservative estimate, the unit cost of replacing one mile of main in Southeast Michigan decreased by 5-7% by utilizing the MGA allowing DTE Gas to add five (5) more miles to the annual replacement mileage for the same level of investment. An analysis of two comparable projects, one utilizing the MGA approach and the other a grid developed around a Risk Rank project, showed a 6.75% reduction ($76.73 versus $71.88) in the overall cost per mile for the project. Consistent with the approach outlined in U-17701, the MGA will allow the Company to utilize smaller diameter plastic main saving both installation and material costs as compared to the previous MRP methods that were employed. This savings and incremental mileage is included in Exhibit A-12, Schedule B6.3, Capital Expenditures – Main Renewal Program.

Q. Has the Company experienced significant new cost drivers while executing the Meter Move Out and Main Renewal Programs using the Modified Grid Approach?

A. Yes. While executing the Modified Grid Approach in 2016 and 2017, the Company faced increasing cost pressures from a variety of sources.

Permit Requirements: Throughout its service territory, DTE Gas is experiencing increased permit requirements. These requirements necessitate costlier restoration and material handling.

Lack of Retirement Candidates: The Company has successfully retired the majority of the segments no longer needed to supply existing customers; which significantly reduced the overall program unit cost in prior years.

Cross- Bore Inspections: The use of cross-bore inspections to identify safety risks resulting from pipeline and sewer lateral conflicts created during the use of directional boring equipment is increasing the expected costs of the program.

Q. How has the Company maintained its planned level of renewal in the face of these cost pressures?

A. DTE Gas has maintained its performance by offsetting the increased costs using continuous improvement methodologies and other cost-saving techniques. Specifically, the Company has been successful in mitigating a portion of these increased costs by:

1) Coordinating MRP and MMO work into 'merge' areas to receive mobilization efficiencies;
2) Developing larger MRP grids requiring fewer tie-ins and providing opportunities for volume pricing with construction contractors;
3) Lowering material costs due to smaller diameter pipe from the MGA; and
4) Renegotiating unit-based contracts to receive more favorable pricing.

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Q. Can you highlight the customer benefits of accelerating the level of main renewal proposed in this proceeding?

A. Yes. The benefits remain the same as put forth in Case Nos. U-16407, which approved the original MRP, U-16999, U-17701, and U-17999. Specifically, the proposed MRP provides:

1) A systematic, accelerated replacement and retirement of the poor performing, unprotected mains within DTE Gas's distribution system will more quickly stabilize distribution system deterioration, thus reducing the threat of a major failure;
2) An improvement in the overall safety and reliability of DTE Gas's distribution system at a level that is affordable to our customer base and the Company;
3) A stabilization of DTE Gas's leak rate allowing existing resources to better manage the leak inventory, minimizing the number of leaks that remain unrepaired in the distribution system; and
4) A reduction in the number of customer reported leaks which should increase customer satisfaction with DTE Gas's natural gas service.

<u>Meter Move-Out (MMO) Program</u>

Q. What is the MMO Program?

A. DTE Gas's MMO Program is a focused effort to relocate existing residential natural gas meters from their inside locations to outside locations. The program also addresses any associated infrastructure needs that arise in the meter relocation area. The long-term meter move-out program filed by DTE Gas in Case No. U-16451 and adopted by the MPSC on September 13, 2011, undertakes a plan to systematically relocate residential inside meters on a block-by-block basis in a cost-efficient manner. The program was developed to improve our infrastructure and system safety and reliability while enhancing customer service.

Q. What level of MMO capital expenditures does the Company support in this proceeding for 2019 through 2021?

A. DTE Gas plans capital expenditures of $22.7 million to impact 12,790 residential gas inside meters annually. In addition, DTE Gas expects to spend an additional $20.0 million annually for an overdue Meter Assembly Check (MAC) MMO program to impact 8,000 inside meters annually. The total expected annual capital expenditures for the expanded Meter Move Out program will be $42.7 million. These expenditures are shown on Exhibit A-12, Schedule B6.

Table 4

	U-16451	**U-18999**
Inside Meters Annually	12,790 MMO	12,790 MMO 8,000 MAC MMO
Dollars	$22.7MM	$22.7MM (MMO) $20.0MM (MAC MMO)

Q. Are inside meters that are moved outside the only meters impacted by the MMO program?

A. No. In addition to relocating meters to the outside building wall, the MMO Program impacts inside meters by cutting and capping of gas services at, theft, demolition, and vacant sites within DTE's block-by-block MMO target areas. While such meters are not relocated, cutting services does "impact" and reduces the number of inside meters that are in-service. Also, a meter located on the outside of the residence in the block-by-block MMO target areas is considered an "impacted" residential meter if the service line is cut for idle, vacant or theft reasons; or the service line is repaired due

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to an identified leak or there is a meter malfunction. The term "impacted meters" is used to describe meters affected by this work. Historically, Staff has supported the Company in this as shown in U-16999 where Witness Chislea states, "Completing cut and caps, service line renewals, and service or main repairs at the same time as the MMO work increases the productivity of the work force. This additional work is necessary to meet the requirements of the MGSS and for the Company to maintain the safety and reliability of the system."

Q. What is DTE Gas's target for annual MMO activity?

A. Prior to the Commission's December 9, 2016 order in Case No. U-17999, DTE Gas's target was to impact 12,790 meters, regardless of location inside or outside of a residence. In U-16999, Company Witness Mr. Persells testified, "The MMO Program was designed to address not only meter relocations, but to also efficiently address any other code or safety issues that are identified while the meter relocation crews are in the field. Rather than call out separate field crews for work other than meter relocations, it is both cost effective and more efficient to have the meter relocation crew complete the cuts and caps for theft, demolition and vacant services, and to complete the main and service line repairs within the MMO area." In its U-17999 order, the Commission clarified that it approved a target of the relocation or removal of inside meters at the rate of approximately 12,790 per year. Until the Commission's clarification, DTE Gas used targets based on its definition in U-16999.

Line No.

Table 5

	2012	2013	2014	2015	2016	Total
MMO						
Inside Meters	10,279	10,940	10,170	9,013	6,699	47,102
Impacted Meters	2,568	2,267	4,408	3,888	7,702	20,832
Total	**12,847**	**13,207**	**14,578**	**12,901**	**14,401**	**67,934**
Target (All meters)	12,790	12,790	12,790	12,790	12,790	63,950
MRP Inside Meters	1,516	3,909	4,185	2,997	2,436	15,043

Q. What were DTE Gas's 2012-2016 results for inside meter move-out work, and did it meet the Company's targets?

A. The DTE's MMO plan for impacted inside meters moved out in 2012-2016 totaled 63,950. The actual results achieved by the MMO program for 2012-2016 were 67,934 impacted meters with 47,102 inside meters moved out, above the target laid out in U-16999 by 3,984 but below the target adopted in U-17999 by a total of 16,848 meters.

Q. Will MMO program costs vary from year to year?

A. No. Unlike the MRP expansion, which may be changed due to customer affordability issues, the MMO capital dollars are subject to little variability. However, MMO units may vary based on several factors. DTE Gas's goal is to perform as much work as needed to achieve full spending of the capital costs allocated to the MMO Program. The program is concentrated in southeast Michigan where most our inside meters are located. The quantity of meters impacted in any given year is a function of the variability in the work mix between moving meters outside to moving the meters and replacing the service lines to cutting the service line and rendering the inside meter obsolete. To meet current safety standards, DTE Gas renews service lines when meters are placed on the outside of customers' buildings. In addition, property restoration related costs may vary depending on municipality permitting requirements.

Q. Why is DTE Gas proposing to expand the MMO program?

A. The Company is proposing to expand the MMO program to address two issues; the Company's inability to access inside meters for purposes of performing meter assembly checks and the declining number of meter relocations resulting from customer-initiated construction activities. In Case No. U-17999 Witness Creisher explained Staff's concerns that inside number of meters impacted each year was declining. The Commission further emphasized the importance of moving a specific number of inside meters outside when it clarified how it interpreted the MMO target. Ultimately, expanding the MMO program to target additional inside meter reduces public safety risk.

Q. What is a Meter Assembly Check inspection?

A. During a MAC inspection, inside natural gas meters are checked for surface corrosion, leaks and other conditions that might require attention or repair. MAC inspections are an important component of DTE's efforts to ensure the continued safety and reliability of gas services to our customers. A MAC inspection is completed to prevent future gas leaks and ensure the safety for customers. To comply with 49 CFR Part 192, DTE Gas is required to inspect a pipeline that is exposed to the atmosphere for corrosion "at least once every three calendar years, but with intervals not exceed 39 months."

Line No.

Q. Is DTE Gas currently able to meet the requirements of 49 CFR Part 192?

A. No. As stated in Witness Creisher's U-17999 testimony, "DTE Gas has experienced issues with gaining access to inside meters to allow for Meter Assembly Check inspections completed to meet the requirements of 49 CFR Part 192." As of September 30, 2017, over 136,817 meters of approximately 277,000 total inside meters do not have a MAC inspection documented in the previous 39 months.

Q. How important is it to Staff and the Commission that the Company completes Meter Assembly Check inspections as required by 49 CFR Part 192?

A. The Staff and Commission find MACs extremely important. In fact, Staff issued a non-compliance to DTE Gas and assessed civil penalties in the amount of $108,000 for failure to perform Meter Assembly Checks at two locations in the Grand Rapids area on May 30, 2017. This action illustrates how critical Staff finds MAC inspections.

Q. Why is it difficult for DTE Gas to complete MACs?

A. Witness Creisher identified the main reason DTE Gas has difficulty in completing MACs in her U-17999 testimony, saying "DTE Gas has experienced issues with gaining access to inside meters to allow for Meter Assembly Check inspections." The issues Witness Creisher references include, among other things, 1) inability to schedule appointments, 2) customers failing to meet appointments, 3) transient and/or customers who are renting vs owning the property, and 4) customers believing that the Company is working with ICE/immigration.

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Q. What is DTE Gas currently doing to address these issues and complete MAC inspections?

A. DTE Gas leverages its routine field service and leak survey activities to perform inspections. The Company has also expanded its current agreements with contractors to focus their efforts solely on completing outstanding MAC inspections outside of the normal leak survey cycle. In addition to field service employees, DTE Gas has established a dedicated team of distribution employees equipped for construction activities to perform MAC inspections at addresses where multiple attempts have failed. In communities where fear or lack of trust may be limiting access, the Company is partnering with community leaders to educate customers on the inspection process and safety importance. The Company has also leveraged requests for turn-ons and offs to gain access for purposes of completing MAC inspections.

Q. Have DTE Gas's efforts in gaining access and preforming MAC inspections been effective?

A. Not always. Through September 2017, DTE Gas completed 49,035 MAC inspections during its routine field service activities and 12,016 during leak survey. Together with the contractors, DTE Gas projects to complete 8,000 MAC inspections from October through December of 2017. However, the Company's efforts to gain access during new customer turns-ons had a success rate of only 18%. These results, while helpful, do not result in the volume of MAC inspections required to eliminate the backlog in a timely fashion. Moreover, DTE Gas will likely face the same issues in accessing these meters in three years when the next cycle of MAC inspections is required.

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Q. Why does DTE Gas turn-on a new customer if a pending overdue MAC inspection exists on a meter without performing the inspection?

A. When an existing Gas customer turns service off it is less costly and intrusive to perform a 'soft-off' rather than physically cutting and capping or locking the service to a residence. When a new Gas customer contacts DTE Gas to establish service, an estimated read is performed at that time. In addition to the cost and intrusiveness of the cutting and reconnecting procedure, the Company has found that by the time a customer contacts DTE Gas to terminate service, they no longer have access to the residence.

Q. What is DTE Gas's plan to reduce the number of overdue MAC inspections and eliminate it in the future?

A. In addition to the routine activities previously stated, DTE Gas proposes to move out 8000 inside meters annually beginning in 2019 based on the age of the last inspection to reduce the backlog as a part MMO program. This expansion of the Company's MMO initiative not only addresses overdue MAC inspections, but also eliminates the need for access to perform any future meter related work; increasing efficiency and reducing safety risk.

DTE Gas will contact customers through a three-lettering process, starting with those with the oldest MACs, to schedule an appointment for a Meter Move Out. DTE Gas will attempt to group the oldest MACs by geography to efficiently impact as many meters as possible (please see exhibit A-12, Schedule B6.8 of the 3,000 inside meters in Dearborn Heights and Redford). During the process of moving the inside meters outside, DTE Gas will also renew the service lines. This effort will be coordinated with the traditional (or block-by-block) MMO activities so that the programs do not duplicate efforts. Customers who fail to respond to the Company's scheduling attempts will be subject to service interruption and customary reconnect fees as prescribed in the tariff. This approach is consistent with the process used in both the MRP and MMO programs.

Q. How many customers is DTE Gas expecting to cut and reconnect on an annual basis?

A. Based on the current Can't Get In (CGI) rates of 13%, DTE Gas expects to disconnect approximately 1,000 customers while attempting to move the first 8,000 MAC inside meters outside. DTE Gas also expects to reconnect nearly 100% of these customers, and appropriately charge the $300 reconnection fee. This fee will help offset some of the cost of disconnecting a customer.

Q. Does DTE Gas expect the CGI rate to stay at 13% during the entire life of the MAC MMO program?

A. No. The Company is confident the CGI rate will decrease to approximately 1% through intensified customer communications and process improvements. The 1% CGI rate is similar that experienced in the traditional MMO program. For traditional MMO, there were 317 cuts due to CGI out of 67,934 impacted meters from 2012 through 2016.

Q. Will DTE Gas hire additional employees due to the expansion of the MMO?

A. Yes. DTE Gas projects it will hire 66 new distribution field employees to expand the MMO program.

Line No.

<u>Pipeline Integrity</u>

Q. What is the Pipeline Integrity Program?

A. Pipeline integrity is the program used by DTE Gas to manage and ensure the integrity of the gas transmission system as prescribed in Subpart O of the MGSS, Pipeline Integrity Management. The regulatory requirements contained in Subpart O of MGSS prescribe minimum requirements for a transmission pipeline integrity management program. The sub-programs of DTE Gas's Pipeline Integrity Management Program are:

(i) Pipeline Integrity Assessments
(ii) In-Line-Inspection (ILI) Expansion
(iii) Remote Control Valves (RCV)
(iv) Maximum Allowable Operating Pressure (MAOP) Record Review
(v) Records Management System Development.

Company Witness Ms. Sandberg discusses the importance, and details, of the PI program in her testimony.

Q. Is DTE proposing changes to the PI program included in the IRM?

A. No. The Company has included all PI IRM capital invested through December 31, 2018 plus an additional non-IRM $3.0 million of Pipeline Integrity expenditures through September 30, 2019 in base rates, as supported by Witness Sandberg. The PI capital expenditures included in the new five year IRM surcharge beginning January 1, 2019 are $11.1 million, consistent with the amount approved in the final order of general rate case, Case U-17999. There is no incremental request for recovery related to PI expenditures in the proposed new five year IRM surcharge.

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IRM Review

Q. How will the MPSC monitor DTE Gas's performance to ensure that the capital expenditures related to the IRM are incurred prudently?

A. Consistent with the order in DTE Gas's last general rate case, the Company will continue to file by March 31st of each year the results of the previous year's activity including footage, units and cost information on a variety of task components. The Company will continue to provide the MPSC a summary report of the total dollars spent during the previous year compared to the target levels for each of the three IRM programs. The report will continue to identify the variations in the IRM capital spending level for the year by each program and the amount of reduced surcharge by customer class, if needed, to properly adjust the increase in the July IRM recovery charge should the Company under-spend its targeted IRM level. As is true under the current approved IRM, the surcharges that will be established in this proceeding cannot increase, but will be reduced if the combined spending level of the three infrastructure programs is less than the annual amount approved.

Q. What is the expected IRM surcharge for residential customers?

A. In Exhibit A-18, Schedule H3, Witness Slater calculates the actual IRM surcharge for residential customers to be $0.59 per month in the first 12 months (January through December 2019) and $2.11 per month in the second 12-month period (January through December 2020). DTE Gas's gas supply cost, which is the more significant part of the customer's bill, is expected to remain at relatively low levels for DTE Gas's GCR customers. Thus, the proposed expansion of the MRP program should have a very small effect on the customers' total energy bill.

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Q. Does DTE Gas expected a sudden increase in customer bills due to the change in the IRM surcharge?

A. No. Customer bills are expected to remain flat into 2019 from our last rate increase approved in MPSC Case No. U-17999 approved in December 2016. This is due to the lower forecasted gas costs offsetting the higher IRM surcharge. As stated by Company Witness Mr. Chapel in his direct testimony the cost of gas for the projected test period is $3.22 per Mcf. The cost of gas has primarily declined for nearly a decade, and is 72% lower than the 2008-09 GCR period reflected in MPSC Case No. U-15451. The cost of gas for the projected test period is the second lowest since the 2003 GCR plan in Case No. U-13549, and only a nominal $0.06 per Mcf higher than the lowest in the time frame. As previously stated, DTE Gas's gas supply costs are the more significant part of the customer's bill. Due to the historically low gas prices, even when coupled with an IRM surcharge the average residential customer bill will still be approximately 26% lower than it was in 2010, with no notable change from the last approved rate increase.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARK C. JOHNSON

DTE GAS COMPANY
QUALIFICATIONS OF MARK C. JOHNSON

Line No.

Q. Please state your name and business address.

A. My name is Mark C. Johnson. My business address is 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 Gas Company (Company or DTE Gas).

Q. What is your educational background?

A. I earned a Bachelor's degree in Business Administration with a concentration in Operations Management from Michigan State University in 1989 and a Master of Business Administration from the University of Michigan in 1997.

Q. What is your previous work experience?

A. I began my career at Ford Motor Company where I spent 18 years working in positions of escalating management responsibility, including six years of experience implementing continuous improvement projects. In March 2007, I joined DTE Gas as a continuous improvement expert dedicated to identifying causes of Lost and Unaccounted for (LAUF) gas. In January 2008, I was promoted to General Manager leading continuous improvement experts and that role was expanded to include direct responsibility for theft operations. I moved to Corporate Services at DTE Energy LLC in 2011 and managed the vehicle fleet and facility operations for DTE Energy. In 2012, I was promoted to Director of Fleet Operations. In December 2015, I transitioned to Director of Revenue Management and Protection.

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Q. What are the responsibilities of the Director of Revenue Management and Protection?

A. The Director is responsible for the overall direction, strategy, leadership and management of collections, theft mitigation and low-income programs for DTE Energy. The Revenue Management and Protection group is responsible for driving reduced uncollectible expense for DTE Electric Company (DTE Electric) and DTE Gas as well as optimizing the Energy Assistance funding for the low-income customers. The Director of Revenue Management and Protection is a member of the Customer Service senior leadership team 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.

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

A. Yes. I sponsored testimony in Case No. U-15985 Michigan Consolidated Gas Company General rate case and Case No. U-18255 DTE Electric rate case.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the details of the Company's historical and actual Customer Accounts, Customer Service and Informational Operating and Maintenance (O&M) expenses. I will support:

1) Historical test year expenses of $48.7 million through December 31, 2016;
2) Projected test year expenses of $58.2 million for the 12-month projected test period ending September 30, 2019;
3) The inflationary impact on forecasted costs;
4) The level of uncollectible expense;
5) Customer Service's performance and areas of improvement; and
6) The Company's Low Income initiative.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-13	C5.4	Projected Operation and Maintenance Expenses – Customer Service
A-13	C5.7	Projected Operation and Maintenance Expenses – Uncollectibles

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

A. Yes, they were.

Q. What work does Customer Service perform for DTE Gas?

A. Customer Service is responsible for managing all DTE Energy's 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. What organizations comprise Customer Service?

A. The organizations comprising Customer Service are Customer Care, Customer Billing, Business Process Optimization and Data Quality (formerly Customer Service Insights), Revenue Management and Protection (RM&P), and Customer Experience. The Customer Service organization supports both DTE Gas Full Service and Gas 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.

Data Quality is responsible for identifying, initiating, planning and implementing continuous improvement initiatives within Customer Service.

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 2016, 33.48% (916,039 customers) of LLC's Customer Care expense was allocated to DTE Gas. Each overlap customer is counted as a one-half electric and one-half gas.

Customer Billing has two cost allocation drivers. The number of non-AMR Gas meters is used to allocate meter reading costs, and the number of customers determines the allocation of costs for billing. For 2016, 45.40% (516,294 meters) of LLC's Customer Meter Reading expense was allocated to DTE Gas. In addition, for 2016, 33.48% (916,039 customers) of Customer Billing expense was allocated to DTE Gas.

Expenses for the LLC's Customer Service, Customer Experience and Data Quality are allocated based on the number of customers. For 2016, 33.48% (916,039 customers) of expenses related to Customer Service, Customer Experience and Data

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Quality was allocated to DTE Gas.

RM&P allocates costs based on the number of accounts in arrears for the previous four quarters. For 2016, 36.39% of RM&P expense was allocated to DTE Gas.

O&M EXPENSES

Q. What was the total Customer Accounts, Customer Service and Informational O&M expenses related to Customer Service for the 2016 historical test year?

A. The total Customer Accounts, Customer Service and Informational O&M costs related to Customer Service for the 2016 historical test year was $48.7 million. See Exhibit A-13, Schedule C5.4, line 14, column (f).

Q. What work activities are included in the $48.7 million 2016 total Customer Accounts, Customer Service and Informational O&M costs?

A. There are two expense components that make up the $48.7 million:

- Customer Accounts Expenses ($42.7 million)
- Customer Service and Informational Expenses ($6.0 million)

Customer Accounts Expenses

Q. In 2016, what type of work activities are the primary drivers in the Customer Accounts Expenses category totaling $42.7 million?

A. The Customer Accounts Expenses category is primarily for work activities related to Meter Reading ($6.5 million) and Customer Records and Collection ($35.1 million). Customer Records and Collection includes:

- Customer Care ($12.1 million)

Line No.

- Revenue Management & Protection (RM&P) ($10.9 million)
- Bill Printing, Mailing & Creation ($5.9 million)
- Merchant Fees ($3.1 million)
- Quality Assurance & Training ($1.9 million)
- Meter Order- Restores ($1.2 million)

Q. In 2016, which work activities comprise the $12.1 million in the Customer Care organization?

A. 87% of the costs within the Customer Care organization are related to handling phone calls with internal call representatives and their direct floor support and the Company's external vendor. In 2016, 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 2.6 million calls internally, costing the Company $7.0 million. The post call survey customer satisfaction for these calls was 92%. The external vendor handled 3.3 million calls, costing the Company $3.7 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. In 2016, the average speed of answer for residential customers was only 57 seconds, 45% better than the 104 seconds average speed of answer in 2015.

Q. In 2016, which work activities comprise the $10.9 million of costs within the RM&P organization?

A. There are five major components that make up the $10.9 million.

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1) Internal and External Collections: $2.6 million. External collection agencies perform collection on outstanding arrears to reduce uncollectible expense. Effective use of this partnership has mitigated the impact of uncollectible expense related to customers who have been disconnected.
2) Field Operations: $2.5 million. Performs theft investigations and non-pay manual disconnects. Outside services expenses of $0.8 million are primarily for theft detection analytics completed by external vendors. Effective management of energy theft improves community safety and minimizes revenue loss.
3) Exceptions: $2.2 million. Exceptions identifies and resolves over 9,000 identify fraud cases, resolves over 500 bankruptcy cases and bills over $2.7 million to parties responsible for energy theft for DTE Electric and DTE Gas combined. Fraud Prevention services are used to verify customer identity information and researching perpetrators of fraud. Preventing and resolving theft and identity fraud helps minimize uncollectible expense and protects the integrity of our customer's data.
4) Advocacy & Customer Offices $2.1 million. The Advocacy team focuses on our most vulnerable customers, including supporting Low-Income Self-Sufficiency Plan (LSP) customers and working with partner agencies. Of the total, $1.3 million, was for labor. In 2016, the team handled approximately 133,000 calls, completed just under 88,000 low income validations and approximately 19,000 medical cases. The Advocacy team provides assistance with LSP customer inquiries and increasing LSP enrollments. The Customer Offices costs of $0.8 million are primarily labor costs of $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. The office

locations help customers understand their bills, resolve customer concerns, direct low income customers to energy assistance resources, and house payment kiosks to allow customers to pay their bills.

5) Strategy & Reporting and RM&P Staff $0.7 million. The Strategy team creates initiatives to reduce uncollectible expense year over year. The Reporting team provides the metrics used to track financial and operational trends. The RM&P Staff supports the Strategy and Reporting teams.

Q. In 2016, which work activities comprise the $5.9 million for bill printing, billing creation and bill mailing?

A. In 2016, the Company paid $3.1 million for postage costs related to invoices and other customer communications and generated 25 million customer statements. The Company spent $2.1 million on internal and contractor labor costs associated with bill printing, accurately billing major accounts, resolving billing concerns for residential and commercial customers, and resolving meter discrepancies. The remaining $0.7 million is primarily vendor related costs for printer maintenance, paper, envelopes and toner used in bill printing.

Q. What is comprised in the $3.1 million in merchant fee costs?

A. DTE Energy offers customers options to pay their bill with a credit or debit card or via a bank account transfer among other methods. Credit card companies and banks charge the Company fees for the processing these transactions. In 2016, DTE Energy received over 7 million customer card payments.

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Q. In 2016, which work activities comprise the $1.9 million for Quality Assurance and Training?

A. The Quality Assurance and Training costs are labor costs associated with a full-time staff that trains new Customer Service employees, provides ongoing training to existing employees, and provides quality assurance of customer calls, using advanced call monitoring and recording technology.

<u>Customer Service and Informational Expenses</u>

Q. In 2016, what are the work activities included in the Customer Service and Informational Expenses category totaling $6.0 million?

A. The Customer Service and Informational Expenses category is primarily Customer Assistance work of $2.7 million, and Miscellaneous Customer Service and Informational Expenses of $3.2 million.

Q. In 2016, what work activities comprise the $2.7 million Customer Assistance Expenses?

A. This group provides innovative and sustainable programs that provide a holistic approach for vulnerable customers through education, financial resources and community involvement.

Q. In 2016, what work activities comprise the $3.2 million "Miscellaneous Customer Service and Informational Expenses?

A. There are 2 major components that make up the $3.2 million:

1) Customer Experience: $2.3 million The Customer Experience group is comprised of individuals responsible for designing DTE's processes for

handling customers' inquiries and transactions in both served and self-service channels. The team is also responsible for providing high customer satisfaction with DTE's mobile application, website, automated phone system and payment kiosks.

2) Business Process Optimization: $0.9 million. Business Process Optimization (BPO) is primarily responsible for customer analytics and reporting. They create customer performance metrics, perform benchmarking studies, and customer survey files for the entire Customer Service organization. They also provide in-depth customer insights that drive technology, resourcing and process changes. BPO manages several technology tools that measure contact center performance and customer feedback results, including post call survey and speech analytics. Other daily operational tasks include the creation of data files used in the customer messaging process.

Q. Why is Energy Waste Reduction adjusted out of 2016 historical test year costs?

A. O&M expenses for the Company's Energy Waste Reduction program were recorded in FERC accounts 905, 907, 908, and 909. Since these costs have their own distinct recovery surcharges and are reconciled in separate MPSC proceedings, I have eliminated them from O&M. These eliminations are shown in columns (d) of Exhibit A-13, Schedule C5.4.

Projected Test Period

Q. What is the total amount of Customer Accounts, Customer Service and Informational Operating O&M expense that DTE Gas forecasts rates for the projected test period?

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A. DTE Gas forecasts $58.2 million in Customer Service O&M in the projected test year.

Q. Which type of work activities comprise the $58.2 million?

A. In addition to continuing with all the 2016 work activities described above, the Company has included the following changes: inflation for 2017, 2018, and 2019 of $5.6 million, Customer 360 amortization of $1.5 million, $1.9 million for the Customer 360 Software Maintenance Fee, and $2.2 million for Customer Service employees returning from Customer 360 project. The inflation factors are supported by Company Witness Ms. Uzenski.

Q. Have you provided any additional detail explaining the Customer Accounts, Customer Service and Informational Operating O&M expense for the historical period of 2016 and projected future test year? Would you please describe?

A. Yes. Exhibit A-13, Schedule C5.4 contains the "Projected Operation and Maintenance Expenses- Customer Service" on page 1, lines 7 and 14. These lines on Exhibit A-13, Schedule C5.4 reflect the O&M costs related to Customer Accounts, Customer Service and Informational Operating Expense for the 2016 historical test year in column (c) and for the projected test period in this case in column (l) for the activities as described above.

Q. Does Exhibit A-13, Schedule C5.4 provide the detailed support for costs you are asking for Commission approval to recover in rates in the future test period?

Line No.

A. Yes. Exhibit A-13, Schedule C5.4 shows total test period O&M for Customer Accounts, Customer Service and Informational Operating Expense using 2016 actual O&M adjusted by rate case eliminations, normalization adjustments, inflation and other known and measurable adjustments. Exhibit A-13, Schedule C5.7 provides the derivation of uncollectible expenses as discussed on the testimony that follows.

<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 Gas determine the accounts receivable (AR) reserve for uncollectible accounts?

A. DTE Gas 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 expense 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 Gas 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 2014 through 2016 resulting in $41.2 million of uncollectible expense. See Exhibit A-13, Schedule C5.7.

Q. What factors have affected uncollectible expense for the historic three-year average period ended 2016?

A. DTE Gas uncollectible expenses are driven by the chronic unemployment in Michigan that leads to vulnerable customers with the inability to pay. In 2016, the number of people unemployed in Michigan averaged 238,433 (5% rate of unemployment).

Q. What has DTE Gas done to maintain control of its uncollectible expense?

A. The Company has taken several proactive steps to control the level of uncollectible expense. DTE Gas 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.

DTE Gas 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. 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. THAW, 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 our collection effectiveness. These efforts include:

- 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
- 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. What is the total projected adjustment for Uncollectibles Accounts Expense?

A. The total projected adjustment for Uncollectible Accounts Expense is $10.8 million. See Exhibit, Projected Uncollectible Accounts Expense A-13, Schedule C5.7, column (g), line 4.

Q. What is the total projected Uncollectibles Accounts expense that you are supporting in this case?

A. I support Customer Service Uncollectibles Accounts expense for the projected test year of $41.2 million.

<u>Low Income Programs</u>

Q. What is the goal of DTE Gas's energy assistance programs?

A. The goal of DTE Gas's energy assistance programs is to decrease disconnects for vulnerable customers, gradually bring down arrears owed, while encouraging and supporting good payment habits and reducing consumption. This program structure leads participants to reduce their arrears over time and adopt 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.

Q. What efforts has DTE Gas taken to help its most vulnerable low income customers?

A. DTE Gas 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. There were multiple pilot projects that evolved into the Low-Income Self-Sufficiency Program (LSP); which currently serves 40,000 customers. The LSP program began in 2012, and was funded during the first year, by the Michigan Department of Human Service (MDHS), and most recently by an MPSC grant of $17 million in 2015 and in 2016. Additional funding sources (Electric Residential Service Special Low Income Pilot tariff, D1.6 and grants from partner agencies) were used in 2015 and in 2016 which allowed the program to grow to 40,000 customers.

The LSP program has proven to be extremely successful. In 2016;

- Only 1% of LSP customers were disconnected for non-payment
- 84% 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 LSP program continued to be successful in 2017;

- Less than 1% of LSP customers were disconnected for non-payment
- 91% of enrollees successfully completed a full year of the program
- Customer satisfaction remains very high at 92%
- 97% of customers remain within the consumption limits of the program

Q. What are the key features of the Low-Income Assistance (LIA) Credit?

A. The Low-Income Assistance Credit offers qualifying Low Income gas customers a $30.00 per month credit on their bill. Gas customers who select this rate must qualify for the Residential Service Rate A. Currently, there is a total customer cap of 20,000. To qualify for this rate, a gas 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 gas 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 will remain a pilot. It has been active for less than a year.

Q. Why is the Pilot Low Income tariff important for DTE’s customers?

A. Many low-income gas customers within DTE Gas’s service territory still continue to struggle to pay their utility bill, despite the improvements in Michigan’s economy. The Residential Service Rate A, Income Assistance Service Provision-Low Income Assistance Credit Pilot tariff provides meaningful assistance to eligible low income customers that will make their utility bills more affordable. As experienced through past and current low income programs, proactive solutions provide vulnerable customers assistance that mitigates the occurrence of a crisis situation.

Q. What are the key features of the Residential Income Assistance (RIA) Credit?

A. The RIA Credit offers Low Income gas customers an $11.25 per month credit on their bill. The total household income cannot exceed 150% of the Federal poverty level, verified by confirmation of an authorized State or Federal agency.

Q. Is DTE Gas proposing to make any changes to the Residential Service Special Low Income Pilot tariff, Residential Service Rate A, Income Assistance Service Provision- Low Income Assistance Credit Pilot approved by the Commission on December 9, 2016 in its general rate case U-17999?

A. Yes. We are proposing to redistribute funds from the RIA to LIA. DTE Gas is proposing to increase the LIA total customer count from 20,000 to 33,000. This increase translates to an increase from **$7.2 million** (20,000 x $30 x 12 months = **$7.2 million**) to $**11.9 million** (33,000 x $30 x 12 months = **$11.9 million**). Additionally, DTE Gas is proposing to reduce the RIA total customer count from 80,000 to 55,000. This decrease translates to a decrease from **$10.8 million (**80,000 x $11.25 x 12 months**)** to $**7.4 million** (55,000 x $11.25 x 12 months). This proposed redistribution will provide more assistance to vulnerable customers.

Q. Why is DTE Gas increasing the LIA customer count while decreasing the RIA customer count?

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A. Data analysis is indicating a downward trend of customers eligible for and receiving the Gas RIA credit since 2014. In September 2014, there were 98,805 customers who received the Gas RIA credit and in September 2017, the number of customers who have received the Gas RIA credit decreased to 65,560. It is projected that the number of customers to receive the Gas RIA credit will decrease to 55,000. Therefore, DTE Gas proposes an RIA funding level at $**7.4 million** (55,000 x $11.25 x 12 months).

Q. Are there changes that DTE Gas would like to make regarding the LIA credit requirements?

A. Yes, instead of distributing the LIA credits randomly to RIA customers, DTE Gas proposes that the LIA credits be applied to all eligible LSP customers and graduates of crisis prevention programs. These customers would have an even greater chance of avoiding disconnection while maintaining an affordable payment plan.

Q. Have randomly enrolling RIA customers on LIA been effective?

A. No. LIA credits were randomly applied in 2017 to existing RIA customers not on LSP who were eligible (in arrears or receiving assistance) and 12.4% (1555 customers) were disconnected between April and August for non-payment. This percentage is directly comparable to those enrolled on LSP who were randomly selected to be on LIA as well, who had a disconnect rate during that same time of 2.8% (322 customers). Data shows that in full year 2016, there were approximately 12,000 RIA customers in crisis who were disconnected, or 33% of the 35,763 RIA customers in crisis. Low income credits alone cannot assist in keeping vulnerable customers out of disconnect. Vulnerable customers receiving low income credits and the benefits of the LSP program are less likely to be disconnected for nonpayment. In 2016, only 1% of LSP customers were disconnected for nonpayment.

Q. Why is DTE Gas proposing these changes?

A. DTE Gas would like to serve more customers who qualify for crisis prevention programs, as well as, target energy assistance to more vulnerable customers.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
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QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DIANE M. MARTINO

DTE GAS COMPANY
QUALIFICATIONS OF DIANE M. MARTINO

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

A. My name is Diane M. Martino and my business address is One Energy Plaza, Detroit, Michigan 48226-1279. I am employed by DTE Energy Corporate Services, LLC as a Principal Engineer of Environmental Management and Resources for DTE Gas Company (DTE Gas or Company).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Gas.

Q. What is your educational and work background?

A. I received a Bachelor of Science Degree in Environmental Science and Geology in 1992 from Lake Superior State University and a Master of Science Degree in Geology in 1995 from Michigan Technological University. Since completing my formal education, I have participated in ongoing professional development and training and worked in several industries in different capacities as an environmental professional, project manager and subject matter expert. My responsibilities included management of State and Federal reporting requirements, and remediation project management.

Q. What are your current job responsibilities?

A. I have worked for DTE Energy for over fifteen years. I am a principal engineer and manage several of the Company's remediation and due diligence projects. I develop long-term project strategy based on the condition of environmental regulation. In addition I comlete environmental liability and SEC financial reporting. As part of overseeing work on several of the Company's remediation projects, I track the environmental efforts for several of the former Manufactured Gas Plant (MGP) properties, including the expenses associated with the investigation and remediation of the MGPs.

Q. What was your professional experience prior to joining DTE Energy?

A. From 1994 to 2001, I worked as an environmental consultant in several different capacities in roles of progressively increasing responsibility. Beginning in 2000, I was a project manager of multi-media environmental projects. During this period, I managed a wide variety of projects for various industries focusing on remediation project management.

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PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and explain details regarding DTE Gas's MGP remediation projects. My testimony will address:

- The history of DTE Gas's former MGP sites
- Investigation and remediation requirements for MGP sites
- Changes in the remediation law
- Remediation progress
- Steps taken to minimize MGP remediation costs
- Review of other liable parties
- Review of remediation costs to date

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-13	C13, Page 1	Manufactured Gas Plant Sites - General Information
A-13	C13, Page 2	Closure Strategy of each MGP Site
A-13	C13, Page 3	Manufactured Gas Plant Environmental Response Expenditures 1984 through July 2017
A-13	C13, Page 4	MGP Environmental Response Expenditures by Site, Project Phase and Total Expenditures for the Period October 2015 to July 2017

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

A. Yes, they were.

MANUFACTURED GAS PLANT REMEDIATION

Q. What are MGPs and what service did they provide?

A. From the early 1800s until the 1950s, manufactured gas plants were widely used for producing gas for lighting and heating from coal. When interstate pipelines were constructed for natural gas transmission in the 1930s, manufactured gas plants rapidly disappeared because they could not compete with less expensive natural gas. Some plants continued operation on a standby basis until the mid-1950s. Manufactured gas properties were usually located adjacent to railways and navigable waters to facilitate the shipment of raw material to the site and for the removal of waste generated from the different processes. There are three types of gas manufacturing: 1) coal or coke oven gas; 2) oil gas; and 3) carbureted water gas. Each process provided different heating values and was used depending on the availability of the supply of raw material during the time period that the plant was in operation. There are some locations where all three processes were utilized to produce and supply manufactured gas.

The older and most common method of manufacturing gas was to extract the gas that resulted from operating coal or coke ovens. A coal gas plant consisted of large brick ovens called retorts, which were partially filled with coal. As the ovens were heated, the coal was vaporized resulting in manufactured gas. The manufactured gas also included several purification processes to remove heavy hydrocarbons such as tar, light hydrocarbons such as condensate, and other impurities such as sulfur compounds. Exhibit A-13, Schedule C13, page 1, describes additional information on the DTE Gas former MGP sites such as size of property, location, date acquired, date of plant retirement, present land use, and other general information.

Q. What are the environmental issues with MGPs?

A. During the production of the gas, both organic (tar, oil, carbon deposit, hydrocarbon sludge) and inorganic (spent oxide waste, ammonium sulfate, coke and ash) process residuals accumulated, which required either on-site or off-site management. Coal tar was typically burned as fuel or sold as-is. The coal tar was often stored on-site in lagoons and underground tar wells. The purification of the manufactured gas generated spent oxide waste. The residual impacts from these processes must be addressed by current State and Federal standards and require remediation consistent with current environmental standards.

Q. What Federal and State environmental regulation applies to the remediation of the MGP sites?

A. There are several State and Federal statutory requirements that provide for handling of the MGP remediation. At the Federal level, in 1980 Congress enacted the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund," which requires responsible entities to respond to actual or threatened releases of hazardous substances such as the MGP contamination. In Michigan, the Environmental Response Act of 1982, commonly known as public Act 307, provided for the investigation, risk assessment, and evaluation/selection of the remedial Action Plan for impacted properties. In 1990, the State of Michigan passed an amendment to Act 307, which established a State

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program similar to the Federal Superfund program. In 1994, the State amended the Act and re-codified it as Part 201 of the Michigan Natural Resources and Environmental Protection Act (NREPA), PA 451 of 1994. DTE Gas works closely with the Michigan Department of Environmental Quality (MDEQ) on the investigation and remediation of the former MGP properties. Under Part 201, those liable for response activity costs include (i) the owner or operator of a facility if the owner or operator is responsible for an activity causing a release or threat of release and (ii) the owner or operator of a facility at the time of disposal of a hazardous substance if the owner or operator is responsible for an activity causing a release or threat of release. Under certain circumstances, others can be liable for response activity costs. Part 201 applies regardless of whether the release or threat of release of a hazardous substance occurred before or after the effective date of Part 201. Therefore, a party may be liable under Part 201 even though the act causing environmental contamination may have been lawful and reasonable at the time. Any potentially responsible party may be held liable for the cost for investigation and remediation of a site.

Q. What is a utility's responsibility at a former MGP site that it owned or operated?

A. Part 201 requires that a current owner or operator of a facility for which they are liable must take appropriate action, including confirming the existence of the release, determining the nature and extent of the release, reporting the release to MDEQ if there was a reportable quantity released, and immediately begin taking steps to stop any continuing release. Part 201 contains affirmative obligations to avoid exacerbation of any existing contamination. The liable owner or operator must "diligently pursue" environmental response activities including investigation and remediation, and ultimately address all contaminants associated with the site. DTE Gas is the current owner or operator of all or a portion of the former MGP sites listed under Exhibit A-13, Schedule C13, page 1.

The MDEQ has a responsibility to oversee and coordinate all activities required under Part 201. The MDEQ is authorized by Part 201 to request or order remediation by one or more responsible parties to undertake response activities and to recover costs incurred from responsible parties later.

Q. What types of environmental response activities may be required at a former MGP site?

A. The sequence, timing and magnitude of response activities varies from site to site depending upon the size of the site, the degree of environmental contamination, current land use, the degree of enforcement discretion exercised by the MDEQ, and other site-specific factors. However, the usual sequence of environmental response activities typically undertaken at a former MGP site would be:

- Site Investigation
- Remedial Investigation
- Initial Response Action
- Feasibility Study
- Remedial Action

Q. What is involved with each of these activities?

A. Each activity is described below.

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Site Investigation. A site investigation involves research for information such as available historical records, past and current site uses, topographical maps, engineering drawings and a review of potential sources of environmental contamination. A site visit is also usually completed during a site investigation to relate the information collected by the records search to current site conditions and to conduct a visual inspection for any obvious signs of MGP contamination.

Remedial Investigation. The purpose of a remedial investigation is to define the nature and extent of contamination at a site. The remedial investigation may include the collection and analysis of surface soil, subsurface soil, groundwater samples, sediment samples, and soil vapor samples. These samples are analyzed for chemicals of concern that are typical of MGP by-products and wastes.

Interim Response Action. Interim response actions may be required and are based on whether the results of the remedial investigation or other information indicates a need to abate a threat to human health or to the environment on an interim basis while further investigation occurs. Examples of the type of interim response activities that may occur for contaminated soils include erecting a fence, installing drainage controls and stabilization, capping, removal, treatment or disposal of the contaminated soils to eliminate direct contact hazards and to prevent further migration. Interim responses may be implemented through the Part 201 Response Activities Plan (ResAP) process that provides for MDEQ approval of response activity before it is undertaken.

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Feasibility Study. The purpose of the feasibility study is to develop, evaluate and select which of the several remedial action alternatives, including no action, may be appropriate.

Remedial Action. Remedial action includes, but is not limited to, clean up, removal, containment, isolation, destruction or treatment of a hazardous substance released or threatened to be released. If remedial action is required, a ResAP is developed for MDEQ approval of response activity before it is undertaken. The ResAP will describe how the remedial action will comply with the requirements of Part 201 and how performance of the remedy will be measured. Once remedial actions have been successfully completed and cleanup objectives have been achieved, a request for No Further Action is submitted to the MDEQ for all or part of the MGP site. The MGP site (or part of the MGP site) is "closed" once MDEQ submits a notice of approval of no further action to DTE Gas.

Q. What is DTE Gas's progress on remediating the MGP sites?

A. Prior to the enactment of Part 201, DTE Gas was responsible for the investigation and cleanup of 18 former MGP sites (See Exhibit A-13, Schedule C13, page 1). Under the new Part 201 regulations, DTE Gas petitioned the State to reclassify its liability status to a non-liable entity on three former MGP sites. DTE Gas received concurrence from the State that it is not liable for the three former MGP sites (Cadillac MGP site, Traverse City MGP site, and Big Rapids MGP site). Additionally, two sites that are the current locations of DTE Gas service centers (Coolidge and Lynch) were identified as Part 201 sites due to the presence of MGP residuals. These are referred to as "holder sites" because they were not sites where

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gas was manufactured but rather a location where gas was stored in a 'holder' prior to distribution to customers. DTE Gas has the responsibility for 15 former MGP sites located in Detroit (4 sites), Grand Rapids (2 sites), Ann Arbor (2 sites), Greenville, Belding, River Rouge, Muskegon, Muskegon Heights, Ludington, and Mt. Pleasant. DTE Gas also has responsibility for nine former holder sites in Detroit (8 sites) and Chelsea (1 site).

DTE Gas has completed the initial site investigation for all 15 former MGP sites and nine former holder sites. Based on the evaluation of the holder sites, DTE Gas concluded that two of the holder sites at DTE Gas service centers (Coolidge and Lynch) were Part 201 sites and required additional investigation under Part 201. Initial site investigations were performed at the other holder sites and no risks were identified.

The Remedial Investigation, Initial Response Action, Feasibility Study and Remedial Action phases are all in progress for the 15 former MGP sites. DTE Gas has submitted and received closure for six former MGP sites (Ludington, Mt. Pleasant, Station B, Station H, Station J, and Wealthy Annex). Additionally, DTE Gas submitted and received closure on the Lynch and Coolidge holder sites. DTE Gas also received partial closures for remediation performed at Broadway, Belding, Station A and two portions of the Muskegon Heights sites. Exhibit A-13, Schedule C13, page 2 provides more detailed information on each site's closure strategy and status.

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Q. What is DTE Gas's approach to receiving site closure following the No Further Action Process?

A. The current Part 201 regulations allow for closure (using the No Further Action (NFA) process) of portions of a site to capitalize on the investments that have been made in remediation. Our approach is to address the entire site when feasible, but in many cases a large and complex site can be divided and addressed in several smaller parts. This is especially effective when significant activities such as source removal and cleanup have been completed at the site, but there are other complex remedial issues to address on a different timeframe. DTE Gas will pursue closure through the NFA process for portions of a site based on site specific conditions that will allow us to gain regulatory certainty for the remedial actions that have been completed.

Q. What steps does DTE Gas take to minimize MGP remediation cost?

A. DTE Gas implemented several steps to minimize the MGP remediation cost as follows:

a) A cost competitive bidding process is initiated for all projects. Consultant and Contractor proposals are evaluated for technical ability, cost effectiveness, and knowledge of rules and regulations.

b) DTE Gas manages its contractors and consultants with experienced in-house remediaton project managers to ensure objectives are met and contracts are managed effectively. In cases where objectives are not met we hold our vendors responsible for rework and/or additional corrective measures that may be needed (in the Case of Belding MGP), to ensure only prudent costs are requested for recovery.

c) DTE Gas continues to identify other responsible parties and collaboratively partner with other parties to share common engineering and construction costs. DTE Gas will continue to aggressively pursue other responsible parties where applicable to ensure that site remediaton costs are appropriately shared, as in the case of Station A MGP.

d) DTE Gas will continue to identify cost effective and risk reducing remediation approaches that share cleanup costs and manage risk in a forward looking, combined remediaton and redevelopment approach whenever opportunities allow.

e) DTE Gas works closely with State agencies to obtain consensus on how it intends to proceed on investigation and remediation. Obtaining consensus is very important to prevent additional unnecessary work on those sites.

f) DTE Gas utilizes in-house expertise to limit the remediation and investigation costs. DTE Gas project managers work closely with consultants, contractors and subcontractors to evaluate all the investigation and remediation activities on a daily basis.

g) DTE Gas communicates with community officials prior to any remediation effort which helps address any potential community concerns prior to initiating our remediation.

h) DTE Gas obtains approvals for access to investigate or remediate from different property owners or municipalities to prevent any future project delay.

i) DTE Gas has purchased former MGP properties to control the remediation cost on those properties, since property owners may demand clean up above the State cleanup standards.

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j) DTE Gas continues to be actively involved in research on remediation techniques that will help in providing more cost effective technologies in investigation and remediation.

k) DTE Gas actively participates in rule and regulation development at the State and Federal level to create a regulatory framework that supports cost effective and scientific remediation and risk reduction.

l) DTE Gas defended and continues to defend cases where parties or current property owners claim DTE Gas has greater remediation liability then provided by State and Federal law.

Q. At which sites has DTE Gas had to defend its cost-recovery claims for MGP impacts?

A. The River Rouge MGP site located in Melvindale, MI is currently in litigation to determine allocation of remediation costs. A part of the former MGP operation is on a parcel of property (40.6 acres) that is currently owned by AK Steel, and formerly Ford Motor Company. While DTE Gas owned the parcel during MGP operations, Ford and now AK Steel have significant waste water operations on the parcel. DTE Gas, Ford, and AK Steel disagree on the apportionment of the liability at the site, and as such DTE Gas is defending a lawsuit regarding claims brought by Ford and AK Steel.

Q. What are DTE Gas's remediation costs to date?

A. DTE Gas has incurred costs of approximately $80.4 million to date. Exhibit A-13, Schedule C13, page 3 identifies the response expenditures from 1984 through July 2017. This incorporates costs included in the following prior general rate cases:

MPSC Case Nos. U-13898, U-15985, U-16999, U-17999 and the costs reflected in this case of approximately $9.6 million. These costs include prudent and reasonable expenses of investigation and remediation of the former DTE Gas MGP sites. Exhibit A-13, Schedule C13, page 4 reflects the breakdown of the total $9.6 million of expenditures by site from October 2015 through July 2017, and for each phase of the remediation. The following table identifies previous rate cases with associated time frames capturing expenditures:

Rate Case Number	Rate Case Expenditure Time Frame
U-13898	1984 through February 2004
U-15985	March 2004 through August 2009
U-16999	September 2009 through June 2012
U-17999	July 2012 through September 2015
U-18999	October 2015 through July 2017

Q. **Did DTE Gas pursue insurance recovery from insurance carriers to offset these MGP expenditures?**

A. Yes. In 1994, DTE Gas began pursuing remediation cost recovery from several insurance companies. The process involved hiring a firm to obtain and review all the former insurance policies and carriers, and to develop all the potential environmental claims under those policies. The following table identifies previous rate cases with associated net insurance proceeds:

Rate Case Number	Rate Case Insurance Proceeds
U-13898	$10,070,622
U-15985	$179,702
U-16999	$37,043
U-17999	$33,380

DTE Gas has not received any insurance settlements since rate case U-17999 and does not anticipate receiving any in the future.

Q. Did DTE Gas pursue any other liable party to pay for the remediation cost of the MGP sites?

A. DTE Gas reviewed property records, contracts, and history to determine if there are any additional liable parties who should help contribute to the remediation cost at any former MGP sites. Based on that investigation, DTE Gas found it is not liable for three former MGP sites. In the late 1990s, DTE Gas requested, and received, waivers of liability from the MDEQ for those three MGP sites. The sites were the only three where DTE Gas determined the Company had no remediation liability. During the early 2000s, DTE Gas evaluated other potential parties associated with property use on and adjacent to Station B. DTE Gas documented that DuPont was a responsible party at the site and shared a portion of the costs of the environmental remedial activities at the site. DTE Gas evaluated potential responsible parties associated with the Station A MGP site and believes that Honeywell is a viable responsible party to share future remediation expenses, however, Honeywell has not committed to contributing to the site cleanup and allocation has not been established.

Q. What costs, net of insurance, is DTE Gas proposing to recover in this rate proceeding?

A. There have been no insurance proceeds recovered since U-17999 and DTE Gas has a zero balance from insurance proceeds. DTE Gas is requesting approval and recovery of $9.6 million for expenses incurred at the former MGPs during the period October 2015 through July 2017.

Q. In your opinion, are the DTE Gas expenditures to remediate former MGP sites reasonable and prudent?

A. Yes. These costs are unavoidable, are based on public policy considerations, and do not arise out of any failure to meet standards at the plants when they were in operation. DTE Gas has taken responsible actions to investigate and remediate former MGP sites in a cost-effective manner and in certain cases, sought and obtained financial participation by third parties.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
______________________________________	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ALIDA D. SANDBERG

DTE GAS COMPANY
QUALIFICATIONS OF ALIDA D. SANDBERG

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

A. My name is Alida D. Sandberg. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Gas Company (DTE Gas or Company) and hold the position of Director, Engineering Services.

Q. What is your educational background?

A. I graduated in June 1988 from the University of Illinois with a Bachelor of Science Degree in Bioengineering. I received an MBA from the University of Phoenix in 2004 with a concentration in Finance.

Q. What is your work experience?

A. I began my career with DTE Gas in 1989 where I held various positions including Industrial Marketing Consultant, Distribution Design Engineer, Supervising Engineer, Manager of Gas Operations, and Manager of Gas Dispatch and Workload Management. In 2008, I was promoted to Director of Productivity and Work Standards and, in January 2014, I accepted my present position with DTE Gas as Director of Engineering Services.

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

A. As Director of Engineering Services, I am responsible for the engineering activities for DTE Gas, including Corrosion Control, Codes and Standards, Gas Laboratory Services, Transmission and Distribution Engineering, Transmission Drafting, Integrity Management, and Geology and Reservoir.

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Q. Have you been involved in any prior regulatory proceedings?

A. Yes. I have provided testimony with the Michigan Public Service Commission in Case No. U-17701, DTE Gas's expanded Main Renewal Program (MRP) and General Rate Case No. U-17999, supporting DTE Gas's Capital Expenditures.

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Purpose of Testimony

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

A. The purpose of my testimony in this proceeding is to support the need for recovery of the following capital expenditures:

1. Projected routine capital expenditures through September 2019; and
2. Other Capital Project expenditures projected through September 2019; and
3. Infrastructure Recovery Mechanism (IRM) capital expenditures through December 2018, including an additional non-IRM Pipeline Integrity expenditure of $3.0 million through September 30, 2019.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits in Part I, Section B.

Exhibit	Schedule	Description
A-12	B5	Projected Capital Expenditures by Plant Type
A-12	B5.1	Capital Expenditures – Routine, Other Capital Projects, and Infrastructure Recovery Mechanism
A-12	B5.3	Highest Cost Top 25 Capital Project Detail

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

A. Yes, they were.

2017-2019 CAPITAL SPENDING LEVELS

Q. What level of capital expenditures does the Company support in this proceeding?

A. Beginning 2017 through September 2019, the end of the projected test year, DTE Gas will have incurred approximately $1.0 billion in routine, other capital, and IRM

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expenditures. See Exhibit A-12, Schedule B5.1, line 22, columns (f) and (g). This amount excludes IRM expenditures beginning January 1, 2019. The Company plans to recover IRM expenditures beginning January 1, 2019 through a surcharge as supported by Company Witness Ms. Harris.

Q. Why should the Commission approve recovery of cost of service related to these capital expenditures?

A. The proposed total capital expenditure levels will be utilized for prudent investments in DTE Gas's natural gas system that are necessary for DTE Gas to maintain a safe and reliable system for distributing natural gas to its customers.

Q. Did the Company spend the approved capital spending plan for the projected test year in the last rate case?

A. Yes. The approved capital spending plan in general rate case, Case No. U-17999, for the projected test year twelve months ended October 31, 2017, was $398.4 million. As seen on Exhibit A-12, Schedule B5, line 21, columns (h) and (i), the Company's ten months of actual spend and two months of forecast for the projected test year from U-17999 is $477.1 million. All approved spending plans were spent by individual plant type and collectively by the Company.

Q. How is your testimony organized?

A. My testimony is divided into three sections for capital expenditures: routine, other capital projects, and IRM program.

Exhibit A-12, Schedule B5 summarizes DTE Gas's capital requirements by major plant type for 2017 through September 2019. This information is used by Company Witness Ms. Uzenski in establishing plant-in-service levels and depreciation expense. It is also used by Company Witness Mr. Slater to allocate the Company's cost of service components to the appropriate sales, transportation, and storage customer classes. These plant types conform to the FERC and MPSC designated reporting categories such as Distribution, Transmission, Storage and General Plant categories.

Exhibit A-12, Schedule B5.1 details the Company's capital expenditures by routine, other capital projects, and IRM from 2017 through September 2019. The Company included all IRM capital invested through December 31, 2018 in base rates plus an additional $3.0 million in non-IRM Pipeline Integrity expenditures through September 30, 2019. The $3.0 million reflects additional expenditures above the Commission approved $11.1 million Pipeline Integrity IRM expenditures in Case No. U-17999.

Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail provides project level detail that supports the capital expenditures for DTE Gas's largest projects from January 2017 through September 2019.

ROUTINE CAPITAL EXPENDITURES

Q. What are routine capital expenditures?

A. Routine capital spending supports distribution, transmission, storage, and general plant expenditures.

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Q. What level of routine capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $381.2 million of routine capital expenditures. See Exhibit A-12, Schedule B5.1, line 5, columns (f) and (g).

Q. How do the Company's 2017 through 2019 routine capital expenditures compare to historical average spend?

A. DTE Gas's 2017-2019 planned routine capital expenditures are, on average, $31.2 million higher per year than the 2012-2016 $106.8 million five-year average. The amount above the five-year average is driven by $18.1 million of Distribution Plant, $12.1 million of General Plant, and $3.8 million of Storage Plant, partially offset by $2.8 million of lower Transmission Plant expenditures, as further discussed in each routine plant section of my testimony.

Q. Are there any notable adjustments to DTE Gas capital expenditures in this proceeding?

A. Yes. As a result of an agreement executed by DTE Gas and the Michigan Department of Treasury to settle a use tax refund claim, which is described and supported by Company Witness Ms. Wisniewski, capital expenditures were adjusted by $16.9 million. These expenditures are reflected as a $12.3 million credit to Distribution Plant and a $4.6 million credit to Transmission Plant as illustrated in Exhibit A-12, Schedule B5, lines 5 and 9, column (c).

Line No.

ROUTINE DISTRIBUTION PLANT EXPENDITURES

Q. What are routine distribution plant capital expenditures?

A. Distribution plant processes include all activity from city gate stations to the individual customer meter. Capital expenditures within this category include:

- Unplanned main renewals: Unplanned replacement and decommissioning of existing mains associated with leaks that cannot be repaired.
- Unplanned service renewals: Replacement and decommissioning of existing service lines as required by DTE Gas's service renewal criteria, Standard 613A, for third party damage, corrosion leak, or scheduled alteration.
- Service abandonments: Physical disconnection of the service line from the gas main and removal of the meter, related to customer facilities being demolished (DEMO's) or where there has been no active customer for 24 months (IDLE's) or due to leaks. Service abandonments are often referred to as cut and caps.
- Service alterations: Relocation or upgrading of existing service lines/meters as requested by customers due to an increase in load or construction activity at their residence or business.
- Cathodic protection: Protecting the metallic components of DTE Gas's infrastructure from external, internal, and atmospheric corrosion.
- Public improvement: Relocation of facilities due to public improvement projects initiated by state, county, or municipal governmental agencies.
- System reliability: Installation, replacement, or repair of district regulators, valves, mains and gate stations to ensure reliable gas supply to DTE Gas customers as a result of general growth, regulatory compliance and obsolescence.
- Meters: Annual purchases of meters.

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Q. What level of routine distribution plant capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $219.9 million of routine distribution plant capital expenditures. See Exhibit A-12, Schedule B5.1, line 1, columns (f) and (g).

Q. How do the Company's 2017 through 2019 routine distribution plant expenditures compare to historical average spend?

A. DTE Gas's 2017-2019 planned routine distribution plant expenditures are on average $18.1 million higher per year than the 2012-2016 $61.8 million five-year average. The amount above the five-year average is primarily driven by $14.8 million in System Reliability projects, $2.2 million in Service Alterations, $1.8 million in Public Improvement, and $1.2 million in Unplanned Main Renewal. These increases are partially offset by a $12.3 million credit resulting from an agreement executed by DTE Gas and the Michigan Department of Treasury to settle a use tax refund claim, which is described and supported by Witness Wisniewski.

Q. What level of routine system reliability capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $60.5 million of system reliability capital expenditures.

Line No.

Q. How do the Company's 2017 through 2019 routine system reliability expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 planned routine system reliability expenditures to be $14.8 million higher per year than the 2012-2016 $7.3 million five-year average. These expenditures include a routine level of capital expenditures plus expenditures for additional system reliability work to ensure a safe and reliable system.

Q. What type of work will be completed with the additional system reliability expenditures?

A. System reliability processes include the installation, replacement, or repair of district regulators, valves, mains and gate stations to ensure reliable gas supply to DTE Gas customers as a result of general growth, regulatory compliance and obsolescence. The type of work that will be addressed with the additional expenditures can be categorized as follows:

<ins>Compliance</ins>

- Upgrade or replace regulator stations that currently lack take-off-valves.
- Upgrade single customer farm taps to enable inspections to be performed or install main and abandon existing single customer farm taps to meet requirements of a new regulation requiring periodic inspection and maintenance of farm taps at least every three years. Pipeline and Hazardous Materials Safety Administration (PHMSA) published the Final Rule on January 23, 2017 with an effective date of March 24, 2017.

Line No.

Obsolescence

- Install new or replace existing mains that are unsuitable to operate at the pressures needed to support planned system operations.
- Replace valves and regulator stations due to corrosion, poor vault condition, and aged/obsolete equipment.
- Abandon regulator and valve stations that are no longer needed.

System Growth

- Install new main and/or regulator stations to address a single source system.
- Install new or replace main and/or regulator stations to address low system pressures due to general system growth.

Q. Are any of the projects supported by the additional system reliability expenditures part of DTE Gas's highest cost projects?

A. Yes. Four of the system reliability projects have expenditures large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail. Specifically, the projects are Chelsea 150 psig System Supply, Fort Street Main Replacement, Farm Tap Upgrades, and Muskegon 50 psig System Supply.

Q. What level of service alteration capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $29.4 million of service alteration capital expenditures.

Q. How do the Company's 2017 through 2019 routine service alteration expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 planned routine service alteration expenditures to be $2.2 million higher per year than the 2012-2016 $8.3 million five-year average. The 2017 and 2018 increase in expenditures is due to an increasing trend in customer requests. 2019 is forecasted to return to the five-year historical average.

Q. What level of public improvement capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $33.7 million of public improvement capital expenditures.

Q. How do the Company's 2017 through 2019 routine public improvement expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine public improvement expenditures to be $1.8 million higher per year than the 2012-2016 $10.3 million five-year average.

Q. Why are public improvement capital expenditures expected to increase from historical levels?

A. Public improvement capital expenditures are driven by governmental agencies increasing their spending on infrastructure. When a governmental agency decides to perform renovations in its right-of-way, if DTE Gas's facilities are in conflict, the Company is obligated to modify the affected gas facilities under the right-of-way agreement with the governmental agency, even if the affected Company assets still have significant remaining life. A large percentage of the Company's gas handling facilities are located in public right-of-way. These expenditures are non-discretionary.

Q. How does DTE Gas know public improvement will be increasing?

A. Several municipalities in DTE Gas's service territory have passed millages for construction in their areas. Specifically, Grand Rapids and Muskegon have water, sewer, and/or road resurfacing projects identified in 2017 and 2018. In 2019, the projected spend returns to the five-year historical level.

Q. What level of unplanned main renewal capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $11.0 million of unplanned main renewal capital expenditures.

Q. How do the Company's 2017 through 2019 routine unplanned main renewal expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine unplanned main renewal expenditures to be $1.2 million higher per year than the 2012-2016 $2.7 million five-year average. The increase in unplanned main renewal capital expenditures is driven by an increase in work being completed and complexity. 2019 is forecasted to return to the five-year historical average.

Line No.

ROUTINE TRANSMISSION PLANT EXPENDITURES

Q. What types of assets are utilized in DTE Gas's gas transmission operation?

A. The transmission system includes the high-pressure pipelines and facilities upstream of the city gate stations. DTE Gas owns and operates approximately 1934 miles of transmission pipeline throughout Michigan. Transmission pipelines are generally defined as pipelines operating at 20% or greater of its specified minimum yield strength (SMYS) and generally consist of the largest diameter and highest pressure pipelines within DTE Gas's integrated transmission and distribution system. The typical range of operating pressures for transmission pipelines on DTE Gas's system is between 300 psig and 1800 psig. Transmission pipelines are utilized to transport gas for delivery to distribution pipelines at city gate stations and to/from storage fields, as well as, to other pipelines at interconnecting locations. At city gate stations, the transmission system pressure is regulated down to the distribution system operating pressure. The gas at these locations is usually heated to prevent the regulators from freezing due to the natural cooling effect during pressure reduction. Odorant may be added at either city gate stations or upstream on the transmission system for leak detection purposes. Additional district regulation is required to further reduce pressure to appropriate levels for residential, commercial, and industrial customers on the distribution system.

Q. What level of transmission plant capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $11.9 million of

Line No.

routine transmission plant capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 2, columns (f) and (g).

Q. How do the Company's 2017 through 2019 routine transmission plant expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine transmission plant expenditures to be $2.8 million lower per year than the 2012-2016 $7.2 million five-year average.

Q. Why are transmission plant capital expenditures expected to decrease from historical levels?

A. There are two primary drivers for the decrease in expenditures from the five-year historical average. First, in 2016, DTE Gas experienced a pipeline rupture due to a vehicle accident at its River Rouge Station in Melvindale, Michigan. The Company spent $6.2 million in unplanned transmission facility replacement costs to ensure the integrity and reliability of the station before placing it back in service. Therefore, 2016 transmission plant expenditures are higher than normal. In addition, $2.0 million in insurance proceeds was credited in 2017. Second, expenditures were reduced by $4.6 million as a result of an agreement executed by DTE Gas and the Michigan Department of Treasury to settle a use tax refund claim, which is described and supported by Witness Wisniewski.

Line No.

ROUTINE STORAGE PLANT EXPENDITURES

Q. What assets are included in DTE Gas's gas storage operations?

A. DTE Gas's storage operations consist of four storage facilities with the combined capability of storing 138.7 Bcf at 14.65 psia of working gas and 179 active wells. Storage facilities can provide DTE with over half of its winter peak day daily system requirements.

Q. How does DTE Gas utilize compression in its day-to-day operations?

A. As of December 31, 2016, DTE Gas owns and operates 42 compressor units totaling 130,980 horsepower. The compressors units are strategically located along the transmission system and storage facilities to provide additional pressure support for storage operations and deliverability to our gate stations and, ultimately, to our customers.

Q. What are routine storage plant capital expenditures?

A. Storage plant processes include all activity related to storage and compressor facilities. Capital expenditures within this category include:

- Compression: Installation, replacement, or repair of compressor facilities
- Storage: Installation, replacement, or repair of storage facilities due to reliability, obsolescence, and integrity. Specifically, this work includes storage field gathering pipe, new wells, well upgrades, well abandonments, and well stimulations.

Q. What level of storage plant capital expenditures does the Company support in this proceeding for 2017 through September 2019?

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A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $61.0 million of routine storage plant capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 3, columns (f) and (g).

Q. How do the Company's 2017 through 2019 routine storage plant expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine storage plant expenditures to be $3.8 million higher per year than the 2012-2016 $18.1 million five-year average. The amount above the five-year average is primarily driven by $1.1 million in storage projects and $2.7 million in compression projects.

Q. Why are storage plant capital expenditures expected to increase from historical levels?

A. The $1.1 million average annual increase in Gas Storage is due to the following:

1) Six Lakes A Header Project, which includes replacing the remaining portion of old gathering pipe with new piggable pipe in 2017 and drilling two new wells in 2018;
2) Additional well plugging to complete partially plugged wells where surface plugs have not been installed; and
3) upgrades to well pads for reducing farming proximity to wells in 2018.

In 2019, capital expenditures for Gas Storage are expected to return to its normal spending plan.

The $2.7 million in Compression is due to

1) Two new heaters at the Six Lakes Compressor Station to support April Minimum Day design injection obligations;
2) A heater addition at the Belle River Compressor Station to support the beginning of the withdrawal cycle; and
3) The implementation of a multi-year program to automate station valves at the Belle River Compressor Station.

Q. What is piggable pipe?

A. Piggable pipe is capable of passing an In-Line inspection (ILI) tool for the purpose of identifying anomalies during pipeline assessments. ILI gathers the most comprehensive data about pipelines, is the most versatile method in terms of coverage of pipeline threats, and is, therefore, the method preferred by most operators. ILI is described in more detail in the IRM section of this testimony.

Q. Are any of the projects supported by storage plant expenditures part of DTE Gas's highest cost projects?

A. Yes. Four of the storage plant projects have expenditures large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail. Specifically, the projects are Six Lakes A Header Integrity, Six Lakes A Header Well Drilling, Six Lakes Heater Installation, and BRM Unit 4 Engine Rebuild.

Line No.

ROUTINE GENERAL PLANT EXPENDITURES

Q. What type of assets are classified as routine general plant?

A. There are five main elements in what is described as DTE Gas's General Plant category. They are:

- structures and improvements: maintain and improve physical structures supporting DTE Gas's operation
- transportation vehicles and equipment: replace and purchase additional vehicles
- tools and equipment: replace and purchase leak detection equipment, pipe locating equipment, measurement equipment, fusing machines, tapping/stopping equipment, laboratory equipment, and other items needed to ensure safe and efficient operation of the system
- communication and control equipment: SCADA system (Supervisor Control and Data Acquisition); the communication network; compressor station process control system; and city gate station and field devices used to monitor flow rates, pressures, and gas quality
- computers and related equipment: Software such as ESRI (automated mapping system), Synergi Gas (models the pressure and flow of natural gas in the system), word processing, spreadsheets, etc.; Interfaces with DTE Corporate operating systems; and Systems such as the electronic bulletin board and nomination system

Capital spent in these categories support the entire operation of the Company's natural gas system.

Q. What level of general plant capital expenditures does the Company support in this proceeding for 2017 through September 2019?

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A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $88.4 million of routine general plant capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 4, columns (f) and (g).

Q. How do the Company's 2017 through 2019 routine general plant expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine general plant expenditures to be $12.1 million higher per year than the 2012-2016 $19.7 million five-year average. The amount above the five-year average is primarily driven by $6.2 million in Structures and Improvements, $3.4 million in Transportation Vehicles and Equipment, $1.7 million in Computers and Related Equipment, and $0.8 million in Tools and Equipment.

Q. What level of structures and improvements capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $26.2 million of structures and improvements capital expenditures.

Q. How do the Company's 2017 through 2019 structures and improvements expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine structures and improvements expenditures to be $6.2 million higher per year than the 2012-2016 $3.3 million five-year average.

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Q. Why are structures and improvements capital expenditures expected to increase from historical levels?

A. The increase is primarily driven by planned routine expenditures in building improvements due to facilities assets beyond useful life that require replacing before failure. The facilities requiring improvements are on average over 40 years old and deferred investment have resulted in emergent failures due to deteriorating equipment. Replacement and upgrades are needed in areas such as, fire detection/suppression, mechanical systems, roofing, electrical, lighting, ceilings, and flooring.

Q. Are any of the projects supported by structures and improvements expenditures part of DTE Gas's highest cost projects?

A. Yes. The Lynch-Asset Preservation project has expenditures large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail.

Q. What level of transportation vehicles and equipment capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $33.2 million of transportation vehicles and equipment capital expenditures.

Q. How do the Company's 2017 through 2019 transportation vehicles and equipment expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine transportation vehicles and equipment expenditures to be $3.4 million higher per year than the 2012-2016 $8.5

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million five-year average. The projected increase in 2017 and 2018 is primarily driven by the purchase of additional vehicles and excavation equipment in preparation for expansion of the Meter Move Out and Main Renewal programs.

Q. What level of computers and related equipment capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $17.7 million of computers and related equipment capital expenditures.

Q. How do the Company's 2017 through 2019 computers and related equipment expenditures compare to historical average spend?

A. On average, DTE Gas expects its 2017-2019 routine computers and related equipment expenditures to be $1.7 million higher per year than the 2012-2016 $4.6 million five-year average. There is an increase primarily in 2018, which is driven by the following technology improvements: 1) automation of work flow processes, 2) improvements in data analytics to predict compressor engine maintenance prior to engine failure, and 3) replacement of outdated outbound dialer for appointment scheduling and delayed appointment notifications.

Q. Are any of the projects supported by computers and related equipment expenditures part of DTE Gas's highest cost projects?

A. Yes. The Astro Voice Replacement System project has expenditures large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail.

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OTHER CAPITAL PROJECT EXPENDITURES

Q. What level of other capital project expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE will have incurred $256.1 million of other capital project expenditures. These expenditures are shown on Exhibit A-12, Schedule B5.1, line 13, columns (f) and (g).

Q. Why are certain projects under "Other Capital Projects" on Exhibit A-12, Schedule B5.1, not part of your annual routine construction level?

A. These items, for the most part, are either new projects with no historical or comparable spending levels or are revenue generating or cost saving projects. I will discuss each of the items that are included in this category separately in my testimony. These projects include 1) New Market Attachments, 2) Advanced Metering Infrastructure (AMI), 3) NEXUS, 4) Belle River Compression, 5) Gordie Howe International Bridge (GHIB), 6) Milford Junction Loop, and 7) Revenue Protection.

NEW MARKET ATTACHMENTS

Q. What work constitutes new market attachments?

A. New market attachments captures the cost of new residential, commercial, and industrial customer connections. The work includes new mains, services, regulators, valves, and meters required to extend gas service to new customers that are not currently connected to DTE Gas's facilities and serve incremental gas loads to existing customers that are expanding their operations.

Q. What level of new market attachment expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $98.8 million of new market attachments capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 6, columns (f) and (g).

Q. What was the 2016 historical capital expenditure for new market attachments?

A. The capital expenditure for 2016 was $27.8 million. This expenditure is illustrated in Exhibit A-12, Schedule B5.1, line 6, column (c). The Company's new market additions for 2016 were 8,295 attachments.

Q. Are the Company's 2017 through 2019 new market attachment expenditures higher than the 2016 historical spend?

A. Yes. New market attachment expenditures are projected to be on average $8.3 million higher per year than the 2016 historical year due to a forecasted increase in new market additions from 8,295 in 2016 to 9,054 new customers in 2019. The Company's new market additions for 2017 through 2019 are 8,759 new customers in 2017, 9,100 new customers in 2018 and 9,054 new customers in 2019, as shown in Company Witness Mr. Chapel's exhibits. DTE Gas is pursing community expansions into areas that do not currently have natural gas available. This is due to increased demand from homeowners wanting to convert from the higher cost of propane to natural gas. DTE Gas has identified areas of community expansion for 2017 thru 2019 in many areas throughout Western and Northern Michigan including Leelanau, Emmet, Mecosta, Antrim, Roscommon, and Ogemaw counties.

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Also, in 2017, expansion to three large volume users contributed to the increase in expenditures, Ford Central Energy Plant, Arauco-Flakeboard America, and Eastern Michigan University.

Q. Are any projects supported by new market attachments expenditures part of DTE Gas's highest cost projects?

A. Yes. Two of the new market attachment projects have expenditures large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail. Specifically, the projects are Ford Central Energy Plant and Arauco-Flakeboard America.

<u>ADVANCED METERING INFRASTRUCTURE (AMI)</u>

Q. Is DTE Gas continuing its Advanced Metering Infrastructure program?

A. Yes, DTE Gas is continuing its Advanced Metering Infrastructure (AMI) program for the reasons discussed and supported by Company Witness Mr. Sitkauskas. DTE Gas's plan is to install the remaining gas installations by year end 2018.

Q. What level of AMI capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $29.6 million of advanced metering infrastructure capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 7, columns (f) and (g).

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DTE GAS NEXUS PROJECT

Q. What is the NEXUS pipeline project?

A. The NEXUS pipeline project consists of a proposed 255 mile, 36" diameter pipeline from Ohio to Michigan, terminating at a proposed NEXUS Meter Station to be located at the Willow Gate Station (WGS) in Ypsilanti Township, Washtenaw County, Michigan. WGS is owned and operated by DTE Gas Company. Tie-in of NEXUS pipeline to DTE Gas facilities is at the outlet flange of the NEXUS Meter Station where up to 1.3 Bcf/day of gas at a maximum pressure of 858 psig may be received. Upon receipt, the gas may be delivered into DTE Gas's distribution system or transported on DTE Gas's system of transmission pipelines for deliveries to any number of inter and intrastate pipelines and gas storage operators. In order to transport the additional NEXUS gas through the DTE Gas pipeline system, a number of system upgrades ("DTE Gas-NEXUS upgrades") are required.

Q. What DTE Gas-NEXUS upgrades are needed to facilitate transportation of NEXUS gas?

A. Major upgrades are required at the following DTE Gas facilities to transport NEXUS gas: Willow Gate Station, Willow Run Compressor Station, and Milford Compressor Station. The DTE Gas-NEXUS project has expenditures large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail.

Q. When will the NEXUS project be placed in service?

A. The current in-service date for the NEXUS project, including the DTE Gas-NEXUS upgrades is tentatively September 1, 2018.

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Q. What level of DTE Gas-NEXUS project capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $101.0 million of DTE Gas-NEXUS project capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 8, columns (f) and (g).

BELLE RIVER COMPRESSOR PROJECT

Q. What is the Belle River Compressor Project?

A. The Belle River Compressor Project is a multi-year project that began in 2015 and ends in 2017 and includes the addition of two (2) gas turbine driven compressors at the Belle River Mills Compressor Station (BRMCS) located in E. China, Michigan. The two (2) new compressor units have a combined horsepower (HP) rating of 17,045 HP, one unit rated at 10,915 HP and the other unit rated at 6,130 HP. The addition of these two (2) units increases the total number of natural gas compression units at BRMCS to eight (8) for a total of 53,745 HP. The new units were placed into service in November of 2016.

Q. Why is the additional horsepower required at the Belle River Compressor Station?

A. As fully described in General Rate Case U-17999, the historically cold winter of 2013/2014 required DTE Gas to withdraw storage gas from Belle River field to record low balances and low pressure levels. A variance between the theoretical and actual pressure content curves in the field was discovered as a result of these withdrawals. The deep cycling (low pressure) of the Belle River storage field revealed deliverability deficiencies that jeopardized the Company's ability to deliver gas to customers during peak demand conditions. Part of the permanent solution to address the gap in deliverability included installing additional horsepower at BRMCS.

Q. What level of Belle River Compressor capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $1.0 million of Belle River Compressor project capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 9, columns (f) and (g).

Q. Why are there expenditures in 2017 when the units were placed into service in November of 2016?

A. The expenditures in 2017 are part of the planned close out phase of the project. These activities include the compilation of the job books that contain all the information related to the equipment and devices installed, modifying the nearly 1,200 construction drawings to account for as-built conditions and final payments to the construction contractors.

GORDIE HOWE INTERNATIONAL BRIDGE PROJECT

Q. What is the Gordie Howe International Bridge project (GHIB)?

A. The GHIB is a new vehicular bridge owned by the Windsor Detroit Bridge Authority (WDBA) crossing the Detroit River from Detroit, Michigan to Windsor, Ontario, Canada. This crossing will be located approximately ½ mile west of the

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Ambassador Bridge in the Delray community, which is bordered on the south by the Detroit River and on the north by the I-75 freeway. The project consists of widening and rebuilding I-75, installation of ramps and bridges connecting the new bridge to I-75, and construction of a plaza for toll booths and customs.

Q. How will this project impact the existing DTE Gas infrastructure?

A. The I-75 and new toll plaza construction work will require abandonment of existing and installation of new distribution mains and services to ensure adequate gas supply is maintained to customers. The GHIB project expenditures are large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail.

Q. When is the GHIB project expected to be placed in service?

A. The GHIB plaza and I-75 supporting infrastructure required DTE Gas to begin preliminary gas infrastructure work in 2015. The Company plans to complete its work in 2020. The current schedule reflects the latest milestones given by WDBA/MDOT to support the bridge construction.

Q. Is DTE Gas bearing the full cost of distribution system work related to the GHIB project?

A. No. Through an agreement between the Company and the Michigan Department of Transportation (MDOT), MDOT has agreed to pay for a portion the work. While the GHIB project costs are not finalized, MDOT's share of the expenditures are estimated to be on the order of $3.2 million in 2018 and $2.1 million in 2019, for a total of $5.3 million and are included in the exhibits in this proceeding.

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Q. How were the costs and allocations determined?

A. DTE Gas and MDOT worked together to reduce the overall project cost and to optimize the project design and scope. This effort led to an agreement on how the costs would be allocated. The ultimate allocation was based on work within the point of entry (POE) that is not within MDOT jurisdiction and, therefore, should be paid for by the entity doing the work. The work within the I-75 corridor, however, is work under the jurisdiction of MDOT and, like other utility relocation work done in areas of MDOT jurisdiction, is not reimbursable.

Q. What level of GHIB project capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $4.6 million of capital expenditures directly related to the GHIB. This amount includes the $5.3 million that is to be reimbursed by MDOT. These expenditures are shown on Exhibit A-12, Schedule B5.1, line 10, columns (f) and (g).

MILFORD JUNCTION LOOP PROJECT

Q. What is the Milford Junction Loop project?

A. Milford Junction Station is a location in the transmission system where several main pipelines converge. The junction provides continuous gas flow to and from various sections of the transmission and distribution systems. The Milford Junction station is a critical facility within the DTE Gas pipeline system that has a significant impact on DTE Gas's ability to deliver gas to its customers. As part of DTE Gas's strategy to identify and mitigate pipeline safety risks, the Milford Junction Loop

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project will, in the event of a facility failure at Milford Junction, allow for isolation of the station and continued flow of gas around the station through the looped pipeline for uninterrupted gas supply.

Q. What system enhancements are required to create a loop around Milford Junction?

A. The Milford Junction Loop Project consists of installing approximately 3,750 feet of 30” diameter pipeline and associated valves to provide a bypass pipeline around the Milford Junction Station. The Milford Junction Loop project has expenditures large enough to fall into DTE Gas’s highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail.

Q. When will the Milford Junction Loop project be placed in service?

A. DTE Gas plans to have the loop in service by November 2017.

Q. What level of Milford Junction Loop project capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $8.0 million of Milford Junction Loop project capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 11, columns (f) and (g).

Q. What is the impact of the Milford Junction Loop project on property owners?

A. Construction of the loop pipeline requires easements for the pipeline and valve stations. DTE Gas’s primary goal in this regard is to minimize impact on property

Line No.

owners and the environment. Consequently, the preferred routing has been selected from possible alternatives based on several considerations including constructability, number of property owners impacted, impact on wetlands, and number of water body crossings. DTE Gas actively engaged property owners and township officials and has secured the necessary easements. The Company received its certificate of public convenience and necessity in accordance with the provisions of state of Michigan Public Act 9 of 1929 on August 23rd, 2016.

REVENUE PROTECTION PROGRAM

Q. What type of work causes DTE Gas's revenue protection capital expenditures?

A. Revenue protection capital expenditures arise from cuts and caps related to the level of theft and non-payment of gas service experienced by DTE Gas. These expenditures, also, include reconnects and service renewals associated with reconnects. First, DTE Gas identifies and disconnects people in our service territory that do not have an active agreement with the Company and are stealing natural gas. Second, DTE Gas disconnects customers for non-payment within the requirements of the Billing Practice Rules. Neither of these processes prevents customers from stealing natural gas or not paying for their gas service. As discussed by Company Witness Mr. Johnson, this process attempts to mitigate the financial impact on DTE Gas once the Company has identified these events are taking place.

Q. What does it mean to "cut and cap," a natural gas user?

A. When the Company performs a cut and cap it means the complete abandonment of natural gas service to a property. When completing a service abandonment of the gas supply to the property, the service line is physically disconnected from the gas main.

Q. Are service renewal costs included in the revenue protection capital expenditures?

A. Yes. When cut and caps are completed for theft or due to non-payment, a certain percentage of customers/sites will eventually ask DTE Gas to reconnect them to the gas main. Many of these reconnected sites require a service renewal, per DTE Gas's service renewal criteria, Standard 613A.

Q. What level of Revenue Protection Program expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $13.1 million of revenue protection program capital expenditures. These expenditures are shown on Exhibit A-12, Schedule B5.1, line 12, columns (f) and (g).

Q. What are DTE Gas's historical revenue protection program capital expenditures?

A. During the period from 2012 to 2016, the Company averaged $5.7 million per year in revenue protection program expenditures.

Q. Are the Company's 2017 through 2019 revenue protection program expenditures higher than the historical average spend?

A. No. DTE Gas's 2017-2019 planned revenue protection program expenditures are on average relatively flat with the five-year historical average.

INFRASTRUCTURE RECOVERY MECHANISM (IRM) EXPENDITURES

Q. What is the IRM Program?

A. The IRM is the program name for a series of capital expenditures that support the long-term improvements to DTE Gas's infrastructure. The three processes making up the IRM capital expenditures are: Pipeline Integrity (PI), Meter Move Out (MMO), and Main Renewal Program (MRP). The PI process is discussed in more detail in my testimony and the MMO and MRP processes are supported in the testimony of Witness Harris. DTE Gas is currently making substantial investments in these three processes and will continue to make substantial expenditures in these areas beyond the Company's projected test period.

Q. What level of Infrastructure Recovery Mechanism Program expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $346.4 million of IRM capital expenditures. The Company has included all IRM capital invested through December 31, 2018 in base rates, as supported by Witness Uzenski, plus an additional $3.0 million in non-IRM Pipeline Integrity expenditures through September 30, 2019. The $3.0 million reflects additional expenditures above the $11.1 million Pipeline Integrity IRM approved expenditures in Case No. U-17999. Also included in base rates is $7.7 million in 2018 for a new MMO MAC initiative as described and supported by Witness Harris. These expenditures are illustrated in

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Exhibit A-12, Schedule B5.1, line 19, columns (f) and (g) and excludes IRM expenditures included in the request for a new IRM surcharge beginning January 1, 2019 as supported by Witness Harris.

Q. Why is it appropriate to include IRM capital expenditures spent through December 2018 in base rates?

A. The Commission's order in DTE Gas's general rate case, Case No. U-16999 approved the proposed IRM, which included a provision that all capital invested as part of IRM would be rolled into rate base in the event DTE Gas filed a rate case. The calendar year approach is administratively simpler because the IRM capital is made and reconciled on a calendar year basis.

Q. What was the 2016 historical capital expenditure for IRM?

A. The capital expenditure for 2016 was $124.1 million. This expenditure is illustrated in Exhibit A-12, Schedule B5.1, line 19, column (c). The planned expenditure for 2016 as filed in DTE Gas's last general rate case, Case No. U-17999 was $102.1 million. This spending level demonstrates DTE Gas's commitment to improving its infrastructure with the prudent capital spending levels proposed in this application.

Q. Are the Company's IRM annual expenditures in this proceeding higher than the Commission approved level in general rate case, Case U-17999?

A. Yes. $127.6 million in annual IRM expenditures was approved in the last general rate case, Case U-17999 beginning January 1, 2017. The Company will have incurred an additional $44.1 million per year on average in 2017 and 2018 to further accelerate the PI, MMO, and MRP processes. IRM capital expenditures from 2019 through 2023 are supported by Witness Harris.

PIPELINE INTEGRITY PROGRAM

Q. What makes up pipeline integrity work?

A. Pipeline integrity is the program used by DTE Gas to manage and ensure the integrity of the gas transmission system as prescribed in Subpart O of the MGSS, Pipeline Integrity Management. The regulatory requirements contained in Subpart O of MGSS prescribe minimum requirements for a transmission pipeline integrity management program. The sub-programs of DTE Gas's Pipeline Integrity Management Program are:

(i) Pipeline Integrity Assessments
(ii) In-Line-Inspection (ILI) Expansion
(iii) Remote Control Valves (RCV)
(iv) Maximum Allowable Operating Pressure (MAOP) Record Review
(v) Records Management System Development.

Item (i) are O&M expenses covered in Company Witness Ms. Tomina's testimony. This testimony will address the capital expenditures, items (ii – v).

Q. Why is it appropriate to include PI expenditures in the IRM?

A. As pointed out by the MPSC in Case U-16999, "The PI program is required under federal and state safety standards and is an integral part of the Company's overall effort to improve the safety and reliability of its system." Similar to the MRP and MMO programs, the PI program involves long-term significant infrastructure expenditures. DTE Gas sought recovery for the cost of service for PI capital

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expenditures in Case No. U-16999, and the Commission approved the request in its final order.

Q. What is the Pipeline Integrity Assessment Program?

A. Pipeline assessments are conducted to identify anomalies in the facilities. After evaluating these anomalies and depending on their severity, remediation methods vary from simply reapplying protective coating, to removal and replacement of a section of pipe containing the anomaly. Accepted assessment methods are In-Line Inspection (ILI) (i.e., smart pigging), Pressure Testing, and Direct Assessment (DA). Once the initial baseline assessment is completed using any of the accepted assessment methods, each covered segment must be reassessed at intervals as specified in Subpart O, generally every seven years.

Q. How is the cost of pipeline integrity assessments and remediation treated?

A. The cost of pipeline integrity assessments and remediation was capitalized through year 2012, as approved in DTE Gas's prior rate case, Case No. U-15985. As approved in DTE Gas's prior depreciation case, Case No. U-15699, beginning in 2013 the costs associated with transmission pipeline integrity assessments and remediation, pipe repair or replacement 50 feet in length or less, are expensed as routine transmission pipeline maintenance and are supported in Witness Tomina's testimony. The following assessment related costs associated with the ILI Expansion or pipeline integrity assessment sub-programs under the transmission integrity management program are capitalized and supported in this testimony:

(i) pipeline retrofits required to prepare the lines for ILI assessment (ILI Expansion),

(ii) replacement of sections of pipeline that are greater than 50 feet in length (under the standard retirement unit policy authorized in Case No. U-15699).

Although pipeline assessments are an O&M expense supported in Witness Tomina's testimony, the assessment methods are described in this testimony to provide background supporting the capital ILI Expansion program.

Q. What is the ILI method for assessing integrity of pipelines?

A. ILI involves inserting an electronic instrumented module into the pipeline at one end and propelling it to the other end utilizing the velocity of the gas, while recording metal loss data and other information about the pipeline. The instrument is often referred to as a "smart pig" and the process is described as launching and receiving a pig.

Q. What is the direct assessment method for assessing integrity of pipelines?

A. Direct assessment is a process for both external and internal corrosion assessment that involves the use of above-ground surveys to gather data that is used to identify areas of possible corrosion. Using sophisticated electronic instruments, small voltage and current gradients in the soil surrounding the pipeline are measured to look for indications of a coating defect and a potential location for external corrosion. These areas are then excavated and evaluated to determine the need for any pipeline remediation. The Company expects that this work will identify every defect that requires pipeline replacement. The Company selected direct assessment as the preferred assessment method for pipelines that have good coating condition, that are accessible for direct examination and are not good candidates for ILI.

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Q. What is ILI Expansion program?

A. ILI Expansion is the program implemented by DTE Gas to increase the coverage of transmission integrity assessments beyond the minimum requirements specified in MGSS, Subpart O, Pipeline Integrity Management. Under this program, pipelines previously assessed by methods other than ILI will be retrofitted with appropriate bends, launchers, receivers and valves to permit passage of ILI tools to assess the integrity of the pipelines beyond HCAs. Selection of expansion candidate lines is based on a combination of risk ranking from risk assessments and reassessment schedule.

Q. Why did DTE implement the ILI Expansion program?

A. DTE Gas started implementing the ILI Expansion program following completion of required baseline assessments in 2012. The ILI method was chosen for the integrity assessment expansion program because ILI gathers the most comprehensive data about pipelines, is the most versatile method in terms of coverage of pipeline threats, and is, therefore, the method preferred by most operators. Further, assessment by ILI provides information beyond HCA to get a full picture of the integrity of the assessed segment for continued service and is the most cost-effective method of assessment based on normalized cost/mile.

Q. Are there regulatory drivers for the ILI expansion program?

A. Yes, there are regulatory drivers described below for the ILI expansion program.

(1) A January 2015 safety report by the National Transportation Safety Board NTSB (NTSB/SS-15/01, PB2015-102735) on “Integrity Management of Gas Transmission Pipelines in High Consequence Areas” stated that “ILI yields the

highest per-mile discovery of pipe anomalies and the use of direct assessment as the sole integrity assessment method has numerous limitations." The NTSB recommends (i) expanding the use of ILI especially for intrastate pipelines and (ii) eliminating the use of DA as the sole integrity assessment method for pipelines.

(2) PHMSA, a division of the Federal Government's Department of Transportation (DOT), issued a Notice of Proposed Rule Making (NPRM) on safety of gas transmission pipelines in April 2016. The NPRM seeks (i) expansion of integrity management requirements beyond HCA and (ii) restrictions on use of specific assessment methods. Although a final rule has yet to be issued, the recent Pipes Act of 2016 requires the Secretary of Transportation to provide updates every 90 days on the status of outstanding regulation until a final rule has been published in the Federal Register. The industry expects a rule soon.

Q. What is the result of the ILI expansion program since inception?

A. Since 2012, eleven pipelines, totaling 229 miles, have been retrofitted for assessment by ILI. By year-end 2017, assessment of these lines by ILI will increase coverage of DTE Gas's transmission lines assessed by ILI to 46.1% from 38% in 2012.

Q. What is DTE Gas's plan for ILI expansion beyond 2017?

A. From 2018 through 2023, DTE Gas's ILI expansion plan includes retrofit of an additional 465 miles of pipeline for inspection by ILI. These retrofits will increase coverage of transmission pipelines assessable by ILI to 67% in 2023 from 38% when the program started in 2012, an increase of 76% in 11 years.

Correspondingly, assessment of HCA by ILI will increase from 71% in 2012 to 95% in 2023.

Q. What is the Remote Control Valve (RCV) program?

A. The RCV program is the automation of transmission pipeline sectionalizing valves (aka Main Line Valves-MLV) in pipeline HCAs, to permit remote closure of the valves in the event of a pipeline emergency.

Q. Why did DTE Gas implement a RCV program?

A. DTE Gas implemented its RCV program to (i) provide quick indication of a pipeline emergency at the Company's Gas Control, (ii) enable faster response and containment of an emergency, and (iii) reduce the consequences of an emergency to life and property in the riskiest segments of the pipelines (HCA areas). Prior to implementing the program, all MLVs in HCA were locally operated. Consequently, an emergency required a call-out to a trained pipeline technician, a process that could result in a response time of several minutes to hours depending on the location of the pipeline technician relative to the incident.

Q. What are the regulatory drivers for the RCV program?

A. (i) The MGSS, Subpart O, Pipeline Integrity Management, requires installation of Automatic Shut Off Valves (ASV) or Remote Controlled Valves (RCV) if an operator determines based on risk analysis that an ASV or RCV would be an efficient means of adding protection to a HCA in the event of a gas release.

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(ii) The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 requires pipeline owners and operators to install RCV, ASV or equivalent technology in HCAs of newly constructed or entirely replaced pipeline segments where economically, technically and operationally feasible.

DTE Gas determined from a risk evaluation conducted in 2008 that automation of MLVs in HCAs with remote control capability will provide faster response time in the event of a gas release and, thereby, reduce the impact of the release on life and property.

Q. What is the result of the RCV program since inception?

A. The RCV program commenced in 2011 and by year-end 2016, 108 MLVs and critical connector valves were automated with remote control capability.

Q. What is DTE Gas's plan for RCV program in 2017 and 2018?

A. An additional 39 valves will be automated in 2017 bringing total to date to 147 valves. The plan for 2018 is to automate an additional 38 valves for a program to date total of 185, which completes the automation of all 185 valves in HCA at the end of 2018.

Q. What is DTE Gas's plan for RCV program in 2019 through 2023?

A. From 2019 through 2023, DTE Gas plans to prioritize automation of valves in Moderate Consequence Areas (MCA) based on risk.

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Q. What is MAOP Records Review program?

A. MAOP Records Review is the review of pipeline records to ensure that the records are traceable, verifiable and complete and substantiate Maximum Allowable Operating Pressure (MAOP).

Q. Why did DTE Gas implement a MAOP Records Review program?

A. DTE Gas implemented the MAOP Records Review program in response to the Advisory Bulletin issued by PHMSA on January 10, 2011. The bulletin advised pipeline operators of their obligations to ensure that data used to establish pipeline MAOP are reliable. Further to the advisory bulletin, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 requires pipeline owners and operators to verify that records for gas transmission pipelines in HCA and class 3 and 4 locations accurately reflect pipeline physical and operational characteristics and can substantiate MAOP.

Q. What is the coverage of DTE Gas's MAOP Records Review program?

A. DTE Gas's MAOP Records Review program exceeds the requirements of the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. Specifically, the program covers all DTE Gas facilities operating at or above 100 psig as follows:

(i) 2200 miles of transmission pipelines, including MLV sites regardless of class location

(ii) 208 transmission gate stations

(iii) 10 compressor stations

(iv) 1367 miles of high pressure steel distribution pipelines

(v) 92 district pressure regulating stations

The wide coverage of the DTE program is in recognition of the risks inherent in pipeline operation. Although pipeline failures triggered by material defects typically result in rupture of transmission lines, distribution lines tend to leak under similar circumstances. A leak from a high pressure distribution pipeline in a populated area can have greater consequences than a ruptured transmission line in a less populated area.

Q. What is the result of the MAOP Records Review program since inception?

A. By year end 2017, records review to substantiate MAOP will be completed for 2200 miles of transmission lines, 208 gate stations, 4 compressor stations, 256 miles of high pressure steel distribution mains and 92 district regulating stations. Defects identified have been categorized by type. Because the release of final rules from PHMSA on acceptable remediation methods and timeline is still pending, only limited proactive remediation of defects is currently coordinated with pipeline integrity remediation schedules to minimize system outages.

Q. What is DTE Gas's plan for MAOP Records Review program beyond 2017?

A. From 2018 through 2023, DTE Gas plans to continue to implement the review plan for compressor stations and steel distribution pipelines operating at or above 100 psig. In addition, we anticipate the release of final rules on acceptable defect remediation methods and timeline by PHMSA in that time-period. The final rules will trigger a ramping up of record defect remediation in order to meet the anticipated timeline in the final rules. The resulting incremental O&M costs are covered in current projections for pipeline integrity O&M expenses in Witness Tomina's testimony.

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Q. What is the Records Management System?

A. DTE Gas's program on Records Management System is a multi-facet program for development of an electronic system to manage pipeline risks and records to assure safe archiving and quick retrieval of the records, as well as, automatic and frequent update of threats and relative risks for pipeline segments. Specifically it includes (i) mapping of transmission lines in ESRI-GIS utilizing GPS coordinates, (ii) creating an electronic records repository in Documentum, (iii) linking repository of MAOP records, construction records, assessment records, cathodic protection (CP) records, and routine O&M records to pipeline segments in ESRI, (iv) updating pipeline relative risk calculations (v) electronic update of HCA and class locations on Population Density Survey (PDS) maps utilizing aerial imagery and (vi) update of legacy construction to reflect current installation (as-built).

Q. Why did DTE Gas implement a Records Management System?

A. DTE Gas implemented an electronic records management system as described above for a number of reasons: (i) the development of an electronic repository of pipeline records replaces current paper records susceptible to loss or degradation over time and ensures compliance with MGSS, which requires records retention for the life of certain facilities (ii) to comply with the positional accuracy and significant increase in pipeline attribute data required in the proposed National Pipeline Mapping System (NPMS) information collection issued by PHMSA, (iii) to minimize the potential for pipeline hits by updating station records to reflect actual installations (as-built), (iv) to ensure that pipeline integrity risk mitigation through assessments and preventive and mitigative (P&M) measures is based on risk ranking reflecting current threats.

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Q. What is the result of DTE Gas Records Management System since inception?

A. From 2012 through 2016, DTE Gas (i) completed mapping of 2200 miles of transmission and 570 miles of gathering pipelines in ESRI-GIS, (ii) scanned data for 2200 miles of transmission pipelines to create an electronic data repository, (iii) completed linkage of 50% of MAOP data with segments in ESRI-GIS, (iv) developed a database for pipeline integrity digs (DA and ILI), (v) completed as-built of legacy gas piping drawings at Belle River Mills, Alpena and Reed City compressor stations, (vi) updated the transmission risk model to prioritize risk mitigation efforts and (vii) completed data acquisition from aerial imagery for electronic update of HCA/ Class location for transmission lines in the southeast region

Q. What is the plan for DTE Gas Records Management System in 2017 and 2018?

A. For 2017 and 2018, the focus of records management system development is (i) completing a functional risk ranking program, (ii) completion of data acquisition from aerial imagery to update PDS and refine relative risk ranking, (iii) management of GIS backlog for as-built in ESRI, (iv) acquisition of software for Preventive and Mitigative (P&M) measures, (v) complete as-built of legacy gas piping drawings at Columbus, Kalkaska and Taggart compressor stations.

Q. What is the plan for DTE Gas Records Management System in 2019 through 2023?

A. From 2019 through 2023, DTE Gas plans to (i) complete acquisition of aerial imagery for development of PDS for the entire transmission pipelines, (ii) perform field surveys to acquire GPS data for 60% of pipeline mileage not meeting the

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NPMS positional accuracy requirement of 100 ft., (iii) develop and implement methodology to extract and format the additional NPMS data requirements to facilitate data reporting annually, (iv) develop and implement a conversion plan to merge separate distribution and transmission pipeline data models into a new Utility and Pipeline Data Model (UPDM) for automatic and seamless extraction of data to calculate relative risks, (v) complete as-built of legacy piping drawings at the remaining compressor stations.

Q. What level of PI capital expenditures does the Company support in this proceeding for 2017 through September 2019?

A. From December 31, 2016, the end of the historical test year, through September 30, 2019, the end of the projected test year, DTE Gas will have incurred $30.6 million of PI capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 15, columns (f) and (g).

Q. Are the Company's Pipeline Integrity annual expenditures in this proceeding higher than the Commission approved level in general rate case, Case U-17999?

A. Yes, $11.1 million in annual PI IRM expenditures was approved in the last general rate case, Case U-17999 beginning January 1, 2017. The Company will have incurred an additional $2.7 million per year on average in 2017 and 2018 plus an additional $3.0 million in non-IRM Pipeline Integrity expenditures through September 30, 2019. The $3.0 million reflects additional expenditures above the $11.1 million Pipeline Integrity IRM approved expenditures in Case No. U-17999. After 2019 DTE Gas expects the PI capital spend to return to the Commission approved levels and is, therefore, not requesting an increase for pipeline integrity work in the proposed IRM, as supported by Witness Harris.

Q. Why are the annual Pipeline Integrity capital expenditures higher in 2017 through 2019?

A. First, the benefits of the RCV program were readily apparent when a RCV was operated to quickly contain the incident at DTE Gas's River Rouge facility in 2016. As a result, the Company decided to accelerate and complete automation of all 185 MLVs in HCA by 2018 instead of the original target date of 2020. This change added $1.2 million annually to the forecast spend in 2017 and 2018. Second, the focus on accelerating retrofit of transmission lines with HCA to permit end to end assessment of the pipelines by ILI to minimize risk, resulted in additional expenses. $2.0 million is planned in 2018 and $4.0 million is planned in 2019 for accelerated retrofit of the Northeast Beltline pipeline, a major supply pipeline to the Ann-Arbor market. Any incident resulting in loss of this supply at any time other than the summer, will result in over 50% outage in the Ann Arbor market. Consequently, accelerating ILI retrofit to enable determination of the condition of this pre-1970 vintage pipeline is crucial. This project is supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Projects.

Q. Are any other projects supported by the PI expenditures part of DTE Gas's highest cost projects?

A. Yes. Nine of the PI projects have expenditures large enough to fall into DTE Gas's highest cost projects and are supported in detail in Exhibit A-12, Schedule B5.3 Highest Cost Top 25 Capital Project Detail. Specifically, the projects are Northeast

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Beltline 24” ILI Expansion, Sparta-Muskegon 16” ILI Expansion, Loreed-Ludington 16” ILI Expansion, Gaylord 8” ILI Expansion, Mackinaw 8” ILI Expansion, Rogers City 8” ILI Expansion, South Suburban 30” ILI Expansion, Lincoln Traverse City 10” Pipe Replacement, and Loreed Ludington 16” Tie Line ILI Expansion.

Q. Are there pending regulations that could result in additional pipeline integrity capital expenditures?

A. Yes. The NTSB report on the San Bruno pipeline incident of 2010 recommended among other things that PHMSA:

(i) Amend Title 49 CFR, part 192 to eliminate the grandfather clause and require a pressure test of previously untested transmission pipelines. The grandfather clause is an exemption that currently allows pipelines installed prior to July 1, 1965 to establish MAOP based on the highest actual operating pressure to which the segment was subjected between July 1, 1965 and July 1, 1970.

(ii) Amend Title 49 CFR, part 192 so that manufacturing and construction related defects can only be considered stable if a gas pipeline has been subjected to a post construction hydrostatic test of at least 1.25 X MAOP.

(iii) Amend Title 49 CFR, part 192 to expand integrity assessments beyond areas currently designated as HCA to include major roadways such as freeways, interstates and expressways.

(iv) Advise pipeline operators to conduct a review of transmission pipeline records to ensure that the records are traceable, verifiable and complete, and substantiate MAOP.

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These recommendations formed the basis of the requirement in the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 for DOT to issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in HCA and operating at a pressure greater than 30% of Specified Minimum Yield strength (SMYS). PHMSA, in response, commenced rule making process in 2011 and has issued a NPRM in April, 2016. The final rule is still pending. DTE Gas has included O&M costs to implement the requirements of the rule in Witness Tomina's testimony. DTE Gas has not included the capital costs to retrofit pipelines for re-establishing MAOP or implement other requirements of the NPRM in this testimony pending guidance of the final rule.

METER MOVE-OUT (MMO) PROGRAM

Q. What is the MMO Program?

A. DTE Gas's MMO Program is a focused effort to relocate existing residential natural gas meters from their inside locations to outside locations and address any associated infrastructure needs that arise in the area impacted by the meter relocation. The long-term meter move-out program filed by DTE Gas in Case No. U-16451 and adopted by the MPSC on September 13, 2011, undertakes a plan to systematically relocate residential inside meters on a block-by-block basis and perform the work in a cost-efficient manner. The program was developed to improve DTE's infrastructure and system safety and reliability while enhancing customer service.

Q. What level of MMO capital expenditures does the Company support in this proceeding for 2017 through 2018?

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A. From December 31, 2016, the end of the historical test year, through December 31, 2018, DTE Gas will have incurred $49.0 million of MMO capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 18, columns (f) and (g).

Q. Are the Company's MMO annual expenditures in this proceeding higher than the Commission approved level in general rate case, Case U-17999?

A. Yes. $22.7 million in annual MMO IRM expenditures was approved in the last general rate case, Case U-17999 beginning January 1, 2017. The Company plans to spend an additional $1.8 million per year on average in 2017 and 2018. The MMO expanded program to address additional meters is supported by Witness Harris. MMO capital expenditures from 2019 through 2023 are supported by Witness Harris.

MAIN RENEWAL PROGRAM (MRP)

Q. What is the MRP?

A. DTE Gas's MRP is a focused main renewal replacement effort that has accelerated the upgrade of DTE Gas's distribution system. The program focuses on DTE Gas's main renewal and retirement efforts on poor performing mains and puts in motion a long-term strategy to reduce the Company's level of incoming leaks and lost and unaccounted for gas resulting from gas leaks. MRP is a Company-wide program, but is concentrated in Southeast Michigan where the majority (approximately 70%) of DTE Gas's cast iron and un-protected steel mains are located.

Q. What level of MRP capital expenditures does the Company support in this proceeding for 2017 through 2018?

A. From December 31, 2016, the end of the historical test year, through December 31, 2018, DTE Gas will have incurred $259.1 million of MRP capital expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1, line 16, columns (f) and (g).

Q. Are the Company's MRP annual expenditures in this proceeding higher than the Commission approved level in general rate case, Case U-17999?

A. Yes. $93.8 million in annual MRP IRM expenditures was approved in the last general rate case, Case U-17999 beginning January 1, 2017. The Company plans to spend an additional $35.8 million per year on average in 2017 and 2018 to further accelerate the replacement of the aging distribution mains. MRP capital expenditures from 2019 through 2023 are supported by Witness Harris.

Q. Are there additional IRM capital expenditures the Company is supporting in this proceeding for 2017 through 2018?

A. Yes. In 2018, the Company is supporting $7.7 million for the new MMO MAC program as described in the testimony of Witness Harris. Witness Harris is supporting the MMO MAC capital expenditures from 2019 through 2023.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KENNETH L. SLATER

DTE GAS 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 Gas Company (DTE Gas).

Q. What is your educational background and business experience?

A. I received a Bachelor of Science Degree in Business Administration, with a major in Accounting, from Lawrence Technological University in 1980. In June 1980, I joined Michigan Consolidated Gas Company (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 are your current duties and responsibilities?

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 Company and DTE Gas Company.

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

A. Yes. I have sponsored testimony before the MPSC in several 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-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 application 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-18251	DTE Electric Company's Reconciliation of its Transitional Reconciliation Mechanism for the Period of January 1, 2016 through December 31, 2016
U-18242	DTE Electric 2016 REP Reconciliation
U-18082	DTE Electric 2015 REP Reconciliation
U-18024	DTE Gas 2015 EO Reconciliation
U-18023	DTE Electric 2015 EO Reconciliation

U-18005	DTE Electric Company's Reconciliation of its Transitional Reconciliation Mechanism for the Period of January 1, 2015 through December 31, 2015
U-17999	DTE Gas Company's application for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority
U-17761	DTE Electric Company for Reconciliation of its Transitional Reconciliation Mechanism associated with the Disposition of the City of Detroit Public Lighting System for the Period of August 1, 2013 through December 31, 2014
U-17238	Approval of a Refund Related to Self-Implementation of general service rates beginning November 1, 2012 and ending December 31, 2012
U-17103	MichCon's Reconciliation of its Revenue Decoupling Mechanism for the Period July 1, 2011 through June 30, 2012
U-16877	MichCon's Reconciliation of its Revenue Decoupling Mechanism for the Period July 1, 2010 through June 30, 2011
U-16447	Approval of a Refund Related to Self-Implementation of general service rates beginning January 1, 2010 and ending June 3, 2010
U-13898	MichCon's Application for Authority to Increase Its Rates and for Other Relief
U-13342	MichCon's 2001 Income Sharing Calculation
U-11210	Complaint Case (Title Transfer Fees)

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Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony in this proceeding is to support DTE Gas's:

- Proposed Cost of service study (Proposed COSS), by rate schedule, for the Projected test year ending September 30, 2019 (projected test year) for both sales and end-user transportation and an alternative COSS, by rate schedule, for the projected test year reflecting the loss of two customers, AK Steel and Ford Motor Company (Alternative COSS);
- Rates for each rate schedule that include a monthly service charge and a commodity distribution charge based on the results of the two cost of service studies (Proposed COSS and Alternative COSS);
- The development of a proposed unbundled rate covering off-system transportation and an alternative unbundled rate covering off-system transportation reflecting the loss of two customers, AK Steel and Ford Motor Company;
- The proposed Infrastructure Recovery Mechanism (IRM) monthly charges and an alternative (IRM) monthly charges reflecting the loss of two customers, AK Steel and Ford Motor Company; and
- Proposed tariff changes relating to modifications applicable to its various rate schedules.

Specifically, my testimony includes the following subjects:

- A discussion of the purpose of a Cost of Service Study (COSS) and how it was performed for DTE Gas;
- Which COSS allocation schedules were used and how they were determined;

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- A discussion of peak day allocation schedules and why use of the design peak day is appropriate;
- The rate classes utilized in the COSS;
- A description of the various exhibits I am supporting; and
- A discussion of how I designed the proposed monthly service charges and distribution rates.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring exhibits for Section B projected test year (ending September 30, 2019).

Q. What exhibits you are sponsoring for the Section B projected test year?

A. I am sponsoring the following projected test year exhibits.

Section B: Projected Year Ending September 30, 2019 Exhibits

Exhibit	Schedule	Description
A-13	C4	Projected Cost of Gas
A-16	F1	Cost of Service Summary for the Projected Test Year Ending September 30, 2019
A-16	F1.1	Cost of Service Study for the Projected Test Year Ending September 30, 2019
A-16	F1.2	Allocation Schedules for the Projected Test Year Ending September 30, 2019
A-16	F2	Summary of Projected Test Year Ending 9/30/2019 Proposed Gas Revenue Increase, Comparison of Rates,

		and Comparison of Present and Proposed Customer Charges
A-16	F3	Calculation of the Projected Test Year Ending September 30, 2019 Current and Proposed Revenues by Rate Schedule
A-16	F4	Comparison of Typical Bills Under Current and Proposed Rates
A-16	F5	Summary of Proposed Tariff Changes
A-16	F5.1	Proposed Tariff Sheets
A-16	F6	Derivation of Transportation Cost of Service Rate
A-18	H3	Calculation of Monthly Charges for Proposed Infrastructure Recovery Mechanism
A-18	H4	Comparison of Typical Bills Under Current and Proposed Rates Including IRM
A-22	L3	Alternative COSS Summary for the Projected Test Year Ending Sept 30, 2019
A-22	L3.1	Alternative COSS for the Projected Test Year Ending Sept. 30, 2019
A-22	L3.2	Alternative Allocation Schedules for the Projected Test Year Ending 9/30/2019
A-22	L4	Summary of Projected Test Year Ending 9/30/2019 Alternative Proposed Gas Rate Increase, Comparison of Rates, and Comparison of Present and Alter. Proposed Customer Charges

A-22	L5	Calculation of the Projected Test Year Ending September 30, 2019 Current and Alternative Proposed Revenues by Rate Schedule
A-22	L6	Comparison of Typical Bills Under Current and Alternative Proposed Rates
A-22	L7	Derivation of Alternative Transportation Cost of Service Rate
A-22	L8	Calculation of Monthly Charges for Alternative Proposed Infrastructure Recovery Mechanism
A-22	L9	Comparison of Typical Bills Under Current and Alter. Proposed Rates Inc. Alter. IRM
A-22	L10	Summary of Projected Test Year Ending 9/30/2019 Proposed Gas Rate Increase, Proposed vs Alternative, and Comparison of Rates - Proposed vs Alternative
A-22	L11	Comparison of Typical Bills Under Proposed and Alt. Proposed Rates

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

A. Yes, they were.

COST OF SERVICE STUDY

Q. What is the purpose of a COSS?

A. The COSS is an allocation of a company's total costs of doing business (i.e., the total revenue requirement) to its various customer classes/rate schedules. The allocation for the projected year Proposed COSS is captured on Exhibit A-16, Schedule F1.1. Exhibit

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A-16 supports the Company's proposed COSS and rates in this case. The allocation for the Alternative COSS is captured on Exhibit A-22, Schedule L3.1. Exhibit A-22 supports the Company's alternative COSS and rates in this case to demonstrate the impact of losing two large customers, AK Steel and Ford Rouge as discussed by Company Witness Mr. Decker.

The projected test year cost of service is an important element used in establishing a utility's proposed tariff rates. It shows the cost of providing service to each customer class needed for the Company to earn the requested rate of return.

Q. What is the process in performing a COSS?

A. The first step in the process is to separate the costs by function. This step is facilitated by the MPSC uniform system of accounts, which segregates most of the utility's plant and costs by function. These functional classifications include direct costs such as gas storage, transportation, distribution, as well as indirect costs such as general plant, and administrative and general costs. The direct costs are directly assigned to the corresponding function as shown on pages 1 and 2 of the proposed (Exhibit A-16, Schedule F1.1) COSS and pages 1 and 2 of the Alternative COSS (Exhibit A-22, Schedule L3.1). The indirect costs must be allocated to the various rate classes. The allocation of Rate Base indirect costs occurs on page 3, Other Operating expenses on page 4, and Revenues on page 5. Page 5 also includes allocations of Uncollectible expense and Federal Income Taxes. The allocation schedules used are summarized on page 6.

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Q. What guiding principles are followed in determining which allocation schedule should be used to assign costs to the individual rate classes within the cost of service study?

A. Cost causation is the main guiding principle used to determine which allocation schedule is appropriate to use to assign costs to the various rate classes. Under this principle, an allocation schedule is selected such that the costs are assigned to the class that caused the cost to be incurred. For example, meters are allocated based on customer counts weighted by the cost of a meter and its installation that serves a particular class of customer.

The allocation schedules used in DTE Gas's proposed and alternative COSSs are generally the result of long-standing practices that have evolved over decades of litigated rate cases.

Q. How are the COSS allocation schedules determined?

A. COSS allocation schedules are determined on Exhibit A-16, Schedule F1.2 for the proposed COSS and on Exhibit A-22, Schedule F3.2 for the Alternative COSS. These allocation schedules are developed to assign/allocate costs to the individual rate classes. There are twenty-three different allocation schedules (Allocation Schedules 1 through 21 and two variants, Allocation Schedules 3A and 12A) in both COSSs. The basic components of the allocation schedules are volume, customer count, demand, and revenue. The result of any allocation schedule is simply to determine the individual rate class's percentage share of the allocation schedule total.

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Certain costs are not allocated to all rate classes. There are plant items and expenses that relate to more than one of the above functions and allocations for these items are made based on the appropriate combination of the allocation results for other costs and plant items. General plant, property taxes, other revenues, and administrative and general expenses are examples of items classified and allocated based on combining the results of allocating other costs. The basic process is to use these schedules, and variants of them, to allocate costs where appropriate.

As needed, additional allocation schedules are developed to allocate costs that are not allocated by one of the base component allocation schedules. These additional allocation schedules are derived from the results of applying the base component schedules where appropriate. The process involves determining the class cost for subsets of all costs allocated by the base schedules, totaling those subsets of costs for each rate class grouping, and then dividing each class total by the sum for all classes.

Q. What are the base customer allocation schedules and their variants?

A. The base customer allocation schedules are simply the number of customers in a class divided by the total number of customers. Some costs are only related to residential customers while others may be related only to transportation customers and others are related only to non-transportation customers. To properly allocate costs in these instances, variant allocation schedules are derived by dividing the number of customers in the class by the total number of customers in the subgroup of interest. In some instances, simple customer count does not adequately define the relationship between customer-related costs and cost causation. Historically, some customer costs have been considered to be a function of both customers and the cost of the physical service

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installation. For these instances, a set of variants is developed that weights the customer counts using costs for installing meters and associated equipment to provide service. The residential class, Rate schedule A, has the lowest meter installation cost and is given a weight factor of one. The weight factors for other rate classes are simply the typical meter and installation cost for the rate divided by the typical meter and installation cost for the residential class.

Q. How are base commodity allocation schedules determined?

A. Commodity allocation schedules are developed based upon the annual gas consumption of each rate class as a percentage of the total of all rate class consumption. As was the case for customer related costs, some commodity related costs are related only to residential volumes while others may be related only to transportation volumes and others are related only to non-transportation volumes. To properly allocate costs in these instances, variant allocation schedules are derived by dividing the volume in the class by the total volume in the subgroup of interest.

Q. Are there demand/capacity allocation methodologies adopted by the MPSC in Case No. U-17999 which are reflected in the design of DTE Gas's current rates?

A. Yes. The MPSC in Case No. U-17999 reaffirmed its long-standing approval of two demand/capacity allocation methods. The Average and Peak (A&P) allocation method was approved for allocating functionalized transportation costs and non-customer related distribution costs. For storage costs, a blended method of 50% cost allocation on the Peak method and 50% cost allocation on the percentage of storage capacity was approved. Both adopted methods used a coincidental peak day assuming operation at design conditions in the determinations of the allocation schedules.

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Q. What is the A&P allocation method?

A. This method blends a rate class's average demand and peak demand giving a weighted percent for use in allocating transmission and distribution costs. The A&P method uses average consumption schedule as an integral part in allocating demand costs. Under the A&P method, the portion used to meet the maximum system load is determined by dividing each rate class's peak day consumption by total peak day consumption. This method is captured as Allocation Schedule No. 3 in both studies.

The A&P allocation method can be represented as:

$$D = 50\%\ x\,[\mathrm{L}\ x\ \frac{A}{\mathrm{B}}] + 50\%\ x\,[\,(1 - \mathrm{L})\ \mathrm{x}\ \frac{\mathrm{C}}{\mathrm{E}}]$$

Where: The first term represents the "average" component and the second represents the "peak" component; and

D = customer group's demand responsibility ratio

L = system's annual load factor = system average / system peak

A = customer group's average volume

B = total system average volume

C = customer group's peak day volume

E = total system peak day volume

Q. How is the storage demand allocation schedule calculated?

A. The storage demand allocation method, identified as Allocation Schedule No. 4, was reaffirmed by the Commission in Case No. U-17999. This method reflects a 50% blend of storage capacity and 50% peak demand to yield the Storage Peak Allocator. The first step in calculating this allocation schedule is to establish the amount of storage to be allocated to the sales and end-user transportation classes. The cyclable storage capacity allocated to end-user transportation customers (including 0.8 Bcf of Exelon) is 11.4 Bcf for the proposed COSS. For the alternative COSS the cyclable storage capacity allocated to end-user transportation customers (including the 0.8 Bcf of Exelon and excluding the 0.58 Bcf of AK Steel and 0.13 Bcf of Ford Rouge) is 10.69 Bcf. For gas sales customers, the assigned cyclable storage capacity is 71.9 Bcf for the proposed COSS and alternative COSS per DTE Gas's 2017/2018 GCR Plan Case No. U-18152. The resulting storage delivery components comprise 50 percent of the Storage Demand allocation schedule used to allocate costs. The other 50 percent of the Storage Peak allocation schedule is based upon the peak demand component developed in Allocation Schedule No. 3. Consequently, the Storage Peak Allocator is equal to the sum of (1) 50 percent of the storage demand component, and (2) 50 percent of the peak demand component.

Q. What peak day volume did you use in developing your demand related allocation schedules in the cost of service analyses?

A. For the projected test year proposed COSS, I used the Company's January design peak day requirement of 2.49 Bcf from DTE Gas's GCR Plan Case No. U-18152. For the alternative COSS, I used the Company's January design peak day requirement of 2.49 Bcf from DTE Gas's GCR Plan Case No. U-18152 adjusted downward by 71,500 MMcf) to 2.42 Bcf to reflect the loss of AK Steel and Ford Rouge provided by Company Witness Ms. Aud.

Q. Why do you use the Design Peak Day?

A. Based upon the testimony of Witness Aud, use of the design peak day is appropriate because it represents a consumption level most reflective of the design of the utility's system versus historical demands. The use of a historical peak day may not reflect consumption for severe cold weather because on that day temperatures may have been above the design conditions. The design peak day is defined as the consumption expected on a day with an average temperature of –4°F. Customer mix impacts the design peak day volume as each class has a different sensitivity to temperature.

Q. Is the design peak still the most appropriate method for allocating costs such as storage and transmission related expenses?

A. Yes. The reasons used by DTE Gas to support the adoption of the design peak day methodology in its past rate case proceedings are still valid today. From a cost causation point of view, this methodology mirrors the allocation of facilities for determining the Company's physical operations that are part of the Gas Cost Recovery process. For the reasons previously stated, the design peak day allocation methodology for allocating storage and transmission expense is superior to the use of other allocation methodologies that might use historical peak day, normal peak day, annual throughput or average customers.

Q. What changes have you made to the rate schedules in the Cost of Service model?

A. None. I continue to support Rate A, Meter Class I and Meter Class II of Rate 2A, Rate GS-1 and GS-2, and Rate S. Also, I continue to separate the End User Transportation (EUT) class into Rate Schedules ST, LT, XLT, XXLT, Exelon and a special contract for Dearborn Industrial Generation, LLC (DIG), consistent with rate schedules approved in Case No. U-17999.

Q. Are you proposing to allocate any costs differently than the methods as approved in Case No. U-17999 in the projected test year COSS or the alternative COSS?

A. Nearly all the allocation methods I use in the projected test year in the proposed COSS (Exhibit A-16, Schedule F1.1) and the alternative COSS (Exhibit A-22, Schedule L3.1) are the same as those approved in Case No. U-17999. However, I have broken out Intangible plant into MARS development, Transmission Software, HPP software, and other. Intangible Plant - MARS development is allocated based on Allocator Number 3, Average and Peak, which is the same allocation approved by the Commission in Case No. U-17999 for this cost. I am proposing allocating Intangible Plant – Transmission based on the same allocator used for Transmission Plant, Allocator Number 3, Average and Peak. For Intangible Plant - HPP I am proposing allocating this by Allocator Number 12, Distribution Plant, which is the same allocator used to allocate the Appliance Service Revenue (HPP Revenue) that this software supports. For Intangible Plant – Other I am proposing allocating this by Allocator Number 8, Customer – All, which reflects that the software systems under Other supports all customers.

Q. Where have you reflected the modifications described above?

A. I reflect the modifications described above in the projected proposed COSS (Exhibit A-16, Schedule F1.1, page 3, lines 12 through 15) and the alternative COSS (Exhibit A-22, Schedule L3.1, page 3, lines 12 through 15). Intangible Plant - MARS development is shown on line 12, Intangible Plant – Other is shown on line 13, Intangible Plant Transmission is shown on line 14, and Intangible Plant – HPP is shown on line 15.

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SECTION B PROJECTED TEST YEAR (Ends September 30, 2019):

Exhibit A-13 Projected Cost of Gas

Q. What is the schedule within Exhibit A-13 that you are sponsoring?

A. I am sponsoring Schedule C4, Projected Cost of Gas. This exhibit calculates the cost of gas sold for the projected test year based upon an assumed cost of gas of $3.22 per Mcf supported by Company Witness Mr. Chapel.

Exhibit A-16 Cost of Service and Rate Design

Q. What schedules within Exhibit A-16 are you sponsoring?

A. I am sponsoring the following schedules within Exhibit A-16:

Schedule F1: Cost of Service Summary for the Projected Test Year Ending September 30, 2019

This schedule provides a summary of DTE Gas's cost of service allocation study for the projected test year. The customer, capacity, and commodity components of the cost of service study are provided for each rate schedule. Customer count and volumes are also provided and used to establish cost of service unit costs.

Schedule F1.1: Cost of Service Study for the Projected Test Year Ending September 30, 2019

This six-page schedule provides details of the allocation of rate base, revenues and expenses from the cost of service study for DTE Gas for the projected test year. This exhibit provides the amounts allocated to the various rate schedule groupings for the various components of revenue requirement. The allocation method is identified and a listing of the allocation methods used is provided on page 6 of the exhibit. Page 5 of this exhibit is a summary of DTE Gas's cost of service allocation study for the projected test year revenue deficiency.

<u>Schedule F1.2: Allocation Schedules for the Projected Test Year Ending September 30, 2019</u>

This twenty-one-page schedule calculates the various allocation schedules used in the cost of service study.

<u>Schedule F2: Summary of Projected Test Year Ending 9/30/2019 Proposed Gas Rate Increase, Comparison of Rates, and Comparison of Present and Proposed Customer Charges</u>

This schedule consists of four pages. Page 1 summarizes by rate class: (1) projected Test Year volumes; (2) annual operating revenues under both current and proposed rates, inclusive of the cost of gas and the IRM surcharge; and (3) the projected increase. Page 2 summarizes current and proposed rates for the gas sales rate schedules. Page 3 summarizes current and proposed rates for the transportation rate schedules. Page 4 compares the following customer charges: (1) current; (2) proposed; and (3) per cost of service study.

<u>Schedule F3: Calculation of Projected Test Year Ending September 30, 2019 Current and Proposed Revenues by Rate Schedule</u>

This schedule consists of four pages detailing the calculation of existing and proposed revenue and increase/(decrease) by rate schedule and the calculation of the proposed rates.

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Schedule F4: Comparison of Typical Bills Under Current and Proposed Rates

This schedule consists of six pages and calculates typical bills for each of the gas sales rates using current and proposed rates.

Q. Why are the monthly customer charges you calculated on Exhibit A-16, Schedule F2, page 4, column (c), not the same amounts that DTE Gas is requesting for approval by the Commission?

A. I calculated a monthly customer charge pursuant to the cost of service method, under which I classified costs as commodity, capacity or customer related. The monthly customer charge I calculated combined the capacity and customer related costs. However, Witness Decker has recommended and instructed me to use the amounts that I have reflected on Exhibit A-16, Schedule F2, page 4, column (d). I developed the distribution charges for end user transportation customers recognizing the relationship between two factors: (1) the monthly customer charges I was directed to use, and (2) the economic breakeven points between ST, LT, XLT and XXLT that I was directed to achieve. Witness Decker describes these economic breakeven points and the considerations provided for establishing the breakeven points in his testimony.

Q. How were the various rates and charges for each rate schedule developed?

A. The starting point for rate design is the net cost of service by rate grouping. For purposes of rate design, residential customers taking service under Rate A and 2A are treated as one group for determining the distribution charge. Rates GS-1 and GS-2 are also grouped together and Exelon and DIG are grouped with the XXLT rate class. Several adjustments are made to the cost of service to arrive at a cost of service for rate making. I will elaborate on these adjustments later in my testimony. Service charge revenue is subtracted from the rate making cost of service to yield the amount to be collected in the distribution charge. The amount to be collected in the distribution charge is divided by the appropriate volume to obtain the unit rate.

Q. What ratemaking adjustments were made to the allocated cost of service?

A. There were several adjustments made to the allocated cost of service. DTE Gas Witness Mr. Johnson has proposed reducing the number of Residential Income Assistance (RIA) credit customers to reflect a level closer to the current level of customers receiving the RIA credit. Witness Johnson is also proposing to increase the participation cap under the LIA credit while maintaining the LIA credit of $30 per month discount. Since the rates are designed to recover the entire cost of service, this deficiency must be reallocated to the cost of service of all other customer groups. In the case of the RIA and LIA credit, consistent with the Commission's order in Case Nos. U-15985 and U-17999 on the RIA credit, an amount equal and opposite to the credit is allocated to all customers using Allocation Schedule No. 20 (cost of service plus cost of gas). This allocation appears on page 5 of Exhibit A-16, Schedule F1.1.

A design criterion for Rate 2A requires that the distribution rate for Rate 2A be equal to the distribution rate for Rate A, since the service being provided to the customers under these rate schedules is essentially the same. This requirement may result in an adjustment to the cost of service for Rate 2A with an equal and opposite adjustment to the rate group containing Rate A.

Various adjustments were made to the EUT rate schedules and are summarized on page 4 of Exhibit A-16, Schedule F3. These adjustments were necessary to achieve the breakeven points discussed earlier in my testimony. I have also included adjustments to Rate Schedules XLT and XXLT to reflect the fixed discount of $0.1468 per Mcf for Ford-Rouge under Rate schedule XLT and to reflect the fixed discount of $0.0423 per Mcf for AK Steel under Rate Schedule XXLT as directed by Witness Decker. I am proposing that the discounts to Ford-Rouge of a fixed $194,000 annually (1,321 MMcf * $0.1468 / Mcf) and to AK Steel of a fixed $495,000 annually (11,705 MMcf * $0.0423 / Mcf), $689,000 in total, be reallocated to the cost of service of all customer groups. On page 5 of Exhibit A-16, Schedule F1.1, the credits are reflected on line 24 for XLT and XXLT and an amount equal and opposite to the credits on line 25 is allocated to all customers using Allocation Schedule No. 20 (cost of service plus cost of gas). Like the RIA and LIA credits the use of Allocation Schedule No. 20 reflects that all customers benefit from keeping these customers on DTE Gas's system by providing the discount to these two customers.

Finally, a small adjustment was made to preserve the breakeven point between Rates S (Schools) and GS-1 (General Service). I reallocated $0.5 million from Rate S to Rates GS-1 and GS-2.

Q. What is Exhibit A-16, Schedule F6 that you are sponsoring?

A. Exhibit A-16, Schedule F6 is the Derivation of Transportation Cost of Service Rate of $0.376. This exhibit provides transportation related unbundled components of the Company rate base and revenue expense items from the cost of service study for the transportation functional group.

Q. What is shown on Exhibit A-16, Schedule F6?

A. This schedule identifies the projected gas transportation system costs used in developing DTE Gas's revenue requirement. These costs were taken directly from the projected test year cost of service by rate schedule. The schedule identifies DTE Gas's sales and transportation throughput for the projected test year. The cost of service for the gas transportation system is divided by the total of sales, transportation and Exelon throughput to arrive at the unit cost of service. This unit cost of service is built into DTE Gas's cost of service for its gas sales tariff, end user transportation customers and Exelon to recover the costs associated with the transportation system. This value represents the maximum or cap of the transportation commodity charge that can be included in the market based rate DTE Gas is proposing to charge off-system or third party shippers for gas transported on DTE Gas's gas transportation system.

<u>Exhibit A-18 Infrastructure Recovery Mechanism Monthly Charges</u>

Q. What schedules within Exhibit A-18 are you sponsoring?

A. I am sponsoring the following schedules within Exhibit A-18:

<u>Schedule H3: Calculation of Monthly Charges for Proposed IRM</u>

This six-page schedule calculates the monthly IRM charge and provides details of the allocation of the IRM revenue requirement for DTE Gas for the years 2019 through 2023. This exhibit provides the amounts allocated to the various rate schedule groupings for the two components of the IRM revenue requirement. The allocation method is identified and the annual charge is calculated. A summary of the calculated monthly charges is provided on page 6 of the exhibit.

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<u>Schedule H4: Comparison of Typical Bills Under Current and Proposed Rates Including IRM</u>

This schedule consists of six pages and calculates typical bills for each of the gas sales rates using current and proposed rates including the 2019 IRM charge.

Q. What information is provided on Exhibit A-18, Schedule H3 entitled "Calculation of Monthly Charges for Proposed Infrastructure Recovery Mechanism?"

A. Exhibit A-18, Schedule H3, pages 1-5, calculates the monthly per meter charge for each rate schedule for years 2019 through 2023 relating to DTE Gas's IRM. Lines 1-6 on pages 1-5, list and calculate the allocation schedules used to allocate the IRM revenue requirement components listed on lines 9 and 10. Lines 2 and 5 remove Exelon from the allocation schedules consistent with the methodology approved by the Commission in Case Nos. U-16999 and U-17999. The initial monthly charge for 2019 through 2023 is calculated on line 16 by dividing the total revenue requirement on line 11 (the total of lines 9 and 10) by number of customers on line 14 over a 12-month period. The maximum charge for the transportation rate schedules ST, LT, XLT, and XXLT calculated on line 16 are capped at 50% of the proposed monthly customer charges shown on Exhibit A-16, Schedule F2, page 3 of 4, column (c) for each rate schedule, respectively. This methodology, except for the calculation of the maximum charge, was previously approved by the Commission in Case No. U-17999. To the extent the calculated charge exceeds the cap, the excess is then reallocated to the other rate schedules on lines 20-22. Line 24 reflects a revised revenue requirement and includes the reallocation from lines 20-22. The proposed monthly charge is calculated on line 28 by dividing line 24 by the number of customers on line 26. Page 6 of Exhibit A-18, Schedule H3 is summary of the monthly IRM charges by rate schedule by year.

Q. Why are you proposing to change the IRM surcharge maximum monthly charge for rate schedules ST, LT, XLT, and XXLT, from the current 25% of the proposed monthly customer charges to 50% of the proposed monthly service charges shown on Exhibit A-16, Schedule F2, page 3 of 4, column (c)?

A. While the current 25% of the proposed monthly customer charges as the maximum monthly charge would not result in excess charges being reallocated to other rate schedules in the first year, 2019, of the program, significant ($5.1 million) excess charges would have been reallocated to other rate schedules starting in 2020, the second year of the program (and larger amounts in subsequent years). To mitigate this shift, I am proposing to increase the maximum monthly charge to 50% of the proposed monthly customer charges shown on Exhibit A-16, Schedule F2, page 3 of 4, column (c). This results in only $0.9 million in excess charges being reallocated to other rate schedules in 2020, the second year of the program.

In addition, a 50% cap will introduce more gradualism to the change between EUT customers' bills when the IRM surcharge is in effect and when IRM costs are rolled into base rates.

Q. How did you allocate the revenue requirement to each Rate Class on lines 9-10 of Exhibit A-18, Schedule H3, pages 1-5?

A. I allocated line 9, MRP and pipeline integrity costs using the A&P allocator because consistent with their treatment in the order in Case No. U-17999. I allocated Meter

Move Out (MMO) costs using the customer allocator because the number of customers is equal to the number of meters consistent with their treatment in the order in Case No. U-17999.

<u>Exhibit A-22 Alternative Cost of Service, Rate Design, and IRM</u>

Q. What schedules within Exhibit A-22 are you sponsoring?

A. I am sponsoring the following schedules within Exhibit A-22:

<u>Schedule L3: Alternative Cost of Service Summary for the Projected Test Year Ending Sept. 30, 2019</u>

This schedule provides a summary of DTE Gas's Alternative cost of service allocation study for the projected test year reflecting the loss of two customers, AK Steel and Ford Motor Company. The customer, capacity, and commodity components of the cost of service study are provided for each rate schedule. Customer count and volumes are also provided and used to establish cost of service unit costs.

<u>Schedule L3.1: Alternative COSS for the Projected Test Year Ending Sept. 30, 2019</u>

This six-page schedule provides details of the allocation of rate base, revenues and expenses from the alternative cost of service study for DTE Gas for the projected test year reflecting the loss of two customers, AK Steel and Ford Motor Company. This exhibit provides the amounts allocated to the various rate schedule groupings for the various components of revenue requirement. The allocation method is identified and a listing of the allocation methods used is provided on page 6 of the exhibit. Page 5 of this exhibit is a summary of DTE Gas's alternative cost of service allocation study for the projected test year revenue deficiency.

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Schedule L3.2: Alternative Allocation Schedules for the Projected Test Year Ending 9/30/2019

This twenty-one-page schedule calculates the various allocation schedules used in the alternative cost of service study reflecting the loss of two customers, AK Steel and Ford Motor Company.

Schedule L4: Summary of Projected Test Year Ending 9/30/2019 Alternative Proposed Gas Rate Increase, Comparison of Rates, and Comparison of Present and Alter. Proposed Customer Charges

This schedule consists of four pages. Page 1 summarizes by rate class: (1) projected Test Year volumes; (2) annual operating revenues under both current and proposed rates, inclusive of the cost of gas and the IRM surcharge; and (3) the projected increase. Page 2 summarizes current and proposed rates for the gas sales rate schedules. Page 3 summarizes current and proposed rates for the transportation rate schedules. Page 4 compares the following customer charges: (1) current; (2) alternative proposed; and (3) per cost of service study.

Schedule L5: Calculation of Projected Test Year Ending September 30, 2019 Current and Alternative Proposed Revenues by Rate Schedule

This schedule consists of four pages detailing the calculation of current and alternative proposed revenue and increase/(decrease) by rate schedule and the calculation of the alternative proposed rates.

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Schedule L6: Comparison of Typical Bills Under Current and Alternative Proposed Rates

This schedule consists of six pages and calculates typical bills for each of the gas sales rates using current and alternative proposed rates.

Schedule L7: Derivation of Alternative Transportation Cost of Service Rate

This schedule identifies the projected gas transportation system costs used in developing DTE Gas's revenue requirement. These costs were taken directly from the projected test year cost of service by rate schedule. The schedule identifies DTE Gas's sales and transportation throughput for the projected test year. The cost of service for the gas transportation system is divided by the total of sales, transportation and Exelon throughput to arrive at the unit cost of service.

Schedule L8: Calculation of Monthly Charges for Alternative Proposed Infrastructure Recovery Mechanism

This six-page schedule calculates the monthly IRM charge and provides details of the allocation of the IRM revenue requirement for DTE Gas for the years 2019 through 2023. This exhibit provides the amounts allocated to the various rate schedule groupings for the two components of the IRM revenue requirement. The allocation method is identified and the annual charge is calculated. A summary of the calculated alternative proposed monthly charges is provided on page 6 of the exhibit.

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<u>Schedule L9: Comparison of Typical Bills Under Current and Alternative Proposed Rates Inc. Alternative IRM</u>

This schedule consists of six pages and calculates typical bills for each of the gas sales rates using current and alternative proposed rates including the alternative 2019 IRM charge.

<u>Schedule L10: Summary of Projected Test Year Ending 9/30/2019 Proposed Gas Rate Increase, Proposed vs Alternative, and Comparison of Rates - Proposed vs Alternative</u>

This schedule consists of three pages. Page 1 summarizes by rate class: (1) annual operating revenues under both proposed and alternative proposed rates, inclusive of the cost of gas and the IRM surcharge; and (2) the increase/(decrease) by rate schedule in annual operating revenues. Page 2 summarizes proposed and alternative proposed rates for the gas sales rate schedules. Page 3 summarizes proposed and alternative proposed rates for the transportation rate schedules.

<u>Schedule L11: Comparison of Typical Bills Under Proposed and Alt. Proposed Rates</u>

This schedule consists of six pages and calculates typical bills for each of the gas sales rates using proposed and alternative proposed rates.

Q. Did you use the same methodologies to prepare the alternative COSS, Rate Design and IRM as you used in preparing the proposed COSS, Rate Design and IRM?

A. Yes. I used all the same methodologies described above for the proposed COSS, Rate Design and IRM, adjusted for the loss of two customers, AK Steel and Ford Motor Company.

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Q. Why did you prepare an alternative COSS, Rate Design and IRM?

A. I prepared the alternative COSS, rate design, and IRM to demonstrate the impact of losing two large customers, AK Steel and Ford Rouge, as discussed by Witness Decker.

<u>TARIFF CHANGES FOR ALL CUSTOMERS</u>

Q. What changes is DTE Gas proposing to its tariff pages applicable to all customers under Section C of DTE Gas's Rate Book?

A. DTE Gas is proposing several changes to Section C of its Rate Book. DTE Gas is proposing to revise the following provisions under Section C of the Company's Rate Book:

(1) To add clarity, the Company is proposing to modify Rate Book Sections C1.2 and C1.7 to be consistent with the Company's enterprise policies regarding signature authority for contracts and financial transactions, establishment of contracts, record retention, and contract management and administration as proposed by Witness Decker;

(2) Clarify the last sentence of Section C1.2 of its Rate Book pertaining to contracts as proposed by Witness Decker;

(3) Section C8 – Customer Attachment Program, Section C8.4 – Connection Fee;

(4) Carrying Cost Rate and Discount Rate under Section C8.9; and

(5) Misspelling Correction under Section C11.2.C;

The tariff sheet modifications are reflected, in their entirety, in the Summary of Proposed Tariff Changes (Exhibit A-16, Schedule F5) and the revised tariff pages (Exhibit A-16, Schedule F5.1).

Q. What changes are proposed for Section C8 - Customer Attachment Program?

A. Witness Decker's testimony proposes the elimination Section C8.4 – Connection Fee and associated references in Sections C8.2 and C8.3. This change is reflected in Exhibit A-16, Schedule F5.1.

Q. What proposed tariff change are you addressing under Section C8 Customer Attachment Program, C8.9, Model Assumptions of DTE Gas's Rate Book?

A. DTE Gas's Customer Attachment Program tariff needs to be updated to reflect the revised percentages for DTE Gas's Carrying Cost Rate under Section C8.9.B(1), and the Discount Rate under Section C8.9B(6), as approved by the Commission in its final Order in this case. Based on amounts proposed and supported by DTE Gas in this case, I have reflected the applicable Carrying Cost Rate of 11.19% and the Discount Rate of 7.66% based on DTE Gas's incremental pre-tax rate of return and weighted cost of permanent capital as shown on Exhibit A-14, Schedule D1 supported by Company Witness Mrs. Suchta.

Q. What misspelling error requires correction in Section C11.2.C in the Company's Rate Book?

A. In Section C11.2.C, there is one minor misspelled word in the last sentence; the word "or" should be replaced with the word "for."

<u>**PROPOSED TARIFF CHANGES FOR SALES CUSTOMERS**</u>

Q. What are the changes that DTE Gas is proposing to its tariff pages applicable to its sales customers under Section D of DTE Gas's Rate Book?

A. The changes to these tariff pages include:

(1) To add clarity, the Company is proposing to modify Rate Book Sections D7 and D8 to be consistent with the Company's enterprise policies regarding signature authority for contracts and financial transactions, establishment of contracts, record retention, and contract management and administration as proposed by Witness Decker;

(2) a revised IRM;

(3) the proposed Monthly Customer Charges and Distribution Charges for each rate schedule; and

(4) the LIA credit.

The tariff sheet modifications are reflected, in their entirety, in the Summary of Proposed Tariff Changes (Exhibit A-16, Schedule F5) and the revised tariff pages (Exhibit A-16, Schedule F5.1).

Q. What is the IRM?

A. The IRM allows DTE Gas to recover its costs related to capital spending for the Company's infrastructure over the next five years. A detailed description of the IRM is provided by Company Witness Mr. Telang. The IRM is a monthly charge and will be implemented as outlined on proposed Sheet No. D-2.01, Section D2.2. Beginning January 1, 2019 and each January 1, thereafter, the IRM will be implemented for each rate schedule as listed in the table on proposed Sheet No. D-2.01 of the Company's Rate Book.

Q. How will the IRM rates detailed on Sheet D-2.01 be adjusted over the course of the IRM program?

A. The IRM charges applicable to each rate schedule may be adjusted annually based upon a reconciliation of program spend. This reconciliation is described in detail in Witness Telang's testimony. If it is determined in the reconciliation that an adjustment to rates is necessary, then a revised Sheet No. D-2.01 will be filed with the IRM rates reflecting such adjustment. Adjustments will be effective July 1 of the year following an underspend. This means that an underspend in 2019 would result in an adjustment in the IRM beginning July 2020. An underspend in 2023 would require a line item be added to the tables for the 2024 and beyond period. No adjustment will be made to Rate Schedules once they meet their monthly surcharge cap in the event of an underspend, because these rate schedules are already receiving a discount. Rate Schedules at the cap may include ST, LT, XLT or XXLT.

Q. How have you reflected DTE Gas's proposed customer charges and distribution rate changes in your exhibits?

A. DTE Gas's revised customer charges and revised distribution rates are shown as part of the revised tariff pages included in Exhibit A-16, Schedule 5.1.

Q. What changes are proposed to DTE Gas's Low Income programs?

A. The proposed change to DTE Gas's low income programs, a higher participation cap for the LIA program, contained in Section D have been addressed in Witness Johnsons' testimony and reflected in Exhibit A-16, Schedule F5.1.

<u>PROPOSED TARIFF CHANGES FOR EUT CUSTOMERS</u>

Q. What are the changes that DTE Gas is supporting to its tariffs for transportation and storage customers under Section E of DTE Gas's Rate Book?

A. DTE Gas is proposing the following changes to its tariffs under Sections E1 through E14 of the Company's Rate Book supported by Witness Decker, which I have reflected in Exhibit A-16, Schedules F5 and F5.1:

(1) To add clarity, the Company is proposing to modify Rate Book Section E14 to be consistent with the Company's enterprise policies regarding signature authority for contracts and financial transactions, establishment of contracts, record retention, and contract management and administration as proposed by Witness Decker.

(2) Clarify the use of the term "sales service" and modify the standard contract extension from Month-to-Month to Year-to-Year in Section E14-Availability, Sheet E-14.00;

(3) Clarify how Gas-in-Kind is applied on injected quantities in the Load Balancing Storage and Charges, Section A, Sheet E-18.00; and

(4) Reflect the Company's proposed Monthly Customer Charges and Transportation Charges for each EUT rate schedule Section E14.

Q. How have you reflected DTE Gas's proposed customer charges and transportation rate changes in your exhibits?

A. DTE Gas's revised customer charges and revised transportation rates are shown as part of the revised tariff pages included in Exhibit A-16, Schedule 5.1.

Q. Is DTE Gas proposing to revise what it charges transportation and storage customers for GIK fuel costs in Section E14 in this case?

A. No. DTE Gas proposes to retain the current 1.41% GIK applicable to EUT service rates for Rate schedules ST, LT, and XLT, and 1.00% GIK for Rate schedule XXLT as supported by Witness Decker.

PROPOSED TARIFF CHANGES FOR OFF-SYSTEM STORAGE AND TRANSPORTATION CUSTOMERS

Q. What tariff changes are you proposing for Off-system Storage and Transportation Customers?

A. DTE Gas is proposing the following changes to its tariffs under Sections E15 through E28 of the Company's Rate Book supported by Witness Decker, which are reflected in my Exhibit A-16, Schedules F5 and F5.1:

(1) To add clarity, the Company is proposing to modify Rate Book Sections E25, E26, E27 and E28 to be consistent with the Company's enterprise policies regarding signature authority for contracts and financial transactions, establishment of contracts, record retention, and contract management and administration.

(2) Incorporate the Company's proposed not to exceed rate under Sections E25 and E26.

The tariff sheet modifications are reflected, in their entirety, in Exhibit A-16, Schedule F5, Summary of Proposed Tariff Changes and Exhibit A-16, Schedule F5.1, Proposed Tariff 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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
______________________________________	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

EDWARD J. SOLOMON

DTE GAS COMPANY
QUALIFICATIONS OF EDWARD J. SOLOMON

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, 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 and its subsidiaries including DTE Gas Company (DTE Gas 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 Gas.

Q. What are your responsibilities as Assistant Treasurer and Director of Corporate Finance for DTE Gas?

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 Company, DTE Gas and DTE Electric Company. 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.

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 a Masters of Business Administration (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 working 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. While at Air Products, my responsibilities increased over time, starting as a Financial Analyst in their Industrial Gases group, to an analyst in Treasury Financial Planning, then to Senior Financial Analyst for the Chemicals group, and finally to a Supervising Financial Analyst in the Corporate Financial Planning Group.

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

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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, 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 have sponsored testimony in the following cases:

U-15768	2009 Detroit Edison General Rate Case
U-15985	2009 DTE Gas General Rate Case
U-16146	2009 DTE Gas 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

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support DTE Gas's projected capital structure, and the cost of its long and short-term debt to be used in the determination of DTE Gas's overall rate of return in this proceeding.

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. 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	Historical Cost of Long-Term Debt – as of 12/31/16
A-4	D3	Historical Cost of Short-Term Debt – as of 12/31/16
A-4	D4	Historical Cost of Preferred and Preference Stock – as of 12/31/16
A-4	D5	Historical Cost of Common Shareholders' Equity – as of 12/31/16
A-11	A2	Projected Financial Metrics – Ratemaking Basis
A-14	D2	Projected Cost of Long-Term Debt – as of 09/30/19

A-14	D3	Projected Cost of Short-Term Debt, Customer Deposits, and Other Interest Items – as of 09/30/19
A-14	D4	Projected Cost of Preferred and Preference Stock – as of 09/30/19
A-17	G1	Current and Historical Credit Ratings
A-17	G2	Recent Utility Corporate Bond Issuances

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

A. Yes, they were.

I. SUMMARY OF RECOMMENDATION

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 Gas?

A. I am recommending a projected permanent capital structure of 48% long-term debt and 52% equity. Permanent capital is long-term perpetual capital. Common equity, preferred stock and long-term debt are sources of permanent capital. This permanent capital structure is reflected in DTE Gas's projected permanent capital structure for the 13-month period ending September 30, 2019, as shown in Company Witness Ms. Suchta's Exhibit A-14, Schedule D1. This capital structure is necessitated by the business and financial risks confronting DTE Gas, as I will discuss in greater detail later in my testimony.

Q. What was the percentage of long-term debt to total permanent capital approved in DTE Gas's last rate case?

A. The percentage of long-term debt to total permanent capital adopted by the Commission in its Order in Case No. U-17999 was 48% based on the Company's projected capital structure in that case.

Q. What is the percentage of long-term debt to total permanent capital forecasted for DTE Gas for the test year ending September 30, 2019?

A. For the projected 12-month period ending September 30, 2019, the percentage of long-term debt to total permanent capital is forecasted to be 48%. This permanent capital structure is reflected in DTE Gas's projected permanent capital structure as of September 30, 2019, as shown in Witness Suchta's Exhibit A-14, Schedule D1.

Q. What is your forecast for DTE Gas's cost of long-term debt, preferred stock, and short-term debt for the 12-month period ending September 30, 2019?

A. I am forecasting 4.59% for the cost of DTE Gas's long-term debt, and 2.36% for the cost of DTE Gas'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 may include long-term debt, short-term debt, preferred equity, common equity, deferred taxes, deferred job development investment tax credits, and deferred investment tax credits. Permanent capital structure includes only long-term debt and equity. Rating agency and credit analysts' calculation of a company's capital structure is comprised of long-term debt, preferred equity and common equity. Depending on rating agency guidelines and individual circumstances, short-term debt may be included or excluded as debt in the capital structure. For example, all, or a portion, of the short-term debt may be excluded from the capital structure if it is seasonal in the normal course of business. Finance professionals will sometimes include capital leases and off-balance sheet obligations, such as operating leases, in their determination of debt. Rating agencies also make adjustments to a company's capital structure for their analysis, including capital leases and off-balance sheet obligations, such as operating leases, unfunded pension liabilities, 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 Gas faces two types of risk: business risk and financial risk. Business risk is a result of systematic and non-systematic risk.

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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 its assets. 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.

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 higher end of the range of rating agency financial metrics in order to have a better chance to receive a credit upgrade.

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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, therefore, increasing the cost of debt for that company. Increased debt costs increase customer rates.

Q. What capital structure is proposed for DTE Gas's projected test year?

A. DTE is proposing a projected test year permanent capital structure of 48% long-term debt and 52% common equity. For the projected test year, the permanent capital structure includes long-term debt and equity as shown on Exhibit A-14, Schedule D1 as supported by Witness Suchta. This capital structure is consistent with the current authorized capital structure.

Q. What is the basis for this permanent capital structure recommendation?

A. The 52% equity level is supported by the significant capital expenditures expected over the calendar period January 2017 through September 2019, the significant risk of variability in cash flows and capital needs over this period and after, and the need to enhance the credit quality and financial soundness of DTE Gas during this period of significant system investment. More specifically:

- It is imperative that DTE Gas be viewed as a financially sound firm with a solid investment grade rating to ensure the reasonableness and competitiveness of capital costs. DTE Gas will be financing and funding approximately $1.0 billion of capital expenditures for the calendar period January 2017 through September 2019, excluding capital spent in 2019 as part of the Company's proposed IRM. A capital structure consisting of 52% equity will enhance the credit quality and financial soundness of DTE Gas during this period of significant system investment.

- DTE Gas faces the need to make significant system investments during a period of significant systematic and non-systematic risks. We believe DTE Gas has non-systematic risks that are greater than our peer gas companies. These risks include those that result from the economic health and challenges of our service territory (including Detroit and its persistently high poverty level and declining population); economic reliance on the automobile industry; DTE Gas's aging assets including main replacement and renewal efforts; and the increased level of investment required to maintain and improve operations to meet customer expectations. Individually, these risks are significant, however, the fact that DTE Gas is required to manage all these risks simultaneously, provides considerable support for the conclusion that DTE Gas's risks are above average relative to its peer group. To mitigate the risks to DTE Gas's cash flows and balance sheet, establishing and maintaining a capital structure consisting of 52% equity will be important to enhance the credit quality and financial soundness of DTE Gas.
- As the allowed ROE declined from 11% in 2012, additional equity was required to maintain credit metrics. A capital structure of 52% equity addresses the potential decline in our cash flow metrics and considers the additional debt that the rating agencies add for asset retirement obligations and other items.

Q. Is DTE Gas committed to maintaining a 52% equity ratio in its capital structure?

A. Yes, DTE Gas is committed to maintaining a 52% equity ratio and has demonstrated its commitment to its targeted equity ratio by receiving equity infusions from DTE Energy when needed to maintain its targeted equity ratio. DTE Energy has made reasonable efforts to strengthen DTE Gas's credit quality by infusing $180 million of common equity in 2016. The equity infusion is consistent with DTE Gas's previous goal of maintaining a capital structure with a common equity ratio as a percentage of permanent capital of approximately 52%. DTE Gas has a planned $90 million equity infusion in 2018 and a $100 million equity infusion in 2019 which will result in a 52% equity ratio for the projected test period.

III. DEVELOPMENT OF COST RATES

Q. What were DTE Gas's historical financial and ratemaking metrics from 2012 through 2016?

A. DTE Gas's historical financial and ratemaking metrics for each of the previous five years (2012 through 2016) 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 Gas's financial reports. The historical ratemaking metrics include year-end financial metrics and are calculated from DTE Gas's annual regulatory filings.

Q. What is the cost of long-term debt outstanding at December 31, 2016?

A. The cost of long-term debt at December 31, 2016 was 4.94%. 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 also includes agents' fees, commissions, financing expenses and is calculated on the net proceeds to the Company. See Exhibit A-4, Schedule D2.

Q. What is the cost of short-term debt outstanding at December 31, 2016?

A. The cost of short-term borrowings for the 13-month period ended December 31, 2016 was 1.46%. 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 cost of equity approved in Case No. U-17999?

A. DTE Gas's present authorized cost of common shareholders' equity is 10.1% as approved in Case No. U-17999. DTE Gas does not have any preferred stock. See Exhibit A-4, Schedules D4 and D5.

Q. What does DTE Gas project its financial metrics to be in the test year?

A. DTE Gas'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 DTE Gas's weighted average cost of long-term debt as of September 30, 2019?

A. Including the planned long-term debt issuance, the weighted average long-term debt cost as of September 30, 2019 is projected to be 4.59%. To calculate this

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cost, DTE starts with the actual December 31, 2016 long-term debt outstanding. Adjustments to the long-term debt were made. Any known maturities were considered redeemed and any forecasted long-term debt issuances were added to arrive at the projected balance as of September 30, 2019. Known issuances include $80 million issued in August 2017. Forecasted long-term debt issuances of $235 million in August 2018 and $220 million in August 2019 were also added. See Exhibit A-14, Schedule D2.

The 2018 and 2019 debt issuances are assumed to be 30-year fixed rate bonds with an interest rate of 4.08% in 2018 and 4.14% in 2019. The interest rate for the debt issuances is based on forward long-term borrowing rates of A-rated utilities, which is comparable to DTE Gas's credit rating. These forward rates were obtained from Bloomberg, a leading provider of financial data, news and analytics, in October 2017.

Q. Why is long-term debt cost calculated 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 expense 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. Thus, 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.

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Q. How did you determine the projected cost of short-term debt?

A. The total cost of short-term debt is comprised of the interest rate on the short-term debt plus associated facility fees. Supporting credit facilities are required by the rating agencies and investors for DTE Gas to issue commercial paper. These facilities have costs associated with them. The interest rate on the short-term debt was determined by adding 6 basis points (bps) to the forecasted 1-month London Interbank Offering Rate (LIBOR). A spread of 6 bps was added to LIBOR because that is the average spread on DTE Gas's recent commercial paper issuances. See Exhibit A-14, Schedule D3.

The average forecast for 1 month LIBOR for the 13-month period ending September 30, 2019 is 1.90%. The forecast was obtained from Bloomberg in October 2017. Adding the spread of 6 bps to the forecasted 1 month LIBOR rate of 1.90% brings the interest rate on short-term borrowings to a total of 1.96%. The cost of the facility fees for the 12-month period ending September 30, 2019 is $724,000. This cost was divided by the average outstanding short-term debt balance of $178 million and equates to 0.41% of the cost of short-term debt. Adding the interest rate on short-term debt of 1.96%% to the facility fee cost of 0.41%, results in the total cost of short-term debt of 2.36%.

Q. What is the cost of preferred stock?

A. Exhibit A-14, Schedule D4 shows that DTE Gas 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-17, Schedule G1 shows DTE Gas'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. 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 Gas'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-17, Schedule G2.

IV. SUMMARY AND CONCLUSIONS

Q. Please summarize your recommendation and conclusions?

A. Due to the significant business risks faced by the Company, DTE Gas's weighted cost of capital established in this proceeding should be based on a capital structure consisting of a minimum of 52% equity as a percentage of permanent capital. DTE Gas continues to face credit risk and to have significant business challenges as well as challenges due to the metropolitan Detroit and Michigan economies. For the projected year, the cost of short-term debt is projected to be 2.36%, and the cost of long-term debt is projected to be 4.59%. I believe these expenses and measures are reasonable, prudent and necessary.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT E. SITKAUSKAS

DTE GAS COMPANY
QUALIFICATIONS OF ROBERT E. SITKAUSKAS

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

A. My name is Robert E. Sitkauskas. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company), as General Manager of the Advanced Metering Infrastructure (AMI) group in Distribution Operations.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Gas.

Q. What is your educational background?

A. I graduated from the University of Michigan Dearborn in 1976 with a Bachelor of Business Administration. In addition, I received a Master of Business Administration degree from the University of Detroit in 1981.

Q. What work experience do you have?

A. In 1978, I joined The Detroit Edison Company as a computer programmer. During my early career, I held positions in Information systems, General Purchasing, Stores and Transportation as well as Distribution Engineering. In 1989, I was appointed Supervisor in the Graphics and Computer Applications group exploring new technology for the company. In 1991, I was part of the team that installed the Voice Response Unit and, subsequently, was appointed Director of Communication Technology in the call center. With the acquisition of MCN Energy Group Inc. by DTE Energy Company, I was assigned to lead the integration of the Customer Service organizations of both companies. Post-acquisition, I was the Director of Billing. In 2006, I was appointed to lead the AMI project.

Line
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Q. What is your current position?

A. I am the DTE Electric Distribution Operations General Manager of AMI. I am responsible for the development, administration and reporting of the AMI project for both DTE Electric and DTE Gas Company (DTE Gas), including the negotiation and execution of the contract with the main project vendor Itron, Inc. (Itron).

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, and DTE Gas cases:

U-18255	DTE Electric General Rate Case
U-18014	DTE Electric General Rate Case
U-17999	DTE Gas General Rate Case
U-17767	DTE Electric General Rate Case
U-17053	DTE Electric AMI Opt Out Program
U-16999	DTE Gas General Rate Case
U-16472	DTE Electric General Rate Case

DTE GAS COMPANY
DIRECT TESTIMONY OF ROBERT E. SITKAUSKAS

Purpose of Testimony

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

A. I am providing testimony to discuss and support the reasonableness of DTE Gas's AMI project from a cost / benefit perspective. I will provide a brief background on the progress made with AMI, and current status of completion.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-21	K1	AMI Detailed Cost/Benefit Analysis
A-21	K2	AMI Financial Summary

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

A. Yes, they were.

AMI Background

Q. What has DTE Gas's progress been related to the AMI program?

A. The AMI pilot installation began in the fall of 2008. DTE Gas 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 30, 2017, DTE Energy has installed over 2.5 million electric meters, 645,000 AMI gas modules and over 300,000 Advanced Meter Reading (AMR) gas only modules for a total over 3.5 million endpoints or 91% of our planned meters.

Line No.

Our plan is to install the remaining gas installations by year end 2018, focused primarily on the Grand Rapids AMR installations.

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 are being eliminated. Monthly and daily reads are being obtained at the 99% plus rate, enhancing customer service operations with the read timeliness and accuracy. Reconnects and disconnects are being completed over the air and within minutes as opposed to the former manual and field visit requirement. The Company continues to work to 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 problems with the remaining installations due to customers with inside meters where access has not been successful.

<u>AMI Benefits</u>

Q. What are the major benefits DTE Gas customers will 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 Gas has about 1.2 million gas meters to read every month of which about 35% are located inside of facilities or homes. AMI eliminates the need to gain access for inside meter reads and thereby reduce meter reading costs. 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 transposition of numbers that could occur with manual entry of meter data as well as 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 will be able to receive tamper events at any time on any day. This is a significant advantage over our current monthly meter reader site review. Additionally, the daily reads can be used to develop algorithms that will further help us to detect theft or unusual use situations.

(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 – DTE Electric only has this functionality which allows DTE Electric to reconnect customers remotely, speeding reconnections, 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 – DTE electric only has this functionality, 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 a lack of information. With AMI, the Company is able to "ping" the meters to determine their power condition. Crews are able to do this ping from their truck as well as staff support personnel during a storm event. I want to emphasize that AMI does not replace the customer call, but it will enhance the operation. AMI will only be 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.

(7) Power Quality – DTE electric only functionality where AMI will also be able to record instances of voltage problems at customer locations. The ability to have this data available to DTE Electric will enhance the engineering design process

of the electric infrastructure.

Q. Can you describe your approach to security of the AMI system?

A. Security is always at the forefront of the project. One cannot rest on a one-time security assessment. It must be continual and in depth. IT professionals continually review, test, and assess the system security. Itron is equally dedicated to developing 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. This is one area of the program that we rely heavily on every day before moving forward in the project.

Cost/Benefit Analysis

Q. Can you describe the information displayed on Exhibits A-21, Schedules K1 and K2?

A. These schedules provide the cost/benefit analysis of the full deployment of AMI throughout both DTE Electric's and DTE Gas's service territories. To properly evaluate the cost/benefit of the AMI project, it was appropriate to review costs for both utilities. The cost/benefit analysis spans the life of the project.

This cost/benefit analysis demonstrates that the benefits to customers of DTE's Gas program, outweigh the costs of the program. The summary of this analysis appears on Schedule K2, which shows that the program has a Present Value Revenue

Requirement (PVRR) for DTE Gas of $39.4 million (column (f), line 27) which indicates that the savings exceed the costs over the life of the program.

All of the savings and costs in the cost/benefit analysis reflect an inflation factor of 3.5% year-over-year and a weighted-average cost of capital of 7.70% assuming a 35% income tax rate throughout the 30-year project life.

Q. Would you describe the details of the cost/benefit analysis as they appear in Exhibit A-21, Schedule K1?

A. Yes. The schedule has two sections. The first section, lines 1 - 71, provides a summary view of the costs and benefits of the AMI program. The second section, lines 72 - 141, provides a more detailed view of these cost and benefits. While the schedule provides information for both DTE Electric and DTE Gas, the focus in this rate case is DTE Gas.

Lines 19 – 26, DTE Gas Capital Expenditures: Please refer to my direct testimony above describing this detail.

Line 25, Avoided Capital Costs: Details of these costs appear in lines 130 through 132. They include the avoided cost of meter and handheld replacements, the receipt of meter credits from Itron for a small population of meters being replaced during the project, any salvage values for traditional meters being replaced during the project.

Lines 28 – 36 show the summation of the DTE Electric and DTE Gas capital expenditures from lines 2 through 26 for the complete business case.

Line No.

Q. How did the Company determine the AMI cost savings?

A. For each of the above listed savings, the volumes and unit costs, where applicable, were obtained. For those savings that might be variable in a given year, multiple years were taken into account to better reflect a normalized annual savings pattern. This method was used to establish a steady state savings for AMI once all of the meters have been installed. The benefits are not all uniformly recognized, however, and have a varied path to steady state. For example, in meter reading locations where contractors are paid by the route, savings are achieved as routes are automated. In contrast, in the areas where DTE employees read meters, DTE must automate one route from each of the 20 read cycles to realize the savings. Other savings categories must be held back until a mass of meters are installed. This is especially true for those areas where direct manpower is involved as reductions cannot be made with partial full time equivalents.

Finally, some savings can be realized directly as meters are installed. For example, this would be true for our “OK on arrival” savings. In these cases, AMI provides the information to our dispatch area that a crew is not required for situations that would be an “OK on arrival.” This is similar to finding a customer fuse is the problem instead of an area outage.

Each of the savings categories were reviewed with the business units who will be impacted by AMI-related savings. The existence of this formal review reflects the importance of the project and cost/benefit analysis across the enterprise

Line
No.

Q. A large portion of your O&M savings is due to a reduction in meter reading personnel. Can you describe your process regarding this saving?

A. In order to lessen the impact of AMI on employment, we have partnered Itron with one of our current Michigan based contract firms (contractor) to perform installations. Itron is training contractors to be AMI meter installers. Itron is also exposing that same contractor's firm to back office operations. The intent is to develop the local firm's expertise in all facets of the business. With the experience gained at DTE Energy, the local firm will be positioned to grow the business across the country.

Q. What can be concluded from the cost/benefit analysis presented?

A. As shown on Exhibit A-21, Schedule K2, line 22, column (d), the AMI project has a capital outlay of approximately $524 million, of which DTE Electric's portion is $386 million and DTE Gas' portion is $138 million. The total project has a Present Value Revenue Requirement (PVRR) of $67.9 million ($39.4 million associated with DTE Gas) with a combined payback at 16 years (15 years for DTE Electric) based on a 30-year project life.

Q. Can you summarize the AMI project efforts?

A. As the cost/benefit analysis shows, the benefits of the project (*i.e.*, the savings attributable to the project) are expected to outweigh the costs of the project, for both DTE Electric and DTE Gas. The results of this analysis are supported by the successful results of the company's AMI pilot programs, where the benefit categories were validated and many expected project benefits were realized. Based on these two factors, it is reasonable to conclude that the AMI program will have a positive impact on customers, and that the AMI investments continue to be a reasonable and prudent use of utility resources.

Q. Will the Company continue providing future AMI cost/benefit analysis in subsequent rate case filings?

A. No. Based on the Commission Order in Case No. U-17767, the Company is required to provide a cost/benefit analysis as long as the program is still in the implementation phase (Order, p. 35). The AMI program is now more than 91% through installation, with an expected completion date in 2018 for DTE Gas installations.

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 GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority ____	)))))))	Case No. U-18999

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARGARET A. SUCHTA

DTE GAS COMPANY
QUALIFICATIONS OF MARGARET A. SUCHTA

Line No.

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

A. My name is Margaret A. Suchta. 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 Consultant, Regulatory Economics.

Q. On whose behalf are you testifying?

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

Q. What is your educational background?

A. I received a Bachelor of Business Administration Degree with a major in Accounting from Western Michigan University and a Master of Business Administration Degree with a concentration in finance from Wayne State University.

Q. What is your work experience?

A. From 1985 to 1990, I practiced public accounting with the international accounting firm of Deloitte & Touche. In 1990, I joined Michigan Consolidated Gas Company (MichCon) as a Rate Analyst in the Michigan Regulation Department where I worked on regulatory analysis and research. I provided support in regulatory filings preparing testimony and exhibits for myself and others. In 1995, I transferred to the Corporate Development department of MCN Energy Group, Inc. as a Project Leader where I worked on the economic analysis and evaluation of regulated investment opportunities. Upon completion of the acquisition of MCN Energy by DTE Energy in 2001, I transferred to DTE‘s Corporate Development organization as a Project Manager where I worked on the economic analysis and evaluation of DTE's major regulated and non-regulated capital projects and acquisition opportunities. Since the merger, I have served in various financial analyses and planning roles within the DTE organization including Budget, Forecast and Reporting; Long Term Planning; and DTE2 Business Planning System. In October 2007, I joined the Regulatory Affairs' Revenue Requirement group as a Principal Financial Analyst. In October 2016, I was promoted to Consultant.

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

A. In my current position, I am responsible for DTE Electric Company's and DTE Gas's revenue requirement studies; regulatory analysis and research; economic analyses, and other short and long-term financial evaluation. I am also responsible for managing certain MPSC filings such as general rate cases and Energy Optimization 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-9902-R	MichCon's 1992 GCR Reconciliation
U-10105-R	MichCon's 1993 GCR Reconciliation
U-10385-R	MichCon's 1994 GCR Reconciliation
U-10603	MichCon's Service Curtailment and Gas Diversion Case
U-11294	Saginaw Bay Pipeline Complaint Case
U-12342	Antrim Expansion Project (AEP) Complaint Case
U-15890	MichCon's Energy Optimization Plan
U-15890-A	MichCon's Energy Optimization Amended Plan

Line No.		
1	U-15985	MichCon's 2009 General Rate Case
2	U-16289	MichCon's 2009 EO Reconciliation
3	U-16999	MichCon's 2012 General Rate Case
4	U-17049	Detroit Edison's 2012 EO Amended Plan
5	U-17701	DTE Gas's IRM Expansion
6	U-17767	DTE Electric 2015 General Rate Case

Line No.

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

A. I am providing testimony in two separate sections. In Section A, I am sponsoring:

- DTE Gas's 2016 historical test year revenue sufficiency,
- the historical 13-month average balance sheet classification and rate base determination,
- the historical revenue multiplier and the net operating income (NOI) adjustments for interest synchronization and income tax savings, and
- the overall historical rate of return (ROR) percentage.

In Section B, I am sponsoring:

- DTE Gas's projected revenue deficiency for the projected test year of October 1, 2018 through September 30, 2019,
- the classification of the projected 13-month average balance sheet and rate base determination,
- the projected revenue multiplier and projected net operating income (NOI) adjustments for interest synchronization and income tax savings,
- the overall projected ROR percentage,
- the calculation of the incremental revenue requirements for DTE Gas's Infrastructure Recovery Mechanism (IRM),
- the calculation a monthly fixed rate reduction for each $1 million of under spend of IRM capital, if DTE Gas incurs such an under spend,
- the calculation of the incremental revenue requirement for the NEXUS lease, and
- the revenue deficiency excluding AK Steel.

In preparing my historical and projected rate case exhibits, I relied on information supplied by DTE Gas Witnesses Ms. Uzenski, Mr. Solomon, Ms. Harris, Mr. Decker, Ms. Sandberg, and Mr. Vilbert.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following historical and projected exhibits.

Section A – Historical Test Year Exhibits

Exhibit	Schedule	Description
A-1	A1	Historical Revenue Deficiency (Sufficiency)
A-2	B1	Historical Rate Base
A-2	B2	Historical Utility Plant
A-2	B3	Historical Depreciation Reserve
A-2	B4	Historical Working Capital
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 Year Exhibits

Exhibit	Schedule	Description
A-11	A1	Projected Revenue Deficiency (Sufficiency)
A-12	B1	Projected Rate Base
A-12	B2	Projected Utility Plant
A-12	B3	Projected Accumulated Provision for Depreciation
A-12	B4	Projected Working Capital
A-12	B4.1	Projected Average Balance Sheet with Classifications
A-13	C2	Projected Revenue Conversion Factor

A-13	C15	Projected Adjusted Net Operating Income - Income Tax Savings
A-13	C16	Projected Tax Effect of Interest Synchronization Adjustment
A-14	D1	Overall Rate of Return Summary
A-18	H1	Infrastructure Recovery Mechanism – Meter Moveouts Incremental Revenue Requirement
A-18	H2	Infrastructure Recovery Mechanism – Main Renewals Incremental Revenue Requirement
A-18	H5	Infrastructure Recovery Mechanism – Under Spend Impact
A-22	L2.A1	Projected Revenue Deficiency excluding AK Steel
A-22	L2.B1	Projected Rate Base excluding AK Steel
A-22	L2.B4	Projected Working Capital excluding AK Steel
A-22	L2.B4.1	Projected Balance Sheet Classification excluding AK Steel
A-22	L2.D1	Overall Rate of Return excluding AK Steel
A-23	M3	NEXUS Lease Incremental Revenue Requirement

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

A. Yes, they were.

Line No.

Section A - Historical Period

Q. What is DTE Gas's Revenue Deficiency/(Sufficiency) for the historical test year?

A. The revenue sufficiency for the 2016 historical period of $61.8 million is based on: Average Rate Base of $3,396 million, Required Rate of Return of 5.68%, and Adjusted NOI of $230.5 million. See Exhibit A-1, Schedule A1. The revenue sufficiency is based on the Average Rate Base, Adjusted Net Operating Income, Overall Rate of Return, and Revenue Multiplier for the Historical Test Year Ended December 31, 2016. Average Rate Base is summarized in Exhibit A-2, Schedule B1. The 2016 Required Rate of Return is set forth in Exhibit A-4, Schedule D1. The 2016 NOI is adjusted on Exhibit A-3, Schedule C1. The Revenue Multiplier of 1.6468 is computed on Exhibit A-3, Schedule C2.

Q. What is the Historical Rate Base?

A. Historical Rate Base is the 13-month average rate base balances for the historical test period utilizing December 31, 2015 through December 31, 2016 balances. See Exhibit A-2, Schedule B1. Total Historical Rate Base of $3,396 million, shown on line 13, is comprised of Net Utility Plant of $2,485.5 million and Working Capital of $910.4 million.

Q. What is Historical Utility Plant?

A. Historical Utility Plant is comprised of investment in Plant in Service, Plant held for Future Use, Construction Work in Progress and Gas in Underground Storage – Non-Current. See Exhibit A-2, Schedule B2. Historical Utility Plant is calculated on a 13-month average basis as of December 31, 2016. Historical Utility Plant for the historical test period is $4,589 million and is used to calculate Historical Rate Base on Exhibit A-2, Schedule B1.

Q. What is Historical Depreciation Reserve?

A. Historical Depreciation Reserve is $2,103 million, calculated on a 13-month average basis as of December 31, 2016, and is shown by function on Exhibit A-2, Schedule B3. The Depreciation Reserve is subtracted from total utility plant in determining the Total Historical Rate Base.

Q. What is the purpose of Exhibit A-2, Schedule B4?

A. Exhibit A-2, Schedule B4, entitled "Historical Working Capital" is a 2-page schedule that shows the development of Historical Working Capital of $910.4 million, line 86 (column (f)), for the 13-month average as of December 31, 2016. This working capital derivation is based on the balance sheet method prescribed in the Commission's generic order in Case No. U-7350 issued on June 11, 1985. The balance sheet method requires that each account on DTE Gas's books be classified into one of four major categories: 1) Investor Supplied, 2) Utility Plant, 3) Non-Utility, or 4) Working Capital.

Q. What balance sheet items are included in the Investor Supplied column of this exhibit?

A. Investor Supplied amounts shown in column (c), contain accounts that typically have a cost associated with them or that earn a return. The main items included in this category are capital structure items such as equity, long-term debt, short-term debt, deferred income taxes and customer deposits.

Line No.

Q. What balance sheet items are included in Utility Plant column?

A. Utility Plant amounts, reflected in column (d), represent gas utility plant in service, gas stored underground, construction work in progress and accumulated depreciation. The Net Utility Plant amount of $2,485.5 million, shown on line 86, column (d), is used to develop historical Rate Base on Exhibit A-2, Schedule B1.

Q. What balance sheet items are included in Non-Utility Plant column?

A. Non-Utility Plant, reflected in column (e), represents items that are not used in providing service to utility customers and are not reflected in rate base. This includes non-utility plant, investments in subsidiaries, and other non-utility investments.

Q. What is the Working Capital?

A. Working Capital is the amount of invested resources needed to operate and maintain the daily activities of the utility. Working Capital is included in rate base because it represents capital investment necessary to provide service to the company's customers on a day-to-day basis and thus requires a return on investment by investors. Working Capital consists of current assets less current liabilities. Certain deferred debits and credits are also classified as Working Capital. DTE Gas's Working Capital requirement for the historical test period is $910.4 million, as shown on line 86, column (f) of Exhibit A-2, Schedule B4.

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 2016,

Line No.

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 Gas's historical test period Revenue Multiplier of 1.6468, which means DTE Gas was required to collect $1.6468 in revenue to produce $1.00 of after-tax income.

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 Gas's actual interest expense for the Year Ended December 31, 2016 as supplied to me by Witness Uzenski. Allowable interest expense starts with the Historical Rate Base of $3,396 million multiplied by the weighted cost of debt of 1.71%. The 1.71% is the summation of the weighted costs associated with long-term debt (LTD), short-term debt (STD), customer deposits and other interest bearing credits from Exhibit A-4, Schedule D1. Line 3 calculates the allowable ratemaking debt interest expense deduction of $58.2 million. DTE Gas's actual interest expense deduction of $59.9 million is what was included in DTE Gas'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 $1.7 million. This lower tax deduction increased federal income tax, state income tax and municipal tax expense and creates a corresponding decrease in NOI of $0.7 million, see line 11 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 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 $33,000 due to the interest deduction associated with the debt component portion of JDITC. This Synchronization Adjustment reduces income tax expense by $33,000, and, as shown on line 11, results in a corresponding increase in NOI.

Q. What is the Historical Rate of Return calculated on Exhibit A-4, Schedule D1?

A. DTE Gas's overall rate of return for the historical test year ended December 31, 2016 is 5.68% based on the 13-month average investor supplied balances on Exhibit A-2, Schedule B4 and the actual cost rates.

On Exhibit A-4, Schedule D1, the long-term debt shown on line 1 includes long-term debt outstanding net of unamortized premium / discount and unamortized debt expense. DTE Gas's long-term debt outstanding at December 31, 2016 is detailed on Schedule D2. The weighted long-term debt cost for 2016 of 4.94% (column (f)) was calculated using the net proceeds method, as specified by the Commission, for each issue outstanding at the end of December 2016. Exhibit A-4, Schedule D2 sponsored by Witness Solomon, details the development of the weighted long-term debt cost of 4.94%.

Line 2 of Schedule D1 shows common shareholders' equity, which includes common stock outstanding, other paid in capital, retained earnings and Other Comprehensive Income (OCI) adjustments. The cost of common shareholders' equity utilized for this exhibit is the 10.1% (column (f)) that was authorized by the Commission in the Company's last general rate case, Case No. U-17999, as displayed on Schedule D5 of this exhibit, supported by Witness Solomon.

The cost of short-term debt, on line 4 (column (f)), of 1.46% is the actual average short-term borrowing cost of the Company in the historical test year. The customer deposits cost rate of 7.50%, on line 5, is the actual cost incurred by the Company in the historical test year. The customer deposit cost rate is defined in the MPSC billing practices rules and supported by Witness Solomon on Exhibit A-4, Schedule D3.

Other interest bearing credits, shown on line 6, are liabilities that have interest associated with them. The actual cost of these other interest bearing credits in the historical test year is 0.18% (column (f)), as supported by Witness Solomon on Exhibit A-4, Schedule D3.

The Job Development – ITC amounts on lines 9 (JDITC – Debt) and 10 (JDITC – Equity) of Schedule D1 reflect the corresponding permanent capital percentages of 45.9% for Long-Term Debt and 54.1% for Common Equity. The associated returns for JDITC – Debt and JDITC – Equity reflect the corresponding permanent capital

Line No.

rates of 4.94% and 10.1%, 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 Tax (line 7) and Deferred Investment Tax Credits (line 8), as shown on Schedule D1 for 2016, are at zero cost.

<u>Section B – Projected Test Year (12 Months Ending September 30, 2019)</u>

Q. What is the Projected Revenue Deficiency for the Projected Test Year?

A. Line 8 of Exhibit A-11, Schedule A1, shows, absent rate relief, the Company will experience, for the 12 Months Ending September 30, 2019 (Projected Test Year) a Total Revenue Deficiency of $85.1 million. This deficiency is based on the Company's projected financial outlook for the 12 months ending September 30, 2019. The Revenue Deficiency is based on a 13-month average Projected Rate Base of $4,278.6 million, Projected NOI of $191.3 million and a Projected Overall ROR of 5.68%. Total Rate Base is detailed in Exhibit A-12, Schedule B1. The Projected NOI is developed on Exhibit A-13, Schedule C1. The Overall Rate of Return is set forth in Exhibit A-14, Schedule D1. The components of projected Rate Base, NOI, balance sheet capitalization and Required ROR are detailed within the exhibits and schedules of Witnesses Uzenski, Solomon, and myself.

Q. What is Projected Rate Base?

A. Projected Rate Base is derived from the 13-month average balance sheet for the Projected Test Period. The Projected Test Period 13-month average Rate Base amount of $4,278.6 million consists of $3,285.8 million Net Plant and $992.8 million Working Capital. See Exhibit A-12, Schedule B1 and Exhibit A-12, Schedule B4.

Q. What information is displayed on Exhibit A-12, Schedule B2 entitled "Projected Utility Plant"?

A. Exhibit A-12, Schedule B-2 provides the 13-month average of Utility Plant by MPSC account for the historical test period and the projected test period. The projected utility plant is based on the December 31, 2016 ending balances plus projected capital expenditures net of removal costs, retirements, and construction work-in-progress captured by Witness Uzenski in her projected test period balance sheet. Gross projected capital expenditures are shown on Exhibit A-12, Schedule B5.

Q. What information is displayed on Exhibit A-12, Schedule B3 entitled "Projected Depreciation Reserve"?

A. Exhibit A-12, Schedule B3 provides the 13-month average of depreciation reserve for the historical test period and the projected test period. The projected depreciation reserve is based on the accumulated balance as of December 31, 2016 plus projected depreciation expense and removal costs, less retirements supported by Witness Uzenski.

Q. How is the Projected Working Capital derived?

A. The Projected Working Capital requirement comes from the Projected 13-month Average Balance Sheet supported by Witness Uzenski on Exhibit A-12, Schedule B4.2. The average balance sheet amounts are classified into the categories: Investor Supplied, Utility Plant, Non-utility and Working Capital following the balance sheet method described previously in my testimony. See Exhibit A-12, Schedule B4.1. The Investor Supplied amounts are carried to Exhibit A-14, Schedule D1. The Utility Plant and Working Capital amounts are carried to Exhibit A-12, Schedules B1, B2, B3 and B4.

Q. What is the Projected Revenue Conversion Factor?

A. Projected Revenue Conversion Factor is 1.6468 and is used to convert after tax income into pre-tax revenue for the Projected Test Year. The derivation of the revenue multiplier is the same mathematical format as my Exhibit A-3, Schedule C2.

Q. What adjustments on Exhibit A-13, Schedule C1, Net Operating Income for Projected Test Year Ending September 30, 2019 are you sponsoring?

A. On this exhibit, I am supporting the adjustments for:

1) Income Tax Effect of Interest (line 21) supported by Exhibit A-13, Schedule C15.
2) Synchronization Adjustment (line 22) supported by Exhibit A-13, Schedule C16.

Q. What is the adjustment for "Income Tax Effect of Interest" on Exhibit A-13, Schedule C1, line 21?

A. This NOI adjustment of $0.338 million, line 21 of Exhibit A-13, Schedule C1, reflects the difference between the tax deduction amounts of allowable interest expense included in the rate case ROR and the forecasted interest tax deductions included in the Projected NOI supported by Witness Uzenski. This change in the income tax expense is set forth in Exhibit A-13, Schedule C15. As shown on line

13 of Schedule C1, this adjustment increases income tax expense by $0.338 million, resulting in a corresponding decrease in NOI of by the same amount.

Q. What is the "Interest Synchronization Tax Adjustment" on Exhibit A-13, Schedule C1, line 22?

A. This NOI adjustment of $0.011 million on line 22 of Exhibit A-13, Schedule C1 is the rate case Interest Synchronization Tax Adjustment for the Projected Test Year. 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 decrease in the income tax expense is set forth in Exhibit A-13, Schedule C16. As shown on line 22 of Schedule C1, this Synchronization Adjustment decreased income tax expense by $0.011 million resulting in an equal increase in NOI.

Q. What is the Projected ROR Summary for Projected Test Year?

A. Exhibit A-14, Schedule D1, develops DTE Gas's defined Projected Test Year required overall ROR. The Projected Test Year 13-month average balance sheet capital structure amounts are carried forward from Exhibit A-12, Schedule B4.1, column (c). Schedule D1 calculates the projected weighted cost of capital of 5.68%, line 12, column (h). This weighted cost of capital is carried forward to Exhibit A-11, Schedule A1 and is used in the determination of the Revenue Deficiency for the Projected Test Year.

Total Long-Term Debt of $1,492 million, shown on line 1 of Schedule D1, has been reduced by the net amount of unamortized premium and discounts and unamortized debt costs. This 13-month average projected balance of Long-Term Debt represents

48% of DTE Gas's permanent capital. DTE Gas's total Long-Term Debt outstanding at September 30, 2019 is detailed on Schedule D2. The weighted Long-Term Debt cost of 4.59% (column (f)) was calculated using the net proceeds method for each issue outstanding at September 30, 2019, including the financing cost of new debt issues supported by Witness Solomon in Exhibit A-14, Schedule D2.

Line 2 of Schedule D1 shows the projected 13-month average Common Shareholders' Equity of $1,616 million, which includes common stock outstanding, less expense, plus premium, retained earnings and OCI adjustments. This level of average projected Common Equity represents 52% of DTE Gas's permanent capital in the Projected Test Year. The cost of Common Shareholders' Equity utilized for this exhibit is 10.50% (column (f)), which is supported by Company Witness Dr. Vilbert in his testimony.

The cost of Short-Term Debt, on line 4, column (f), of 2.36% is the forecasted average short-term borrowing cost of the Company in the Projected Test Year supported by Witness Solomon on Exhibit A-14, Schedule D3. The Customer Deposits cost rate on line 5 is assumed to be 5.0%. This is based on the Company's understanding that new billing rules are forthcoming and 5% will be the customer deposit rate set forth in those rules.

Other interest bearing credits, shown on line 6, are liabilities that have interest associated with them. The cost rate of these other interest bearing credits in the projected year is 2.36%, as supported by Witness Solomon on Exhibit A-14, Schedule D3.

The 13-month average Projected Test Year Job Development – ITC amounts on lines 10 (JDITC – Debt) and 11 (JDITC – Equity) of Schedule D1 reflect the corresponding permanent capital percentages of 48% for Long-Term Debt and 52% for Common Equity. The associated returns for JDITC–Debt and JDITC–Equity reflect the corresponding permanent capital rates of 4.59% 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.

The 13-month average Projected Test Year Net Deferred Income Tax of $976 million (line 7), as shown on Schedule D1 are at zero cost of capital.

Revenue Requirement for DTE Gas's Infrastructure Recovery Mechanism

Q. What information is provided on Exhibit A-18, Schedule H1 entitled "Infrastructure Recovery Mechanism – Meter Moveouts Incremental Revenue Requirement"?

A. Exhibit A-18, Schedule H1, page 1, identifies the annual incremental Revenue Requirements / Cost of Service for years 2019 through 2023 relating to the meter move-out capital costs associated with DTE Gas's IRM, as discussed by DTE Gas Witnesses Harris, Uzenski and Mr. Telang. The Revenue Requirements / Cost of Service components consist of Return on Net Rate Base, Depreciation, and Property Taxes. Lines 10 through 13, on Page 1 of Exhibit A-18, Schedule H1 show the Cost of Service Requirement amounts for years 2019 through 2023 that are used by DTE Gas Witness Mr. Slater to derive the IRM charges for the respective years. Line 2 is the meter capital investment amounts supported by Witness Harris on Exhibit A-12, Schedule B6.2. Lines 4 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 11.19%. Depreciation, line 11, is based on the half year convention, using depreciation rate of 2.52% approved in DTE Gas’s depreciation case U-16769 for distribution meters. The line 12 Property Taxes are derived on page 2 of this exhibit.

Q. What information is provided on Exhibit A-18, Schedule H2 entitled “Infrastructure Recovery Mechanism – Main Renewals Incremental Revenue Requirement”?

A. Exhibit A-18, Schedule H2, page 1, identifies the annual incremental Revenue Requirements / Cost of Service for years 2019 through 2023 relating to the main renewal capital costs associated with DTE Gas’s IRM, as discussed by DTE Gas Witnesses Harris, Uzenski and Telang. The Revenue Requirement / Cost of Service components consist of Return on Net Rate Base, Depreciation, and Property Taxes. Lines 12 through 15, on page 1 of Exhibit A-18, Schedule H2 show the Cost of Service Requirements for years 2019 through 2023 that are used by Company Witness Slater to derive the IRM charges for the respective years. Lines 2 and 3 are the transmission and distribution capital investment amounts (Main Renewal and Pipeline Integrity) supported by Witness Harris, on Exhibit A-12, Schedule B5.2. Lines 6 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 11.19%.

Line
No.

Depreciation, line 13, is based on the half year convention, using a weighted depreciation rate of 2.04%. The line 14 Property Taxes are derived on page 2 of this exhibit.

Q. What is the basis for the pre-tax rate of return of 11.19%?

A. The 11.19% pre-tax rate of return is DTE Gas's permanent capital projected weighted cost rates from Exhibit A-14, Schedule D1, grossed up by the appropriate pre-tax multiplier discussed previously in my testimony.

Q. What is the basis for the weighted depreciation rate of 2.04% on Exhibit A-18, Schedule H2?

A. The 2.04% depreciation rate is based on depreciation rates approved in DTE Gas's depreciation case U-16769 for distribution mains – plastic and transmission mains. The respective depreciation rates are applied to the program expenditures for distribution mains and transmission mains projected for the five years shown on Exhibit A-18, Schedule H2, column (h).

Q. What is the purpose of page 2 of Exhibit A-18, Schedules H1 and H2?

A. Page 2 of Exhibit A-18, Schedules H1 and H2 shows the calculations of the accumulated deferred tax expense used in the derivation of Net Rate Base and the property taxes included in the cost of service, shown on page 1 of Exhibit A-18, Schedules H1 and H2.

Line
No.

IRM Capital Under Spend Impact

Q. What is the purpose of Exhibit A-18, Schedule H5?

A. Exhibit A-18, Schedule H5 entitled "Infrastructure Recovery Mechanism – Under Spend Impact" calculates the proposed customers' monthly charge reduction for every $1 million of IRM capital costs DTE Gas under spends. This calculation was performed consistent with the methodology approved by the Commission in MPSC Case No. U-16999. The resulting fixed customer monthly rate reduction is designed to reduce customer charges by a fixed rate for every $1 million of actual IRM capital cost DTE Gas fails to spend in any year. The parameters for applying this reduction to the monthly surcharge are described in Witness Telang's testimony. This schedule follows the same calculation flow that I discussed in Schedules H1 and H2 of this Exhibit A-18.

Q. What rate do you recommend using as the fixed customer monthly rate reduction for each $1 million of IRM capital under spent?

A. I recommend decreasing the customers' monthly charges by $0.013 for each $1 million of IRM capital under spent by the Company. The $0.013 monthly rate reduction per customer is based on an average of the Year 2 rate reduction and the summation of the rate reductions for Year 1 and Year 2. This calculation is shown on line 17, column (d), of Exhibit A-18, Schedule H5.

Q. What is the purpose of page 2 of Exhibit A-18, Schedule H5?

A. Page 2 of Exhibit A-18, Schedule H5 shows the calculations of the accumulated deferred tax expense used in the derivation of Net Rate Base and the property taxes supporting the cost of service, shown on page 1 of Exhibit A-18, Schedule H5.

Line No.

Revenue Deficiency Excluding AK Steel

Q. What information are you supporting regarding discount recovery related to AK Steel?

A. As requested by Witness Slater, I have calculated the revenue deficiency for DTE Gas based on financial statements reflecting the removal of all costs and revenues related to AK Steel prepared by Witness. Uzenski and discussed by Witness Decker. Based on this information, DTE Gas's revenue deficiency would be $88.6 million in the projected test year (Exhibit A-22, L2.A1), $3.5 million more than that projected in Exhibit A-11, A1, which includes AK Steel and Ford-Rouge as customers. The removal of related AK revenues and costs impacted working capital, NOI and the Overall ROR. Thus, in addition to Exhibit A-22, Schedule L2.A1, I am sponsoring Exhibit A-22, Schedules L2.B1 (Rate Base), L2.B4 (Working Capital), L2.B4.1(Balance Sheet with classifications) and L2.D1 (Overall ROR).

Revenue Requirement for Pipeline Lease between DTE Gas and NEXUS

Q. What is the purpose of the NEXUS revenue requirement presented on Exhibit A-23, Schedule M3?

A. In the Commission's order in U-17999, dated December 9, 2016, the Company was directed to provide a complete revenue requirement calculation for the NEXUS project including evidence on the project costs and revenues in its next rate case. I have calculated the Revenue Requirement/Cost of Service and compared it to the contract lease revenues for the initial 15-year lease term (2019 through 2033) based on the lease agreement between DTE Gas and NEXUS, as discussed by Witness Decker, and capital cost components provided to me by Witness Sandberg. The Revenue Requirements / Cost of Service components consist of Return on Net Rate

Base, Operation and Maintenance Expense, Depreciation, and Property Taxes. Lines 8 through 13, on Page 1 of Exhibit A-23, Schedule M3 show the Cost of Service Requirement amounts for the initial term of the lease (15 years). Line 2 is the capital investment amounts supported by Witness Sandberg on Exhibit A-12, Schedule B5.1. Lines 4 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 8, is based on the Average Net Rate Base multiplied by a pre-tax rate of return of 11.19%. Depreciation, line 11, is based on the half year convention, using depreciation rate of 1.95% approved in DTE Gas's depreciation case U-16769 for transmission plant. The line 12 Property Taxes are derived on page 2 of this exhibit.

Q. What is the basis for the pre-tax rate of return of 11.19%?

A. The 11.19% pre-tax rate of return is DTE Gas's permanent capital projected weighted cost rates from Exhibit A-14, Schedule D1, grossed up by the appropriate pre-tax multiplier discussed previously in my testimony.

Q. What is the purpose of page 2 of Exhibit A-23 Schedule M3?

A. Page 2 of Exhibit A-23, Schedules M3 shows the calculations of the accumulated deferred tax expense used in the derivation of Net Rate Base and the property taxes included in the Cost of Service, shown on page 1.

Q. What is the resulting revenue requirement for the NEXUS lease based on your calculations?

A. For the 15-year period of the lease contract between the Company and NEXUS, the cumulative customer benefit is $91.4 million.

Summary

Q. In summary, 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, DTE Gas's Revenue Deficiency for the projected test period ending September 30, 2019 of $85.1 million.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

RENEE M. TOMINA

DTE GAS COMPANY
QUALIFICATIONS OF RENEE M. TOMINA

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

A. My name is Renee M. Tomina. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Gas Company (DTE Gas or Company) as Director of Southeast Michigan Gas Operations.

Q. On whose behalf are you testifying?

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

Q. What is your educational background?

A. I graduated from Lawrence Technological University with a Bachelor degree in Electrical Engineering with a concentration in Electronics. I also earned a Master of Science degree in Systems Engineering with a concentration in Manufacturing Processes, from Oakland University.

Q. What is your DTE Energy work experience?

A. I have been employed by DTE Energy since November 2010 in a number of positions of increasing responsibility. In November of 2010, I joined DTE Energy as a Continuous Improvement (CI) Expert in the CI Strategy group where I was responsible for providing support and coaching to build distinctive continuous improvement capabilities. In 2011, I was promoted to CI Manager supporting the Corporate Services Organization. In this role, I was responsible for coordination and successful implementation of the Operations and CI Committee principles and deliverables for Corporate Services across Fleet, Facilities and Supply Chain. In 2012, I was promoted to Director of Facilities within the Corporate Services Organization. In this role, I was the operations leader responsible for overseeing all

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maintenance in regards to real estate and property of DTE Energy and ensuring that all operations complied with the Occupational Health and Safety Administration. In 2014, I was assigned to the role of Director of Revenue Management & Protection in Customer Service. I was responsible for all collection operations including Customer Offices, Field Collections, Theft Operations, Phone Collections, Customer Advocacy, Strategy and all support operations with the goal of improving collection efficiency and reducing arrears and uncollectible expense for both DTE Electric and DTE Gas. In June of 2015, I was assigned to my current position of Director of Southeast Michigan Gas Operations for DTE Gas where I am responsible for all areas of operations in Southeast Michigan including Field Service, Distribution, Construction support and Drafting.

Q. What testimony have you previously provided to the Michigan Public Service Commission (MPSC or Commission)?

A. I have provided testimony in Case No. U-17767, DTE Electric Company's general rate case and Case No. U-17999, DTE Gas Company's general rate case.

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Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support DTE Gas's historical and projected Operation and Maintenance (O&M) expenses for which I am responsible. I will also communicate DTE Gas's leak backlog status and Meter Assembly Check (MAC) activities. My testimony will address:

- The 12 months-ending September 2019 (projected test year) Gas Operations O&M expense;
- The status of DTE Gas's leak backlog;
- MAC Activities

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-13	C5.1	Projected Operation and Maintenance Expenses – Natural Gas Storage
A-13	C5.2	Projected Operation and Maintenance Expenses – Transmission
A-13	C5.3	Projected Operation and Maintenance Expenses – Distribution
A-20	J1	August 2017 Leak Inventory Compliance Filing
A-20	J2	August 2017 Meter Assembly Check Status

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

A. Yes, they were.

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Q. What are the major categories of O&M expenses?

A. The major O&M expense categories are natural gas storage, transmission, and distribution. I also address the reclassification of Company Use and adjustments for Pipeline Integrity, Distribution Integrity Management Program Engineering, ANR/Alpena-Grand Rapids Transmission fees, MAC inspections, Blue Lake transmission fees and NEXUS related O&M. Capital expenses for these assets are supported by Company Witness Ms. Sandberg.

Q. What does DTE Gas project its total O&M expenses will be during the test year?

A. DTE Gas projects a total of $184.2 million of O&M expenses, adjusted for Company Use Reclass, during the test year ending September 30, 2019.

	Expenses in Millions
Natural Gas Storage	$ 12.2
Transmission	57.4
Distribution	114.6
Total	$ 184.2

Q. How did DTE Gas project its O&M expenses for the test year?

A. The Company projected its O&M expenditures based on actual expenses incurred during the 2016 historical test year. These 2016 expenses were then adjusted for known and measurable changes and inflation through September 30, 2019. Additional adjustments were made for certain known and measurable changes. The inflation percentages are supported by Company Witness Ms. Uzenski.

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Q. Why is it reasonable to use historical information to project O&M expenses?

A. O&M expenses are routine in nature and occur year after year at generally consistent levels, subject to inflation. Inflation rates for the bridge period and test year are 2.9% for the calendar year 2017, 2.8% for calendar year 2018 and 2.2% for the 9-month period ending September 2019.

<u>Natural Gas Storage</u>

Q. What is the O&M expense for natural gas storage operations for the 2016 historical test period?

A. The adjusted historical 2016 O&M expense for natural gas storage is $11.3 million excluding Company use. See Exhibit A-13, Schedule C5.1, column (f), line 22. The unadjusted historical test period amounts in column (c) are consistent with the storage expenses in the 2016 MPSC Form P-522, page 322 (Accounts 814 through 837).

Q. How is the O&M expense for storage operations incurred?

A. The O&M expense for storage operations is incurred for two sub-processes: compression and storage.

1) Storage compression – Storage compressors provide pressure support for storage injection into and withdrawal operations out of the storage reservoirs. Routine maintenance is required to operate compressors, driving O&M Storage Compression costs.

2) Storage – Gas storage operations facilitates the Company's acquisition of reliable natural gas supplies during the summer period (when natural gas is typically cheaper) to meet the customers' demand of natural gas during the

high-demand days throughout the winter period. DTE Gas's storage fields are part of the integrated transmission, compressor, and storage system ensuring reliable natural gas delivery to DTE Gas's interstate and intrastate customers. O&M Storage costs are for the routine maintenance required to continue operations of gas storage.

Q. What O&M expense level is projected for natural gas storage in the projected test period?

A. The projected test period O&M for natural gas storage, excluding the cost of Company Use gas, is $12.2 million. See Exhibit A-13, Schedule C5.1, column (l), line 22. To calculate the projected amount, inflation was applied to the adjusted actual 2016 historical test period.

<u>Natural Gas Transmission</u>

Q. What is the O&M expense for transmission expenses for the 2016 historical test period?

A. The adjusted historical 2016 O&M expense for transmission expense is $39.2 million excluding Company Use. See Exhibit A-13, Schedule C5.2, column (f), line 22. The unadjusted historical test period amounts in column (c) are consistent with the transmission expenses in the 2016 MPSC Form P-522, pages 323-324 (Accounts 850 through 867).

Q. How is the O&M expense for Transmission operations incurred?

A. O&M expense for transmission operations relates to the following five sub-processes: 1) Compression, 2) Transmission, 3) Gas Control, 4) Gas Supply, and 5) Engineering Services.

Q. How is O&M expense for transmission compression operations incurred?

A. Transmission compression units are located along the transmission system. Transmission compression may provide additional pressure support for storage injection and accommodate pressure requirements for deliverability to DTE Gas's city gate stations. Routine maintenance is required for continued operations of those compression unit and drives O&M costs.

Q. How is O&M expense incurred for transmission operations?

A. The transmission system includes all other high pressure pipelines and facilities owned by the Company upstream of and including city gate stations. Transmission pipelines deliver gas to the distribution pipeline system downstream of city gate stations as well as to other pipelines at off-system delivery locations. Routine maintenance required for continued operations of the transmission system drives transmission operations O&M.

Q. How is the O&M expense incurred for Gas Control?

A. The O&M expense for Gas Control is incurred primarily for the following five operational activities: 1) Gas Control, 2) Measurement and Control Maintenance, 3) Gas Measurement, 4) Gas Nominations, and 5) System Planning. These operational activities support the physical receipt and delivery of natural gas on the DTE Gas

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system. The overall process includes the planning, monitoring, controlling and tracking of gas received from production, pipelines, and storage and ensures that it is delivered safely and reliably to its final destination. The destination may be a delivery for DTE Gas sales customers, end-use transportation, as well as off-system transportation or storage customers. Since natural gas is a co-mingled product, record-keeping, volume measurement, and recording are critical functions in the natural gas business.

1) Gas Control - Gas Control is a 24/7 operation that utilizes the DTE Gas Supervisory Control and Data Acquisition (SCADA) system to monitor, control and manage the operation of the DTE Gas system to ensure safe, reliable service and meet contractual obligations. The SCADA system allows the Gas Control group to monitor and control the physical activity of the transmission, storage and distribution systems on a real-time basis and is critical in operating DTE Gas's system. It provides the ability to identify and respond to operational issues/problems in a timely manner by monitoring the flow, pressure, and alarms at all DTE Gas's major pipelines, city gate stations, and storage field facilities. SCADA provides the ability to operate the pipeline within federal safety guidelines.

2) Measurement and Control Maintenance – Measurement and Control Maintenance is responsible for maintaining a radio network spread across both the upper and lower peninsulas of Michigan. The Company responds to trouble calls on a 24 hour-a-day basis and performs maintenance on a regularly scheduled basis to ensure system reliability. Measurement and Control Maintenance is responsible for calibration of orifice and ultrasonic metering stations and gas quality monitoring devices. Compressor station distributed

control and automation systems are also maintained by the group. All SCADA communication networks (satellite, cellular and radio) and associated SCADA Remote Terminal Units (RTUs) are maintained by the Measurement and Control Maintenance department.

3) Gas Measurement – Gas Measurement manages and ensures the accuracy, integrity, and completeness of all flow measurement and gas quality data for DTE Gas's transmission, storage system and large industrial customers. This information is loaded to accounting systems for month-end closing. Within this process, personnel review and audit interconnecting pipeline gas statements for billing accuracy and work closely with field operations to identify and resolve system measurement problems. In addition, Gas Measurement is responsible for maintaining the primary and backup host SCADA system and related hardware used to support the Gas Control room operations of the DTE Gas system.

4) Gas Nominations – Gas Nomination validates, confirms, and processes all inbound nominations for storage, gathering, and transportation transactions on DTE Gas's systems using the Company's "eNominator" electronic bulletin board. Approximately 900,000 nominations are processed annually. The Gas Nominations group also enters nominations on upstream interstate pipelines to transport purchased gas to DTE Gas's city gates. In addition, the Gas Customer Choice program and Exelon Easement Agreement are administered through this group.

5) System Planning – System Planning performs system modeling to optimize DTE Gas's current transmission, distribution, compression and storage assets to ensure cost efficient, safe and reliable deliveries to existing customers on a

daily, monthly, seasonal and annual basis. They support the Gas Supply, Marketing and Gas Control activities regarding planned and unplanned operations. In addition, the team also completes the analysis, design and recommendation of optimized operations and expansions of DTE Gas's system to capture new EUT, transportation and storage opportunities.

Q. What functions does Gas Supply provide that are incurred for O&M expense?

A. The Gas Supply function handles the development, negotiations, and management of the master agreements for all gas supply and interstate transportation. In addition, this process is responsible for price risk management of DTE Gas's gas supply and the administration of all gas supply contracts. The amount expensed to O&M relates to payroll, subscriptions and other related Gas Supply expenses.

Q. How is the O&M expense incurred for Engineering Services?

A. O&M expense for Engineering Services is incurred for the following four operational activities:

1) Geology and Reservoir Engineering, 2) Pipeline System Engineering (includes transmission, distribution, compression & processing systems), 3) Pipeline Integrity Management (includes transmission and distribution), 4) Corrosion Control, and 5) Codes & Standards and Laboratory Services.

Q. How is O&M expense incurred for Geology and Reservoir Engineering?

A. Geology & Reservoir Engineering O&M services include inventory, deliverability and reliability verification for DTE Gas's four gas storage fields, as well as feasibility studies on enhancing performance of these fields or developing new storage fields. This work includes: Designing, supervising and analyzing well pressure surveys, well logs, water well samples, field and well flow tests and well and wellhead maintenance activities; performing geological and reservoir assessments and modeling activities; managing the wellhead electronic measurement system that collects hourly well pressure, flow and temperature data; and maintaining daily field and well activity reports.

Q. How is O&M expense incurred for Pipeline System Engineering?

A. Pipeline Engineering Services performs day to day activities necessary to comply with regulatory requirements and provide technical support for the safe, reliable and cost efficient operation of DTE Gas's transmission, storage, gathering and distribution systems. In addition, they are involved in analysis related to feasibility of unusual system operations, equipment failures, operational problems or emergency response. They also maintain documentation of transmission facility infrastructure such as pipeline location maps (GIS System), Population Density Survey (PDS) maps, as well as researching facility requests that are initiated within the Miss Dig System.

Q. How is O&M expense incurred for Pipeline Integrity Management?

A. Pipeline Integrity Management is responsible for compliance with two federally mandated programs, Transmission Integrity Management Program - TIMP (section 49 CFR, part 192, subpart O) and Distribution Integrity Management Program – DIMP (section 49 CFR, part 192, subpart P). Both programs identify and mitigate risks to the transmission and distribution pipeline systems. Pipeline Integrity Management costs result from these compliance activities. The O&M portion of

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such activities include required assessments of transmission pipelines at prescribed frequencies, evaluation of transmission and distribution system threats, conducting risk assessments to rank system risks, developing and implementing risk mitigating plans for prioritized risk management, and evaluating effectiveness of risk mitigating activities. The Integrity Management team maintains Population Density Survey (PDS) and High Consequence Area (HCA) maps.

Q. How is O&M expense incurred for Corrosion Control?

A. Corrosion Control responsibilities include protecting the metallic components of DTE Gas's gas handling system from external, internal and atmospheric corrosion by performing annual pipeline surveys and other services including inspection, testing and monitoring. Since most of DTE Gas's system consists of metal piping, equipment and fabricated housing units, DTE Gas's efforts in this area are critical to system operations and for the protection and safety of its customers and employees. The Company protects compressor and regulator station equipment; pipelines, valves and fittings; storage field piping and equipment assemblies; odorization equipment; pigging facilities; and prefabricated buildings.

Protection from external corrosion on buried metallic components is provided through application of effective coatings and cathodic protection. Corrosion Control specifies coatings to be used and provides monitoring, troubleshooting, and implements the remediation work required to maintain the various cathodic protection systems.

Protection from internal corrosion on metallic components (e.g., transmission pipelines, inside the pipe) is provided by designing to minimize liquids accumulation and performing periodic maintenance that includes liquids collection and removal, monitoring, cleaning/pigging, and chemical treatment. The Corrosion Control department coordinates with Transmission Engineering, Gas Operations and Laboratory Services with these functions.

Protection from atmospheric corrosion is provided through use of effective coatings of the metal components exposed to the elements. Corrosion Control specifies coatings and assists Gas Operations with inspection and monitoring of the various types of metallic components.

Q. How is O&M expense incurred for Codes & Standards and Laboratory Services?

A. Codes & Standards and Laboratory Services ensure that the Company complies with the rules and regulations mandated by state, federal, and other regulatory authorities. They create standards and interpret new rules. Codes and Standards serves as the Company's interface with the MPSC and Office of Pipeline Safety (OPS) personnel regarding code interpretation and resolution. The Laboratory Services group performs gas analysis to ensure it meets pipeline specifications, odor intensity, and pipeline material evaluation.

Q. What O&M transmission expense is projected for the test period?

A. Projected test year O&M for transmission expense, excluding the cost of Company use gas, is calculated at $57.4 million. See Exhibit A-13, Schedule C5.2, column (m), line 22. To calculate the projected amount, inflation was applied to the adjusted actual 2016 historical test period.

Q. What projection adjustment(s) are assumed within Transmission Expense other than inflation?

A. Five known and measurable adjustments, other than inflation, are assumed within Transmission expense (See Exhibit A-13, Schedule C5.2). These adjustments are related to:

1. Pipeline Integrity: $8.2 million (line 3, column (k))
2. Blue Lake transmission: $2.9 million (line 9, column (k))
3. ANR/Alpena-Grand Rapids Transmission: $2.8 million (line 9, column (k))
4. Nexus Transmission & Storage Optimization: $1.2 million (line 15, column (k))
5. Sales and Use Tax Adjustment: $0.12 million (line 22, column (j)) sponsored by Company Witness Ms. Wisniewski

Q. Why is pipeline integrity expense projected to increase?

A. Pipeline Integrity Management O&M increases result from requirements in both TIMP and DIMP.

The increase in TIMP expenses of $1 million in 2017, $3.7 million in 2018 and $8.2 million in 2019, reflects:

1) Increasing number of pipelines to be reassessed, dictated by the last time the immediate prior assessment was conducted, typically a 7-year cycle,
2) Increase in the number of actionable anomalies detected due to advances in technology used to perform the assessments,

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3) Increase in the miles of pipe assessable by the more expensive In-Line-Inspection (ILI) method under the ILI expansion program. Witness Sandberg's testimony supports the benefits of ILI as well as the regulatory drivers for the ILI expansion program,
4) Expenses associated with pending regulations anticipated to be finalized by second quarter of 2018. These expenses are described in Witness Sandberg's testimony.

The increase in DIMP expenses reflects the costs of:

(1) A risk expert. In its order in case No. U-17999, the Michigan Public Service Commission (MPSC) recommended that DTE Gas seek the services of a risk expert specializing in cast iron and steel pipes to perform an independent review of the risk model and main renewal priority-selection procedure. DTE hired a risk expert to perform and complete the recommended review by Nov. 4, 2017.
(2) Enhancements to the distribution integrity risk model. These enhancements will expand threat coverage, enhance risk calculation and implement recommendations from the risk expert review in 2018. These enhancements ensure that risk output accurately reflects the threats in the distribution system so that risk mitigation activities are appropriately directed to reduce system risk.

Q. Why are Blue Lake transmission fees projected to increase by $2.9 million?

A. As described in Company Witness Mr. Decker's testimony, the Settlement Agreement between ANR Pipeline Company, Blue Lake Gas Storage Company and

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DTE Gas Company, dated February 1, 2016, resulted in an incremental 11.4 Bcf of storage capacity available for DTE to market to off-system customers. This incremental capacity is a permanent capacity release of Blue Lake Storage Company capacity held by ANR. The cost of this capacity, including transport for injections and withdrawals, is $2.9 million per year. As explained in Witness Decker's testimony, the annual revenue forecasted for this capacity is $4.2 million per year.

Q. Why are ANR/Alpena-Grand Rapids Transmission fees projected to increase by $2.8 million?

A. As described more fully by Company Witness Mr. Chapel, the costs under the ANR Alpena transport agreement are projected to increase by $1.6 million due to an increase in ANR rates effective August 1, 2016, as approved by the Federal Energy Regulatory Commission, and the costs under the ANR Grand Rapids transport agreement are projected to increase by $1.3 million due to an increase in the transport capacity effective November 1, 2017.

Q. Why are you projecting $1.2 million in Nexus Transmission & Storage Optimization?

A. Nexus Transmission & Storage Optimization are projected for the following reasons:

(1) Transmission Storage and Operations (TS&O) will add resources to support the Nexus Expansion. Due to the increase in units and auxiliary equipment, which will require daily monitoring therefore adding three repairmen and a Supervisor. Two Tech II's will be added to work at Willow Gate and

surrounding lines to handle all code work at the two compressor stations given the added valves and equipment. Due to the increase in units and demands on the team, a Reliability Engineer will be added as well.

(2) DTE Gas will be moving from a Passive Nominations system to an Active Nominations system. Two additional Gas Nominations staff members will be required to monitor all gas day cycles and provide confirmations after each cycle for the Active Nominations system. Monitoring is required 365 days a year with two shifts.

(3) Control Maintenance will add two Control Technicians to support the maintenance of the gas measurement and control equipment. Most of this work will be with the control equipment at Willow and Milford compressor stations.

<u>Natural Gas Distribution</u>

Q. What was the O&M expense for distribution operations in the 2016 historical test period?

A. The Adjusted Historical 2016 O&M distribution expense is $105.7 million excluding Company Use gas. See Exhibit A-13, Schedule C5.3, column (f), line 22. The historical test period amounts in column (c) are consistent with the distribution expenses displayed in the 2016 MPSC Form P-522, page 324 (Accounts 870 through 894).

Q. How does DTE Gas's Gas Operations incur O&M expense for distribution operations?

A. O&M expense for distribution operations is for 3 major sub-processes: 1) Field Service, 2) Distribution, and 3) Enterprise Performance Management.

Q. How is O&M expense incurred for Field Service?

A. Field Service is staffed to cover the entire DTE Gas service territory, which spans large portions of both the upper and lower peninsulas of Michigan. Field Service conducts its Operations from 17 Distribution stations located throughout its service territory. DTE Gas maintains a 24-hour, 365-day staffing requirement to respond to gas leaks and provide safe, reliable service to all DTE Gas's customers. The O&M expense for Field Service is due to the following five sub-processes: 1) emergency gas leak response, 2) meter orders, 3) meter and regulator maintenance, 4) standby time, and 5) meter reading.

1) Emergency Gas Leak Response - This process begins when a Field Service employee receives an emergency dispatch order from our Dispatch group. The Field Service employee drives to the location and investigates the situation, makes repairs if possible, or refers the problem to a Distribution crew for underground repairs. DTE Gas's guidelines (generally accepted within the industry and by the MPSC Gas Safety Staff) target an average response time of 30 minutes or less. Multiple leaks and long distance travel requirements cause some responses to exceed 30 minutes. The Company's average response time during 2016 was 24.7 minutes.
2) Meter Orders - There are two types of meter orders, customer requested and Company generated. In terms of units of Field Service work, meter orders comprise the largest single process performed by the Company. A customer

requested meter order is a request from a customer who is moving in or out of a home or requesting an additional meter read. These orders are referred to as "Ons," "Offs," "Read for Change," or "Miscellaneous Read." Orders are scheduled per the customer request date and placed in the Company's appointment book for execution. Company generated meter orders arise when the Company determines the need for maintenance on its equipment. Company generated meter orders include meter assembly checks, hexagram repairs, or change meter orders.

3) Meter and Regulator Maintenance – These expenses result from Company generated work covering rotary meter inspections, meter repairs and manifold repairs and maintenance. In accordance with regulatory requirements, DTE Gas's rotary meters are inspected annually or bi-annually to ensure that they are operating correctly, proper pressure is being delivered, and proper billing factors are used to charge the customer.

4) Standby Time - Standby time is paid to employees in Greater Michigan who are on call after hours. DTE Gas does not staff all its service stations on a 24-hour basis because of insufficient workload during the late night. Standby time is intended and used for emergency preparedness. Employees on standby time are ready to cover off-hour emergencies related to leaks, fires, explosions, MISS Dig and no heat requests. When called on these jobs, the employee will charge the specific process and not standby time.

5) Meter Reading - Gas Operations is responsible for reading meters in the following 12 Greater Michigan service areas: Alpena, Tawas, Mt. Pleasant, Big Rapids, Cadillac, Ludington, Traverse City, Petoskey, Grayling, Sault Ste. Marie, Escanaba, and Kingsford. The Greater Michigan reads include

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residential, commercial, industrial and transportation customers. The Company also performs meter-reading services for Alpena Power, which generates incremental revenues for the Company. For DTE Gas's markets located in Detroit, Grand Rapids and Muskegon, the Company's Customer Service group performs the meter reading process. When this work is performed by Greater Michigan Distribution personnel, meter reading expenses are charged to the Customer Service FERC accounts.

Q. How is O&M expense incurred for distribution operations?

A. Distribution operations are responsible for the installation, repair, maintenance, and modification of all the Company's equipment between the transmission gate stations and the customer meters. O&M expense for the Distribution process includes four sub-processes: 1) Pressure, 2) Leak Survey, 3) Leak Repair and 4) Damage Prevention.

1) Pressure - The Company operates and maintains city gate stations and regulation stations across the system. Pressure personnel complete the following tasks: annual and quarterly inspections (per code) on all gate stations, regulator and valve locations, elevated pressure rotary meter inspections, measurement meter calibrations, operation of catalytic heaters, facility maintenance, response to meter freeze offs, gas sampling, annual high-pressure tests of valves and additional code-related work. Maintenance work includes valve repair, facility repairs, minor and major meter repairs, gas chromatograph inspection and general preventative maintenance. This group also maintains odorization equipment, and performs any tapping, welding, and stopping of

high pressure gas mains up to 300 pounds of pressure. In addition, they support emergency work for station and customer locations (e.g., freeze offs, pressure complaints, leaks), meter orders for large industrial customers and other construction related work including pipeline integrity and public improvement.

2) Leak Survey - Leak survey is responsible for the surveying of all pipe assets including mains, service lines and meters to the outlet of the meter. These surveys are conducted in accordance with regulatory requirements laid out in the Michigan Gas Safety Standards and are enforced by the MPSC. Leak surveys are completed by either physically walking directly over the pipe and service lines with leak detection or with mobile-mounted leak detection equipment. The Company surveys its cast iron pipelines and business district mains every year and residential area mains and services every three years.

3) Leak Repair - Leak Repair includes the tasks leading to the ultimate repair of gas leaks on mains and services and does not include leaks repaired under the Infrastructure Renewal Program.

4) Damage Prevention - Damage Prevention is responsible for partnering with MISS DIG 811, excavators, municipalities, other utilities and locating teams for preventing excavation damage to Company assets. In performing this process, the Company must make effective use of the one-call locating request system, provide accurate location and marking of underground facilities, and ensure those who dig around Company facilities are educated and understand the risks from improper excavation. As part of this process, DTE Gas works with various organizations and takes an active role in educating the public regarding the potential hazards of working around our facilities as well as promoting safe excavating practices. Damage prevention is critical to DTE Gas's effort to

protect our customers and the public from serious personal injury, property damage and in some cases, the interruption of natural gas service to segments of DTE Gas's service territory. DTE Gas also partners with excavators to ensure training compliance, safe digging education and damage claims/collections.

Q. How is the O&M expense incurred for Enterprise Performance Management?

A. O&M expense for Enterprise Performance Management includes two sub-processes: 1) Dispatch and Workload Management and 2) Meter Shop.

1) Dispatch and Workload Management – The responsibilities of this group include the forecasting, planning, scheduling, dispatching, reporting, record keeping and measurement of all workload related to meter orders, emergency response, and workload. This function aligns the available workforce to meet workload requirements and satisfy the customer and regulatory commitments of DTE Gas. Personnel within this process have responsibility for managing and monitoring computer and communication technology within the operating area. This process affects all field personnel statewide including represented, non-represented and contract employees. In 2016, this group planned and coordinated close to 1.2 million orders, including approximately 86,000 emergency response orders.
2) Meter Shop - Meter Shop is responsible for managing the Inspection-Testing program for testing diaphragm meters, field testing of rotary meters, and meter refurbishments. In 2016, this group tested about 40,000 meters to maintain code compliance.

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Q. What O&M distribution expense is projected for the test period?

A. Projected 2019 O&M for Distribution Expense excluding Company Use Gas is \$114.6 million, see Exhibit A-13, Schedule C5.3, column (m), line 22. To calculate the projected amount inflation was applied to the adjusted actual 2016 historical test period. Additionally, an adjustment was made for MAC inspections. To become MPSC compliant with MAC requirements, DTE Gas is projecting to spend \$0.72 million for MAC inspections. More details about DTE Gas's MAC efforts are outlined in Company Witness Ms. Harris's testimony.

Q. What projection adjustment(s) are assumed within distribution operations expense other than inflation?

A. Two known and measurable adjustments are assumed within distribution operations expense. These adjustments are related to (Exhibit A-13, Schedule C5.3):

1. Meter Assembly Checks: 0.72 million (column (k), line 8)
2. Sales and Use Tax Adjustment: \$0.41 million (column (j), line 22) sponsored by Witness Wisniewski

<u>**DTE Gas's Leak Backlog**</u>

Q. What requirement does DTE Gas have in this rate case proceeding related to the final Order requirements of Paragraph L Case No. U-15985, and reaffirmed in the final Order in Case No. U-17999, covering the Company's need to address the backlog of leaks?

A. Paragraph L states, in part, "In each subsequent general rate case, Michigan Consolidated Gas Company shall file information addressing the capital expenditures associated with, and progress made in, reducing the backlog of leaks."

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Q. Does your testimony cover the Company's compliance with Paragraph L of Case No. U-15985?

A. Yes. I address the capital expenditures and leak remediation results associated with DTE Gas's efforts in controlling its leak backlog during the specified timeframes. My testimony also addresses the Company's expected 2017 capital expenditure for addressing the leak backlog. In addition, Exhibit A-20, Schedule J1, August 2017 Leak Inventory Compliance Filing provides detail on incoming leaks and remediation.

Q. What was DTE Gas's leak backlog as of January 1, 2016?

A. The leak backlog was 1,821.

Q. What were DTE Gas's actual leak remediation results in 2016?

A. In 2016, DTE Gas remediated 13,937 leaks out of approximately 14,793 new incoming leaks, which resulted in a balance at the end of 2016 of 965 leaks.

Q. What type of work can contribute to the prevention of future leaks?

A. Main renewals, service renewals, and service/main retirements all contribute to eliminating future leaks. A main or service renewal replaces the old facility with a new facility that is much less likely to leak. Main or service retirement removes a facility from service, eliminating all future leaks on those facilities.

Q. What were the leak volume activity and capital expenditures associated with the backlog of leaks?

A. The summary below provides the 2016 actual results, 2017 forecast, and the 2018 plan.

	Leaks				*Expense ($ MM)*
	Jan. 1	**Incoming Leaks**	**Leaks Repaired**	**Year End Balance**	**Capital**
2016 Actuals	1,821	13,937	14,793	965	5.3
2017 Projected	965	15,063	14,028	2,000	7.3
2018 Base Plan	2,000	14,024	14,024	2,000	7.5

Q. What is DTE Gas's base work plan for 2018 regarding leak remediation?

A. For 2018, DTE Gas forecasts 14,024 new incoming leaks and plans to remediate 14,024 leaks during the year resulting in a year-end backlog of 2,000 leaks.

Q. What type of leak remediation work is included in O&M expense?

A. O&M work includes the repair of mains and services due to gas leaks, which does not require the complete renewal of the main or service line segment.

Q. What type of leak remediation work is included in capital expenditures?

A. Construction capital expenditures include the renewal of service lines due to gas leaks. These capital expenditures are discussed by Witness Sandberg in her testimony.

Q. What other plans does DTE Gas have in place to address the impact of leaks on the DTE Gas system?

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A. As discussed by Witness Harris, DTE Gas's Infrastructure Recovery Mechanism will in the long term significantly reduce the number of poor performing main, including cast iron main, thus helping to address the impact of leaks on the DTE Gas system.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
______________________________________	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THERESA M. UZENSKI

DTE GAS COMPANY
QUALIFICATIONS OF THERESA M. UZENSKI

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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 (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 Gas Company (DTE Gas 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-eight years in various accounting, finance and management positions. I am currently the Manager of Regulatory Accounting for DTE Gas Company as well as DTE Electric 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

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1	U-16246-R	Detroit Edison 2010 RETM Reconciliation
2	U-16356	Detroit Edison 2009 REP Reconciliation
3	U-16472	Detroit Edison 2010 Rate Case
4	U-16574	Detroit Edison 2010 UETM Reconciliation
5	U-16582	Detroit Edison 2014 REP Plan
6	U-16769	MichCon Depreciation
7	U-16952	Detroit Edison 2014 CIM Reconciliation
8	U-16956	Detroit Edison 2014 RETM Reconciliation
9	U-16964	Detroit Edison 2014 UETM Reconciliation
10	U-17302	DTE Electric Company 2017 REP Plan Update
11	U-17437	DTE Electric Company Transitional Cost Recovery Mechanism
12	U-17767	DTE Electric Company 2014 Rate Case
13	U-17999	DTE Gas Company 2015 Rate Case
14	U-18014	DTE Electric Company 2016 Rate Case
15	U-18122	DTE Electric Company Customer 360 Program Accounting
16	U-18255	DTE Electric Company 2017 Rate Case
17	U-18419	DTE Electric Company Certificates of Necessity

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support DTE Gas's financial statements for the historical test year ended December 31, 2016, the interim forecast period and a twelve-month projected test year ending September 30, 2019, including a 13-month average balance sheet. The financial statements have 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 gas operating income based on forecasted changes from the normalized historical gas operating income and the inflation rate used to develop projected O&M costs.

I also support the Corporate Staff Group (CSG) expenses for the historical and forecasted periods and explain the function of this group and the method for allocating costs to DTE Gas and the other DTE subsidiaries. I also support the labor amounts included in O&M and capital, as well as the related headcount.

I support that costs recovered from other mechanisms are excluded from the financial statements in this case (Energy Optimization, Infrastructure Recovery Mechanism, Gas Cost Recovery Mechanism, and Revenue Decoupling Mechanism).

I am also requesting deferral accounting for the impacts to certain post-employment benefit (OPEB) and pension costs from a new FASB rule, Accounting Standards Update (ASU) 715. The ASU prohibits the capitalization of all components of OPEB and pension costs except for service costs. I am requesting deferral treatment for the previously capitalized cost components. My testimony will demonstrate that the deferral treatment will provide consistency with past ratemaking practice for both rate base and depreciation expense.

I explain the accounting and reconciliation process for the Infrastructure Recovery Mechanism (IRM). My testimony will describe the changes from the methodology approved by the Commission in U-17999. I also describe how the mechanism will be handled if DTE Gas files another rate case during the IRM period.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am supporting the following exhibits:

Section A - Historical Test Year (Calendar Year 2016)

Exhibit	Schedule	Description
A-2	B4.1	Historical 13-Month Average Adjusted Balance Sheet
A-2	B4.2	Historical Year-End Adjusted Balance Sheet
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 Cost of Gas Sold
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 Advertising Adjustments
A-3	C15	Historical Corporate Memberships Adjustment
A-3	C16	Historical Executive Incentive Plan Adjustment

A-3	C17	Historical Employee Incentive Plan Adjustment
A-3	C18	Historical Weather Normalization Adjustment

Section B – Projected Test Year (Twelve Months Ending September 30, 2019)

Exhibit	Schedule	Description
A-12	B4.2	Historical and Projected 13 Month Average Balance Sheet
A-12	B4.3	13-Month Average Common Equity Reconciliation
A-13	C1	Projected Net Operating Income
A-13	C3	Projected Sales Revenue
A-13	C3.1	Projected Distribution Revenue by Rate Schedule
A-13	C5	Projected Operation and Maintenance Expenses Summary
A-13	C5.6	Projected Operation and Maintenance Expenses - Administrative and General
A-13	C5.12	Pension and OPEB Regulatory Assets and Liabilities
A-13	C6	Projected Depreciation and Amortization Expense
A-13	C11	Projected AFUDC
A-13	C12	Projected Inflation Factors
A-13	C14	Projected Amortization of Loss on Reacquired Debt

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

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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-522. 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 Ms. Suchta and Ms. Wisniewski support certain adjustments to interest and taxes. I support the O&M for the Corporate Support Group (CSG).

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 are provided by Company Witness Mr. Chapel, and Company Witness Mr. Decker supports various Midstream and certain other revenues. 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 are then used in Witness Suchta's files to calculate the revenue deficiency.

SECTION A – Historical Test Year

Q. What information are you providing with respect to the Historical Test Year ended December 31, 2016?

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A. For the historical test year ended December 2016 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 B4.1 and B4.2 contain the historical test year balance sheet information. Schedule B4.1 is a 13-month average balance sheet for the periods December 2015 through December 2016. Schedule B4.2 contains similar information but as of December 31, 2016. The balances in column (b), together with certain eliminations and reclassifications in columns (c) through (i) reflect the balance sheet for rate case purposes. The 13-month average adjusted balance sheet line items from Exhibit A-2, Schedule B4.1 column (j) are carried to Exhibit A-2, Schedule B4, "Historical Working Capital," supported by Witness Suchta.

The December 2016 year-end adjusted balance sheet in column (j) of Exhibit A-2, Schedule B4.2 is used as the starting point for developing DTE Gas's projected balance sheet in Section B.

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 balances that are being recovered or refunded via other mechanisms or surcharges

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including Energy Optimization (EO), Revenue Decoupling Mechanism (RDM), and Gas Cost Recovery (GCR). 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. The adjustments are shown on the balance sheets on Exhibit A-2, Schedules B4.1 and B4.2, columns (c) through (i). 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. 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 Gas 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 B4.1 and B4.2, column (c) eliminates the 2016 balance sheet impacts related to ASC 715. This treatment is also consistent with DTE Gas's presentation in Case Nos. U-15985, U-16999 and U-17999.

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.

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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. To ensure that there is no impact on revenue requirements from ARO accounting in the forecast years, I have removed all 2016 regulated balance sheet impacts on Exhibit A-2, Schedules B4.1 and B4.2, column (d).

Q. Why has the Company's historical balance sheet been adjusted to exclude the MGP Environmental Liability Reserve and Deferred Lost Gas?

A. As required under generally accepted accounting principles, DTE Gas has recorded a reserve for the expected liability of future Manufactured Gas Plant (MGP) environmental obligations with an offsetting deferral to the MGP Regulatory Asset account. An adjustment to exclude the MGP reserve is appropriate for ratemaking purposes to demonstrate that only the allowable portion of the MGP Regulatory Asset is included in working capital that the Company is entitled to earn a return on, pursuant to Commission Order in Case Nos. U-13898/U-13899 dated April 28, 2005.

The impact of Deferred Lost Gas accounting is also eliminated, together with its impact on Common Equity, because this accounting treatment adopted by the Company is not recognized by the Commission.

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Q. Why are the EO, GCR Over/Under Collection, and RDM removed from the Company's historical balance sheet for rate case purposes?

A. The MPSC has established separate proceedings to address the recovery of the GCR Over/Under Collection and RDM. Therefore, the related regulatory assets/liability balances, together with impacts on associated deferred taxes and short-term debt are removed. Similarly, the MPSC has established a separate proceeding to address the recovery of the EO program. Therefore, the related regulatory assets/liability balances and intangible assets, together with impacts on associated deferred taxes, short-term debt, long-term debt and common equity are removed.

<u>Historical Income Statement</u>

Q. What information are you supporting on Exhibit A-3, Schedule C1, Historical Adjusted Net Operating Income?

A. On Exhibit A-3, Schedule C1, DTE Gas's Historical Adjusted Net Operating Income for the historical test year ended December 31, 2016 was determined by starting with the financial information reported on the Company's MPSC Annual Report Form P-522, page 114. Then I adjusted the reported financial information for certain exclusions and inclusions to get to a rate case filing level. Column (c) of the exhibit shows the various components of the $203.6 million Net Operating Income (line 18) as reported in the Company's 2016 Annual Report to the MPSC on Form P-522.

The adjustments necessary for ratemaking purposes include adjustments and normalizations in column (d). The net result of these adjustments is an adjusted Net Operating Income of $230.5 million (line 25) and as shown in column (e).

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Q. What are the specific adjustments and normalizations that have been made to Net Operating Income for the historical test year?

A. Exhibit A-3, Schedule C1.1 provides a detailed reconciliation of Net Operating Income (NOI) for the historical test year. Line 2 of the exhibit shows the various components of the $203.6 million NOI reported in the Company's 2016 Annual Report to the MPSC on Form P-522.

Q. What items are included in the Adjustments of Recorded Net Income for the historical test year?

A. The Adjustments are shown on Exhibit A-3, Schedule C1.1, lines 4 through 34 and represent income effects of items that are a) disallowed or adjusted, b) reclassified within utility operating earnings, c) reclassified to or from other income and deductions, or d) eliminated because they are covered under separate proceedings. The result of the adjustments and reclassifications is an increase of $26.9 million in Net Operating Income.

Q. What impact do the adjustments have on the various components within NOI?

A. The NOI impact of the adjustments is reflected on Exhibit A-3, Schedule C1.1 on the following lines:

- Gas in Kind (line 4) of $17.5 million, originally reflected as credit within Cost of Gas sold on line 2, is reclassified to Other Revenue.
- Lost Gas Expense (line 5) of $6.2 million is reclassified out of Cost of Gas Sold into the separate Company Use and Lost Gas Expense component.
- Company Use Expense (line 6) of $8.9 million is reclassified out of O&M into the separate Company Use and Lost Gas Expense component.

- Blue Lake Income (line 7) increases NOI by $3.5 million, and is comprised of $5.6 million of Other Revenue offset by $2.1 million of income taxes. The Equity Earnings were originally recorded to Non-Utility Income net of tax.
- Vector Interest Revenue (line 8) increases Other Revenue and NOI by $5.6 million. The adjustment is displayed on a pretax basis since this is merely a reclassification from interest revenue to operating revenue and income taxes are already reflected in recorded utility income taxes.
- Grantor Trust Investment Income (line 9) increases NOI by $0.7 million and is comprised of $1.2 million of Other Revenue less $0.5 million for income tax expense that was previously reflected in non-utility income taxes.
- Short-Term Interest Income (line 10) increases Other Revenue and NOI by $0.8 million. The adjustment is displayed on a pretax basis since this is merely a reclassification from interest revenue to operating revenue and income taxes are already reflected in recorded utility income taxes.
- Title Transfer Fees (line 11) reduces NOI by $0.9 million, and is comprised of a $1.5 million reduction in revenue from Third Party Transportation & Storage, and a $0.6 million corresponding Income Tax reclassification pursuant to the Commission order in Case No. U-11210.
- Non-Utility Depreciation (line 12) removes $61,000 of depreciation expense and increases NOI by $37,000.
- Cost of Gas (line 13) removes $455.4 million of GCR Cost of Gas and the related Distribution Revenues because they are included in a separate reconciliation proceeding.
- Lost Gas Deferral (line 14) eliminates $4.5 million of deferred expense reflected in Distribution Revenues in 2016 because it relates to an accounting

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treatment adopted by the Company that is not recognized by the Commission. This results in an after-tax increase to NOI of $2.9 million.

- Revenue Decoupling Mechanism (RDM) (line 15) removes amounts related to the RDM as there is a separate reconciliation for this mechanism. The $2.1 million increase in revenue results in an after-tax increase to NOI of $1.3 million.
- Other Surcharges (line 16) removes the residual impacts from self-implementation refunds related to the last general rate case, decreasing NOI by $6.5 million.
- Energy Optimization (EO) (line 17) removes amounts related to EO because there is a separate recovery mechanism for this program. The $28.8 million reduction in revenue plus the removal of the related expense items results in an after-tax reduction to NOI of $2.3 million.
- Disallowed Advertising Expenses and Corporate Memberships (lines 18 and 19) removes $2.4 million in expenses which are not recoverable for ratemaking purposes, and results in an after-tax increase in NOI of $1.5 million. Exhibit A-3, Schedule C14 identifies the actual advertising expenses by categories as prescribed by the standard filing requirements. The purpose of this exhibit is to identify the advertising expenses that are not recoverable per the Commission's rate case filing requirements. Allowable advertising expenses for ratemaking include public safety, conservation and billing practices. Exhibit A-3, Schedule C15 identifies operating expenses for corporate memberships unrelated to utility operations that that are not recoverable per the Commission's rate case filing requirements.

Line No.

- Executive Incentive Plan (line 20) removes incentive compensation expense of $2.8 million for the top five officers of DTE, increasing NOI by $1.7 million as shown on Exhibit A-3, Schedule C16 and as directed by Company Witness Mr. Cooper.

Q. What items are included in the Normalizations to Recorded Net Income for the historical test year?

A. Normalizations are shown on Exhibit A-3, Schedule C1.1, lines 23 through 28 and include the effects of an incentive plan adjustment, vacation accrual adjustment, an account reconciliation adjustment, a one-time regulatory credit, and warmer than normal weather. The result of the normalizations is an increase of $16.7 million in Net Operating Income.

Q. How did you determine the Incentive Plan adjustments for the historical test year?

A. Line 24, Employee Incentive Plan Adjustment, is supported by Exhibit A-3, Schedule C17 and reduces 2016 incentives expense by $3.1 million. The 2016 historical period includes $0.4 million for mark-to-market adjustments related to 2013 performance shares paid out in 2016. Also, 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 2016 includes a $1.1 million accrual for an anticipated increase

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in cash payouts for the 2014 through 2016 performance shares based on stock price changes. Since the mark to market and 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 2016 includes $1.6 million for amounts paid above the 100% target. Since payments above the target may not recur, I have removed that amount. These normalizations increase NOI by $1.9 million.

Q. How did you determine the Weather normalization adjustment for the historical test year?

A. The Weather normalization for distribution revenue (line 25) reflects warmer than normal temperatures in 2016, requiring a $25.9 million margin increase and an after-tax increase to NOI of $15.7 million to normalize earnings. See the calculation on Exhibit A-3, Schedule C18 for the volume and revenue impact of weather by customer class (Residential, Commercial, and Transportation). As shown on line 4, column (b), weather was 11.5 Bcf warmer than normal in the historical test year. The computation was estimated based on 15-year rolling heating degree day (HDD) weather normalization as supported by Witness Chapel. The volume impacts are then multiplied by an average distribution rate for the customer class in column (c), resulting in a total margin impact of $25.9 million on line 4, column (d) and $15.7 million on a net of tax basis as shown on line 7.

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Q. What are the Vacation Accrual and Customer Accounts Receivable normalizations?

A. Line 26 normalizes vacation accrual expense using an average due to volatility in cost levels and is supported by Witness Cooper. Line 27 removes a one-time charge in 2016 from the reconciliation of prior period accounts receivable.

Q. What is the Regulatory Credit normalization?

A. Line 28 removes a one- time credit in 2016 that resulted from the establishment of a regulatory asset related to municipal cut and cap fees, as ordered by the Commission in Case No. U-17999.

Q. What operating income items did you include in adjusted historical net operating income?

A. Operating income adjustments are shown on Exhibit A-3, Schedule C1.1, lines 31 through 34 for Allowance for Funds Used During Construction, Amortization of the Loss on Reacquired Debt, Income Tax Effect of Interest, and Interest Synchronization Tax Adjustment. These adjustments increased NOI by $1.6 million.

- Allowance for Funds Used During Construction (AFUDC) (line 31) adds $3.8 million of Debt and Equity AFUDC to net operating income. The adjustment is displayed on a pretax basis since income taxes are already reflected in recorded utility income taxes.
- Amortization of Loss on Reacquired Debt (line 32) increases other expense and reduces NOI by $1.6 million because the loss on reacquired debt is not included in the cost of long-term debt for ratemaking purposes. The adjustment is displayed on a pretax basis since this is merely a reclassification from interest

expense to operating expense and income taxes are already reflected in recorded utility income taxes. This amortization is a result of DTE Gas's efforts to reduce interest costs by redeeming and refinancing long-term debt securities in advance of their scheduled maturities. The cost related to each of these early redemptions is amortized over the life of the new issue.

- Income Tax Effect of Interest (line 33), supported by Witness Suchta decreases NOI by $0.7 million to align the actual interest expense tax deduction with the allowable ratemaking interest expense tax deduction associated with the capital structure debt components.
- Interest Synchronization (line 34) increases NOI by $33,000 for the additional tax deduction associated with the Job Development Investment Tax Credit (JDITC) debt component of the capital structure, as supported by Witness Suchta.

Q. What information is displayed in Exhibit A-3, Schedule C3, Historical Sales Revenue?

A. Schedule C3 provided the amount as reported on MPSC Annual Report Form P-522 for residential, commercial, industrial, wholesale, transportation, refund provisions and miscellaneous revenues, underlying total revenue reported on line 2, column (c), of Exhibit A-3, Schedule C1.1.

SECTION B – Projected Test Year (October 1, 2018 – September 30, 2019)

Q. How was the financial forecast for the projected test year prepared?

A. Projected DTE Gas financial statements for the twelve-month period ending September 30, 2019 were based on projected changes from the adjusted normalized amounts for the year ended December 31, 2016. The financial forecast for the projected test year incorporates assumptions supported by the various DTE Gas witnesses including myself. Monthly data was used to derive 13-month average balance sheet calculations.

Balance Sheet Forecast

Q. How was the 13-month average balance sheet developed in support of DTE Gas's Rate Base for the projected test year ending September 30, 2019?

A. I started with the December 31, 2016 adjusted balance for each component. Certain line items were projected if warranted by key assumptions in the case, while other line items were held constant at the historical balance as of December 31, 2016. Exhibit A-12, Schedule B4.2, provides a comparison of the 13-month average balance sheet for historical test year December 31, 2016 and projected test year September 30, 2019. The balance sheet line items in column (b) represent the Adjusted Historical Test Year balances carried from Section A, Exhibit A-2, Schedule B4.1.

Q. What are the major components making up the Balance Sheet in Exhibit A-12, Schedule B4.2?

A. Exhibit A-12, Schedule B4.2, is comprised of the following major components:

1) Property, Plant and Equipment (Net Utility Plant)
2) Other Property and Investments
3) Current and Accrued Assets & Liabilities
4) Deferred Debits & Credits
5) Capitalization (Common Equity and Long-Term Debt)

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Property, Plant and Equipment (Net Utility Plant)

Q. How did you develop the Net Utility Plant balance for the projected test year?

A. Net Utility Plant on line 5 of Exhibit A-12, Schedule B4.2, page 1 of 2, increases over the historical test year due to capital additions in excess of depreciation expense levels. The projected change in Plant in Service is driven by construction added to plant in service less retirements from January 1, 2017 through September 30, 2019. Additions to plant in service are $317.0 million in 2017, $551.9 million in 2018 and $131.3 million from January 1 through September 30, 2019, offset by retirements of $30.7 million in 2017, $35.3 million in 2018 and $40 million from January 1, 2019 through September 30, 2019.

Capital expenditures of $1,005 million for the period January 2017 through September 2019 are supported and explained by Company Witness Ms. Sandberg and include approximately $381 million of routine investments and $256 million of special projects including Nexus, the Belle River Compressor, Gordie Howe Bridge, Milford Junction Loop, Revenue Protection, AMI and New Market Attachments. It also includes approximately $346 million of IRM related projects in 2017 and 2018. The overlay of $21 million is for the impact of a new accounting rule, ASU 715. I will explain this adjustment in my testimony regarding O&M expense. Construction Work in Progress generally assumes all projects are completed and unitized within the calendar year except for three multi-year projects: Gordie Howe Bridge, Milford Junction Loop, and Nexus transmission plant. Retirements were assumed based on either a historical five-year average (Distribution, Transmission, and Storage Plant) or scheduled retirements (Intangible and General Plant).

The projected Accumulated Depreciation has been developed based on estimated plant depreciation expense of $225.0 million for the interim period January 2017 through September 2018 and $139.6 million for the test year ending September 2019, including approximately $5.1 million of annualized Transportation and Mobile Power Equipment depreciation which is charged to O&M and capital clearing accounts. The calculation of depreciation expense is described later in my testimony. Accumulated Depreciation is also adjusted for retirements of approximately $106 million from January 1, 2017 through September 30, 2019, consistent with those assumed in Plant in Service. Net removal cost of approximately $94.2 million annually was assumed, based on a five-year average.

<u>Other Property and Investments</u>

Q. What is included in Other Property and Investments?

A. Other Property and Investments are reflected on lines 8-13 of Exhibit A-12, Schedule B4.2. These are comprised primarily of Blue Lake and the Grantors Trust. During the projected test year, it is assumed that Blue Lake subsidiary will pay a dividend equal to its Equity Earnings at the end of each quarter while the Grantors Trust Investment is held at the December 31, 2016 historical balance.

<u>Current and Accrued Assets</u>

Q. What is included within the Current and Accrued Assets section of the balance sheet?

A. Current and Accrued Assets are listed on lines 15-30 of Exhibit A-12, Schedule B4.2. This category consists primarily of Customer Accounts Receivable, Intercompany and Other Accounts Receivable, Uncollectibles Reserve, Unbilled Revenue, Inventories (Gas in Storage and Materials), Prepayments, Gas Customer Choice (GCC) Deferred Asset and various other current assets.

Q. How did you calculate the projected balances for Customer Accounts Receivable and Unbilled Revenue?

A. The Customer Accounts Receivable and Unbilled Revenue balances for 2018 and 2019 were forecasted at the 2017 actual monthly balances through September, adjusted for normal weather. September 2017 year to date weather normal gas sales of 130.3 Bcf are 113% higher than actual gas sales of 115.8 Bcf. This percentage was applied to the 2017 actual balances through September. October through December were forecast using the month-to-month percentage change in the balances from 2016, applied to the September 2017 balance.

Q. What other forecast assumptions were made within the Current Assets section?

A. Items within this category that were assumed to be held constant at the December 31, 2016 balance include Cash, Temporary Investments, Notes Receivable, Other Accounts Receivable, Intercompany Accounts Receivable, Materials and Supplies, and Other Current Assets. There is also no change in the Uncollectible Reserve balance since it is assumed the forecasted provision is exactly equal to net write-offs and recoveries. The Intercompany Notes Receivable balance at December 31, 2016 is assumed to be collected in the projected period. Gas in Underground Storage and the GCC Deferred Asset reflects inventory activity based on a Source and Disposition provided by our Gas Planning Department. Prepayments were projected based on projected property tax payments, offset by property tax accruals.

Line No.

Current and Accrued Liabilities

Q. What is included within the Current and Accrued Liabilities section of the balance sheet?

A. Current and Accrued Liabilities are listed on lines 52-65 of Exhibit A-12, Schedule B4.2 page 2. This category consists primarily of Short-Term Debt, Accounts Payable, Intercompany Accounts Payable, Intercompany Notes Payable, Customer Deposits, Taxes and Interest Payables, Inventory Equalization, and various other current liabilities.

Q. How was the Short-Term Debt balance calculated?

A. Short-term debt is used to finance DTE Gas's working capital requirements not funded through permanent capital. Thus, to the extent long-term financing does not cover monthly working capital requirements, short-term debt was calculated as the amount needed to fund the Company's operations on a month to month basis. Short-term debt includes intercompany notes payable to Parent. The forecast assumes the loan from DTE Energy, outstanding at December 31, 2016, is paid off in the projected period.

Q. What activity is included within the various Payable Accounts?

A. Accounts Payable is based on 2017 monthly balances through September, adjusted for weather, consistent with the treatment of Customer Accounts Receivable. Income Taxes Payable is supported by Witness Wisniewski. It reflects monthly accruals and the expected pattern of quarterly payments in January, April, July, and October. All other payables were held constant at the December 31, 2016 balance, including

Line No.

Intercompany Accounts Payable, Intercompany Notes Payable- Other Affiliates (DTE Gas Subsidiaries), and Interest Payable.

Q. What is Inventory Equalization?

A. Inventory equalization represents the difference between the current year gas purchase rate and the average prior year-end LIFO inventory gas rate applied to volumes withdrawn from storage in the early part of the calendar year. While inventory balances are reduced by only the low LIFO cost, the equalization reserve reflects the difference between the current period cost and the LIFO cost as a temporary liability. For example, a liability is forecasted to be accrued during the first quarter of 2019, reaching $81.4 million in March. As gas is injected in the summer months to replace the gas withdrawn earlier in the year, the equalization reserve is reduced by the same methodology until the gas storage balance reaches the prior year-end level. The equalization account balance reaches zero by year-end but does have an impact on the 13-month average balance sheet as shown on Exhibit A-12, Schedule B4.2, line 61.

Q. What other forecast assumptions were made within the Current Liabilities section?

A. Customer Deposits and Non-MGP Environmental Reserve were held constant at the December 31, 2016 balance because the historical fluctuation in these accounts has not been material. Other Current Liabilities were forecasted based on the December 2016 balance reduced for known payments of one-time accruals.

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Deferred Debits and Credits

Q. What is included in Deferred Debits and Credits?

A. Exhibit A-12, Schedule B4.2 lists Deferred Debits on page 1 (lines 32-44) and Deferred Credits on page 2 (lines 67-83). The major accounts within this category relate to Unamortized Debt and Loss on Reacquired Debt, Vector Pipeline Lease, Prepaid Pension Asset and Negative Pension Liability, Postretirement Benefits, MGP Environmental Regulatory Asset, a new regulatory asset related to Demolition Fees, Accumulated Deferred Income Taxes, Michigan Business Tax, Provision for Injuries and Damages, and a new regulatory liability related to Postretirement Benefits.

Q. How did you develop the balances for Unamortized Debt Expenses and Unamortized Loss on Reacquired Debt?

A. Unamortized Debt Expenses and Unamortized Loss on Reacquired Debt are included in Deferred Debits on lines 32-33 of Exhibit A-12, Schedule B4.2, page 1. Unamortized Debt Expense is reduced by annual straight-line amortization of about $0.6 million and increased by 0.7% of projected long-term debt issuances. Unamortized Loss on Reacquired Debt is reduced by annual straight-line amortization of $1.6 million.

Q. What impact does the Vector Pipeline Lease have on the balance sheet?

A. The Vector Pipeline lease is a 20-year capital lease agreement between DTE Gas and Vector Pipeline, similar to a mortgage loan. The Vector Pipeline Lease (Exhibit A-12, Schedule B4.2, line 34) is credited for the $9 million of annual lease payments with an offsetting debit for the interest portion of the payment. The net reduction in the Vector Lease balance represents the principal portion of the lease payments.

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Q. What impact does the Prepaid Pension asset together with the Negative Pension Regulatory Liability have on the balance sheet?

A. The balance included in the Prepaid Pensions Deferred Debit account (Exhibit A-12, Schedule B4.2, line 35) represents prepaid pension costs related to DTE Gas's union and non-union plans. The prepaid balance decreases by the cost accruals, and increases by planned annual contributions of $25 million, as sponsored by Witness Cooper.

The related Deferred Credit account, Negative Pension Regulatory Liability, (Exhibit A-12, Schedule B4.2, line 78) was established pursuant to the Commission's order in Case No. U-13898 that authorized the accrual of a regulatory liability for the non-capitalized portion of the negative pension cost. When the return on plan assets was greater than pension service and interest costs, the net pension cost was a credit to expense (i.e. negative). The Negative Pension Regulatory Liability was established to set O&M pension expense at zero in the determination of the Company's revenue requirement and thus avoided the growth in the prepaid pension asset. Now that the projected pension cost is no longer negative, the net pension expense will continue to be set to zero in the Company's revenue requirement until the Negative Pension Regulatory Liability has been eliminated. Accordingly, the Negative Pension Regulatory Liability decreases in the projected test year by the projected pension cost less amounts capitalized, transferred, or deferred.

Q. What components are used to derive the projected balance for Postretirement Benefits?

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A. Prepaid Postretirement Benefits reflected in the Deferred Debit section of the balance sheet (Exhibit A-12, Schedule B4.2, line 40) has been increased by negative OPEB cost accruals sponsored by Witness Cooper. Changes in the prepaid OPEB balance in the projected period, less amounts capitalized, transferred or deferred, are offset by a regulatory liability, similar to the accounting treatment for the negative pension regulatory liability, pursuant to the Commission's order in Case No. U-17999. The impact is reflected on line 81. I explain the calculation of the OPEB regulatory liability as part of my discussion of OPEB expenses.

Q. What is included in the MGP Environmental Regulatory Asset?

A. As more fully described in the discussion of the projected MGP expense below, the Commission has established a cost deferral and rate recovery mechanism for investigation and remediation costs related to environmental cleanup at the Company's former Manufactured Gas Plant (MGP) sites. The related regulatory asset as shown on Exhibit A-12, Schedule B4.2, line 37 reflects the unamortized balance of allowable MGP costs which are tracked by vintage year layers and amortized over ten years beginning the year after payments are made, pursuant to the Commission Order in Case No. U-13898. Payments of $1.5 million are assumed for the 2017 vintage year layer as supported by Company Witness Ms. Martino.

Q. What is the Cost to Achieve Regulatory Asset?

A. The Cost to Achieve (CTA) Regulatory Asset (Exhibit A-12, Schedule B4.2, line 38) was established by the Commission in Case No. U-14909 (consolidated with Case No. U-14907) to recover costs associated with the Company's Performance Excellence Plan (PEP). The Commission also authorized DTE Gas to amortize the

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deferred CTA over a 10-year period starting the year following the deferral. DTE Gas deferred $28 million of CTA costs in 2006 through 2008 which were approved by the Commission in Case No. U-15985. The CTA regulatory asset will be fully amortized by December 2018. The related amortization has been removed from Depreciation and Amortization in the projected test year income statement.

Q. What is the Demolition Fees Regulatory Asset?

A. As approved by the Commission in Case No. U-17991, the Company recorded a regulatory asset for demolition fees that were not charged to municipal customers during 2016. The projected test year in this case reflects that the regulatory asset will be fully amortized by the end of 2018. The related amortization has been removed from Depreciation and Amortization in the projected test year income statement.

Q. What is included in Accumulated Deferred Income Tax within the Deferred Debits and Deferred Credits section?

A. Accumulated Deferred Income Taxes are reflected on the balance sheet in Deferred Debits (Exhibit A-12, Schedule B4.2, line 41) and Deferred Credits (Exhibit A-12, Schedule B4.2, line 71). The balances within these accounts include both federal and state deferred income tax. These deferred tax balances are netted for purposes of the capital structure and cost of capital calculation sponsored by Witness Suchta. Witness Wisniewski explains the primary drivers underlying deferred income taxes.

The Accumulated Deferred JDITC (Post-1970 Job Development Investment Tax Credit) balance is reflected on Exhibit A-12, Schedule B4.2, line 70. This account represents deferred tax credits generated and utilized by the Company with the tax

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benefits flowing back to customers on the same basis as the assets that generated these tax credits are depreciated. Feedback of the post-1970 Job Development Investment Tax Credit benefits continues at approximately $0.9 million annually.

Q. What is the Miscellaneous Deferred Debit-Tax Related account?

A. Witness Wisniewski supports the Miscellaneous Deferred Debit–Tax Related account shown on line 42 of Exhibit A-12, Schedule B4.2. This account is an offset to the deferred tax liabilities related to tax law and tax rate changes, such as the enactment of the Michigan Corporate Income Tax.

Q. What is the Regulatory Liability – FAS 109 Deferred Credit?

A. The Regulatory Liability – FAS 109 Deferred Credit account shown on line 76 of Exhibit A-12, Schedule B4.2, is an offset to the federal deferred tax asset that was recognized by the Company upon implementation of FAS 109 "Accounting for Income Taxes" (now ASC 740). This account was established to offset deferred income taxes for cumulative book/tax temporary differences originating before the implementation of FAS 109 and to record the impact on the deferred taxes of a reduction in the statutory federal income tax rate. The FAS 109 regulatory liability will be fully amortized by December 31, 2017.

Q. What other forecast assumptions were made within the Deferred Debits and Credits sections?

A. All other Deferred Debits and Credits were assumed to be held constant at the December 31, 2016 balance because the historical fluctuation in these accounts has not been material.

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Capitalization

Q. How were the projected capitalization amounts determined in this case?

A. Capitalization is comprised of Common Equity and Long-Term Debt as shown on lines 47 and 49 of Exhibit A-12, Schedule B4.2. DTE Gas has assumed common dividend payments of $217 million from January 2017 through September 2018 and $180 million in the projected period. Long-Term Debt includes bonds, less unamortized discounts. Key long-term debt drivers include: new capital requirements, scheduled retirements, refinancing, level of equity, and the amount of short-term debt. Long-Term Debt includes bond issuances of $315 million from January 2017 through September 2018, and $220 million in the projected test year, as discussed by Company Witness Mr. Solomon. There are $100 million of bonds maturing in 2018.

Q. How did you develop the 13-month average Common Equity balance?

A. Common equity will increase to finance the growing asset base and to meet targeted capitalization percentages. Exhibit A-12, Schedule B4.3 reconciles DTE Gas's monthly common equity starting from year-end December 31, 2016 by adding net income in column (c) and subtracting dividend payments in column (d). I then solved for the equity infusions/rate relief in column (e) to arrive at the ending monthly balance in column (f) needed to support the targeted capital structure of 52% equity discussed by Witness Solomon.

Q. Do the equity balances include amounts to support the infrastructure program?

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A. No. Costs related to the infrastructure program after December 31, 2018 are proposed to be recovered through a separate infrastructure recovery mechanism (IRM), as will be discussed later in my testimony. Therefore, the infrastructure program rate base and capitalization are not included in the projected financial statements used to determine the revenue deficiency for base rates.

<u>Net Operating Income Forecast</u>

Q. What is reflected on Exhibit A-13, Schedule C1 "Net Operating Income, Projected Twelve Month Period Ending September 30, 2019?"

A. DTE Gas's projected Adjusted NOI for the twelve months ending September 30, 2019 is provided on Exhibit A-13, Schedule C1, with the historical test year, projection adjustments and projected period amounts. As shown on line 24 in column (e), the net operating income for the projected test year ending September 30, 2019, is $191.3 million, which is a $39.2 million decrease from the 2016 adjusted historical test year. The decrease in income is due to higher operating costs partially offset by increased revenues. The increase in costs results from growth in plant and higher depreciation rates; and higher O&M, uncollectibles, and lost gas expense. Operating revenues reflect new base rates effective December 2016, the addition of off-system transportation sales to Nexus, and the discontinuation of the IRM surcharge. Exhibit A-13, Schedule C1, develops the projected net operating income detailing the changes from historical test year 2016. Each of these projected changes is sourced from separate exhibits sponsored by various witnesses in this case.

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Q. What items are you sponsoring with respect to development of the Net Operating Income for the projected twelve-month period ending September 30, 2019?

A. I am sponsoring the development of DTE Gas's projected test year Operating Revenue, Operation & Maintenance Expense, Depreciation and Amortization, and AFUDC. I am also providing the projected inflation rates used for developing O&M and Capital.

<u>Operating Revenue</u>

Q. How were DTE Gas's revenues developed for the projected twelve-month period ending September 30, 2019?

A. Projected sales revenues were developed in Exhibit A-13, Schedule C3, which details the major categories of revenue and sponsoring witnesses.

- Gas Sales revenue – I am the sponsoring witness for these revenues
- End-User Transportation – sponsored by Witness Decker
- Exelon – I am the sponsoring witness for these revenues
- Off-System Transportation and Storage – sponsored by Witness Decker
- Other Operating Revenue – Witness Decker is sponsoring Appliance Service Programs, Gas Choice Supplier Revenue, Other Gas Revenue, and Blue Lake Investment Income. Gas in Kind Revenue from third parties and end-user transportation customers is based on volumes sponsored by Witness Decker multiplied by the cost of gas rate, and is shown on Company Witness Ms. Aud's Exhibit A-15, Schedule E8. I am sponsoring the remaining items.

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Q. What is the projected change in revenues from the historical normalized period to the projected test year?

A. Exhibit A-13, Schedule C3, displays revenue for the historical test year including the reclassifications and adjustments previously discussed in Section A in column (b) totaling $874.6 million. Total operating revenue is expected to increase by $88 million to $962.7 million, as shown on line 8 of column (d). The projected changes in revenue shown in column (c) are comprised of:

- $96.7 million increase in Gas Sales revenue
- $10.4 million increase in End-user Transportation revenue
- $34.7 million decrease from the discontinuation of the current IRM surcharge
- $32.2 million increase from the addition of the pipeline lease to Nexus, partially offset by a decrease of $9.3 million in exchange gas and other off-system transportation
- $7.3 million decrease in other operating revenues, including $4.9 million in lower income from the Company's investment in Blue Lake

Q. How did you develop Gas Sales revenues for the projected twelve-month period ending September 30, 2019?

A. Gas Sales revenues of $661.9 million were developed in Exhibit A-13, Schedule C3.1. These revenues were derived from the forecasted sales volumes and customer counts provided by Witness Chapel, multiplied by existing tariff rates and service charges authorized in Case No. U-17999. Gas Sales revenue includes $483.8 million of distribution revenue, $197.4 million of service charges and a $19.3 million reduction for the Residential Income Assistance (RIA) and Low Income Assistance

(LIA) programs. The change in gas sales revenue reflects increased sales and higher rates that became effective in December 2016.

Q. What assumptions were used related to the Residential Income Assistance (RIA) credit?

A. The RIA credit in current rates is designed to assist 80,000 low-income customers within the DTE Gas service territory. The RIA provides enrolled customers a $11.25 credit per month. DTE Gas is proposing to reduce the RIA customer count to 55,000, as supported by Company Witness Mr. Johnson. Therefore, the projected annual credit within service charge revenue for Residential Rate A is $7.4 million.

Q. What assumptions were used related to the Low-Income Assistance (LIA) credit?

A. Also supported by Witness Johnson, DTE Gas is proposing to increase the LIA maximum customer count from the 20,000 approved in the Order in Case No. U-17999 to 30,000. Customers enrolled in the LIA program will receive a $30.00 credit per month. Therefore, the projected annual LIA credit within service charge revenue for Residential Rate A is $11.9 million.

Q. How did you develop the Exelon revenue for the projected twelve-month period ending September 30, 2019?

A. Pursuant to a contract between DTE Gas and Exelon, Exelon makes a fixed annual payment of $3.8 million for an initial 5 Bcf block of easement capacity, and an additional payment of $2.1 million for 3 Bcf of supplemental easement capacity, for

Line No.

a total fixed annual easement capacity payment of $5.9 million, shown on Exhibit A-13, Schedule C3, column (d), line 3.

Q. What components of Other Operating Revenue are you sponsoring on Exhibit A-13, Schedule 3 for the projected twelve-month period ending September 30, 2019?

A. I am sponsoring the following other operating revenue components included on Exhibit A-13, Schedule C3:

1. Late Payment/NSF Charges
2. Miscellaneous Service Revenue
3. Rent from Gas Property
4. Vector Lease Interest
5. Grantor Trust
6. Short-Term Interest Income

Projected Late Payment Revenue/NSF charges and rent revenue are forecasted at the 2016 historical level. Miscellaneous service revenue reflects a $0.3 million reduction in reconnect fees, supported by Witness Decker.

Q. How did you forecast Vector Lease interest revenue?

A. As previously mentioned, the Vector Pipeline lease is a 20-year capital lease agreement between DTE Gas and Vector Pipeline, that is like a mortgage loan. Therefore, interest revenue will decrease year to year as the principal balance is reduced. Per the amortization schedule, interest revenue in the projected test year will be $4.6 million compared to $5.6 million in the historical 2016 period as shown on line 18.

Q. Why is the projected income from the Grantor Trust Investment Fund zero?

A. The Grantor Trust Investment Fund realized a gain of $1.2 million in 2016 but any gains or losses in the projected period are dependent on the future performance of the fund. Due to the unpredictability of the financial markets, the most reasonable estimate for the projected test year is $0 as shown on line 19.

Q. How is Short-Term Interest Income calculated?

A. Short-Term Interest Income is forecasted for customer attachments. The customer attachments balance at December 2016 of $3.5 million is multiplied by 11.03%, the pre-tax weighted rate of long-term debt and common equity authorized in Case No. U-17999, resulting in $387,000 of interest income in the projected test year shown on line 20.

<u>Company Use and Lost and Unaccounted for Gas</u>

Q. What is the projected change in Company Use and Lost Gas from the historical period to the projected test year?

A. Line 7 of Exhibit A-13, Schedule C1, column (d) reflects a projected increase in Company Use and Lost Gas of $11.1 million. Witness Aud explains the change in volumes. The projected higher volumes are then multiplied by the cost of gas rate to derive the revenue as reflected on her Exhibit A-15, Schedule E8.

Line
No.

Operation and Maintenance Expense

Q. What is the projected change in Operation and Maintenance (O&M) expense from the historical period to the projected test year?

A. Line 8 of Exhibit A-13, Schedule C1, column (d), shows a projected increase in O&M expense of $82.1 million due primarily to a higher volume of pipeline integrity work, increased transmission costs, expenses related to Customer 360, increased benefits expense, inflation, and a higher capital usage fee from DTE Electric.

Q. How was DTE Gas's O&M Expense developed for the projected twelve-month period ending September 30, 2019?

A. Exhibit A-13, Schedule C5 provides a reconciliation of O&M starting with the published amount on page 325 of the 2016 MPSC Form P-522, incorporating reclassifications and adjustments, and arriving at the historical test year amount of $332.3 million in column (f). Forecast adjustments include the effects of general inflation in columns (g) through (i), assumed to be 2.9% in 2017, 2.8% in 2018, and 2.9% in 2019 prorated 9 months at 2.2%. I support the projection adjustments for Administrative and General expense and the impact of a new accounting rule on Witness Cooper's Exhibit A-13, Schedule C5.9. Witnesses Tomina, Johnson, Decker and Cooper support the other major categories of O&M expense. Each line is supported with a schedule as indicated in column (b). These adjustments result in a projected Base O&M expense of $414.4 million for the twelve months ending September 2019 shown on line 7, column (l).

Q. What is the basis for the general inflation rate assumption used in this case?

A. The inflation rate assumptions displayed in Exhibit A-13, Schedule C12, were used to support various projections in this case including O&M and Capital expenditures. The inflation factor is a weighted rate using the CPI-Urban projected inflation indexes as of July 2017 through the end of the projected test year for non-labor costs and expected wage increases (supported by Witness Cooper) for labor costs.

<u>**Administrative and General**</u>

Q. What were the actual O&M expenses incurred in the Administrative and General Expense category in the 2016 historical test year?

A. Historical 2016 O&M expense for Administrative and General (A&G) expense, excluding benefits, was $91.9 million, as shown in detail on Exhibit A-13, Schedule C5.6, column (c). The Historical Test Year amounts in column (c) are consistent with the A&G expenses displayed in the 2016 MPSC Form P-522, page 325. Columns (d) and (e) are the Section A adjustments related to advertising, corporate memberships, incentive plan, and EO expenses previously discussed. Many of the A&G costs are charged to DTE Gas by the Corporate Staff Group.

Q. What is the Corporate Staff Group (CSG)?

A. The CSG is a shared services LLC organization, 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.

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
- 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 types 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 Gas benefit expenses.) Exhibit A-13, Schedule C5.6, provides the

Line No.

detailed expense projections for the CSG organizations, excluding employee benefit costs.

Q. How are the CSG cost allocations to DTE Energy companies accomplished?

A. CSG costs are first incurred and accumulated at the LLC in cost pools. The pools are distributed and billed to DTE Gas and other DTE entities using an appropriate cost driver. A cost driver is the unit of work/output that is used to determine a formula for billing the products or services to the DTE entities.

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 Gas and other DTE entities and thus, payroll processing costs are billed based on the volume of paychecks processed for DTE Gas 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?

Line No.

A. Yes. This methodology is the same cost allocation methodology supported by DTE Gas and approved by the Commission in DTE Gas's general rate cases, Case Nos. U-13898, U-15985 and U-17999; as well as DTE Electric's last six general rate cases, Case Nos. U-13808, U-15244, U-15768, U-16472, and U-17767, U-18014.

Q. How has the Company billed costs for which no direct cost driver was discernable?

A. While most costs have been billed to DTE Gas 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 Gas. 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 reviewed and approved by the Commission in DTE Gas's general rate cases as well as in DTE Electric'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.

Line
No.

Q. What O&M expense level is projected for Administrative and General Expense in the twelve months ending September 2019 projected test year?

A. Projected 2019 O&M for Administrative and General Expense is $97.9 million, as shown on Exhibit A-13, Schedule C5.6, column (l). In developing this projected amount, the inflation factor I described earlier was applied to historical costs except for Injuries and Damages, MGP Amortization, and Rent.

Q. What projection increases are assumed within the Administrative and General Expenses category other than inflation?

A. There are five projection adjustments within Administrative and General Expenses as shown in column (j) of Exhibit A-13, Schedule C5.6:

1) $520,000 increase in administrative and general salaries for employees returning to normal operations after the C360 project is complete (line 3).
2) $1.6 million decrease in Injuries & Damages based on a five-year average of recorded expense, consistent with prior treatment approved by the Commission (line 8)
3) $399,000 increase in MGP Amortization expense (line 13)
4) $350,000 increase in memberships for Gas Technology Institute's Utilization Technology Development program as supported by Witness Decker (line 14)
5) $10.9 million increase in Capital Usage Charge from DTE Electric, an intercompany charge assessed from DTE Electric to other DTE affiliates for the use and benefit of capital assets that reside on DTE Electric's books (line 15).

Line No.

Q. What is the basis for the $10.9 million increase in Capital Usage Charge?

A. The Capital Usage Charge represents an intercompany billing from DTE Electric for the cost of assets such as buildings and information systems, which are jointly used by the companies. DTE Gas's forecasted shared asset cost is $36.5 million as shown in column (l) of Exhibit A-13, Schedule C5.6, line 15, which is an increase of $10.9 million from the historical period. The increase is primarily driven by charges from DTE Electric for Customer 360, the new customer billing system that went into service in April 2017. DTE Gas's share of the Customer Service asset costs is about 34%.

<u>Pension and Other Post-Employment Benefits Deferral</u>

Q. Can you explain the adjustments you made to Witness Cooper's forecasts?

A. Yes, Witness Cooper has forecasted retiree health care costs including DTE Gas's Pension plan and traditional Other Post-Employment Benefit (OPEB). I am proposing the existing deferral treatment of OPEB and Pension expense be continued, and have reflected the impact on Witness Cooper's Exhibit A-13, Schedule C5.9, line 5. I am also proposing a new deferral to offset the impacts of new accounting rules related to pension and OPEB accounting.

Q. What are the new accounting rules related to pension and OPEB accounting?

A. In March 2017, the Financial Accounting Standards Board (FASB) issued ASU 2017-07 that is required to be implemented on January 1, 2018. Currently, all components of OPEB and pension are capitalized when the related labor cost is capitalized. The change in accounting will require all the elements of OPEB and pension, except current service costs, to be charged 100% 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 "financing" costs.) Only the current service cost component may be capitalized.

Q. What is the impact of the new accounting standard?

A. In theory, since the new accounting standard only allows capitalization of service costs, the financing 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, there is no immediate impact to Pension or OPEB expense, or rate base, because DTE Gas has regulatory deferral mechanisms in place that record all costs that are not capitalized to a regulatory asset or liability.

Q. If there is no immediate impact to DTE Gas's benefits expense or rate base, how is this new accounting relevant to rate making?

A. It is relevant because the new accounting impacts depreciation expense. The current mechanisms for OPEB and Pension defer the net expense *after* capitalization. Since the financing costs related to capital labor will not be capitalized, those amounts will never be depreciated. Instead, they will be deferred to the current regulatory liabilities into perpetuity, as each year's financing costs get added to the regulatory liability balance.

Q. What is your proposal to offset the impact of the new accounting standard?

A. In lieu of recognizing an increase in the current regulatory liabilities, I propose that the financing costs that would have been capitalized under the traditional accounting treatment be recorded to new regulatory liabilities. These new liabilities are illustrated on Exhibit A-13, Schedule C5.12. Page 1, lines 14 and 15, shows the impact to capitalized pension expense in the projected period. Page 2, lines 32 and 33, shows the impact to capitalized OPEB expense in the projected period. The new regulatory liabilities will be depreciated using the composite depreciation rate for plant in service. This treatment will allow the Company to both conform to historical rate-making treatment, and comply with the new accounting rule for SEC reporting. It is also consistent with the treatment I proposed for DTE Electric in Case No. U-18255.

Q. Why are you recommending a continuation of the existing pension and OPEB deferral mechanisms?

A. As shown on Witness Cooper's Exhibit A-13, Exhibit C5.10, line 11, column (d), pension expense is forecasted to be positive in the projected period. Because the current balance in the deferred pension account is a liability, any positive pension expense should be absorbed by reducing the regulatory liability instead of including the expense in rates.

In Case No. U-17999, the Commission approved the deferral of negative OPEB expense to a regulatory liability effective in mid-December 2016. In 2016, OPEB costs were a negative $44 million as reflected on line 11 of Exhibit A-13, Schedule C5.11, column (b). Even though forecasted OPEB expense reflects a $26 million increase over 2016, it is still a negative $18 million in the projected period, as shown in column (d). Therefore, I propose that the deferral be continued.

Line No.

Depreciation and Amortization Expense

Q. How was DTE Gas's twelve months ending September 2019 projected test year Depreciation and Amortization expense developed?

A. To develop depreciation expense, composite depreciation rates are applied to average plant in-service estimated for Distribution, Transmission, Storage, and General plant. The depreciation rates were authorized in Case No. U-16769. Average plant in-service balances were derived based on estimated additions, largely driven by the capital expenditure forecast provided by Witness Sandberg, together with estimated retirements of Storage, Transmission and Distribution plant based on historical averages and scheduled retirements of Intangible and General plant assets.

Intangible plant is amortized over its expected service life. Amortization of the CTA regulatory asset and the Demolition Fees regulatory asset will be complete by the end of 2018 so I did not reflect it in the projected test period.

Q. What is the projected change in Depreciation and Amortization expense from the historical period to the projected test year?

A. Line 10 of Exhibit A-13, Schedule C1, column (d) shows a projected increase in Depreciation and Amortization expense of $27.8 million. This is further supported on Exhibit A-13, Schedule C6, which displays the adjusted historical and projected year totals on page 1, line 5. Schedule C6, page 2 provides details on how depreciation expense is derived from the various types of plant.

Q. What is the reason for the increase in Depreciation and Amortization expense between 2016 and the twelve-month period ending September 2019?

A. Depreciation and Amortization expense is projected to increase by $27.8 million. Of this, approximately $12 million is due to increased depreciation rates effective January 2017. Growth in plant-in-service balances also increases depreciation expense, including approximately:

- $3 million related to added compression for the capacity lease agreement with Nexus
- $7 million from main renewal and meter move-outs
- $2 million related to distribution in new markets
- $6 million from routine distribution and smaller projects
- $6 million related to routine investments in general, storage and transmission plant
- Offset by a $4 million reduction related to intangible plant and fully amortized regulatory assets, and $3 million from plant retirements

Taxes

Q. What is the projected change in Property Taxes?

A. Line 11 of Exhibit A-13, Schedule C1, column (d) shows a projected increase in Property Taxes of $13.9 million. Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedule C7.

Q. What is the projected change in Other General Taxes?

A. Line 12 of Exhibit A-13, Schedule C1, column (d) shows a projected increase in Other General Taxes of $1.6 million due primarily to increases in the public utility assessment, and inflation on payroll taxes.

Line
No.

Q. What is the projected change in State and Local Income Taxes?

A. Column (d) on line 13 of Exhibit A-13, Schedule C1, reflect the projected changes in State and Local Taxes, with a total decrease of $6.5 million. 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 the projected year?

A. Column (d) on line 14 of Exhibit A-13, Schedule C1, reflect the projected changes in Federal income tax expense, with a total decrease of $16 million. Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedule C8.

Other Income

Q. Why is other income decreasing?

A. Other income primarily reflects AFUDC and Amortization of Losses on Reacquired Securities. Losses on securities is based on an amortization schedule with no change from 2016. AFUDC is projected to decrease $2.7 million from the historical test year as seen on line 19 of Exhibit A-13, Schedule C1, column (d), due primarily to the completion of the Nexus project. The equity and debt components of AFUDC are displayed on Exhibit A-13, Schedule C11, lines 1 and 2. The rate used to compute AFUDC is based on DTE Gas's overall rate of return of 5.764% authorized in Case No. U-17999.

Line No.

<u>Accounting for Infrastructure Recovery Mechanism</u>

Q. How does the Infrastructure Recovery Mechanism (IRM) impact the projected financials?

A. An overview of the mechanism is provided by Company Witness Mr. Telang. The Commission order in Case No. U-17999 required the IRM be terminated effective when new base rates are implemented. All related net plant forecasted through December 2018 is reflected in base rates in this case. The IRM capital expenditures and plant balances, the related costs and revenues, and the related debt and equity are excluded from my projected financial statements for the periods after December 2018 because the Company is proposing to recover those costs in a new IRM. This exclusion ensures that the revenue requirement for the IRM is separate and distinct from the revenue requirement for base rates. All IRM-related net plant forecasted for 2019 through 2023 is included in the proposed new IRM and supported by Company Witness Ms. Harris.

Q. How should the 2018 IRM spend be reviewed?

A. Since the IRM capital spend for 2018 is included in projected test year in this general rate case, it should be reviewed as part of the Staff audit in the instant case.

Q. How does DTE Gas intend to record activity under the IRM?

A. Consistent with past practice, DTE Gas 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.

Line
No.

Q. Is DTE Gas 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.

Accounting Requests

Q. Are you requesting any new accounting authority?

A. Yes. I am requesting regulatory asset and liability treatment for Pension and OPEB financing costs to mimic the current capitalization practice that includes all cost components. These new accounts will be expensed over the average life of plant in service by applying the composite depreciation rate.

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 GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	**Case No. U-18999**
schedules and rules governing the	)	
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority.	)	

DIRECT TESTIMONY

OF

MICHAEL J. VILBERT

LIST OF TOPICS ADDRESSED:

COST OF COMMON EQUITY CAPITAL

DTE GAS COMPANY
DIRECT TESTIMONY OF MICHAEL J. Vilbert

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BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION

	)	
DTE GAS COMPANY	)	**CASE NO. U-18999**
	)	
	)	

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 of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm with offices in Boston, Washington, London, San Francisco, Madrid, Rome, and New York City. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy 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 Gas Company ("DTE Gas" 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 gas local distribution utility companies ("gas LDCs") expanded to include regulated water utility companies ("my sample" or "the expanded sample"). I also consider the financial risk of the Company's proposed 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:

Exhibit	Schedule	Description
A-14	D5	Cost of Common Shareholders' Equity
A-14	D5.1	Table of Contents
A-14	D5.2	Classification of Companies by Assets
A-14	D5.3	Market Value of the Expanded Sample
A-14	D5.4	Capital Structure Summary of the Expanded Sample
A-14	D5.5	Estimated Growth Rates of the Expanded Sample
A-14	D5.6	DCF Cost of Equity of the Expanded Sample
A-14	D5.7	Overall After-Tax DCF Cost of Capital of the Expanded Sample
A-14	D5.8	DCF Cost of Equity at DTE Gas Company's Proposed Capital Structure
A-14	D5.9	Risk-Free Rates
A-14	D5.10	Risk Positioning Cost of Equity of the Expanded Sample
A-14	D5.11	Overall After-Tax Risk Positioning Cost of Capital of the Expanded Sample
A-14	D5.12	Risk Positioning Cost of Equity at DTE Gas Company's Proposed Capital Structure
A-14	D5.13	Hamada Adjustment to Obtain Unlevered Asset Beta
A-14	D5.14	Expanded Sample Average Asset Beta Relevered at DTE Gas Company's Proposed Capital Structure
A-14	D5.15	Risk-Positioning Cost of Equity using Hamada-Adjusted Betas
A-14	D5.16	Risk Premiums Determined by Relationship Between Authorized ROEs and Long-term Treasury Bond Rates
A-14	D5.17	Academic Literature on Financial Risk Adjustments
A-14	D5.18	Qualifications of Dr. Michael J. Vilbert

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 testified previously 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 an expanded sample of gas LDCs and water utilities, identified as being similar in risk and business operations to DTE Gas, specifically the regulated gas local distribution and water utility businesses. 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.e., its after-tax weighted-average cost of capital ("ATWACC"). I also provide an ROE estimate based upon the risk premium model.

Q8. What is the result of the cost of capital estimation process?

A8. The result of this process is a sample average ATWACC for each cost of equity estimation method. I then report the cost of equity consistent with the sample's average estimated ATWACC as if the sample's average market-value capital structure had been one with a 52 percent equity ratio, which is the equity ratio DTE Gas 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 ATWACC method, I use the method originally proposed by Professor Robert S. Hamada to account for the differences in financial risk through adjustments to the beta estimate for a firm.[1] 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 ATWACC method in order to further inform my recommendations that account for differences in the financial risk between companies in my expanded sample and DTE Gas Company.

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. Although economic conditions have improved since the start of the crisis in about mid-2008, uncertainty remains in the capital markets due, in part, to the disappointing rate of economic growth, not only in the U.S., but also worldwide. Worries about the low interest rate outlook in Europe and Japan as well

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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 56-74.

as the United Kingdom's exit from the European Union have added to the concern. In addition, long-term government bond yields, which had dropped dramatically after the 2008-2009 credit crisis to unusually low levels, remain depressed relative to both historical levels and forecasts of future interest rates.

As a result, bond yield spreads remain higher than before the credit crisis,[2] both for riskier assets as well as for less risky investments such as investment grade-rated utility debt. (See Table 1 below) Although the capital market indices have returned to and have now 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, including the long-term risk-free interest rate, 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 Gas, I modified the parameters of the risk positioning model to recognize the effect of the increased volatility in the capital 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") and risk-free interest rate for use in the risk positioning model. These scenarios are discussed in more detail below. Further, given the current economic uncertainty and the downward bias it creates in the CAPM model results, I also place substantial weight on the results of the DCF analyses in

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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.

determining the range of reasonableness for the ROE, for reasons explained later in this testimony.

Q12. Can you summarize your findings about the expanded sample's costs of capital?

A12. The sample ROE estimates range from a low of 8.5 percent to a high of 12.0 percent, but I believe that the estimates at the lower end of the range are not 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. For a regulated natural gas distribution company of average business risk and with an equity ratio of approximately 52 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 the sample companies comparable to DTE Gas Company's financial and business risk because I believe that DTE Gas is of greater risk than the average company in the sample.

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. Section IV discusses the selection of the expanded 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

[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.

sample's overall costs of capital. Section VI concludes my testimony. The calculations supporting my analyses are provided in Exhibit A-14.

II. COST OF CAPITAL THEORY

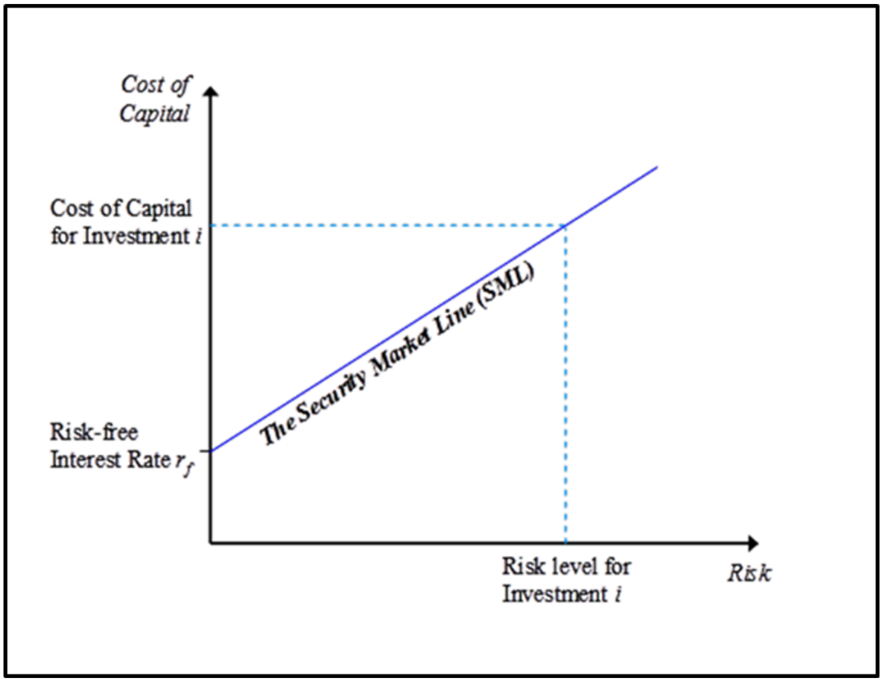
A. COST OF CAPITAL AND RISK

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 natural gas distribution 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. What did you mean by the "ATWACC" mentioned earlier?

A17. The ATWACC is calculated as the weighted average of the after-tax cost of debt capital and the cost of equity. Specifically, the following equation pertains:[6]

$$ATWACC = r_D \times (1 - T_c) \times \%D + r_E \times \%E \quad (1)$$

where 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 ATWACC is commonly referred to as the WACC in financial textbooks and is used in investment decisions.[7] The return on equity consistent with the sample's overall cost of capital estimate (the ATWACC), 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 (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

6 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.

7 See, for example, Brealey, Myers and Allen (2017), *Principles of Corporate Finance, 12th Edition*, McGraw-Hill Irwin, New York, pp. 448-453.

ATWACC for the sample companies, I can apply that same ATWACC or an ATWACC adjusted for risk differences to the regulated entity, in this case DTE Gas.[8]

Q18. Why is the ATWACC relevant to these proceedings?

A18. The ATWACC 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 Gas. 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). 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 ATWACC values. The "apples to apples" comparability of ATWACC across companies with different capital structures makes it a consistent measure of the representative cost of capital in an industry.

Q19. How does the ATWACC approach differ from procedures where the cost of equity and the regulatory capital structure are determined separately?

A19. The ATWACC 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

8 I refer to the ATWACC 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.

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 Gas. 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.

Q20. Why is it necessary to consider the sample companies' capital structures as well as the regulatory capital structure in your analysis?

A20. 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 Gas.

Q21. What is the basis for the development of the ATWACC method?

A21. Computing the ATWACC—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 ATWACC 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 ATWACC 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 ATWACC 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 original cost (i.e., 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.

Q22. Is the use of the ATWACC method unconventional?

A22. No. The ATWACC is presented in every textbook on corporate finance of which I am aware.[9] These textbooks calculate the ATWACC in exactly the same way as I do.

Q23. Is the ATWACC approach used by other regulators?

A23. Yes, a number of regulators in the U.S. and in countries around the world rely upon the ATWACC 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

[9] 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 75-91 for the excerpt from *Valuation* textbook.

apparently regard the ATWACC as proper regulatory policy and appropriate for setting rates in a regulatory proceeding.

Q24. What regulators in the U.S. use the ATWACC approach?

A24. Although use of the ATWACC is not prevalent in the U.S., it is used by some regulators. The Surface Transportation Board ("STB") uses the ATWACC 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 ATWACC to value property. The FERC used the ATWACC (calculated as I do) as a discount rate in a valuation dispute.[10] In a decision, the Alabama Public Service Commission said

> [t]he Commission recognizes that the ATWACC analysis is not a prevalent methodology in the United States; however, the focus of that methodology on the relationship between the market value and the associated financial risk of the utility is compelling.[11]

Q25. Is financial risk properly measured by the market value or book value capital structure?

A25. 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.[12] Further, the view is not just an ivory-tower creation. Professional valuation books and guides advocate the use of market value capital structure.[13] Morningstar and Duff and

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[10] Order Conditionally Accepting Tariff Revisions, Subject to Compliance Filings, Docket No. ER14-2940-000, PJM Interconnection, L.L.C., issued November 28, 2014.

[11] 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.

[12] 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.

[13] 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.

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.[14] Similar views were also endorsed by legal decisions on bankruptcy proceedings.[15] 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 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.

Q26. Can you provide academic evidence that financial leverage is and should be measured on a market value basis?

A26. 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.[16] One key corollary of the MM theorems and their various extensions is that cost of equity increases as financial leverage increases. Although the exact

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Niculita, 2008, *Valuation a business: The analysis and appraisal of closely held companies*, 5th edition, McGraw-Hill, at pp. 216 – 217.

[14] See, *e.g.*, Morningstar, *Duff & Phelps 2016 Valuation Handbook – Guide to Cost of Capital*, at p. 15.

[15] 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.

[16] 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 92-129. For a modern textbook exposition of the capital structure theories, see Brealey, Myers, and Allen, *op cit.*, Chapter 17.

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.[17] 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 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.

Q27. Are there any other academic articles that discuss how a company's cost of equity changes as its capital structure changes?

A27. 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."[18] Professor Hamada's adjustment method is consistent with the ATWACC 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 ATWACC approach, so the

[17] In developing the theory, MM assume that investors can adjust the capital structures of their portfolios at no cost.

[18] *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 56-74.

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).

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:[19]

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \qquad (2)$$

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:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \qquad (3)$$

[19] Technically, the relationship requires that there are no additional costs to leverage and that the book value capital structure is fixed.

Unlike Equation (2), Equation (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 (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 (2), or Equation (3). Rather than estimating debt betas, I note that the standard financial 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[20] while other academic literature has reported debt betas of 0.25.[21] I consider this range of 0.05 to 0.25 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.

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[20] Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

[21] "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. D5.17 at 130-160.

Hamada adjustment procedures are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

III. IMPACT OF THE RECENT ECONOMIC UNCERTAINTY

Q28. What is the topic of this section of your testimony?

A28. 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.

Q29. Do you believe that capital markets are "back to normal"?

A29. No. Although the Federal Reserve has decided to raise the target range for the federal funds rate to a range of 1 to 1¼ percent since the beginning of 2017[22] and volatility in the financial markets has lessened, economic conditions are not yet back to normal as measured by their status prior to the 2008-2009 credit crisis. For example, although the spread between U.S. utility bond yields and government bond yields ("yield spread") has narrowed from their peak at the height of the crisis, the yield spread is still elevated relative to the spread before the crisis. This is especially true for lower-rated bonds, including BBB-rated utility bonds. This is, in part, the result of a deliberate policy by the Fed to lower long-term as well as short-term bond yields in an effort to induce investors to move to riskier assets such as stocks.[23]

Q30. Please describe in more detail how the yield spread between U.S. government and utility bonds has changed since the start of the credit crisis.

A30. Although the yield spread on utility bonds has declined from the height of the 2008-2009 credit crisis, the yield spread still remains elevated in relation to pre-crisis levels in response to world economic events and the efforts of the Fed. The yield spread on utility bonds, such as Bloomberg's BBB-rated utility bonds, has been substantially higher during most of the past eight years than prior to the credit crisis. For example,

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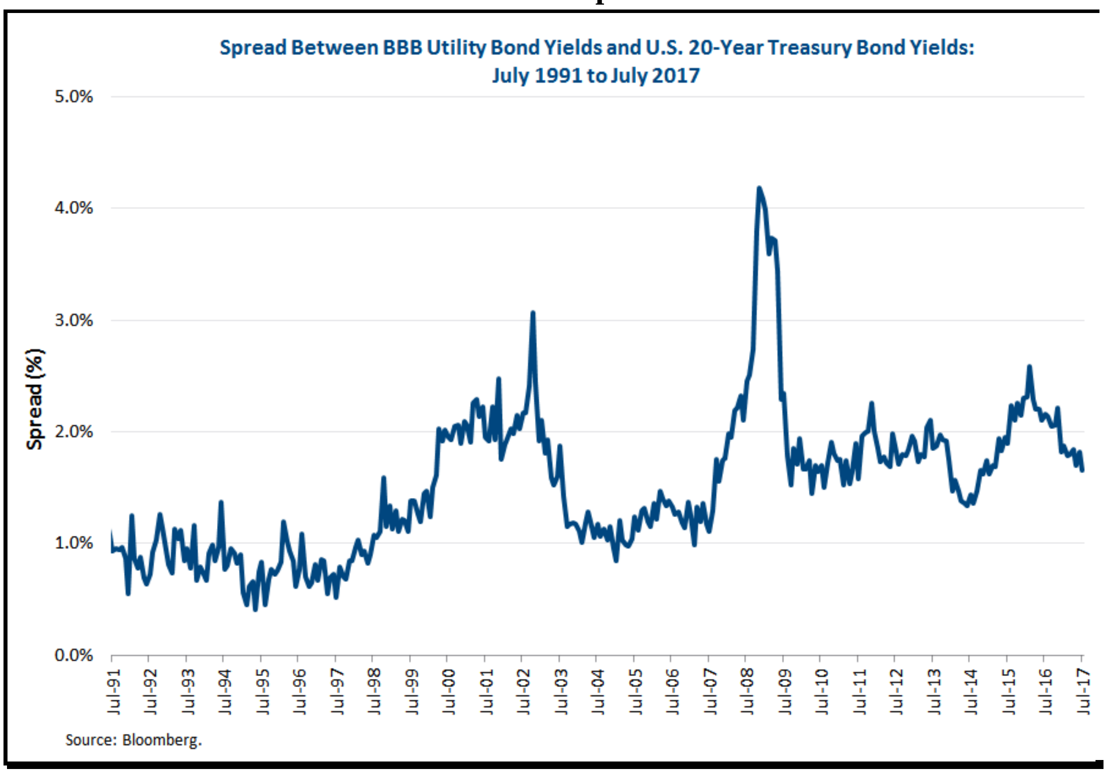
[22] See Federal Open Market Committee, Press Release, September 20, 2017.

[23] *Id.*

since the last major peak in November 2008, the spread between the yield on BBB-rated 20-year utility bonds and the yield on 20-year U.S. government bonds, as shown in Figure 2 below, has ranged from a low of 133 basis points to a high of 408 basis points, compared to a historical average of approximately 120 basis points.[24] Additionally, the average yield spread in 2016 of 218 basis points is highly unusual and has reached higher levels in only three of the past 25 years: in 2008 and 2009 during the credit crisis and in 2002 following the collapse of the tech bubble. The yield spread is slightly lower for January 2017 to July 2017 at 178.

Figure 2
Bond Yield Spreads



In addition to the spike in the spread between utility and government bond yields, the variability in bond yields is also high. BBB utility 20-year bond yields have varied from a high of 4.75 percent to a low of 3.98 percent for a high-to-low difference of

[24] Historical average ranges from the beginning availability of U.S. utility bond yield data (April of 1991) through the beginning of the financial crisis (December of 2007) accessed from Bloomberg as of August 24th, 2017.

approximately 77 basis points over the period July 2016 to July 2017. Table 1 below presents the yield spreads for 20-year utility bonds over several historical periods. Yield spreads have remained elevated compared to historical averages.

Table 1
Comparison of Historical Bond Yield Spreads

Spreads between U.S. Utility Bond (20 year maturity) and U.S. Government Bond (20 year maturity) - bps			
Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average Apr-1991 - 2007	93	123	[1]
Period 2 - Average Aug-2008 - Jul-2017	153	200	[2]
Period 3 - Average Jul-2017	126	165	[3]
Period 4 - Average 15-Day (Aug 04, 2017 to Aug 24, 2017)	126	165	[4]
Spread Increase between Period 2 and Period 1	60	77	[5] = [2] - [1]
Spread Increase between Period 3 and Period 1	33	42	[6] = [3] - [1]
Spread Increase between Period 4 and Period 1	**32**	**42**	[7] = [4] - [1]

Sources and Notes:
Spreads for the periods are calculated from Bloomberg's yield data.
Average monthly yields for the indices were retrieved from Bloomberg as of August 24, 2017.

Q31. What is the implication of higher than normal yield spreads?

A31. A higher than normal yield spread is one indication of the higher cost of capital prevailing in the capital markets. Investors consider a risk-return tradeoff like the one displayed in Figure 1 above and select investments based upon the desired level of risk. The expected return on debt (i.e., the cost of debt) is higher relative to government bond yields than is normally the case even for regulated utilities. Because debt is less risky than equity, the cost of equity is also higher relative to government bond yields than is usually observed. If this fact is not recognized, the traditional cost of capital estimation models will underestimate the cost of capital prevailing in the capital markets.

Q32. Haven't the U.S. stock markets reached record highs and interest rates begun to rise recently?

A32. Yes, the U.S. stock market has been trading at Price-to-Earnings ("P/E") levels which are above historical medians and government bond yields have increased since the

U.S. presidential election and the Fed's increase of the federal funds rate. This does not mean, however, that economic conditions are fully back to normal.

Q33. What further evidence can you provide that U.S. medium- and long-term government bond yields are currently depressed?

A33. 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.[25] The most recent 15-day average of long-term government bond yield is at 2.80 percent.

Although the U.S. Federal Reserve 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 $4.4 trillion in assets from this purchasing program.[26] Until there is an intended unwinding of these holdings, uncertainty will persist.

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 European Central Bank (ECB) continues its accommodative stance, which targets a *negative* 0.4% interest rate[27] and continues to purchase billions of euros worth of assets each month (50 billion euros of assets purchased in July 2017),[28] and the Bank of Japan's policy,

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[25] See Duff & Phelps's Ibbotson Stocks, Bonds, Bills, and Inflation ("SBBI") 2017 Valuation Yearbook at 2-9.

[26] Board of Governors of the Federal Reserve System, Credit and Liquidity Programs and the Balance Sheet, as of September 25, 2017.

[27] European Central Bank, Key ECB Interest Rates, EUROPEAN CENTRAL BANK, https://www.ecb.europa.eu/stats/monetary/rates/html/index.en.html (last visited Sep. 18, 2017).

[28] European Central Bank, Asset purchase programmes, EUROPEAN CENTRAL BANK, https://www.ecb.europa.eu/mopo/implement/omt/html/index.en.html (last visited September 15, 2017).

which has maintained negative yields on government bonds since early 2016,[29] represent divergent approaches from that currently of the Federal Reserve ("Fed"), which halted its asset purchases and has recently decided on a modest increase in interest rates. However, as Janet Yellen's term as the chairman of the Fed comes to a close in February 2018, uncertainty persists concerning who will be the next chairman and how monetary policy may change with that transition. Finally, increased testing of ballistic missiles by North Korea has had noticeable impacts on the market, such as pushing down yields on 10-year U.S. Treasury Bonds as "investors sought safety."[30]

While U.S. capital markets may currently be benefiting from investors fleeing economic turmoil elsewhere, these global weaknesses underscore investors' lack of confidence in the global economy. These global weaknesses can affect the relatively more stable U.S. economy, and any aggressive action by the Fed on interest rates can easily exacerbate these weakened global economies, which in turn may affect U.S. capital markets.

Q34. Are interest rates and treasury yields expected to rise in the future?

A34. Yes. Since the beginning of 2017, the Fed has increased the federal funds target interest rate twice, which increased yields on U.S. Treasury notes briefly, but for many reasons discussed above, yields on U.S. Treasury bonds are currently lower than at the beginning of 2017. Yields on the 10-year Treasury bond have declined from 2.43 percent in January 2017 to 2.22 percent in August 2017. Similarly, yields on the 30-year Treasury bond have declined from 3.02 percent to 2.80 percent.[31] However, economists and investors do not expect yields to persist at these unprecedented low levels indefinitely. According to the *Blue Chip Economic*

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[29] 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 and Bank of Japan, Statement on Monetary Policy, BANK OF JAPAN, July 20, 2017.

[30] See *Financial Times* article "Flight to havens after North Korea missile launch", https://www.ft.com/content/5dab7a38-8c56-11e7-a352-e46f43c5825d.

[31] Bloomberg accessed as of August 24, 2017.

Indicators report dated March 10, 2017, the consensus economic projections for the yield on 10-year U.S. Treasury notes are 3.7 percent on average in 2019 to 2023 and 3.9 percent on average from 2024 to 2028.[32] These forecasts are substantially higher than the current yield on 10-year U.S. government notes.[33] 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 the 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.

Q35. How do you adjust your cost of capital estimation methods to correct for current economic conditions?

A35. I make no adjustment to the DCF method. For the risk positioning method, I recognize the unusually large yield spreads on utility debt by adding a "yield spread adjustment" to the current long-term risk-free rate. This has the effect of increasing the intercept of the Security Market Line displayed in Figure 1 above. I also present results from the risk positioning model by increasing the MRP over the 6.9 percent historical MRP. This has the effect of increasing the slope of the Security Market Line displayed in Figure 1. I present a sensitivity test of the effect of an increase in the MRP to 7.9 percent, and yield spread adjustments of 35 basis points ("bps"). Table 5 below lists the parameters of these two scenarios.

Q36. How do you estimate the increase in MRP needed to adjust for the increased cost of capital stemming from the current market turmoil?

A36. Estimating the MRP is always imprecise and controversial. Measuring the change in MRP due to the current economic situation is likely to be no different, but it is still

[32] See *Blue Chip Economic Indicators*, dated March 10, 2017, page 15.

[33] See Exhibit A-14, Schedule No. D5.9 at 44.

necessary to estimate the MRP as carefully as possible given the change in economic conditions. Fortunately, there is a way to provide a quantitative benchmark for the required increase in MRP based upon a paper by Edwin J. Elton, et al., which documents that the yield spread on corporate bonds is normally a combination of a default premium, a tax premium, and a systematic risk premium.[34] As displayed in Table 1 above, the yield spreads for A-rated and BBB-rated utility debt have currently increased compared to the average for the period 1991-2007.

Q37. How do you use the information in Table 1 concerning the increase in yield spreads to estimate the increase in the MRP?

A37. Table 1 shows that recent yield spreads for A-rated and BBB-rated utility debt have increased by about 30 bps and 40 bps respectively for 20-year maturities. This means that investors require a higher return on investment grade utility debt relative to the return on U.S. Government debt than before the credit crisis. Some of the increase in yield spread for A-rated debt may be due to an increase in default risk (although this is more likely a component of the larger increase in BBB-rated utility spreads).[35] The increase in A-rated utility yield spread is due to a combination of an increase in the systematic risk premium on A-rated debt and the downward pressure on the yield of risk-free debt due to the flight to safety. The increase in the default risk premium for A-rated debt is undoubtedly very small because A-rated utility debt has not been at the center of the wave of defaults based upon collateralized mortgage debt. This means that the vast majority of the increase in yield spreads is due to a combination of the increased systematic risk premium and the downward pressure on the yields of government debt. In other words, either the MRP has increased or the risk-free rate is under estimated, or, alternatively, both. In my analysis, to be conservative, I assume that there has been an approximate 35 bps increase in utility spreads, due to either an

[34] "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. D5.17 at 130-160.

[35] Although there is no increase in tax premium due to coupon payments, there may be some increase due to a small tax effect resulting from the probability of increased capital gains taxes when the debt matures.

increase in the MRP (which drives the increase in systematic risk premium), or to downward pressure on the risk-free rate.

Q38. How do you allocate the increase in the yield spread (not due to the estimated increase in default risk) to the increase in systematic risk or to the under estimation of the risk-free rate due to downward pressure on government bond yields?

A38. There is no precise way to allocate the increase in yield spread between the increase in systematic risk and the under estimation of the risk-free rate arising from downward pressure on government bond yields; however, assuming a debt beta of 0.25[36] means that an increase in the MRP of one percentage point translates into a ¼ percentage point increase in the risk premium on debt (i.e. 0.25 (beta) times 1 percentage point (increase in MRP) = ¼ percentage point). The relationship among the increased yield spread for A-rated utilities ($\Delta spread$), the underestimation of the expected risk-free rate (Δr_f), and the required adjustment to the market risk premium (ΔMRP) can be represented as follows.

$$\Delta spread - \Delta r_f = 0.25 \cdot \Delta MRP$$

A 35 bps increase in the yield spread is therefore consistent with a 140 bps increase in the MRP if there were no under estimation of the risk free rate. Alternatively, with a 10 bps under estimation of the risk-free rate, a 35 bps increase in the utility yield spread would be consistent with a one percent increase in the MRP (i.e., 35 bps less 10 bps = 25 bps/.25 = 1.00).

The greater the increase in yield spread assumed to be attributed to an increase in systematic risk, the larger must be the corresponding increase in the MRP and the smaller the effect of the downward pressure on the risk-free rate. As illustrated above, if all of the non-default increase in the yield spread were due to the increase in systematic risk, the MRP would have to increase by 1.4 percentage points (i.e., 35 bps

36 Elton, *et al*. estimate the average beta on BBB-rated corporate debt as 0.26 over the period of their study, and A-rated debt will have a slightly lower beta than BBB-rated debt.

= 0.25 (beta) times 1.4 percentage points (increase in MRP)). Alternatively, a 35 bps increase in the yield spread is also consistent with a 35 bps under estimation of the risk-free rate, assuming that none of the change in yield spread is driven by an increase in systematic risk. The latter sensitivity would reduce the 35 bps increase in the risk-free rate by 25 bps per 100 bps increase in the MRP.

Q39. Would the estimate of the effect of an increase in the MRP be different if the estimate of the beta of an A-rated bond were different?

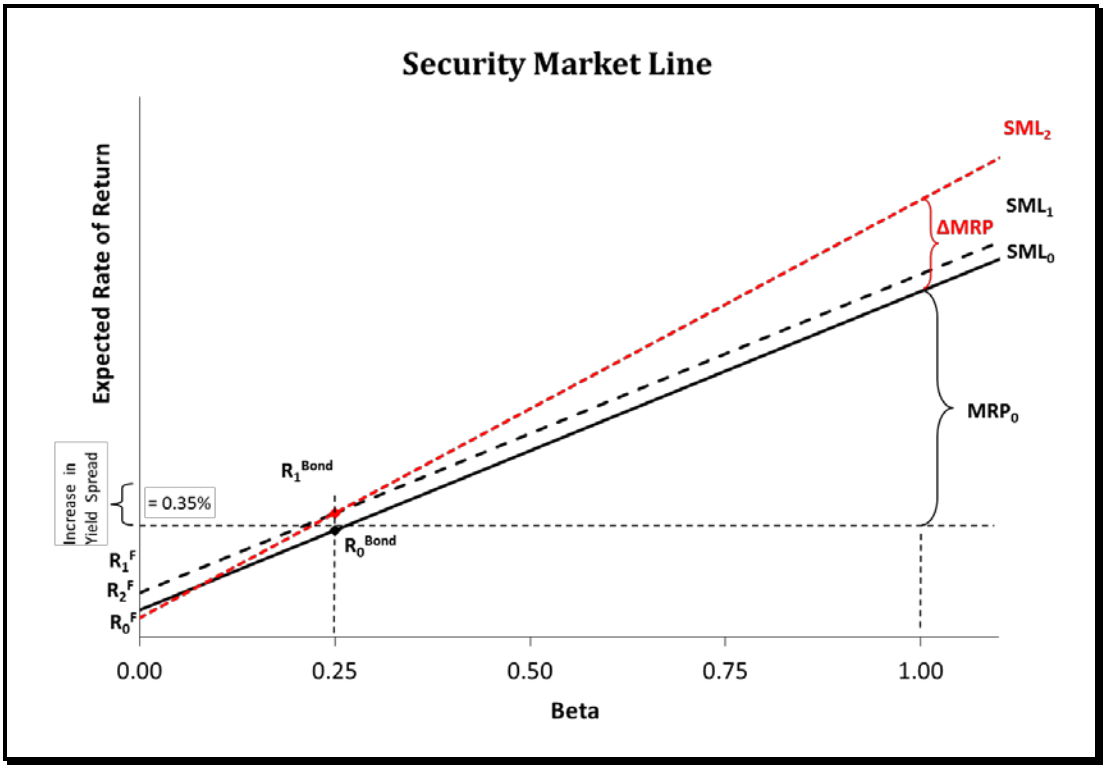
A39. Yes. If the beta of an A-rated bond were higher, the increase in the systematic risk premium in the yield spread for each one percentage point increase in the MRP would be smaller. Alternatively, if the beta of an A-rated bond were lower, the increase in the systematic risk premium in the yield spread for each on percentage point increase in the MRP would be larger.[37] However, I believe that a beta estimate of 0.25 for A-rated utility debt is reasonable for this purpose, because the debt of any company is less risky than its equity. A beta estimate of 0.25 for A-rated utility debt is likely to be conservative, especially when compared to an average estimated beta of 0.73 (*Value Line* average beta) for the expanded sample. Moreover, a beta estimate of 0.25 is no doubt conservative because if the estimated beta were lower (as is likely) then the increase in the MRP necessary to result in a 35 bps increase in the yield spread would be higher. As noted above, the average estimated beta for BBB-rated debt was 0.26 at the time of the Elton et al study, and A-rated debt will have a lower estimated beta. Even if the average beta for BBB-rated debt is higher today than at the time of the Elton et al study, it is likely that an estimate of 0.25 for A-rated debt is reasonable.

[37] As noted above, the Berk and DeMarzo textbook reports average debt betas for A-rated debt to be 0.05.

Q40. Would you provide a graph of how the scenarios you consider affect the Security Market Line?

A40. Yes. See Figure 3 below. Scenario 1 (shown as SML_1 in Figure 3) attributes the entire increase in the yield spread on A-rated utility debt to underestimation of the risk free rate by shifting the Security Market line up in parallel fashion by 35 bps ($R_1^F - R_0^F$). Scenario 2 (shown as SML_2 in Figure 3) includes a 10 bps upward shift, and attributes the rest of the increase in the yield spread to an increase in the market risk premium by increasing the slope of the line by 1.0 percentage point (ΔMRP).

Figure 3
Security Market Line under Two Scenarios



Q41. Can you summarize your thoughts with regard to the MRP and the financial crisis?

A41. Yes. There remain serious concerns of a very slow growth recovery. Economic and political uncertainty continues in countries around the world, in an increasingly global economy. It defies logic to believe that the MRP has not increased from 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 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 alternative adjustments to the risk-free rate and 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 naïve, mechanical implementation of the models might suggest.

IV. SAMPLE SELECTION

A. THE EXPANDED SAMPLE

Q42. What factors do you consider in selecting a proxy group?

A42. 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 Gas is a regulated gas distribution utility, but currently there is available only a relatively small sample of publicly-traded gas distribution utilities (five companies) whose primary business is distribution of natural gas under cost of service regulation. I therefore expanded the sample to include state regulated water utilities.

Q43. Can you summarize how you selected the expanded sample?

A43. I formed the sample from the universe of publicly traded natural gas distribution utilities as classified by the *Value Line Investment Survey Plus Edition*.[38] This

[38] The 19 companies are from *Value Line Investment Analyzer*, accessed as of August 24, 2017.

resulted in an initial group of 11 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. This ultimately yielded only five natural gas LDCs which is too few for statistical reliance. Therefore, I expanded the initial sample to include regulated water utilities, another regulated industry with similar risk characteristics to gas LDCs. This added 8 more utilities after screening for the criteria described below for a total of 13 companies in the expanded sample, five of which are gas LDCs.

Q44. Why is it appropriate to expand the gas sample with regulated water utilities?

A44. The ideal sample would comprise of companies that are publicly traded "pure plays" whose operations are concentrated entirely in regulated natural gas distribution business. While such a sample is ideal for cost of capital estimation, absolute pure plays do not exist, therefore, for my analyses, I relied on companies with high proportion of assets devoted to rate regulated natural gas distribution service activities. However, applying my standard sample selection procedure– designed to remove companies with unique circumstances that may bias the cost of capital estimates – resulted in only five rate regulated natural gas LDCs which is too few for statistical reliance. Thus, to further expand the five company sample and to ensure robustness in my estimation of ROEs, I looked to water utilities, another regulated industry with similar risk characteristics to natural gas LDCs. I found the water utilities to be of comparable risk because, like the gas LDCs, they operate similarly capital intensive transmission and distribution assets, are rate regulated public good service providing entities, and have similar asset and financial risk characteristics, as informed by similarities in average equity betas, and five-year average market value capital structures. They are regulated by state regulators and have a similar mix of industrial, commercial, and residential customers.

Q45. What additional selection criteria did you apply?

A45. 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.[39] 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),[40] no significant merger activity, no dividend cuts, and no other activity that could cause the growth rates or beta estimates to be biased. 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.

Q46. Do any of the companies in your expanded sample have a revenue decoupling mechanism?

A46. Yes. Like DTE Gas, several of the companies in my comparable sample have a decoupling mechanism in place.[41] 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 natural gas than was forecast, the decoupling mechanism improves the probability that the utilities can recover their costs despite the decrease in revenues. DTE Gas's revenue decoupling mechanism is not a full revenue decoupling mechanism[42] because it is not designed to capture weather related variation in revenues. Its focus is on loss of revenues from energy conservation.

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[39] 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).

[40] I use the Edison Electric Institute's methodology used for classification of electric utilities to determine the percentage of assets classified as regulated, mostly regulated or diversified, for the companies in my sample. Specifically, and consistent with Edison Electric Institute's methodology, I applied the following asset percentage thresholds: Regulated - greater than 80 percent of total assets are regulated; Mostly Regulated - 50 to 80 percent of total assets are regulated; Diversified - less than 50 percent of total assets are regulated. I used company asset information as reported by S&P Capital IQ as of August 24th, 2017 or from the companies' most recent 10K for performing my calculation of asset classification for the sample companies.

[41] See Edison Electric Institute, "Alternative Regulation for Evolving Utility Challenges: 2015 Update," November 2015 for a compilation of decoupling mechanisms by company and state.

[42] A full revenue decoupling mechanism adjusts revenues to the level used to set rate irrespective of the reason for any difference.

B. COMPARISON OF DTE GAS TO THE EXPANDED SAMPLE COMPANIES

Q47. What are the characteristics of the expanded sample companies you have chosen?

A47. The expanded sample is comprised of regulated companies whose primary source of revenues and majority of assets are in the regulated portion of the natural gas distribution industry or the water utility industry. The final sample consists of the thirteen regulated utility companies listed in Table 2 below. Of the 13 companies in the expanded sample, five are natural gas LDCs.[43]

Q48. Can you describe the financial and regulatory characteristics of the sample in comparison to DTE Gas?

A48. Table 2 below reports the sample companies' annual revenues for the trailing twelve months ended June 2017 and the percentage of their assets devoted to regulated operations according to EEI's classifications of being either regulated ("R"), having greater than 80 percent regulated assets or mostly regulated ("M"), having 50-80 percent regulated assets. Table 2 also displays the Market Capitalization and the S&P Credit Rating for each company as of June 30, 2017, and the weighted average long-term (5-year) earnings growth rate estimate from Thomson Reuters IBES and *Value Line* for all of the companies in the expanded sample.

The Company had operating revenue of approximately $1.3 billion in 2016.[44] By comparison, the average sample company had $1.1 billion in revenues during the twelve months ended June 2017.[45] DTE Gas's parent company, DTE Energy Company, had $10.6 billion in revenue over that same period.[46] DTE Gas is

[43] The gas LDCs are Atmos Energy, Chesapeake Utilities, Northwest Nat. Gas, ONE Gas Inc, and Southwest Gas.

[44] DTE Energy Company's 2016 SEC Form 10-K at 64.

[45] The revenue figures in Table 2 are the reported annual revenue over the four fiscal quarters ending December 31, 2016.

[46] DTE Energy Company's 2016 SEC Form 10-K at 56.

somewhat larger than the average sample company. DTE Gas has an S&P credit rating of A, which is comparable to the sample.[47]

Table 2
Financial Characteristics of the Expanded Sample

Sample

Company [1]	Annual Revenue (2Q 2017) (MM) [2]	Regulated Assets [3]	Market Cap. (2Q 2017) ($MM) [4]	S&P Credit Rating [5]	Moody's Credit Rating [6]	Long-Term Growth Estimate [7]
Atmos Energy	2,973	R	8,918	A	A2	6.7%
Chesapeake Utilities	560	R	1,225	A-	WR	10.2%
Northwest Nat. Gas	755	R	1,766	A+	A3	6.7%
ONE Gas Inc.	1,503	R	3,719	A-	A2	6.3%
Southwest Gas	2,397	R	3,576	BBB+	N/A	6.8%
Amer. States Water	443	R	1,779	A+	N/A	5.8%
Amer. Water Works	3,332	R	14,362	A	N/A	7.3%
Aqua America	815	R	5,981	A-	N/A	6.6%
California Water	628	R	1,760	A+	N/A	7.5%
Conn. Water Services	101	R	674	A	N/A	5.4%
Middlesex Water	133	R	652	A	N/A	8.1%
SJW Corp.	363	R	1,048	BBB+	N/A	5.7%
York Water Co. (The)	48	R	474	A-	N/A	8.0%

Sources and Notes:
[2]: Bloomberg as of August 24, 2017.
[3]: 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.
[4]: See Schedule No. D6.3 Panels A through H.
[5]: Bloomberg as of August 24, 2017.
[6]: Bloomberg as of August 24, 2017.
[7]: See Schedule No. D6.5.

Q49. How does the business risk of DTE Gas compare to that of the sample?

A49. DTE Gas Company's business is concentrated in regulated natural gas distribution services. Regulatory policy plays a role in the business risk of the Company, and as mentioned above, DTE Gas does have some regulatory mechanisms in place such as revenue decoupling that are comparable to those of the proxy group companies. It also has a credit rating A that is comparable to those of the sample companies.

47 S&P Capital IQ.

However, in the current environment of low demand growth and falling natural gas consumption by U.S. households, the fact that DTE Gas does not have a full weather normalization adjustment mechanism typical to gas LDCs, places it at increased risk of under-recovering its cost of service relative to the companies in the sample group that benefit from such a mechanism. A weather normalization mechanism allows a company to mitigate the adverse impact of warmer-than-normal weather to its earnings, and as I noted earlier and shown in Table 3, most of the proxy group's gas companies operate in jurisdictions that allow a weather normalization mechanism to mitigate such adverse effects.[48] In contrast, DTE Gas is allowed to recover only a portion of under recovered revenues due to abnormal weather. Specifically, DTE Gas bears the risk of under-recovery of revenues arising from differences in its actual volumetric sales and the weather normalized volumetric sales it is required to report. When this difference manifests, DTE gas only recovers revenues from weather normalized volumetric sales and revenues arising from any difference between the weather normalized volumetric sales and a preset forecast of volumetric sales for the Company. Large differences between actual volumetric sales and weather normalized volumetric sales can lead to significant under-recovery for the Company. As a result, DTE Gas's revenue decoupling mechanism does not fully shield the Company from variations in recovery due to weather.

Table 3: Summary of Revenue Decoupling Mechanisms for Natural Gas Companies in the Sample

		Decoupling		
Utility	**Ticker**	**Full**	**Partial**	**Key Notes**
Atmos Energy	ATO	-	x	*Weather Normalization Adjustment Allowed*
Chesapeake Utilities	CPK	-	-	*No Decoupling Mechanism*
Northwest Nat. Gas	NWN	-	x	*Designed to counteract the impact on revenues of changes in average residential and commercial customers' consumption patterns due to conservation efforts. The company has a separate weather-adjusted rate mechanism in place for these customers. No*
ONE Gas Inc.	OGS			*Not Known*
Southwest Gas	SWX	x	x	*Full decoupling mechanism allowed in CA and NV, with partial decoupling in AZ*

48 "Adjustment Clauses" Section of Commission Profiles from Regulatory Research Associates (RRA), SNL. Accessed November 25, 2015. https://www2.snl.com/interactivex/CommissionProfiles.aspx

Another revenue risk for DTE Gas comes from its End Use Transportation customers, who represent DTE Gas's largest commercial and industrial customers (C&I). These C&I customers have the ability to bypass DTE Gas and take service directly from interstate transmission pipelines unless DTE Gas' rates remain sufficiently competitive. As a result, DTE Gas is exposed to the risk of losing a large volume of its sales anytime such C&I customers decide to bypass service from DTE Gas for better rates from competitors. Company witness Decker discusses this risk in detail in his testimony.

Q50. Does adoption of revenue decoupling affect the cost of capital?

A50. Brattle has studied the effect of decoupling on the cost of capital[49] 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 Gas represents a higher than average risk to investors relative to the sample companies, some of which benefit from full revenue decoupling mechanisms.

[49] "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.

Q51. How does the state of the economy in DTE Gas's service territory affect the Company's business risk?

A51. The risk of under-recovery of DTE Gas's fixed costs due to its reliance on volumetric charges to recover fixed costs is increased by the state of Michigan's economy. 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 only slowly recovering, but it continues to experience a high unemployment rate and over 40 percent of the its population lives under the federal poverty threshold.[50] The City has experienced falling population year-over-year since 2005 (See Table 3 below.) In spite of the State of Michigan's financial woes as evidenced by the City of Detroit's recent 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 Gas'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 Gas 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 could increase DTE Gas's systematic business risk and thus its cost of capital.

[50] U.S. Census Bureau 2011-2015 American Community Survey 5-Year Estimates.

Table 4
Economic Challenges for the City of Detroit

Year	Population	Household Mean Income	BLS Employment	Census Unemployment Rate (%)	BLS Unemployment Rate (%)	Population Below the Poverty Level (%)
	[1]	[2]	[3]	[4]	[5]	[6]
2005	921,149	$37,271	324,368	20.5	13.5	31.4
2006	918,849	$37,144	321,446	22.2	13.4	32.5
2007	917,234	$39,434	314,777	20.9	13.5	33.8
2008	912,632	$38,655	304,376	20.4	15.0	33.3
2009	910,921	$36,699	283,041	28.3	25.1	36.4
2010	713,777	$36,206	208,289	32.5	24.8	37.6
2011	706,640	$35,709	206,305	29.3	21.1	40.9
2012	701,524	$35,538	207,617	27.7	19.2	42.3
2013	688,740	$36,381	207,456	25.3	19.1	40.7
2014	680,281	$36,776	209,692	21.6	16.7	39.3
2015	677,116	$37,570	210,242	24.9	12.4	40.3

Note: Analysis conducted by DTE Electric Company.
[1]: Population 2005-2009 from file SUB-EST2009-01, published by Census Bureau's Population Estimates section.
Population 2010 from Roger Johnson (301-763-6045) of the Census Bureau's Population Estimates section.
Population 2011-2014 from Census Bureau's American Fact Finder.
[2]: Household mean income from American Fact Finder.
[3]: Bureau of Labor Statistics Employment from www.milmi.org (Michigan Department of Technology; Management & Budget posts same data as BLS.)
[4]: Census unemployment rate from American Fact Finder.
[5]: Bureau of Labor Statistics unemployment rate from www.milmi.org.
[6]: Population below the poverty level from American Fact Finder.

Q52. How do the poor economic conditions in DTE Gas's service territory contribute to specific operational and financial challenges for the Company?

A52. 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 gas distribution, since infrastructure is built to serve a particular population distribution. While DTE Gas'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.

Q53. Can you please summarize your assessment of DTE Gas's business risk relative to the sample?

A53. In consideration of the factors mentioned above, I believe DTE Gas is of higher than average business risk relative to the sample companies.

C. CAPITAL STRUCTURE

Q54. What regulatory capital structure is DTE Gas requesting in this proceeding?

A54. DTE Gas has proposed a regulatory capital structure consisting of approximately 52 percent equity and 48 percent debt,[51] as further explained by company witness Solomon. The expanded sample averages about 53 percent equity and 47 percent debt on a book basis, and the five gas LDCs average about 55 percent equity. The highest percent of book equity for the companies in the sample is 62 percent equity (ONE Gas Inc.) and the lowest is 42 percent equity (Amer. Water Works). My recommended range for ROE is a function of the requested capital structure, the sample average ATWACC estimates, the Hamada adjustment procedures, and the relative risk of the Company compared to the sample.

V. COST OF CAPITAL ESTIMATES

Q55. How do you estimate the sample companies' costs of equity?

A55. 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 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.

[51] By regulatory capital structure, I mean the capital structure used to set rates in this proceeding.

A. THE CAPM-BASED ESTIMATES

Q56. Can you explain the CAPM?

A56. 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:

$$r_s = r_f + \beta_s \times MRP \tag{4}$$

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

Q57. What interest rates do your calculations require?

A57. 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, it is my understanding that the test period for this proceeding is such that the final tariff rates will not go into effect until October 2018. 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 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 2.9 percent yield on the 10-year U.S Treasury bond forecasted to be in effect in 2018,[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 unadjusted risk-free rate is 3.2 percent.

Q58. Why didn't you use the version of the CAPM that relies on the short-term risk-free rate in this proceeding?

A58. 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 expected return, because debt holders are paid before equity holders in the event of bankruptcy or other financial distress.

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[52] *Blue Chip Economic Indicators*, dated August 10, 2017.

2. The Market Risk Premium

Q59. Why is a risk premium necessary?

A59. 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.

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. 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 do these factors affect the cost of capital for the Company?

A61. The Company invests in long-lived assets which cannot be easily liquidated (they are hard physical assets that once put in place cannot easily be moved). Investment is a voluntary activity, and investors generally require an expected 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.

Q62. What is your conclusion regarding the MRP?

A62. 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 in and of itself, 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 6.9 and 7.9 percent.[53]

3. Beta

Q63. Can you more fully explain beta?

A63. 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.

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[53] Duff and Phelps's *Ibbotson SBBI 2017 Valuation Yearbook* reports the realized arithmetic average MRP from 1926 to 2016 to be 6.94 percent.

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.[54] 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.

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.)

54 See Brealey, Myers and Allen (2017), *Principles of Corporate Finance, 12th Edition*, McGraw-Hill Irwin, New York, p. 172.

Q64. What does a particular value of beta signify?

A64. 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.

Q65. How is beta measured?

A65. 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 return data for a company.[55] In my analyses for these proceedings, I present results using the beta estimates reported by *Value Line*.

Q66. What are the betas that you used for the sample companies?

A66. Table 4 below lists the *Value Line* betas I used to calculate my risk-positioning estimates of the cost of capital for the expanded sample.

[55] *Value Line* Glossary, http://www.valueline.com/Glossary/Glossary.aspx

Table 5
Value Line Betas for the Expanded Sample

Company	Value Line Betas [1]
Atmos Energy	0.70
Chesapeake Utilities	0.70
Northwest Nat. Gas	0.70
ONE Gas Inc.	0.70
Southwest Gas	0.75
Amer. States Water	0.80
Amer. Water Works	0.65
Aqua America	0.70
California Water	0.80
Conn. Water Services	0.65
Middlesex Water	0.80
SJW Corp.	0.75
York Water Co. (The)	0.80
Gas Sample Average	0.71
Expanded Sample Average	0.73

Sources and Notes:
[1]: From Valueline Investment Analyzer as of Aug 24, 2017

4. The Empirical CAPM

Q67. What other equity risk premium model do you use?

A67. 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,

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \tag{5}$$

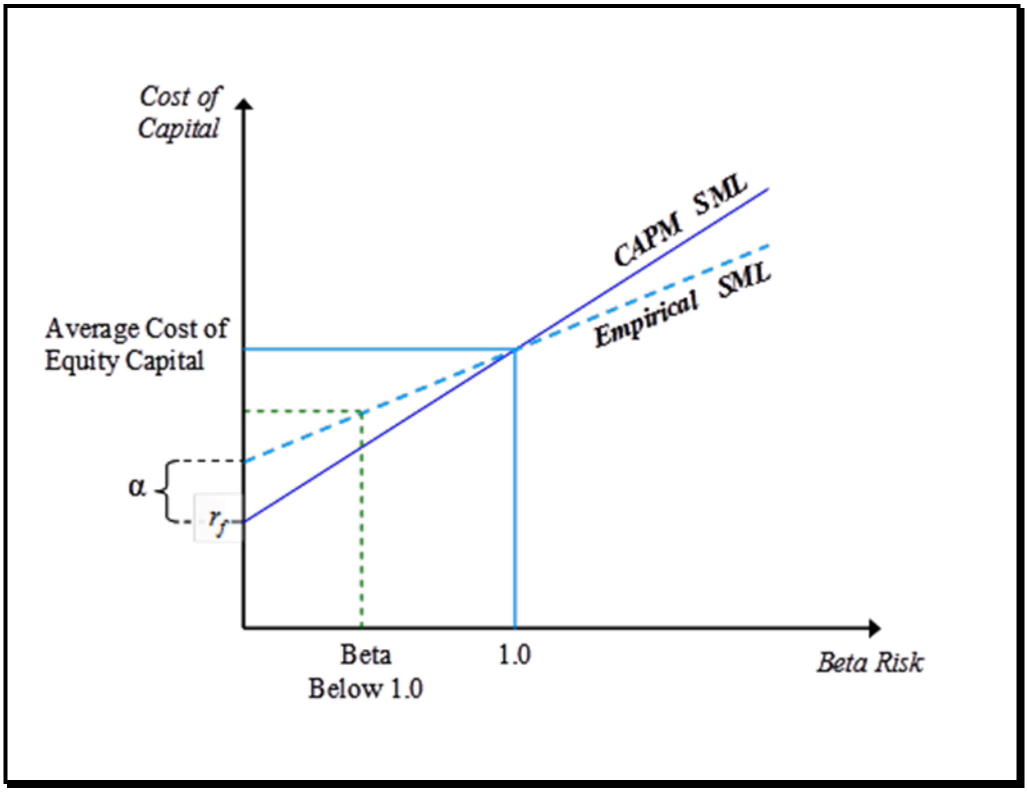
where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (4) above).

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.

Q68. Why is it appropriate to use the Empirical CAPM?

A68. 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 4 below.

Figure 4
The Empirical Security Market Line



Q69. Does *Value Line* make any adjustments to the beta estimates it reports?

A69. 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.

Q70. Can you explain further why using *Value Line*'s adjusted betas do not correct for the issues raised by empirical tests of the CAPM?

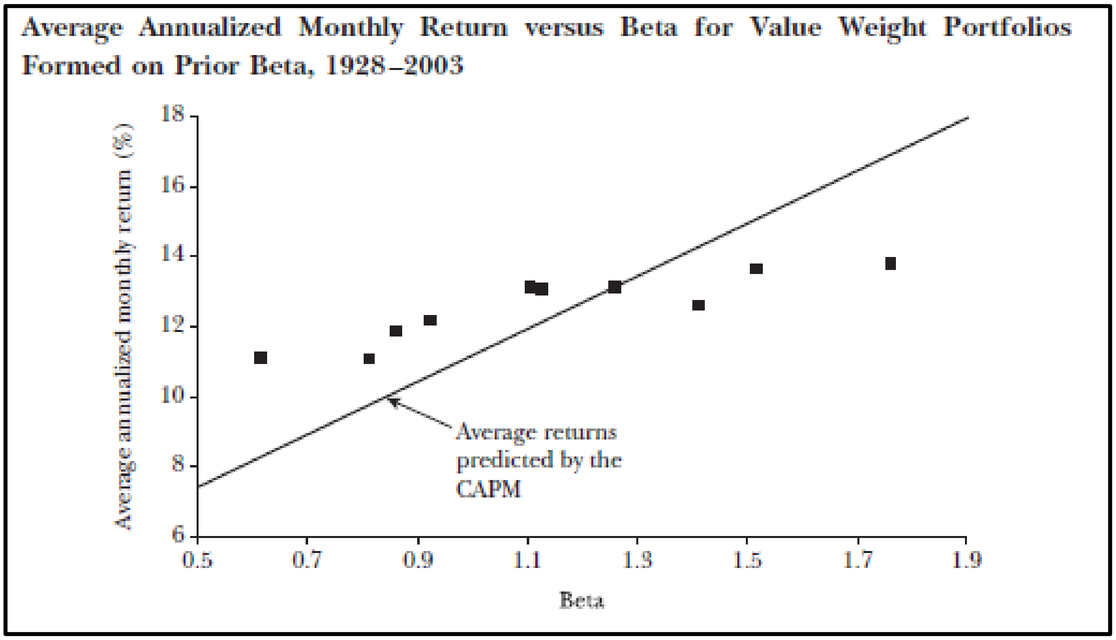
A70. Yes. It is because the issues raised by the empirical tests are completely independent from the reason betas are adjusted. The beta adjustment performed by *Value Line* is based on the method outlined by Professor Marshall Blume,[56] based on his empirical observation that historical measurements 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 5 below, which comes from the 2004 paper by Professors Eugene Fama and Kenneth French.[57] 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.

[56] Blume, Marshall E. (1971), "On the Assessment of Risk," *The Journal of Finance*, 26, pp. 1-10.

[57] 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 5
Evidence from Empirical Tests of the CAPM[58]



Q71. Did the empirical tests that gave rise to the ECAPM use raw betas in their analyses?

A71. 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 4 and Figure 5.

Q72. Does using adjusted betas in the ECAPM double count the adjustment to the estimated required return on equity?

A72. 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.

58 *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 (s)he 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.

Q73. Can you summarize the independent reasons for using adjusted betas and employing the ECAPM?

A73. 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.

5. Results from the Risk Positioning Models

Q74. What are the parameters of the scenarios you considered in your risk positioning analyses?

A74. The parameters for the two scenarios are displayed in Table 5 below. The motivation for the scenarios is the empirical observation that the yield spread is higher than normal. The increased yield spread could be the result of an increase in the MRP or downward pressure on the yield of risk-free bonds due to a flight to quality or a combination of the two factors. Therefore, I reduce the risk-free rate for use with a higher estimate of the MRP as illustrated in Table 5. In other words, the approximately 35 bps increase in the yield spread is allocated between an increase in the MRP and the downward pressure on the risk-free rate according to the method described above in Section III. The more of the increase in yield spread that is allocated to the underestimation of the risk-free rate, the less the MRP is increased and vice versa.

Table 6
Risk Positioning Scenario Parameters

	Scenario 1	Scenario 2
Risk-Free Interest Rate	3.55%	3.30%
Market Risk Premium	6.90%	7.90%

Q75. Can you summarize the results from applying the CAPM and ECAPM methodologies to the sample?

A75. The results of the risk positioning analyses (the CAPM and the ECAPM) are presented in Table 6 using *Value Line*'s estimated betas for the expanded sample of companies. (The underlying calculations are also presented in Exhibit A-14.[59]) 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 6.9 and 7.9 percent in accordance with the adjustments I made to reflect the elevated yield spread as described above. The long-term risk-free interest rate as of August 2017 was 3.2 percent before adjustments for the downward pressure on government yields due to the flight to safety. The ROE estimates in Table 6 reflect the ATWACC and Hamada adjustment procedure estimates adjusted for differences in capital structure between the sample companies and DTE Gas. Specifically, the ROE associated with each method and a capital structure with 52 percent equity is displayed in Table 6 for the *Value Line* betas.

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59 Results for the CAPM and ECAPM based on the ATWACC financial risk adjustment can be found in Exhibit A-14, Schedule No. D5.12 at 49. Results for the CAPM and ECAPM based on the Hamada adjustment can be found in Exhibit A-14, Schedule No. D5.15 at 52-53.

Table 7
Risk Positioning Cost of Equity Estimates

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Sample		
Financial Risk Adjusted Method		
CAPM	10.2%	10.9%
ECAPM (α = 0.5%)	10.4%	11.0%
ECAPM (α = 1.5%)	10.8%	11.4%
Hamada Adjustment Without Taxes		
CAPM	9.5%	10.1%
ECAPM (α = 0.5%)	9.6%	10.2%
ECAPM (α = 1.5%)	9.7%	10.3%
Hamada Adjustment With Taxes		
CAPM	9.2%	9.8%
ECAPM (α = 0.5%)	9.3%	9.9%
ECAPM (α = 1.5%)	9.5%	10.1%

Sources and Notes:
Scenario 1: Long-Term Risk Free Rate of 3.55%, Long-Term Market Risk Premium of 6.94%.
Scenario 2: Long-Term Risk Free Rate of 3.30%, Long-Term Market Risk Premium of 7.94%.

Q76. What conclusions do you draw from the risk positioning model (i.e., CAPM and ECAPM) results?

A76. 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 adjust 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 (Scenario One) results for the sample, the results range from 9.3 percent to 10.8 percent. The ECAPM risk positioning results for Scenario Two range from 9.9 percent to 11.4 percent. The five company gas subsample results are comparable to that of the expanded sample. For Scenario 1, the results range from 9.1 percent to 10.5 percent. For Scenario 2, the results range from 9.7 percent to 11.0 percent.

B. RISK PREMIUM MODEL ESTIMATES

Q77. 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?

A77. Yes. In this type of analysis, sometimes called the "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:

$$Cost\ of\ Equity = r_f + Risk\ Premium \tag{6}$$

Q78. What are the merits of this approach?

A78. 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.

Q79. How did you use rate case data to estimate the risk premiums for your analysis?

A79. The rate case data from 1990-2017 is derived from Regulatory Research Associates.[60] Using this data I compared (statistically) the average allowed rate of return on equity granted by U.S. state regulatory agencies in natural gas distribution cases to the

[60] SNL Financial as of September 7, 2017.

average 20-year Treasury bond yield that prevailed in each quarter.[61] 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. Then I used the statistical technique of ordinary least squares ("OLS") regression to estimate the parameters of the linear equation:

$$Risk\ Premium\ =\ A_0\ +\ A_1 \times (Treausury\ Bond\ Yield) \qquad (7)$$

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=0.83) and the parameter estimates, A_0 equals 8.451 percent and A_1 equals -0.5523, 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, the allowed ROE on average declined by less than 100 basis points when the government bond yield declined by 100 basis points. Based on this analysis, current market conditions suggest an allowed ROE of slightly over 10 percent (i.e., 10.04 percent) for an average risk natural gas LDC.[62]

Q80. What conclusions did you draw from your risk premium analysis?

A80. 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

[61] 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. Rate cases limited to natural gas distribution only (excludes rate cases for transmission or limited-issue rider.

[62] Results for the Risk Premium analysis can be found in Exhibit A-14, Schedule No. D5.16 at 54.

estimated ROE is consistent with recent practice. My risk premium model cost of equity estimates demonstrate that the results of my DCF and CAPM analyses are in line with the allowed return 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.

C. THE DCF BASED ESTIMATES

Q81. Can you describe the discounted cash flow approach to estimating the cost of equity?

A81. 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:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \tag{8}$$

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,

$$P_0 = \frac{D_1}{r-g} \tag{9}$$

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 (9) is a simplified version of Equation (8) that can be solved to yield the well-known "DCF formula" for the cost of capital:

$$r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1+g) + g \tag{10}$$

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 (10) says that if Equation (9) 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.[63]

Q82. Are there other versions of the DCF models in addition to the "simple" one?

A82. 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.[64] It is

63 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.

64 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

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.

Q83. What is your assessment of the DCF model?

A83. 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 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.

growth, you know the company's stock price and its dividend growth forecast are inconsistent with the assumptions of the steady-growth DCF model.

Q84. What growth rate information do you use?

A84. 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 expanded sample.[65] 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.[66]

Q85. How do these growth rates correspond to the theoretical criteria you discuss above?

A85. 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, 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.

Q86. Does the multistage DCF improve upon the simple DCF?

A86. 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

65 Short-term (5 year) EPS growth rates as of August 24, 2017. I develop a weighted average growth rate weighted by the number of analysts and counting *Value Line* as one analyst.

66 *Blue Chip Economic Indicators*, March 10, 2017.

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.

Q87. What are the relative strengths and weaknesses of the DCF and risk-positioning methodologies?

A87. 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 which relies upon 5 years of historical data.

Q88. What are the DCF estimates for the sample?

A88. The corresponding DCF estimates for the sample are presented in Table 7. The ROE estimate is 12.0 percent for the single-stage "simple DCF" model and 8.5 percent for the multistage model.[67]

[67] Results for the DCF analysis can be found in Exhibit A-14, Schedule No. D5.8 at 42.

Table 8
DCF Cost of Equity Estimates

	DCF	
	Simple	Multi-stage
Sample		
Cost of Equity	12.0%	8.5%

I note that the results of the single-stage DCF can be influenced by high individual growth rates.

Q89. What conclusions do you draw from the DCF analysis?

A89. Although I made no adjustment for the current market conditions for the DCF model, the DCF cost of equity estimates are in line with those from the risk positioning models displayed above in Table 6. Specifically, the multistage DCF estimate is lower than the range suggested by the risk positioning analysis while the simple DCF is somewhat higher. 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. Moreover, I believe the forward-looking nature of the DCF model makes the DCF estimates less susceptible to downward biases in inputs that have resulted from the continued uncertainty in the economy and extremely low interest rate environment. Thus I rely more heavily on the DCF estimates than I would in normal economic times.

VI. CONCLUSIONS

Q90. Can you summarize the evidence from the expanded sample regarding the ROE for a natural gas distribution utility of average risk?

A90. Table 6, Table 7, and Table 8 summarize the results of the analyses for the risk positioning and DCF models for the expanded sample companies. I also compare these results to the 10.04 percent allowed ROE for an average natural gas LDC suggested by the risk premium model. 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 Gas. 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. Based on the sample's cost of capital estimates, which range from 8.5 percent (multi-stage DCF) to 12.0 percent (simple DCF), I believe a company of DTE Gas Company's business and financial risk should have an allowed ROE in the range 9¾ percent to 10¾ percent.

Q91. What is your recommended range of the ROE for the Company?

A91. As noted above, I judge the Company to be of higher risk than the sample companies on average. I therefore recommend that the Company be allowed an ROE of 10½ percent, with a range of 10 to 11 percent, on the equity financed portion of its rate base.

Q92. Why doesn't your recommended range for the samples cover all of the estimates?

A92. 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.

Q93. Is there any other reason to support an allowed ROE of 10½ percent?

A93. Yes. It is important to maintain DTE Gas 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. A supportive allowed return on equity is therefore important to signal an adequate level of stable cash flows and avoid putting downward pressure on DTE Gas Company's credit metrics. Moody's highlighted this factor in its rating outlook on DTE Gas by noting that "an adverse change in Michigan's supportive regulatory environment" was a risk factor that could lead to a downgrade.[68] 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.

Q94. Does this conclude your direct testimony?

A94. Yes, it does.

[68] Moody's Investor Service, "Rating Action: Moody's downgrades DTE to Baa1, affirms utility subsidiaries, outlook stable," October 25, 2016.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE GAS COMPANY for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18999
distribution and supply of natural gas,	)	
and for miscellaneous accounting authority	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHERRI L. WISNIEWSKI

DTE GAS COMPANY
QUALIFICATIONS OF SHERRI L. WISNIEWSKI

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 Gas Company (DTE Gas 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 was the tax witness in DTE Electric Company Case No. U-18255, and I have also been involved over the years in various inputs and analyses in support of other regulatory proceedings.

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PURPOSE OF TESTMIONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss and support the reasonableness of DTE Gas's Federal Income Tax (FIT), Michigan Corporate Income Tax (MCIT), municipal (city) income tax, property tax and other general taxes for the 2016 calendar year historical period and the twelve months ending September 30, 2019 projected test period.

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	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% and a MCIT rate of 6% for all periods in this case. In addition, I am assuming for all periods in this case a municipal income tax rate of 0.5789%, which represents a composite rate including all cities in which DTE Gas has a municipal income tax obligation.

HISTORIC PERIOD

Q. What was the 2016 historical period property tax expense?

A. The 2016 historical period property tax expense in Exhibit A-3, Schedule C7, line 1 of $50.0 million represents property tax expense on all DTE Gas's 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, you will see a difference annually between liability and expense.

Q. Is there anything unique or unusual regarding 2016 historical period income tax expense?

A. No. 2016 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-17999. Income tax expense includes both current income taxes (taxes payable currently) and deferred taxes (taxes payable in the future).

Total 2016 historical year income tax expense of $86.7 million is shown on Exhibit A-3, Schedules C8 and C9. Company Witness Ms. Uzenski uses these expenses in

Exhibit A-3, Schedule C1, lines 13 and 14, along with rate case and normalization adjustments, to calculate an adjusted total income tax expense of $98.4 million.

Q. How did you calculate the 2016 historical period payroll tax expense?

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 expense for the historic period is $10.5 million.

Q. Are there taxes for the historic period for which you are not displaying a calculation?

A. Yes. Due to the immateriality of the tax, I am not showing a calculation of miscellaneous other tax expense of $0.01 million. In addition, I am not showing a calculation of the Public Utility Assessment fees of $2.8 million. These all appear in the category Other General Taxes in Exhibit A-3, Schedule C7.

FORECAST PERIOD

Q. What subjects will your testimony and exhibits cover related to the twelve months ending September 30, 2019 projected test period?

A. I am supporting the FIT, MCIT, Municipal Income Tax, Property Tax and Other general taxes shown on exhibits, Exhibit A-13, Schedules C7 through C10. These schedules, which are primarily based on forecasted amounts sponsored by other

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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.

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

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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. Has the Company made any changes in the method used to project its property tax liability since the Company's last general rate case?

A. Yes.

Q. What is new in this case with respect to the method used to project the Company's property tax liability?

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A. Taking into consideration Commission comments in the order in Case No. U-17999, the Company revised both the model and the exhibit used for projecting property tax expense to simplify the projection and increase transparency. As part of this effort, the Company has also presented property tax expense in its own exhibit, Exhibit A-13, Schedule C7.1, separate from other non-income taxes, which are now shown on Exhibit A-7, Schedule C7.

In addition, as the model was being revised for this current rate case, the Company identified a process gap in Rate Case No. U-17999 regarding the 2015 property tax liability computation. The Company continually looks for opportunities to reduce the property tax liability by identifying costs that should not be subject to property tax and excluding them from the taxable value of capital additions every year. These are referred to as nontaxable expenditures. The process followed in Rate Case No. U-17999 to calculate the prior year liability did not measure and exclude these nontaxable expenditures from the 2014 capital additions, causing the 2015 liability to be overstated. The Company has implemented a new process for this rate case, which validates the 2017 liability in a manner that remediates this previous defect. In the current rate case, the Company has also estimated nontaxable expenditures on forecasted 2017 and 2018 capital additions and has excluded them from the estimated taxable value and 2018 and 2019 liabilities accordingly.

Irrespective of methods applied, the property tax liability will increase annually as the Company continues to invest in capital. The amount by which it will increase is driven not only by the amount of capital investment, but also by the type of costs that make up the investment. The type of costs will determine whether the capital investment is subject to property tax and, if it is, how the taxable value is determined. As such, the increase from year to year does not follow any average growth pattern, making the application of a methodology such as the CAGR inappropriate.

Q. Is the 2017 property tax liability set forth in any of your exhibits?

A. Yes. Exhibit A-13, Schedule C7.1 shows the 2017 property tax liability on line in column (c), respectively.

The 2017 tax liability of $56.0 million (lines 3 and 37, column (c)) represents the estimated property taxes that will be paid on all property on hand at 12/31/2016. This 2017 estimated tax liability increased $3.7 million over the 2016 tax liability of $52.3 million. The estimate is based on the taxable value per the assessments received and assumes, with the exception of an anticipated increase in the City of Highland Park, no material increase in millage rates.

Q. Is the 2018 property tax liability set forth in any of your exhibits?

A. Yes. Exhibit A-13, Schedule C7.1, shows the projected 2018 property tax liability of $62.3 million.

Q. How was the projected 2018 property tax liability on Exhibit A-13, Schedule C7.1, line 39, column (c) calculated?

A. DTE Gas's projected 2018 property tax liability represents the projected property taxes that will be assessed and paid on all property projected to be on hand at

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12/31/2017 and is calculated as follows: 2017 tax liability of $56.0 million (lines 3 and 37, column (c)) plus the increase in liability projected for 2018 of $6.3 million (line 38, column (c)). The increase in liability projected for 2018 is calculated on lines 18 through 36, column (c). The taxable value of 2017 additions is estimated to be $128.9 million (line 28, column (c)), driven primarily by 2017 capital additions less retirements and nontaxable expenditures. The increase in liability projected for 2018 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 obsolescence of property on hand as of 12/31/2016 is estimated to be a reduction in taxable value of $18.4 million (line 33, column (c)). The millage rate, which is based on the historical composite millage rate on property of 57.099, is then applied to the net increase in taxable value of $110.5 million (line 34, column (c)) resulting in the $6.3 million incremental tax liability (line 36, column (c)). The 2017 capital additions and retirements are supported by Company Witnesses Ms. Harris and Ms. Sandberg.

Q. Is the 2019 property tax liability set forth in any of your exhibits?

A. Yes. Exhibit A-13, Schedule C7.1, shows the projected 2019 property tax liability of $71.2 million.

Q. How was the projected 2019 property tax liability on Exhibit A-13, Schedule C7.1, line 41, column (e) calculated?

A. DTE Gas's projected 2019 property tax liability represents the projected property taxes that will be assessed and paid on all property projected to be on hand at 12/31/2018 and is calculated as follows: 2018 tax liability of $62.3 million (lines

39, column (e)) plus the increase in liability projected for 2019 of $8.9 million (line 36, column (e)). The increase in liability projected for 2019 is calculated on lines 18 through 36, column (e). The taxable value of 2018 additions is estimated to be $175.8 million (line 28, column (e)), driven primarily by 2018 capital additions less retirements and nontaxable expenditures. The increase in liability projected for 2019 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 obsolescence of property on hand as of 12/31/2017 is estimated to be a reduction in taxable value of $20.5 million (line 33, column (e)). The millage rate, which is based on the historical composite millage rate on all property of 57.099, is then applied to the net increase in taxable value of $155.3 million (line 34, column(e)) resulting in the $8.9 million incremental tax liability. The 2018 capital additions and retirements are supported by Witnesses Harris and Sandberg.

Q. What is the amount of property tax expense the Company is seeking recovery of in this case?

A. The Company is seeking recovery of property tax expense of $63.9 million for the projected test period (October 1, 2018 through September 30, 2019), which is included in column (e) of Exhibit A-13, Schedule C1 (line 11).

Q. How was the projected future test year property tax expense calculated?

A. It is important to remember that property tax *expense* refers to the amount of property taxes deducted for book purposes whereas 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 2018 calendar year property tax expense of $58.5 million represents 61% of the 2017 property tax liability and 39% of the 2018 property tax liability. Due to the two-year expensing methodology, the increase of $4.8 million over the 2017 property tax expense of $53.7 million was driven by the increases in both the 2017 estimated tax liability and the 2018 estimated tax liability.

The 2019 calendar year property tax expense of $65.8 million represents 61% of the 2018 estimated property tax liability and 39% of the 2019 projected property tax liability. Due to the two-year expensing methodology, the increase of $7.3 million over the 2018 property tax expense of $58.5 million is driven by the increases in both the 2018 estimated tax liability and the 2019 projected tax liability.

Projected test period property tax expense of $63.9 million is calculated by taking 3/12^{ths} of the 2018 calendar year expense plus 9/12^{ths} of the 2019 calendar year expense.

Q. What is the Other Tax Expense portion of DTE Gas's operating expense?

A. DTE Gas is seeking recovery of Other Tax expense for the projected test period of $14.8 million, which is contained in column (e) of Exhibit A-13, Schedule C1 (line 12). Other Tax expense consists of payroll taxes ($11.3 million), Public Utility

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Assessment fees ($3.5 million), and miscellaneous other taxes ($0.01 million, primarily use taxes) as shown on Exhibit A-13, Schedule C7.

Q. How did you forecast the Other General Tax Expense?

A. DTE Gas'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 Gas's assumed annual inflation rate. Exhibit A-13, Schedule C1, which is supported by Witness Uzenski, lists inflation rates for the interim forecast and projected test periods. Witness Uzenski also supports the projected Public Utility Assessment Fee. Other miscellaneous tax expense (primarily use tax) was held to the 2016 actual amount.

Q. How much total income tax expense is the Company seeking recovery of?

A. DTE Gas is seeking recovery of total income tax expense of $75.9 million. This is comprised of FIT expense of $61.6 million, MCIT Expense of $13.2 million, and municipal income tax expense of $1.1 million. Total income tax expense is $10.8 million less than 2016 income tax expense of $86.7 million driven primarily by lower pretax book income.

Q. How was the FIT Expense portion of DTE Gas's operating expense developed?

A. Column (e) of Exhibit A-13, Schedule C1, (line 14) shows DTE Gas's FIT expense for the projected test period is $61.6 million. Exhibit A-13, Schedule C8, illustrates that FIT expense is comprised of current FIT expense (line 6) and deferred FIT expense (line 7). Current FIT expense is calculated based on taxable income as shown on lines 10 through 44. Deferred FIT expense is shown on lines 46 thru 51

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and is based on book versus tax temporary differences (line 36), the NOL carryforward (line 47) and annual amortization of several Deferred Debits and Credits (Medicare Part D Subsidy and Investment Tax Credit (ITC)) (lines 49 – 50). Total federal income tax expense is adjusted for the Income Tax effect of Interest – Federal from Exhibit A-13, Schedule C15 (line 10) and Interest Synchronization Tax Adj. – Federal from Exhibit A-13, Schedule C16 (line 10).

Q. Is there a significant change in the amortization of Deferred Credit in the test period related to DTE Gas's FAS 109 regulatory liability?

A. Yes. A regulatory liability was established in 1992 related to the Statement of Financial Accounting Standard No. 109, Accounting for Income Taxes, which required an asset and liability approach for financial accounting and reporting for income taxes (FAS 109 regulatory liability). Recovery of the FAS 109 regulatory liability was authorized in Case No. U-10083. The FAS 109 regulatory liability will be fully amortized by December 31, 2017.

Q. What is the impact of the federal net operating loss carryforward in the projected test period?

A. DTE Gas generated a federal net operating loss from prior years and carried it forward to apply against taxable income in future years. DTE Gas is utilizing a portion of this federal net operating loss carryforward (NOL) in the projected test period shown on Exhibit A-13, Schedule C8. The remaining estimated NOL carryforward of $175.2 million will be utilized after September 30, 2019.

The utilization of the NOL is accounted for as a reduction to the deferred tax asset

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related to the NOL, which increases in the net deferred tax liability. This, along with the deferred tax liability created by accelerated depreciation and other accelerated tax deductions, is a source of zero cost capital.

Q. How was the MCIT expense portion of DTE Gas's operating expense developed?

A. Column (e) on Exhibit A-13, Schedule C1, line 13, contains DTE Gas's state and municipal income tax expense for the projected test period. Line 15 of Exhibit A-13, Schedule C9, shows DTE Gas's MCIT expense for the projected test period is $13.2 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 that arose from Michigan tax law changes of 2008 and 2012.

Q. How was the Municipal Income Tax Expense portion of DTE Gas's operating expense developed?

A. Column (e) on Exhibit A-13, Schedule C1, line 13, contains DTE Gas's state and municipal income tax expense for the projected test period. The municipal income tax portion of line 13 is $1.1 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 reduced for the utilization of municipal net operating loss carryforward with certain modification related to the local income tax adjustment. Deferred municipal income tax is based on book versus tax temporary differences, the reversal of deferred tax asset related to the municipal net operating loss carryforward being utilized, and the annual amortization of the City of Detroit Deferred Debit that arose from the City of Detroit tax law change of 2012.

Q. Did DTE Gas settle any tax issues with the State of Michigan and, if so, what was the outcome of that settlement?

A. DTE Gas filed amended use tax returns for tax years 2008 through 2015 to claim a refund of use tax paid on expenditures the Company believed should have been eligible for an industrial processing exemption. The Michigan Department of Treasury denied the Company's refund claim.

On August 23, 2017, an agreement was executed by DTE Gas and the Michigan Department of Treasury to settle the refund claim (the "Agreement"). The Agreement provides for a refund for tax years 2008 through 2015 of 67% of tax due, resulting in a refund of $18.4 million of taxes ($17.1 million) and interest ($1.3 million). The Company also incurred $1.4 million of professional fees payable to an outside consulting firm hired to assist with the preparation and filing of these amended tax returns.

The Agreement provides that for 2016 forward, 100% of transmission expenditures and 50% of distribution expenditures are eligible for the industrial processing exemption (the "Exemption Percentages"). Pursuant to the Agreement, in September 2017, DTE Gas filed an amended return for the 2016 tax year seeking a refund of $3.7 million on exempt expenditures made that year.

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Upon signing the Agreement in August 2017, DTE Gas recorded the refund of taxes and interest for the 2008 through 2016 tax years totaling $22.1[1] million. Of this total, $16.9 million was a reduction to capital, $3.9 million was a reduction to use tax expense, and $1.3 million was interest income. DTE Gas also recorded $1.4 million of expense related to the professional fees due.

Starting in August 2017, DTE Gas's monthly use tax return filings applied the Exemption Percentages. In addition, DTE Gas will file amended use tax returns in early 2018 to seek a refund of taxes paid on exempt expenditures made from January through July 2017.

Q. What is the impact on this case of the agreement that was signed by DTE Gas and the Michigan Department of Treasury to settle the use tax refund claim (the "Agreement")?

A. As a result of the Agreement, DTE Gas made a journal entry in August 2017 to reduce capital and, therefore, rate base by $16.9 million. This journal entry has been reflected in Exhibit A-12, Schedule B5 (lines 5 and 9, column (c)), supported by Witness Sandberg. Company Witness Ms. Tormina has also reflected a reduction in operating and maintenance expenses of $527 thousand in Exhibit A-13, Schedule C5.2 (line 22, column (j)) of $120 thousand and Exhibit A-13, Schedule C5.3 (line 22, column (j)) of $407 thousand.

[1] $22.1 million is the sum of the 2008-2015 refund of $18.4 million per the Agreement and the 2016 refund of $3.7 million per the amended tax return.

Q. Does this complete your direct testimony?

A. Yes, it does.