STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARKUS B. LEUKER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MARKUS B. LEUKER

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Markus B. Leuker (he/him/his). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am Manager of Corporate Energy Forecasting in the Business Planning and Development organization.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (Company or DTE Electric).

Q3. What is your educational background?

A3. I received a Bachelor of Science in Business Administration from Xavier University in Cincinnati, Ohio with a concentration in Marketing and Management in 1991. I received a Master of Business Administration from Xavier University in Cincinnati, Ohio in 1998. I have also completed several Company sponsored courses and attended various seminars to further my professional development.

Q4. What is your work experience?

A4. I joined the Company in November 2010 as Manager, Corporate Energy Forecasting. Prior to DTE Electric, I worked for IHS/CSM Worldwide as a Sr. Manager, North American Advisory Services where I led the pursuit, development, execution and delivery of key client projects. Some of my experiences at IHS/CSM Worldwide included: Market Research & Analysis, Market Opportunity Analysis, Business Modeling and Strategic Analysis, Regulatory Market Assessment, and Financial and Scenario Analysis. In addition to my experience with DTE Electric and IHS, I worked as North American Manager, Market Research & Analysis for Visteon Corporation where I managed global coordination of the research function

Line No.

and led a team of researchers in various studies including customer and competitor research, new product creation, and customer satisfaction. I have also had prior experience in the utility industry working as a Senior Analyst at Cinergy Corporation (currently Duke Energy). While at Cinergy, I worked on various non-regulated activities and regulated marketing activities.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. I am a member of Edison Electric Institute's (EEI) Load Forecasting Group (LFG). The LFG's purpose is to enhance load forecasting capabilities by exchanging information among the group's base of experienced and knowledgeable load forecasters. I am also a member of the Detroit Association for Business Economics (DABE). DABE discusses economic issues affecting Southeastern Michigan.

Q6. What are your current duties and responsibilities?

A6. I am responsible for the development of the economic and electric sales forecasting activities for DTE Electric. These activities include data collection, statistical analysis of data, forecast model building and interaction with other departments on forecast-related activities. My role also includes the preparation of long-term (one year or greater) sales forecasts, short-term (monthly) forecasts, next day forecasts, and the economic forecast that supports the sales forecast.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I have sponsored testimony in the following cases:

Line No.		
1	U-17049	2012 Energy Optimization Plan
2	U-17097	2013 Power Supply Cost Recovery (PSCR) Plan
3	U-17302	2013 Renewable Energy Plan Update
4	U-17319	2014 PSCR Plan
5	U-17680	2015 PSCR Plan
6	U-17762	2016-17 Energy Optimization Plan
7	U-17767	DTE Electric General Rate Case
8	U-17793	2015 Renewable Energy Plan
9	U-17920	2016 PSCR Plan
10	U-18014	DTE Electric General Rate Case
11	U-18111	2016 Amended Renewable Energy Plan
12	U-18143	2017 PSCR Plan
13	U-18255	DTE Electric General Rate Case
14	U-18262	2018-19 Energy Waste Reduction Plan
15	U-18403	2018 PSCR Plan
16	U-18419	2017 Certificate of Necessity
17	U-18232	2018 Renewable Energy Plan
18	U-20162	DTE Electric General Rate Case
19	U-20221	2019 PSCR Plan
20	U-20471	2019 Integrated Resource Plan (IRP)
21	U-20561	DTE Electric General Rate Case
22	U-18232	2020 Amended Renewable Plan
23	U-20836	2022 DTE Electric Rate Case
24	U-21193	2022 Integrated Resource Plan
25	U-21297	2023 DTE Electric Rate Case

Line
No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to provide the Company's current electric sales, maximum demand and system output forecast for the period 2023-2028, including the projected 12-month test period January 1, 2025 through December 31, 2025. I will discuss the outlook for the national and local economy which is the basis of the forecast. I will describe how the forecast of electric sales, maximum demand and system output is developed. My testimony will support the reasonableness of the electric sales forecast used by DTE Electric in this proceeding.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-5	E1	Annual Sales by Major Customer Classes and System Output 2018-2022 Historical
A-15	E1	Annual Sales by Major Customer Classes and System Output 2023-2028 Forecast
A-15	E2	Annual System Output, Maximum Demand and Load Factor
A-15	E3	Projected Period Known and Measurable Changes to Sales
A-15	E4	Summary of Economic Outlook
A-15	E5	Variance of Weather-Normalized Electric Sales and Peak and ITRON's Benchmarking Survey Results

Line No.

A-15	E6	Annual Customer Counts by Major Customer Classes 2018-2022 Historical 2023-2028 Forecast

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following parts:

Part I: Economic Outlook

Part II: Forecast Development and Assumptions

Part III: Historical and Current Electric Forecast Sales and Demand

Part IV: Electric Load Forecast Accuracy

<u>Part I: Economic Outlook</u>

Q12. What was the condition of the national economy in 2023?

A12. Real gross domestic product increased at an annualized rate of 2.2% in the first quarter, 2.1% in the second, and 4.9% in the third. Real personal consumption expenditures increased at an annualized rate of 3.8% in the first quarter, 0.8% in the second, and 4.0% in the third. Real disposable personal income increased at an annualized rate of 10.8% in the first quarter and 3.5% in the second, although decreased at an annualized rate of 1.0% in the third. The Consumer Price Index for All Urban Consumers (CPI-U) grew at an annualized rate of 3.8% in the first quarter, 2.7% in the second, and 3.6% in the third. Seasonally adjusted housing starts declined at an annualized rate of 5.6% in the first quarter, increased at an annualized rate of 19.9% in the second, and declined at an annualized rate of 20.9%

in the third. Light vehicle production was 2.6 million in the first quarter and 2.7 million in the second.

Q13. What is the outlook for the nation's economy in 2024 and 2025?

A13. Gross domestic product is expected to increase by 1.3% in 2024 and by 1.6% in 2025. Disposable personal income is expected to increase by 2.6% in 2024 and by 2.3% in 2025. Personal consumption expenditures are expected to increase by 1.2% in 2024 and by 1.5% in 2025. These measures from the national income and product accounts are in real terms, meaning that inflation has been removed from them. The CPI-U is forecast to increase by 2.7% in 2024 and by 2.4% in 2025. Total light vehicle production in the United States is forecast to reach 10.7 million units in 2024 and 11.1 million in 2025.

Q14. What is the outlook for Southeast Michigan's economy in 2024 and 2025?

A14. Total non-farm employment is forecast to decline by 0.6% in 2024 but increase by 0.3% in 2025. Natural resources, mining, and construction employment is expected to decline by 2.5% in 2024 and by 0.7% in 2025. Total private non-manufacturing employment is forecast to decline by 0.2% in 2024 and increase by 0.6% in 2025. In the government sector, employment is expected to rise by 0.7% in 2024 and by 0.8% in 2025. Southeast Michigan automotive production is expected to reach a level of 1.5 million vehicles in 2024 and 1.7 million in 2025. Population is forecast to increase by 0.10% in 2024 and by 0.07% in 2025.

Line
No.

Part II: Forecast Development and Assumptions

Q15. What is the general approach used in developing the forecast of DTE Electric's service area electric sales and system output?

A15. The general approach reflects widely accepted industry standards for electricity forecasting, including regression and end-use modeling. Using this approach has resulted in high accuracy rates when comparing forecasted DTE Electric service area electric sales to actual historical annual sales. Forecast accuracy is discussed in more detail in Part IV of my testimony.

Most customer class sales and customer forecasts are built from linear regression models that relate monthly sales to economic activity, weather, changes in end-use saturation, and energy efficiency. The forecast is developed separately for each major rate classification: Residential, Commercial and Industrial (C&I), and other. The residential sales forecast is derived by combining a use-per-customer forecast, using a statistically adjusted end-use (SAE) specification, with a customer forecast. Separate models are estimated for small and large C&I customers. Small C&I, comprised of over 200,000 small business customers, is modeled similarly to residential, while large C&I, comprised of over 3,000 high consumption large business customers, is forecast using econometric models unique to seven supersectors. The Other (street lighting) forecast is provided by Company Witness Bellini. The system output is forecasted as the sum of the electric sales values and the projected system losses.

There are many factors that impact the sales and customer forecasts for each customer class. Examples of forecast drivers include:

- National, state, and local economic projections provided by sources including, but not limited to: S&P Global (formerly IHS Markit), Moody's Analytics, and Polk Automotive.
- The Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2022 end-use intensity and end-use saturation estimates for the East North Central Census Division (modified to reflect DTE Electric's end-use information)
- Historical weather data from the Detroit Metropolitan Airport, with normal weather assumptions in the forecast horizon
- DTE Electric's Energy Waste Reduction (EWR) targets
- DTE Electric's behind-the-meter distributed generation (DG) projections
- DTE Electric's electric vehicle (EV) forecast for light-duty and fleet vehicles
- Large customer load adjustments that would not be reflected in the historical data or economic projections

Q16. Can you please describe the data used to construct the forecast models?

A16. Each model used to forecast sales was estimated with monthly historical consumption data beginning in January 2006, with estimation ending in June 2023. Customer count forecast models were estimated with monthly historical customer count data beginning in January 2012, with estimation ending in June 2023.

The forecast for both sales and customers was extended through 2028 and used to develop the long-term system energy and peak demand forecast.

A bottom-up hourly load model, described later in my testimony, utilized hourly historical customer class level data as the basis for developing a suite of load profiles that were used to forecast the peak demand.

Q17. How is weather applied in the load forecast?

A17. Weather is one of the primary variables used in each customer class forecast model. In each model, actual weather, measured in the form of heating degree days (HDDs) and cooling degree days (CDDs) is used to understand the unique relationship that a customer class's energy consumption has with weather. HDDs are calculated by subtracting average daily temperature from a defined base such as 65 degrees Fahrenheit. Conversely, CDDs are calculated by subtracting the base, from average daily temperature.

In regression modeling, a coefficient is calculated to quantify this impact. Once the coefficient is calculated, it is applied to the weather assumed in the forecast horizon. In the forecast horizon, normal weather is assumed as the most prudent form of future weather expectations.

Q18. Can you please describe the HDD and CDD bases used in the forecast?

A18. As seen in Figures 1 and 2, weather impact is different depending on the customer class. Residential sales are more impacted by weather and customers typically begin cooling their buildings at an average temperature of 60 degrees. Small C&I sales are not as influenced by weather, although customers typically begin cooling their buildings at an average of 50 degrees. The relationships to weather are also non-linear, creating a need to utilize multiple HDD and CDD bases to accurately capture the weather response. HDD and CDD bases, represented by the name and temperature of the base, for each customer class include:

- Residential: HDD25, HDD60, CDD60, CDD65, CDD70 and CDD75
- Small C&I: HDD50, CDD50, CDD60, and CDD70
- Large C&I (varies by supersector):
  - Education and Health: CDD50
  - Transportation, Trade and Utilities (TTU): HDD50 and CDD50
  - Offices: HDD45 and CDD55
  - Other Markets: HDD45 and CDD55
  - Automotive: HDD50 and CDD60
  - Other Manufacturing: CDD55

Figure 1 : Residential Daily Use-Per-Customer vs Temperature

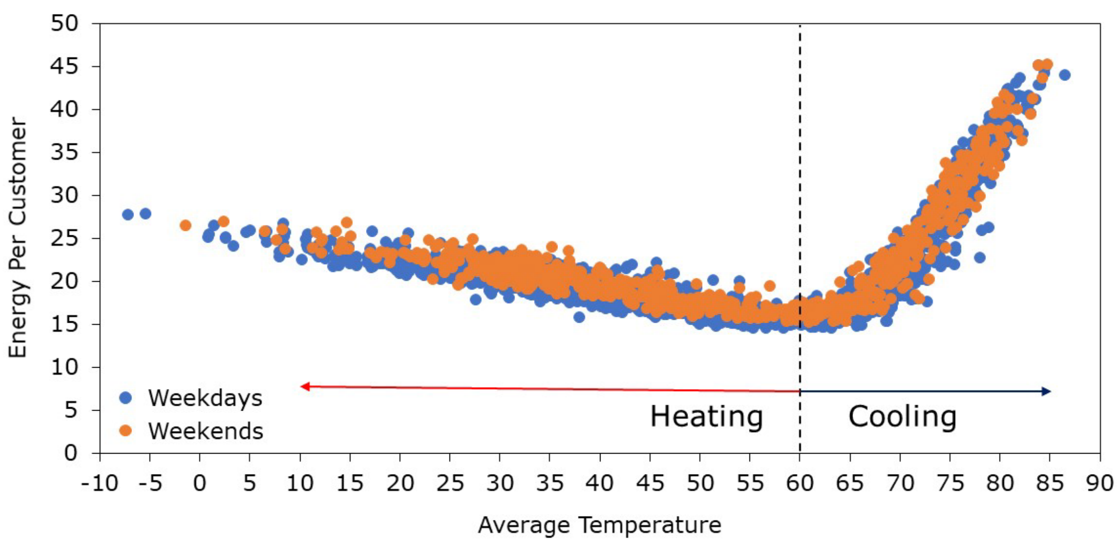
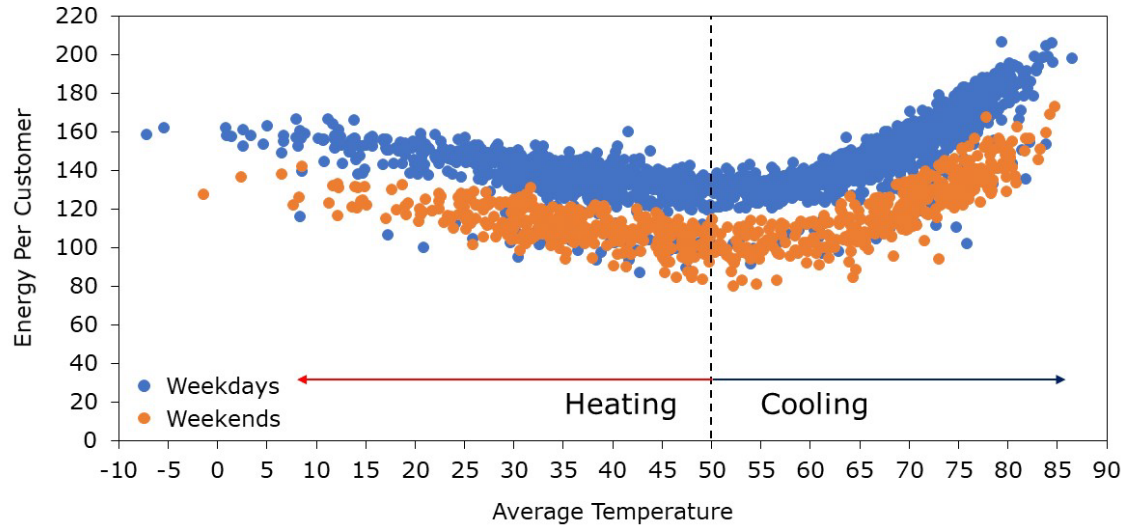


Figure 2 : Small C&I Daily Use-Per-Customer vs Temperature



Q19. How does DTE Electric define normal weather?

A19. DTE Electric defines normal weather as a 15-year average of historical values, updated on an annual cadence as recommended by the Commission in Case No. U-20471. In this instant case, 2008-2022 is the timeframe for normal weather. Additionally, historical actual sales in my Exhibits were weather normalized with the same normal weather assumed in the forecast for comparison purposes. Daily average temperature is converted to HDDs and CDDs for various bases and averaged across years. As a result, this process calculates and defines normal HDDs and CDDs for various bases in a given day, month and year.

Q20. How was the Residential class forecast developed?

A20. Electricity sales in the residential class were forecast using the SAE model which specifies energy use as a function of 22 end-uses, including DG and EV demand, along with factors that affect the end-use requirements such as economic activity and weather. The residential class forecast begins with a standard end-use model, with appliance saturation projections and average electricity usage per end-use provided by a Company-conducted residential appliance saturation survey and the EIA's AEO 2022 for the East North Central region in which DTE Electric operates. Residential EWR programs are applied directly to the corresponding end-uses in the SAE model. The combination of appliance saturations and average electricity per end-use is indexed and calibrated to the Company's usage per customer for a base year to create an electricity forecast for each end-use.

Utilization variables, which explain how much an end-use is utilized, are combined with end-use intensities. For residential, the primary variables used to explain utilization are weather, real personal income, population, households, and workplace occupancy. The utilization variables are then combined with the end-use intensities to compute three explanatory variables that are:

- XHeat – An aggregated heating variable that captures changes in heating end-use saturation and efficiency, and combined with HDDs, economic, and other factors that impact the utilization of heating equipment.
- XCool – An aggregated cooling variable that captures changes in cooling end-use saturation and efficiency, and combined with CDDs, economic, and other factors that impact the utilization of cooling equipment.
- XOther – An aggregated base-load variable that captures changes in base-load end-use saturation and efficiency, and combined with number of days in a month, economic, and other factors that impact the utilization of base-load equipment.

Along with seasonal factors, the resulting explanatory variables are then regressed against the Company's residential monthly use per customer sales. The model effectively acts as the statistical adjustment and calibrates the end-use forecast to the Company's historical sales.

The number of residential customers was forecasted using historical and projected households for southeast Michigan provided by S&P Global. Customer counts are modeled using a regression, with households as the primary explanatory variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total residential class sales forecast.

Q21. How was the small C&I forecast developed?

A21. Similar to the residential class forecast, small C&I class sales are also forecast using an SAE model, utilizing 11 end-uses including DG and EV demand. Additionally, C&I EWR programs are incorporated directly into the SAE model. The small C&I sales forecast begins with a standard end-use model with saturation projections and average electricity usage per end-use derived from the EIA's AEO 2022 for the East North Central region in which DTE Electric operates. Since small C&I buildings within the DTE Electric service territory consume electricity differently, the projections are weighted by intensity and prevalence of 11 different building types as defined by the EIA. To better calibrate these projections to the Company's service area, employment values are used to weight end-use intensities with the Company's service area employment data. The combination of saturations and average electricity per end-use is indexed and calibrated to the Company's usage per customer for a base year to create an electricity forecast for each end-use.

Line No.

Utilization variables, which explain how much an end-use is utilized, are combined with end-use intensities. For small C&I, the primary variables used to explain utilization are weather, gross state product, non-manufacturing employment and households. The utilization variables are then combined with the end-use intensities to compute three explanatory variables that are:

- XHeat – An aggregated heating variable that captures changes in heating end-use saturation and efficiency, and combined with HDDs, economic, and other factors that impact the utilization of heating equipment.
- XCool – An aggregated cooling variable that captures changes in cooling end-use saturation and efficiency, and combined with CDDs, economic, and other factors that impact the utilization of cooling equipment.
- XOther – An aggregated base-load variable that captures changes in base-load end-use saturation and efficiency, and combined with number of days in a month, economic, and other factors that impact the utilization of base-load equipment.

Along with seasonal factors, the resulting explanatory variable is then regressed against the Company’s small C&I monthly use per customer sales. The model effectively acts as the statistical adjustment and calibrates the end-use forecast to the Company’s historical sales.

Small C&I customers are modeled using a regression with households used as the primary variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total small C&I class sales forecast.

Q22. How was the large C&I forecast developed?

A22. The large C&I forecast begins by disaggregating all primary service sales into seven distinct supersector markets. Granular market segments defined by the customer's North American Industry Classification System (NAICS) code are aggregated into supersectors defined by the Bureau of Labor Statistics. The seven supersectors are medical and education, transportation, trade, and utility (TTU), offices, other markets, automotive, other manufacturing, and steel.

Econometric models, a commonly used technique among utility forecasters, are used to forecast sales for the Company's service territory at the supersector level. Individual regression equations are applied to all supersectors, using various explanatory variables such as corresponding supersector employment and gross state product, automotive production, weather, and cumulative EWR savings, to drive the forecast. The regression results are evaluated for reasonableness and validated through various model statistics.

Regression modeling alone does not account for incremental growth of technologies such as electric vehicles. Unlike residential and small C&I, large C&I is not modeled by end-use. Therefore, it is necessary to make post-regression adjustments to the forecast to incorporate future technology and customer specific closings or expansions. The two main post regression adjustments include EV growth and large customer projects that are informed by customer account managers.

Line
No.

Q23. Is the method to forecast customer class sales the same as what the Company proposed in Case No. U-21297?

A23. For the most part, yes. The underlying methods used to forecast by customer class remain foundationally the same, with only changes to the input data. In general, most changes to the forecast consist of refreshing data sources to reflect the most current outlooks, or routine process updates such as updating the normal-weather period to include the most recent year of data.

Q24. What level of EWR is assumed in the forecast?

A24. The load forecast assumes EWR savings consistent with Case No. U-21322 and Case No. U-21193, the Company's most recent EWR Plan and Integrated Resource Plan filings respectively. For 2025, the Company plans to achieve 2% annual savings, made up of a 1.4% reduction in residential sales, and a 2.4% reduction in C&I sales.

Q25. What type of DG resources were included in the forecast?

A25. The Company, for purposes of the forecast, is defining DG as customer-sited resources that are: 1) interconnected to the distribution system on the customer's side of the utility's service meter and 2) installed to offset site load with incidental export. For forecasting purposes, the projected additional DG resources were assumed to be solar photovoltaics (PV).

Q26. How was the DG outlook applied to the forecast?

A26. The DG outlook was developed utilizing the Company's residential and non-residential interconnection history. The forecast begins with a collection of

Line
No.

historical and projected PV economics for both residential and non-residential customers. Variables such as, but not limited to, capital costs, operating and manufacturing costs, tax credit schedules, and electricity prices were used to determine the PV economics. These economics are used as the primary explanatory variable in a regression model, with the Company's interconnection history as the dependent variable, to project the levels of DG expected in the future.

Two separate forecasts are produced for residential and non-residential. The historical and forecast DG is applied directly as an additional end-use into the models for residential and small C&I.

Q27. How was the EV outlook applied to the forecast?

A27. For the EV forecast, the cumulative vehicle stock forecast presented by Witness Bennett was used as a starting point to estimate the historical and forecasted load in the Company's service territory.

The EV stock is multiplied by a kWh/vehicle value and the assumed vehicle miles traveled unique to each vehicle segment to arrive at the load associated with the forecasted vehicle volumes. Vehicle segments modeled include battery-electric light-duty vehicles, plug-in hybrid light-duty vehicles, buses, medium-duty trucks, and heavy-duty trucks.

For light-duty vehicles, the Company's appliance saturation survey suggests approximately 75% of EV charging is done at personal residences while the other 25% is done at non-residential locations, such as workplace or public charging stations. Therefore, approximately 75% of the light-duty EV sales forecast was applied to the residential model as an additional end-use while the remaining was applied to the small and large C&I models as a starting point. Over time, as EV adoption becomes more mainstream, the forecast assumes these dynamics will shift in favor of more non-residential charging. As public infrastructure is built out to support direct current (DC) fast charging and consumers without access to home charging begin to adopt EV's, the boundary between home and public charging is projected to overlap.

For fleet (medium-duty and heavy-duty) vehicles, 100% of the fleet EV sales forecast was applied to the large C&I model as an incremental adjustment to the forecast.

Q28. How was the Electric Choice sales forecast developed?

A28. The Electric Choice sales forecast was based on 10% of retail sales. Historical class ratios are applied to the Electric Choice cap and new customer load is added separately.

Q29. How was the DTE Electric system peak demand forecast developed?

A29. A bottom-up hourly load model was used to forecast annual DTE Electric service area and DTE Electric bundled peak demand. This was also utilized to determine monthly peak demands in the forecast period.

Q30. What is a bottom-up hourly load model?

A30. A bottom-up approach, put simply, obtains the peak demand forecast by summing hourly values from the bottom-up. Load profiles are developed for each of the sales classes utilizing the Company's historical hourly AMI data. Residential and small C&I classes were further broken into base, cooling, and heating end-uses which captures changing peak demand levels based on the composition of the underlying load shapes, and changes in end-use consumption. Additional load profiles for technologies such as EVs and DG are also used.

The profiles are scaled to the monthly energy forecasts by customer class, adjusted for losses, and summed to predict the system total. The highest hourly value in a year or month is the peak forecast. Modeling system peak using a bottom-up approach is advantageous in that it captures load shape diversity. For example, as customers adopt more efficient HVAC units, or technologies such as EVs increase in penetration, a bottom-up approach provides the ability to understand changes in the system peak, as well as the hour in which it occurs.

Q31. What temperature assumptions were made regarding the peak demand forecast?

A31. Normal temperature on the day of the annual peak is assumed to be 82.3 F, which is the mean temperature at Detroit Metropolitan Airport. This value is based upon an average peak-day mean temperature for a 15-year period (2008 through 2022). The mean temperature is calculated as the average of hourly temperatures for the day. The peak day is assumed to occur on a weekday in July.

Q32. Are Demand Response programs included in the Company's peak forecast?

A32. Demand Response programs are not included in the peak forecast. Demand Response programs, such as Interruptible Space-Conditioning, are used to meet the Company's Midcontinent Independent System Operator (MISO) resource adequacy requirements. Demand Response programs are accounted for on the supply side as load modifying resources.

Part III: Historical and Current Electric Forecast Sales and Demand

Section 1: Electric Sales

Q33. When referring to 2023 in this testimony, how many months of actuals are included?

A33. When 2023 is referenced in this testimony, it includes ten months of actual sales and two months of forecasted sales.

Q34. What has been the compound annual growth rate of DTE Electric sales over the last five years?

A34. As shown in Exhibit A-5, Schedule E1, page 4 of 4, weather normalized service area sales from 2018 to 2022 have declined during the five-year historical period. In 2018, total service area sales were 47,362 GWh and 2022 sales were 45,117 GWh, representing a compound annual growth rate (CAGR) of -1.2%.

Bundled sales have decreased from 42,625 GWh in 2018 to 40,631 GWh in 2022, representing a CAGR of -1.2%. The electric choice sales declined from 4,737 GWh in 2018 to 4,486 GWh in 2022, a CAGR of -1.4%. Refer to Exhibit A-5, pages 1 through 3 for additional detail regarding historical actual sales for the service area, bundled, and electric choice.

Line
No.

Q35. What are sales for the projected test period, January 2025 through December 2025?

A35. The service area sales for the projected test period, January 2025 through December 2025 are 44,189 GWh and bundled sales are 39,756 GWh. The projected test period service area and bundled sales are displayed in Exhibit A-15, Schedule E1, pages 1 and 2, line 3 and electric choice sales are displayed in Exhibit A-15, Schedule E1, page 3, line 2. The projected known and measurable changes for bundled sales from 2022 to the projected test year are detailed in Exhibit A-15, Schedule E3.

Q36. What is the CAGR of the DTE Electric service area electric sales from 2022 through the forecast period to 2028?

A36. The service area sales are expected to decrease to 44,170 GWh in 2028. This represents a -0.4% CAGR. The forecast of annual sales and system output for DTE Electric's service area for the years 2023 through 2028 is reflected on Exhibit A-15, Schedule E1, page 1 of 3.

Q37. What is the CAGR of DTE Electric bundled electric sales from 2022 through the forecast period to 2028?

A37. The bundled sales are projected to decrease over the forecast period, consistent with the declining trend seen in the historical data. The bundled sales are expected to decline to 39,786 GWh in 2028. This represents a -0.3% CAGR. The current forecast of bundled sales and system output for the years 2023 through 2028 are shown on Exhibit A-15, Schedule E1, page 2 of 3.

Q38. What is the CAGR of Electric Choice sales from 2022 through the forecast period to 2028?

A38. Electric Choice sales are expected to decrease to 4,383 GWh in 2028. This represents a -0.4% CAGR. The current forecast of electric choice sales and system output for the years 2023 through 2028 are shown on Exhibit A-15, Schedule E1, page 3 of 3, line 7.

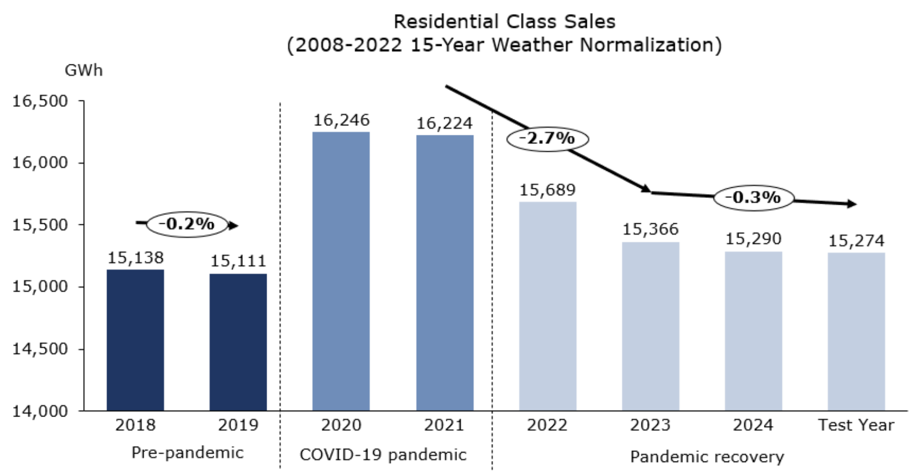
Q39. What is the outlook for residential class sales?

A39. DTE Electric's service area residential Class sales are forecast to decline -0.3% annually, on average, between 2023 and the 2025 projected test period in the instant case. As seen in Figure 3, residential sales experienced a sharp increase in sales from 2019 to 2020 as a result of work from home policies implemented due to the COVID-19 pandemic. Residential sales continued to remain elevated through 2021 and have since been on a downward trajectory as more people begin to navigate back to in-person work. From 2021 through October of 2023 (ten months of actuals and two months of forecast), residential sales have declined at a -2.7% CAGR. As hybrid work arrangements are continuing to stabilize[1], residential sales are expected to follow a similar trajectory through the projected test period as they did pre-pandemic. Figure 3 shows that from 2018 to 2019 residential sales declined at a -0.2% CAGR, while sales from 2023 to the projected test year are expected to decline at -0.3% CAGR. Modest average annual growth of 0.4% in residential customer count is expected from 2022 through 2028 due to a moderating housing market. Annual customer counts are shown in Exhibit A-15, Schedule E6. Use-

[1] The Future of the Office Has Arrived: It's Hybrid (gallup.com) available at https://www.gallup.com/workplace/511994/future-office-arrived-hybrid.aspx, accessed on 1/3/2024

per-customer from 2022 through 2028 is expected to decrease by 0.5% annually on average. For a graphical view of the residential forecast, refer to Figure 3 below.

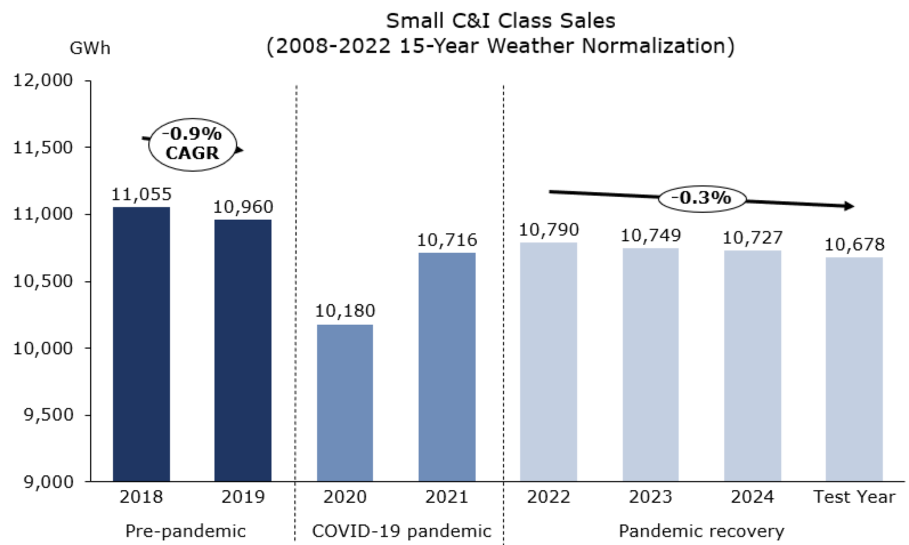
Figure 3 : Residential Forecast



Q40. What is the outlook for small C&I class sales?

A40. DTE Electric's service area small C&I class sales are forecast to decrease -0.3% annually, on average, between 2022 and the 2025 projected test period. The CAGR for 2022 through the 2025 projected test year is consistent with the CAGR of -0.9% observed in pre-pandemic years of 2018-2019. Inversely to residential, small C&I sales declined in 2020 as a result of various policies implemented due to the COVID-19 pandemic. From 2020-2022 sales recovered as policies implemented on commercial business such as restrictions on in-person events were lifted and more people returned to in-person work. Through 10 months of 2023, sales have stabilized around 2022 levels, mainly due to the conclusion of restrictive policies from COVID-19 in June of 2021, combined with stabilizing hybrid work arrangements. Modest average annual growth of 0.4% in Small C&I customer count is expected from 2022 through 2028 due to modest residential customer growth. Use-per-customer from 2022 through 2028 is expected to decrease by -0.7% annually on average. Growth in the Small C&I class is constrained by the increase in energy efficiency programs targeting Commercial and Industrial customers bundled with limited economic growth in the near term. For a graphical view of the small C&I forecast, refer to Figure 4 below.

Figure 4 : Small C&I Forecast



Q41. What is the outlook for large C&I class sales?

A41. DTE Electric's service area large C&I class sales are expected to decrease by 0.7% annually, on average, from 2022 to the projected test period in this instant case. As mentioned previously, Large C&I class sales are allocated between seven supersector markets: education and health, trade, transportation, and utilities (TTU), offices, other markets, automotive, steel and other manufacturing. The decrease in sales is primarily due to projected declines in TTU and manufacturing employment from 2023 to 2025 affecting the largest supersectors in large C&I. The declines in the employment values are due to slowing demand and inventory levels caught up from supply chain issues over the past three years. Furthermore, increased energy efficiency initiatives targeting C&I customers minimizes positive employment projections in the smaller supersectors; education & health, offices, and other markets. Table 1 shows the 2023-2025 CAGRs for the employment drivers including in Exhibit A-15, Schedule E4, used in each supersectors' regression model.

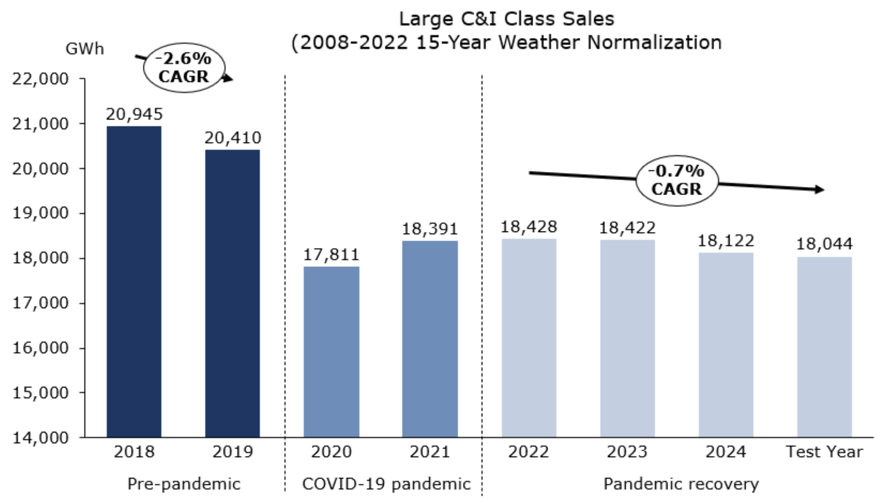
Table 1 Large C&I Employment CAGRs

Economic Index	**2023-2025 CAGR**
Education & Health Employment	1.7%
TTU Employment	-4.0%
Office Employment	1.9%
Other Markets Employment	3.1%
Manufacturing Employment	-5.3%

As seen in Figure 5, the decreasing trend in sales observed pre-pandemic are expected to continue, although at a slower rate. The CAGR for 2022 to the 2025 projected test period is -0.7% which is less of a decline than the CAGR of -2.6% observed in pre-pandemic years of 2018-2019. For a graphical view of the large C&I forecast, refer to Figure 5 below.

Line
No.

Figure 5 : Large C&I Forecast



Q42. What is the outlook for other class sales?

A42. DTE Electric's service area Other Class sales are expected to decrease 1.5% annually, on average, from 2022 through 2028. The Other Class consists of street lighting and traffic signals. The main reason for the decline in sales is the use of more energy efficient lighting. For further detail on street lighting see the testimony of Company Witness Bellini.

<u>Section 2: Electric Peak Demand</u>

Q43. What has been the CAGR of DTE Electric peak demand for the historical period 2018-2022?

A43. As shown in Exhibit A-5, Schedule E1, page 4 of 4, the service area peak demand in 2018 was 11,344 MW and 2022 peak demand was 10,959 MW, representing a CAGR of -0.9%. The bundled peak demand was 10,447 MW in 2018 and 10,207 MW in 2022 at a CAGR of -0.6%.

Line No.

Q44. What are the system output and annual peak demand for the projected test period, January 2025 through December 2025?

A44. The service area system output and annual peak demand for the projected test period, January 2025 through December 2025 are 47,341 GWh and 10,911 MW, respectively. The projected test period bundled system output and annual peak demand are 42,683 GWh and 10,157 MW, respectively. The service area and bundled system outputs and peak demand can be found on Exhibit A-15, Schedule E2, pages 1 and 2, line 8. The Electric Choice impact is displayed in Exhibit A-15, Schedule E2, page 2 of 2. Low (10%) and high (90%) confidence bands on forecasted summer peak demand are provided for DTE Electric's service area and DTE Electric's bundled sales levels and can be found on Exhibit A-15, Schedule E2, pages 1 and 2.

Q45. What is the CAGR of the DTE Electric service area system peak demand from 2022 over the forecast period to 2028?

A45. As shown in Exhibit A-15, Schedule E2, page 1 of 2, DTE Electric's temperature normalized service area peak demand declines from 10,959 MW in 2022 to 10,905 MW in 2028, representing a CAGR of -0.1%. The decline in peak demand is mainly due to a decline in residential air-conditioning electricity sales, which is projected to decline 1.6% on average annually, due to increased efficiency.

Q46. What is the CAGR of the DTE Electric bundled peak demand from 2022 over the forecast period to 2028?

A46. DTE Electric’s bundled peak demand forecast declines from 10,207 MW in 2022 to 10,151 MW in 2028, representing a CAGR of -0.1%. The bundled peak demand forecast from 2023 to 2028 is shown in Exhibit A-15, Schedule E2, page 2 of 2.

Part IV: Electric Load Forecast Accuracy

Q47. How are DTE Electric’s sales forecast and methodologies validated?

A47. DTE Electric's service area sales forecast is tracked annually, and the Company continuously checks the accuracy of the sales forecast models. For example, as shown in Exhibit A-15, Schedule E5, page 1, the DTE Electric total service area forecast in 2022 was 45,306 GWh (line 13). Total weather-normalized service area sales (adjusted for normal weather assumed in that year) in 2022 were 45,081 GWh (line 6). This represents a 99.5% accuracy for the 2022 total sales forecast. On average, for historical years 2018 through 2022, the absolute percent variance for the total sales forecast is 1.87% using the Company’s forecasting methods, as shown in Exhibit A-15, Schedule E5, page 1.

Q48. Which Company forecast was used for the accuracy measures used in Exhibit A15, Schedule E5? Why?

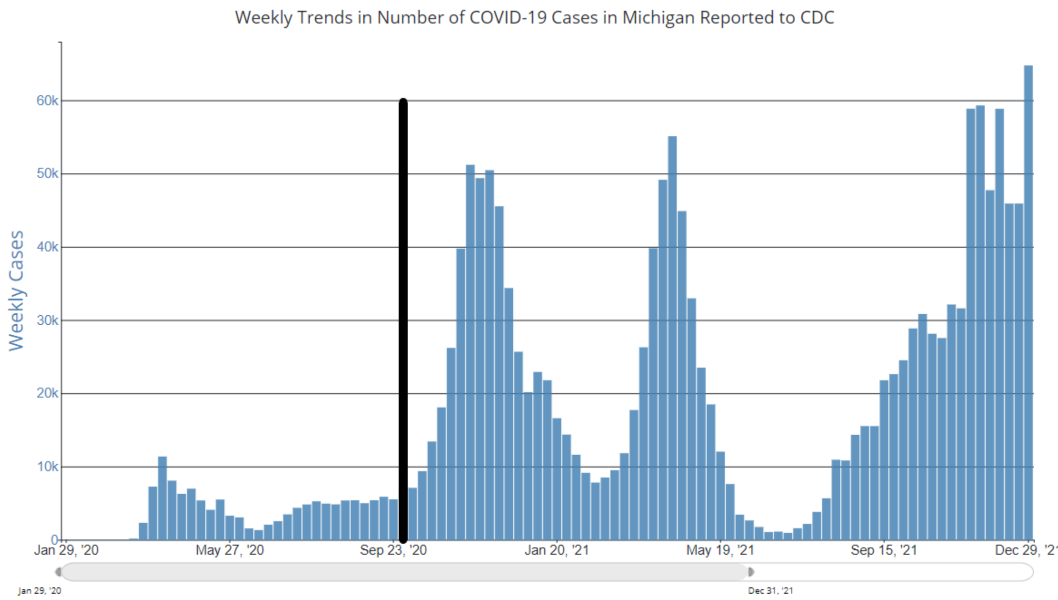
A48. The Company uses the last forecast produced in a given calendar year as the basis for the accuracy measurement shown in Exhibit A-15, Schedule E5. For example, the Company typically produces a forecast in Q4 of any given calendar year for the next calendar year sales. This forecast was chosen as the basis for accuracy to most closely resemble the forecasts submitted by peer utilities in the ITRON Benchmarking analysis referenced in Q51.

Line No.

Q49. Can you explain the deviation in accuracy experienced in 2020 and 2021, as shown in Exhibit A-15, Schedule E5, page 1?

A49. The forecast for 2020 was completed in 2019, before the COVID-19 pandemic began to impact the United States. In March 2020, the spread of COVID-19 caused a shift in electricity consumption throughout DTE Electric's service territory. Commercial and industrial sales fell due to business closures from government mandates while residential sales increased as a result of work from home policies enacted to mitigate the spread of COVID-19. As seen in Figure 6, mid-way through 2020, case counts of COVID-19 began to stabilize which led to business activity attempting to gradually resume pre-pandemic operations. While still uncertain, it appeared that the effects of COVID-19 likely began to subside through the rest of 2020 and into 2021. The forecast for 2021 was completed in the third quarter of 2020, marked in black in Figure 6, just prior to the rise in cases caused by the emergence of the Delta variant. The sharp spike in cases experienced in the fourth quarter of 2020, as well as the subsequent waves experienced in 2021 caused more business closures, as well as continued work from home policies, ultimately creating sustained sales variances through 2021. This was contrary to what the trends in the data suggested at the time that the 2021 forecast was completed.

Figure 6 : Michigan COVID-19 Case Counts 2020 & 2021



Q50. How has the Company's forecast accuracy performed in the periods following the COVID-19 pandemic?

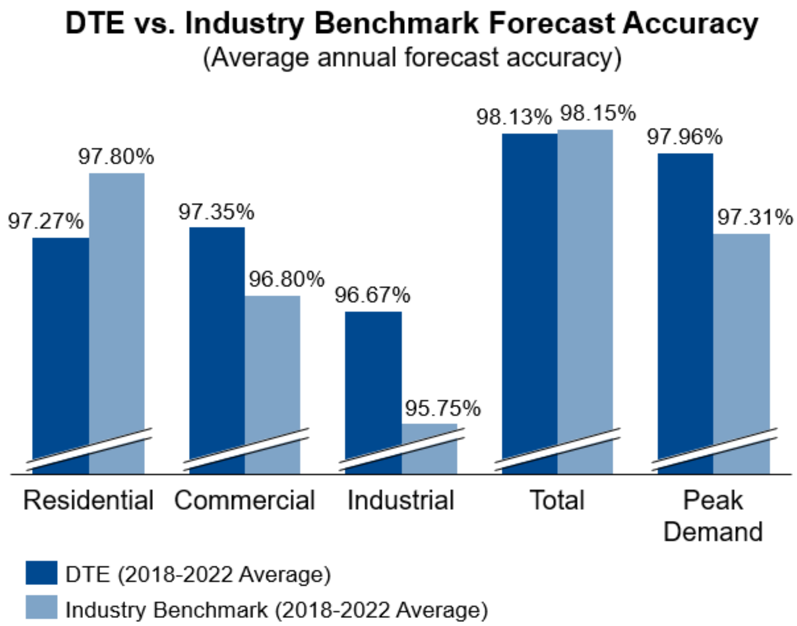
A50. As seen on Exhibit A-15, Schedule E5, page 1 of 2, Line 20 and 22, the Company achieved an absolute percent variance of 0.50% in 2022 (99.5% accurate) and is on track to achieve 0.76% in 2023 (99.2% accurate) which is based off 10 months of historical data. When excluding 2020 and 2021 data from the historical averages, the Company's average absolute percent variance for years 2018, 2019, 2022, and 2023 is 0.94%, representing 99.1% accuracy. The results for 2022 and 2023 are in-line or better than the pre-pandemic results achieved in 2018 and 2019.

Q51. Does the Company perform any benchmarking on forecast accuracy?

A51. Yes. The Company conducts benchmarking activity by researching forecast accuracy studies. A study, conducted by ITRON in 2023 is shown in Exhibit A-

15, Schedule E5, page 2. DTE Electric is on par with peer utilities across the nation in forecasting by customer class and peak demand, as shown in Figure 7 below.

Figure 7 : DTE Electric vs. ITRON Forecast Accuracy Benchmark



Q52. Does this complete your direct testimony?

A52. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

HABEEB J. MAROUN

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF HABEEB J. MAROUN

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Habeeb J. Maroun (he/him/his). My business address is One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC (DTE Energy or DTE) as a Regulatory Strategy Consultant in the Revenue Requirements Department of the Regulatory Affairs Organization.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Mechanical Engineering from the University of Michigan in 2001, a Master's in Finance from Walsh College in 2009, and a Master's in Business Administration from the University of Michigan in 2015.

Q4. Have you completed any seminars or other training courses?

A4. Yes. I attended utility financing and ratemaking coursework taught by Excidian, LLC. I completed cost of service and utility pricing courses taught by EUCI. I also completed the Ratemaking program at the Institute of Public Utilities at Michigan State University.

Q5. What is your work experience?

A5. From 2002 to 2004, I was employed by Lear Corporation and participated in their engineering rotational program. After program completion, I accepted a position in product engineering where I managed several vehicle programs. In 2005, I left

Lear to pursue a role as an independent consultant managing procurement for an international glass distributor. In 2009, I assumed additional responsibilities leading the client's expansion from distribution to fabrication. In 2015, I concluded this work to finish my MBA and begin a summer internship with DTE Energy in their Corporate Development group. In this role, I developed revenue requirement models and scenarios. I joined DTE Energy full-time in 2016 as a Senior Strategist within DTE Electric, including roles within the Business Planning and Development and Fossil Generation organizations, where I performed financial analysis, strategic planning, and provided rate case support. In 2019, I accepted a position in Regulatory Affairs as a Principal Financial Analyst in their Revenue Requirement group and was promoted to Regulatory Strategy Consultant in 2022.

Q6. What are your current duties and responsibilities?

A6. As a Regulatory Strategy Consultant for Revenue Requirements within DTE Energy's Regulatory Affairs organization, my responsibilities include the preparation of revenue requirements, cost of service and rate design studies for regulatory filings, along with regulatory analysis and research.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes, I have. I have sponsored testimony in the following MPSC cases:

U-20484	DTE Electric's 2018 Renewable Energy Plan Reconciliation
U-20642	DTE Gas's 2019 Rate Case
U-20837	DTE Electric's 2020 Revised AMI Opt-Out Program
U-20940	DTE Gas's 2021 Rate Case

U-20836	DTE Electric 2022 Rate Case
U-21322	DTE Electric & DTE Gas 2024-2025 EWR Plan
U-21297	DTE Electric 2023 Rate Case

<u>Purpose of Testimony</u>

Q8. What is the purpose of your testimony in this proceeding?

A8. The purpose of my testimony is to present Unbundled Cost of Service (UCOS) Studies for DTE Electric's projected test year ending December 31, 2025. I also provide an Alternate Cost of Service Study with DC Fast Charging (Alternate COSS with DCFC) as a separate class, as required by the Commission in their order on December 1, 2023 in Case No. U-21297. Finally, I support revenue requirement calculations for: (1) customer-related costs, (2) capacity charge by customer class, and (3) Infrastructure Recovery Mechanism (IRM) by voltage class.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-16	F1.1	UCOS, Production by Customer Class, TME December 31, 2025
A-16	F1.2	UCOS, Distribution by Voltage Class, TME December 31, 2025
A-16	F1.3	Functionalization and Allocation Overview
A-16	F1.4	Customer Charges by Voltage Class

A-16	F1.5	Capacity Charge Revenue Requirement by Customer Class
A-16	F1.6	*Alternate COSS with EV DCFC*, Production by Customer Class, TME December 31, 2025
A-16	F1.7	*Alternate COSS with EV DCFC*, Distribution by Voltage Class, TME December 31, 2025
A-16	F1.8	*Alternate COSS with EV DCFC*, Capacity Charge Revenue Requirement by Customer Class
A-33	X6	IRM Distribution Operations - Revenue Requirement by Voltage Class

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. Can you provide an overview of your testimony and recommendations in this proceeding?

A11. Below is a summary of my testimony and recommendations:

Table 1. Summary of Allocation Methodologies in UCOS

Cost Type	Proposed Method
Production Plant	4CP 75-0-25
Transmission O&M	12CP 100-0-0
Fuel	12CP 10-0-90
Distribution	Various (by voltage class)
Customer-related	Various; uncollectibles by total revenue

- I performed forecast test year UCOS studies that apply the allocation methodologies summarized in Table 1, where CP = Coincident Peak, 12 represents an average of twelve months and 4 represents an average of the four summer months, June through September;

- The proposed allocation methods for production plant, transmission O&M, fuel and distribution reflect the methods approved in Case No. U-21297;
- The proposed allocation of customer-related cost is consistent with past practice. Uncollectibles are allocated to classes based on total revenue;
- Customer-related distribution costs are calculated using the "Staff" method as approved by the Commission in Case No. U-21297;
- Allocation methods for electric vehicle program costs and demand-related distribution plant-related costs for the secondary voltage level are the same as those approved by the Commission in their order in Case No. U-21297;
- Capacity related Power Supply Costs are calculated by reducing total Production Cost of Service for fuel costs, variable O&M, Midwest Energy Resource Company (MERC) and non-capacity power supply costs as approved by the Commission in their order in Case No. U-21297.

Q12. How is your testimony organized?

A12. My testimony consists of the following six parts:

Part I – Forecast Unbundled Cost of Service Studies

Part II – Cost Allocation Methods

Part III – Customer Charge Costs

Part IV – Capacity Charge Revenue Requirement and SRM Capacity Charge

Part V – IRM Distribution Revenue Requirement by Voltage Class

Part VI – Alternate Cost of Service Study with DCFC Class

<u>**Part I: Forecast Unbundled Cost of Service Studies**</u>

Q13. What is a fully allocated embedded UCOS?

A13. A UCOS allocates all items of utility property and cost to determine the fully allocated embedded cost of service for each consolidated customer class of service and shows each customer class's share of costs by major function (Power Supply and Distribution).

Q14. What is the objective of a UCOS?

A14. The objective of a UCOS is to apportion all costs required to serve customers among each customer class in a fair and equitable manner. This is defined as that allocation of costs which best reflects the engineering and operating characteristics of the electric utility system and generally results in the costs of the system being allocated to those who caused the costs to be incurred.

Q15. What process steps are typically performed in developing a UCOS?

A15. The typical process to develop a UCOS consists of three steps: functionalization, classification, and allocation. Functionalization assigns all costs to the major functions, i.e., Power Supply and Distribution. Classification divides these costs into customer-related costs, demand-related costs, and energy-related costs. The sum of these three types of costs within a given class is the cost to serve that class. The last step, allocation, apportions the cost classifications to the respective customer classes based upon each class's responsibility for the incurrence of these costs.

Q16. What functions did you use in the cost studies?

A16. The major utility functions used in the cost studies are Power Supply (Generation and Transmission) and Distribution. Power Supply includes costs associated with the Company's generating plants, fuel, purchased power and the expense associated with transmission services provided to DTE Electric by the Midcontinent Independent System Operator (MISO) and the International Transmission Company (ITC). Distribution includes the costs associated with the Company's distribution system that generally operates at voltages of 40 kV and below and includes customer service costs.

Q17. How does the UCOS functionalize DTE Electric's costs?

A17. On Exhibit A-16, Schedule F1.3 page 1 titled "Functionalization and Allocation Overview", I present an overview of the approach I used to functionalize the Company's costs. The MPSC Uniform System of Accounts (USofA) governs utility accounting for ratemaking purposes and serves as the basis for functionalizing direct costs. For example, the USofA requires utilities to record generating plant costs in accounts 310 through 359 and the associated operation and maintenance (O&M) expense in accounts 500 through 557. These costs are directly assigned to the power supply function. Similarly, the USofA requires utilities to record distribution plant costs in accounts 360 through 373 and O&M costs in accounts 580 through 598 that are directly assigned to the distribution function.

The O&M cost in accounts associated with providing customer service are directly assigned to distribution because they apply whether a customer receives power supply from DTE Electric or an alternative electric supplier (AES). Because DTE

Electric has divested its transmission plant, all that remains in the USofA's accounts designated for transmission are the plant costs associated with generator step-up transformers. These costs are directly assigned to power supply. In addition, power supply includes the expense charged to account 565, "Transmission of Electricity by Others" including MISO charges. The property tax associated with production plant is directly assigned to power supply based on tax information provided by the Company's Property Tax Department. A share of the property tax associated with general and intangible plant is allocated to power supply in proportion to the power supply-related general and intangible plant and the remaining balance is assigned to distribution. Indirect costs are comprised of general and intangible plant costs recorded in accounts 303 and 389 through 399, Administrative and General (A&G) expense in accounts 920 through 935, taxes, and working capital. The cost study also includes a credit for miscellaneous revenue, which is applied to the appropriate functional component based on a combination of direct assignment and allocation.

Q18. How did the Company functionalize General and Intangible (G&I) plant in the Forecast UCOS?

A18. The Forecast UCOS relies on the G&I direct assignment study utilized in Case No. U-21297.

Q19. How are the remaining indirect costs and miscellaneous revenues functionalized in the Forecast UCOS?

A19. A&G expense is functionalized using the direct labor cost. Working capital is functionalized using allocators appropriate to each of the asset and liability line items. For example, fuel inventory is directly assigned to power supply and

Line No.

accounts receivable is functionalized based on net plant. Miscellaneous revenue is functionalized using a combination of direct assignment and allocation.

Q20. What is shown on pages 2 to 28 of Exhibit A-16, Schedule F1.3?

A20. Pages 2 through 28 of Schedule F1.3, "Functionalization and Allocation Overview" provide a detailed list of the functionalization factors and allocation methodologies used in the development of the UCOS study. The column titled "Func. Factor" identifies the functionalization method applied to the cost or revenue on that specific line. The "Prod Alloc" and "Dist Alloc" columns identify the allocation number being applied, and the "Prod Alloc Description" and "Dist Alloc Description" columns shows a brief description of the allocation method.

Q21. How does the Forecast UCOS allocate costs to the various customer classes?

A21. In general, the allocation schedules used for each function are intended to reflect the load that utilizes the infrastructure associated with that function.

Q22. What method was used to allocate production plant-related costs and transmission O&M costs in the Forecast UCOS?

A22. The Forecast UCOS used the 4CP 75-0-25 method of cost allocation for production plant-related costs and 12CP 100-0-0 for transmission O&M costs, which are the same as approved in Case No. U-21297. For plant-related costs, the first component is the average of the 4 monthly coincident peaks weighted 75%, the second component is energy use coincident to the MISO on-peak period weighted 0%, and the third component is total energy use weighted 25%, i.e., 4CP 75-0-25. For transmission O&M, the first component is the average of the 12 monthly coincident peaks weighted 100%, the second component is energy use coincident to the MISO on-peak period weighted 0%, and the third component is total energy use weighted 0%, i.e., 12CP 100-0-0.

Q23. Does the UCOS develop costs for each individual rate schedule?

A23. No, it does not. The allocation process apportions costs to classes of service that are comprised of one or more individual rate schedules.

Q24. How are the allocation schedules used in the UCOS developed?

A24. The allocation schedules in the UCOS are either developed external to the UCOS model or internally generated by the UCOS model. The externally developed allocation schedules are based on customer class parameters, such as the number of customers, customer energy use and customer demand, and serve as inputs to the UCOS. The internally generated allocation schedules are calculated within the UCOS model and are based on previously allocated plant investment and/or O&M expense. An example of an internal allocation schedule is schedule 521, "Distribution Plant-In-Service." This schedule reflects the sum of the class allocations of distribution plant in service from each USofA account, some of which are further subdivided by voltage level.

Q25. What is the source for the externally developed allocation schedules used in the UCOS?

A25. The UCOS contains 16 basic externally developed allocation schedules. Of these 16 schedules, 11 are developed and supplied by Company Witness Willis and are described in his testimony. I develop the other five schedules: 1) Schedule 800 is based on the number of customers in each class using data from the Company's billing system, 2) Schedules 370T and 370A are based on the number of meters (traditional and advanced metering infrastructure (AMI), respectively) associated with each class and the approximate average cost of the metering equipment associated with each class, 3) Schedule 370C is used to allocate meter related costs; this is a combination of Schedules 370T and 370A, and 4) Schedule 402, total revenues by class, is an aggregate of the production and distribution present revenues (allocators 400 and 401), which I use to allocate uncollectible expense.

Q26. How are Distribution System costs allocated within the UCOS?

A26. The direct distribution costs are allocated based on Schedules 201 - 205. The plant-related costs are allocated on the schedule appropriate to the voltage level at which the equipment operates. Distribution O&M expense is allocated based on the corresponding plant-related cost. For example, overhead lines maintenance expense (account 593) is allocated based on the sum of plant-in-service for poles and fixtures (account 364A), overhead conductors (account 365A), and overhead services (account 369A). The cost of some components within distribution, such as those associated with single customer substations and street-lighting, are directly assigned to the voltage cost of service class.

Q27. How are the indirect costs allocated within the UCOS?

A27. As stated in my discussion of functionalization, indirect costs are comprised of general and software plant costs recorded in accounts 303 and 389 through 399, A&G expense in accounts 920 through 935, taxes, and working capital. The functionalized general and software plant costs are allocated based on the corresponding functional plant in service. In other words, the general and software plant costs associated with power supply are allocated based on production plant in service and the general and software costs associated with distribution are allocated based on distribution plant in service. Property taxes are allocated based on the corresponding functional plant in service. The functionalized A&G and payroll taxes are allocated based on the corresponding functional labor ratios. The working capital allocations are driven by the numerous allocators associated with each of the line items that comprise working capital, many of which are the sum of several other lines.

Q28. What forecast test year was used for the Forecast UCOS?

A28. The forecast test year is the 12 months ending December 31, 2025.

Q29. What is the source of the financial information used to produce the Forecast UCOS?

A29. I used the financial information supplied by Company Witness Uzenski.

Q30. Do the levels of historic investment for each of the distribution accounts within the Cost of Service match the figures as they are typically presented in the Company's financial records and Form P-521?

A30. Not entirely. Although the total distribution investment matches the Company's financial records, the levels of investment for some distribution accounts within the Cost of Service do not match. These accounts do not match because I break out separately the cost of equipment that operates at sub-transmission voltage (24/40 kV) and apply allocation methods that reflect the engineering and operating characteristics of the associated equipment and expense. This redistribution of investment to the accounts in which it was classified prior to the Company's reclassification of 24/40 kV from 350 series accounts (Transmission) to 360 accounts (Distribution) is necessary to properly allocate the associated costs. A reclassification for accounting purposes does not change the engineering and operating characteristics of the associated equipment and expense.

Q31. Why did the Company reclassify the 24/40 kV investment in the first place?

A31. This reclassification was the result of the Order in MPSC Case No. U-11337 and was pursued to comply with FERC Order 888.

Q32. What does Exhibit A-16, Schedule F1.1 show?

A32. Schedule F1.1, "Unbundled Cost of Service, Production by Customer Class TME December 31, 2025" summarizes the results of the Year Ended December 31, 2025, UCOS for Production. It shows the production related revenue deficiency/(sufficiency) associated with each consolidated cost of service rate class. This exhibit shows the Company experienced a base production revenue deficiency of $148.7 million as shown on page 1, line 27, col. (a) of Schedule F1.1. This deficiency includes an additional $137.5 million revenue deficiency related to the Monroe Regulatory Asset. The revenue deficiency related to the Monroe Regulatory Asset is calculated by Company Witness Vangilder and is reflected on line 10 of Exhibit A-11, Schedule A1. I functionalized the Monroe Regulatory Asset revenue deficiency as production because it consists of production plant costs and allocated it to various customer classes utilizing the same allocator used to allocate production plant costs (4CP 75-0-25).

Line No.

Q33. Can you explain the Rider 10 Tax Gross-Up Adjustment on line 29 of Exhibit A-16, Schedule F1.1?

A33. The Rider 10 (R10) tax gross-up adjustment on line 29 of Exhibit A-16, Schedule F1.1 is a calculation that was approved by the Commission on page 298 of the Case No. U-21297 order. While the net impact of this adjustment to total production revenue requirement is zero, it is a necessary step to eliminate the R10 administrative charge, as required by the Commission on page 431 of their order in Case No. U-20836. The methodology proposed in the instant case is consistent with the calculation utilized in the rates approved by the Commission in their order in Case No. U-21297.

Q34. What does Exhibit A-16, Schedule F1.2 show?

A34. Schedule F1.2, "Unbundled Cost of Service, Distribution by Voltage Class TME December 31, 2025" summarizes the results of the year ending December 31, 2025, UCOS for Distribution. It shows the distribution related revenue deficiency/(sufficiency) associated with each cost of service voltage class. This exhibit shows the Company experienced a base distribution revenue deficiency of $307.7 million as shown on page 1, line 27, col. (a) of Schedule F1.2. This deficiency includes an additional $18.8 million revenue deficiency related to the Tree Trim Surge. The revenue deficiency related to the Tree Trim Surge is calculated by Company Witness Vangilder and is reflected on line 9 of Exhibit A-11, Schedule A1. I functionalized the Tree Trim Surge as distribution because it consists of costs included in O&M account 593 (Maintenance of Overhead Lines) and allocated it to various voltage classes using the same allocator used to allocate account 593.

Q35. What are the results shown on Exhibit A-16, Schedules F1.1 and F1.2?

A35. The sum of the base revenue deficiencies on line 27 of Schedules F1.1 and F1.2 equals $456.4 million, which matches the total revenue deficiency on Exhibit A-11, Schedule A-1, supported by Company Witness Vangilder. The base revenue deficiency is then adjusted by D13 incremental revenues totaling -$0.219 million as shown on line 28 of each exhibit (-$0.278 million F1.1 + $0.059 million F1.2). to arrive at the total revenue deficiency/(sufficiency) for ratemaking purposes on line 30 and total base revenue requirement on line 31. Lines 30 and 31 of Schedule F1.1 and Schedule F1.2 are used by Company Witnesses Willis and Bellini to calculate rates.

Q36. How are revenues from the D13 high-load factor class apportioned to classes?

A36. I used the same allocation methods initially approved by the Commission in their December 20, 2022 order in Case No. U-21163 (which established D13) and also utilized in the rates approved by the Commission in their order in Case No. U-21297.

Production and distribution present revenues recovered from D13 are allocated to existing cost of service classes based on production billed revenue excluding R10 (allocator 400a) and distribution billed revenue (allocator 401) respectively; this is shown on line 3 of Exhibit A-16, Schedules F1.1 and F1.2.

Incremental production and distribution revenues, which equal the difference between proposed and present D13 revenues, are allocated to existing cost of service classes on line 28 of Exhibit A-16, Schedules F1.1 and F1.2 using the same allocation methods as used to allocate D13 present revenues.

Part II: Cost Allocation Methods

Q37. Are the cost allocation methods used to produce the forecast UCOS consistent with the ones approved by the Commission in Case No. U-21297?

A37. Yes.

Q38. What allocation methods did you use for the forecast UCOS in this proceeding?

A38. I performed UCOS Studies for the forecast test year based on the proposed allocation methods summarized in Table 2. These allocation methods are the same as those approved in Case No. U-21297:

Table 2. Summary of Allocation Methodologies in UCOS

Cost Type	Proposed Method
Production Plant	4CP 75-0-25
Transmission O&M	12CP 100-0-0
Fuel	12CP 10-0-90
Distribution	Various (by voltage class)
Customer-related	Various; uncollectibles by total revenue

Q39. What allocation method are you proposing for Production Plant?

A39. I propose to continue using the 4CP 75-0-25 method approved in the Commission's December 1, 2023 order in Case No. U-21297. Further, this method has been approved in the Company's last seven electric rate cases (U-17767, U-18014, U-

18255, U-20162, U-20561, U-20836, and U-21297). The Company is not proposing a deviation from the previously approved production plant allocation at this time.

Q40. What allocation method are you proposing for Transmission O&M?

A40. The transmission system that serves DTE Electric's service territory is owned by ITC. DTE Electric's share of the cost of providing transmission service to its customers is determined based upon a 12CP load ratio share. Therefore, an allocation basis that relies on the 12CP 100% demand is reflective of cost causation and was utilized in the final rates approved in the Commission's order in Case No. U-21297.

Q41. What allocation methodology changes did the Commission adopt in their order in Case No. U-21297?

A41. In Case No. U-21297, the Commission adopted in their order the following allocation methodology changes:

- <u>EV Program Costs (order, pg. 295)</u>: functionalized and allocated using present revenues (allocators 400a and 401)
- <u>Demand-Related Distribution Plant-Related Costs (order, pg. 300)</u>: allocated based on non-coincident peak (NCP) demands (allocator 205)
- <u>Rider 10 Tax Gross-Up Adjustment (order, pg. 297)</u>: allocated using production present revenues excluding R10 (allocator 400a)

Q42. Did you use the same allocation methodologies in the instant case?

A42. Yes.

Q43. What is DTE Electric's allocation methodology for distribution?

A43. The Company uses three allocation bases for distribution: demand, customer, and those based on special studies. Demand based allocators are used for poles, wires, conduit, substations, transformers, and other equipment that comprise the distribution system. Customer based allocators are used for service drops and billing. A special study was utilized to develop the basis for allocating meters. The proposed allocation method selected for distribution allocates distribution by voltage class. Specifically, distribution is broken into residential secondary, commercial secondary, primary, sub-transmission, transmission, and lighting (E-1 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals). Distribution allocation methods in the instant case are consistent with those approved by the Commission in their December 1, 2023 order in Case No. U-21297.

Q44. Why is lighting maintained as a separate class as opposed to being grouped by voltage?

A44. Unlike the distribution service for other classes, the lighting class has a significant amount of dedicated infrastructure costs that should be directly assigned.

Q45. What determines cost causation for distribution?

A45. For distribution, the parameters used to design and build the system determine cost causation. The principal system design parameters are the geographic area to be covered and the maximum demand placed on the system at a given voltage level. Because rebuilding a circuit is expensive, distribution planning must consider future load growth and reliability. Also, many of the components of the distribution system are standardized to achieve efficiencies. Consequently, circuits initially have extra capacity, but once demand reaches a certain threshold, either the circuit configuration must be changed, or the components replaced with components having greater capacity. To meet reliability criteria, distribution planning engineers sometimes add alternate lines and transformers. This redundancy maximizes, to the degree practical, the Company's ability to maintain service in the face of storms and other outage related events. Because of the need to consider future growth, reliability, and standardized components, the capacity of the system will generally support loads greater than those initially experienced. Therefore, once installed, distribution system costs are generally not affected by increases or decreases in either demand or energy until the circuit limit (demand threshold) is approached. However, when viewed prospectively, distribution system design cost is caused (driven) by the number of customers served and the maximum demand placed on the system at a given voltage level.

Q46. How did you produce the UCOS by voltage level?

A46. I used the allocation schedules and distribution revenues by voltage for customers served at voltage levels primary and above developed by Witness Willis. In addition, I performed calculations to break out the UCOS inputs that I prepare by voltage level. I used these inputs to produce the proposed UCOS that allocates and displays costs by voltage level.

Q47. How are you proposing to allocate costs associated with uncollectible expense?

A47. The costs associated with uncollectible expense are allocated based on total revenues, as previously discussed. This allocation method is consistent with the methodology utilized in the final rates approved by the Commission in their December 1, 2023 order in Case No. U-21297.

Q48. How are you proposing to allocate merchant fees within Account 903?

A48. Consistent with the Company's last rate case, Case No. U-21297, residential merchant fees are directly assigned to the residential secondary class and commercial merchant fees are directly assigned to the commercial secondary class in the Company's UCOS. This methodology ensures that no cross subsidization occurs across cost-of-service rate classes related to merchant fees.

<u>Part III: Customer Charge Costs</u>

Q49. What type of costs are included within distribution?

A49. The Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners (NARUC Manual) classifies both distribution plant and expenses as being either demand-related, customer-related, or a combination of the two (Electric Utility Cost Allocation Manual, NARUC, January 1992). Chapter 6 of the NARUC Manual titled "Classification and Allocation of Distribution Plant" includes Table 6-1 "Classification of Distribution Plant" and Table 6-2 "Classification of Distribution Expenses". Within both tables and Chapter 6, the only cost classification types identified are demand and customer; energy is not listed as a basis for classifying any portion of distribution-related cost. The only energy-related costs identified are production-related.

Q50. Can you describe Exhibit A-16, Schedule F1.4 "Customer Charges by Voltage Class"?

A50. Exhibit A-16, Schedule F1.4 is a one-page exhibit that calculates monthly customer charges for each voltage level, using the "Staff" method approved in the Commission's December 1, 2023 order in Case No. U-21297. These costs are detailed on Exhibit A-16, Schedule F1.4.

Q51. How did you determine which costs to include on Exhibit A-16, Schedule F1.4 "Customer Charges by Voltage Class"?

A51. I included the same cost items reflected on Staff Exhibit S-6, Schedule F1.4, from Case No. U-21297 supported by Staff Witness Pung. I have reflected all the same line items as Staff Exhibit S-6, Schedule F1.4 from Case No. U-21297, with updated numbers from the proposed UCOS for distribution reflected in the instant case.

<u>Part IV: Capacity Charge Revenue Requirement and SRM Capacity Charge</u>

Q52. What costs have you included in your calculation of capacity revenue requirement reflected on Exhibit A-16, Schedule F1.5?

A52. The capacity revenue requirement includes all Production related costs per Exhibit A-16, Schedule F1.1, except fuel, variable O&M, MERC, and certain purchase power costs explained later in my testimony. This is consistent with the methodology approved in the Order in the Company's last electric rate case, Case No. U-21297.

Line No.

Q53. Can you describe in more detail the costs reflected on Exhibit A-16, Schedule F1.5?

A53. Line 1 of Exhibit A-16, Schedule F1.5 exactly matches line 31 from Exhibit A-16, Schedule F1.1 (UCOS Production). Line 2 is a reduction to the revenue requirement for fuel included in the Production UCOS. Line 3 is a reduction for MERC revenue requirement, which is calculated on line 9 of page 6 of the exhibit. Lines 4 and 5 are a reduction to the revenue requirement for non-capacity related purchased power. Line 6 is a reduction to the revenue requirement for variable O&M. Line 9 is a reduction in revenue requirement for projected energy sales revenue net of fuel-related costs, calculated by Company Witness Burgdorf on Exhibit A-26, Schedule P3. Line 11 is the total capacity charge revenue requirement that I supply to Witnesses Willis and Bellini.

Q54. How did you calculate MERC revenue requirement on line 3 of the exhibit?

A54. This calculation is consistent with the methodology utilized in the final SRM capacity charge approved by the Commission in their December 1, 2023 order in Case No. U-21297. This calculation can be found on page 6 of the exhibit. I calculated MERC net plant on lines 1 through 4. I then multiplied net plant by the weighted average cost of capital on line 5 to determine the return on net plant. Line 7 represents MERC depreciation expense, and line 8 represents MERC property tax. Lines 6 through 8 are summed to calculate the MERC revenue requirement on line 9.

Q55. Did you reduce the capacity charge revenue requirement for any non-capacity related purchased power?

A55. Yes. On lines 4 and 5 of Exhibit A-16 Schedule F1.5, I reduced the capacity charge revenue requirement for non-capacity related purchased power. The reason for this adjustment is that these costs are not capacity-related; rather, these purchase power costs are for energy purchased from MISO for Rider 3 and Rider 10 (line 4) and other energy related purchased power (line 5). For this reason, the $439.2 million purchased power expense identified on page 1 line 7 of Exhibit A-16, Schedule F1.1 is considered to be all capacity except for the $39.6 million directly assigned to Rider 10 and $0.8 million assigned to Rider 3 (which is included with D11) and $260.8 million of other energy-related costs. The $40.4 million of non-capacity cost is equal to the sum of the R10 MISO Pricing Option costs listed on line 21 of Exhibit A-13, Schedule C4 and Voltage Level Adder costs listed on line 22 of Exhibit A-13, Schedule C4, sponsored by Witness Willis. The $260.8 million of other energy-related purchased power is the difference between the capacity related purchased power costs of $138.1 million calculated by Witness Burgdorf on Exhibit A-26, Schedule P3, line 7 and the total remaining purchased power costs of $398.8 million ($439.2 million less $40.4 million directly assigned to D11 and Rider 10).

Q56. Did you make any other adjustments?

A56. Yes. I also adjusted for variable O&M on page 1 line 6 of Exhibit A-16, Schedule F1.5.

Q57. What costs did you include on line 6 of Exhibit A-16, Schedule F1.5 for variable O&M?

A57. I calculated variable O&M on Exhibit A-16, Schedule F1.5, page 5. I included the costs in Account 501 (Fuel Handling) and the non-labor portions of Accounts 502

(Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants and Water), 520 (Steam Expenses), 538 (Electric Maintenance Expenses) and 548 (Peaker Expenses).

Q58. Why did you only include the non-labor portion in variable O&M for accounts other than 501?

A58. The NARUC Manual describes the classification of production plant in Chapter 4. Chapter 4 describes those accounts 502, 505, 519 and 538 should be: Classified between demand and energy based on labor expenses and materials expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related. Therefore, I determined only the material related costs are variable, and that account 548 should be handled in the same manner. On page 35 in Chapter 4, the NARUC Manual states:

> *Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes, and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered, or purchased and are classified as energy-related.*

Q59. Why did you only include the above accounts in variable O&M?

A59. Based on my review of the descriptions of the various production O&M accounts, only the chosen accounts appear to be variable. The descriptions for these accounts include variable material costs such as lubricants, chemicals, and water.

Q60. How did you allocate the Capacity Charge revenue requirement to the various rate classes on Exhibit A-16 Schedule F1.5?

A60. I allocate the Capacity Charge revenue requirement to the various rate classes using the 200B (4CP) allocator excluding Rider 10, which is the methodology approved in Case No. U-21297. The values for this allocation schedule are listed on Line 20 of pages 1-4 of Exhibit A-16 Schedule F1.5. Line 23 of Schedule F1.5 reflects the amounts allocated to customer classes and is calculated by multiplying line 20 by the total Capacity Charge revenue requirement of $973.7 million on line 11, divided by 100. Line 24 is the Non-Capacity revenue requirement and is the difference between line 23 and the total production revenue requirement on line 25. Line 25, total production revenue requirement, is equal to line 31 of Exhibit A-16, Schedule F1.1.

Q61. Can you describe the SRM Capacity Charge calculation shown in the Exhibit?

A61. The SRM capacity charge calculation starts with the capacity revenue requirement on line 11, whose calculation was previously described in my testimony, and the capacity in MW from the Company's 2022 10-K filing shown on line 13. The SRM Capacity Charge per MW-Year is calculated on line 15 by dividing line 11 by line 13 and multiplying by 1,000. This SRM Capacity Charge per MW-Day on line 17 is then calculated by dividing line 15 by 365 days.

<u>Part V: IRM Revenue Requirement</u>

Q62. What is reflected on Exhibit A-33, Schedule X6?

A62. Exhibit A-33, Schedule X6, is a one-page exhibit that reflects the allocation of the distribution related IRM revenue requirement to the various voltage classes.

Q63. What adjustment to the allocation of IRM revenue requirement did the Commission require in their order in Case No. U-21297?

A63. The Commission stated on pg. 290 of their December 1, 2023 order in Case No. U-21297 that allocator 521 proposed by the Company to allocate IRM revenue requirement should be modified to "remove any allocation of IRM costs from transmission level customers."

Q64. Has the Company complied with this requirement in this proceeding?

A64. Yes.

Q65. What is shown on Lines 1 and 2 of Exhibit A-33, Schedule X6?

A65. Lines 1 and 2 of Schedule X6 shows the previously approved IRM revenue requirement by voltage class for 2024 and 2025. The amounts exactly match the IRM revenue requirement by voltage class for 2024 and 2025 utilized to calculate the IRM charges approved in the December 1, 2023 order in Case No. U-21297.

Q66. How did you allocate the proposed distribution related IRM revenue requirement to the various rate classes for 2026 and 2027 on Exhibit A-33, Schedules X6?

A66. I allocated the proposed distribution related IRM revenue requirement to the voltage classes for years 2026 and 2027 using allocation schedule 521T, a variant of allocator 521 which was modified to exclude transmission. Allocator 521 is calculated in the UCOS, described in Part I above, and is equal to each voltage classes' share of distribution related plant. The basis for using allocator 521T is because the components of the IRM revenue requirement are all plant or plant related. The value of the allocator is listed on line 3 of Schedule X6. Each voltage classes' share is calculated by multiplying the total proposed distribution related IRM revenue requirements listed on column (a), lines 4 (2026) and 5 (2027) on page 1 of Schedule X6 by the allocation percentages on line 3. The proposed IRM revenue requirements listed on column (a) of Schedule X6 are calculated on Exhibit A-33, Schedule X4 by Witness Vangilder.

Part VI: Alternate Cost of Service Study

Q67. Was an alternate cost of service study required as part of the order in Case No. U-21297?

A67. Yes. On pages 342 and 373 of the order, the Commission states "DTE Electric shall conduct a separate cost of service study to allocate appropriate costs fast charging and propose rates for this specific class of customer" to be submitted in the Company's next rate case.

Q68. How has DTE Electric addressed these order provisions?

A68. I am submitting an Alternate COSS with EV DC Fast Charging (Alternate COSS with EV DCFC) as a separate class, and Company Witness Willis will be calculating the proposed rates for this class.

Q69. What exhibits are you providing that summarize the results of the Alternate COSS?

Line No.

A69. The Alternate COSS exhibits with EV DCFC as a separate class are based on exhibits prepared for the Company's main unbundled cost of service study. The following list of exhibits are being provided:

1. Exhibit A-16, Schedule F1.6: Alternate COSS with EV DCFC, Production by Customer Class, TME December 31, 2025 (based on Exh A-16, Sch F1.1)
2. Exhibit A-16, Schedule F1.7: Alternate COSS with EV DCFC, Distribution by Voltage Class, TME December 31, 2025 (based on Exh A-16, Sch F1.2)
3. Exhibit A-16, Schedule F1.8: Alternate COSS with EV DCFC, Capacity Charge Revenue Requirement by Customer Class (based on Exh A-16, Sch F1.5)

Q70. How was the Alternate COSS with DCFC prepared?

A70. After the Company's main UCOS was completed, I created a duplicate version of the model and then modified it so that EV DCFC would be represented as a separate class. Next, I incorporated present revenues, sales, and customer counts based on information provided by Witness Willis. Finally, I updated the allocation schedules also provided by Witness Willis.

Q71. Does this complete your direct testimony?

A71. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DAVID C. MILO

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF DAVID C. MILO

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is David C. Milo (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric as a Fuel Resources Specialist in the Operations and Logistics group within the Fuel Supply department.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (Company or DTE Electric).

Q3. What is your educational background?

A3. I have a Bachelor of Arts Degree in Accounting and a Master of Business Administration Degree, in Finance, both from Michigan State University, East Lansing, Michigan.

Q4. Please summarize your professional experience.

A4. In 2004, I joined DTE Energy in the Property Tax department as a Senior Tax Advisor. In this capacity, I was responsible for property tax compliance for Michigan Consolidated Gas Company and various other subsidiaries of DTE Energy.

In 2008, I transferred to the Budget, Forecast and Reporting group as a Principal Analyst. In this capacity, my responsibility was to assist in the preparation of corporate budgets and forecasts and to prepare reports for management on various financial performance measures for DTE Energy.

In 2010, I transferred to the Asset Management group where I prepared reports on capital asset expenditures for DTE Energy. In November of that same year, I transferred to the Gross Margin group as the fuel accountant. In this capacity, my responsibilities were to prepare the accounting for the purchase and expense of all fuels used in the production of electricity for DTE Electric and preparation of internal and regulatory reports thereon.

In 2013, I transferred to the Fuel Supply department of DTE Electric as a Fuel Resources Specialist in the Planning and Procurement group. My responsibilities included preparation of the budget and forecasts regarding all fossil fuels (i.e., coal, natural gas & oil) used by DTE Electric for electric generation, preparing management reports on DTE Electric's fossil fuels, and assisting in various accounting activities.

Q5. What are your current duties and responsibilities?

A5. In 2016, I moved to the Operations and Logistics group of Fuel Supply where I currently manage the Company's railcar fleet. I am responsible for the procurement and maintenance of the Company's railcar fleet. My duties include ensuring an adequate number of railcars are under the Company's control to meet coal delivery needs and they are maintained to meet operational, safety and contractual standards. In that role, I work with Midwest Energy Resources Company (MERC) personnel and their operations to coordinate coal deliveries and movements of railcars.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following cases:

U-17097-R	2013 Power Supply Cost Recovery (PSCR) Reconciliation
U-17319	2014 PSCR Plan
U-17319-R	2014 PSCR Reconciliation
U-17680	2015 PSCR Plan
U-18014	2016 DTE Electric Rate Case
U-18255	2017 DTE Electric Rate Case
U-20162	2018 DTE Electric Rate Case
U-20561	2019 DTE Electric Rate Case
U-20836	2022 DTE Electric Rate Case
U-21297	2023 DTE Electric Rate Case

Line No.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to discuss and support the reasonableness and prudence of DTE Electric Fuel Supply's (Fuel Supply) and MERC's Fuel Handling actual $8.3 million of O&M expenses for the 12-month historic period ended December 31, 2022, and the projected $8.1 million O&M expenses for the 12-month projected test period ending December 31, 2025. I also discuss and support $2.2 million of capital expenditures for the historical test year ended December 31, 2022, the projected capital expenditures of $2.9 million from January 1, 2023, through the projected bridge period ending December 31, 2024, and the projected capital expenditures of $1.2 million for the 12-month projected test period ending December 31, 2025. I also address how the Company's transition from coal generated electricity, as explained in the Company Integrated Resource Plan Case No. U-21193, will affect MERC transshipment operations and the railcar fleet for the Company. Furthermore, I specifically address the planned retirement of operations at MERC as directed in the December 1, 2023, Commission Order in Case No. U-21297 (December 1 Order).

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.2	Projected Capital Expenditures – Midwest Energy Resources Company (MERC) & Fuel Supply
A-13	C5.2	Projected Operation and Maintenance Expenses – Fuel Supply & Midwest Energy Resources Company (MERC)

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

Q10. How is your testimony organized?

A10. My testimony consists of the following three (3) parts:

Part I	Overview of MERC and Fuel Supply
Part II	MERC and Fuel Supply Capital Investments
Part III	Fuel Supply and MERC Operations & Maintenance Expenses

Part I – Overview of MERC and Fuel Supply

Q11. What is MERC?

A11. MERC, a wholly owned subsidiary of DTE Electric, is a coal terminal which provides coal transportation and transshipment services to DTE Electric and other third-party utility and industrial customers through its Superior, Wisconsin terminal. MERC accepts coal deliveries by rail from the western United States and loads those coal deliveries onto Great Lakes freighters for delivery to power plants and other industrial facilities around the Great Lakes basin.

Q12. Why is MERC included in this rate case filing?

A12. As a wholly owned subsidiary of DTE Electric, MERC is fully consolidated into DTE Electric. The accounting and ratemaking treatment of MERC's revenues and costs are specified by MPSC Orders in Case No. U-5041[1] , dated September 17, 1976, and Case No. U-5108[2] , dated May 27, 1977.

Q13. What is MERC's role in coal transportation to the Company's two remaining operating coal-generation power plants?

A13. MERC is critical to the Belle River Power Plant (BRPP) as it is the only source of low-sulfur western (LSW) coal for the plant. MERC is also an important coal delivery option, supplying a significant portion of LSW coal to the Company's Monroe Power Plant (MPP). BRPP does not have a rail unloading system or direct-rail delivery capacity capable of supplying its coal consumption requirements and can only be supplied by lake vessel deliveries. There are no other facilities and/ or options for delivering the large coal quantities to BRPP, since other U.S. coal terminals cannot consistently accommodate the required lake vessel sizes. The continued utilization of MERC is the most economic method of delivering LSW coal to the BRPP, including and through the period of the plant's planned cessation of coal-fired operation as proposed in Case No. U-21193. Regarding MPP, MERC supplies a large amount of LSW coal to the plant. These deliveries through MERC

[1] https://adms.apps.lara.state.mi.us/Mpsc/ViewCommissionOrderDocument/16522, Order MPSC Case No. U-5041, accessed February 16, 2024.
[2] https://adms.apps.lara.state.mi.us/Mpsc/ViewCommissionOrderDocument/16595, Order MPSC Case No. U-5108, accessed February 16, 2024.

Line No.

are utilized to maintain reliable coal supply to MPP and are the most economical means to supplement rail deliveries to MPP.

Q14. What is the planned future of MERC?

A14. The planned future of MERC, in light of the Order in Case No. U-21193 approving a fuel conversion from coal to natural gas at BRPP, is to cease MERC transshipment operations at the end of June 2026. This timing coincides with the projected end of coal deliveries to BRPP. Given this planned retirement date for MERC, any spending will be designed to maintain safe and environmentally compliant operation but otherwise minimize investment. Financial resources and expenditures will be reviewed for reasonableness and prudence and limited to those that are determined to be necessary for coal deliveries to the two DTE Electric plants still burning coal through MERC's retirement date.

Q15. Can you describe the railcar fleet and its role in supplying fuel to the power plants that rely on coal for the generation of electricity.

A15. The Company, through its Fuel Supply department, currently controls a fleet of railcars to transport coal from the mines in Wyoming, Montana, and Pennsylvania to the Company's power plants. This fleet is critical to delivering the required large amounts of coal at the lowest reasonable cost. Each car has the capacity to hold approximately 120 tons of coal. The coal is moved from the mines to the Company's power plants in a group of 130 connected railcars (using couplers), commonly referred to as a unit train, and a railcar can travel over a hundred thousand miles in a single year. This method is standard across the utility industry and has been used for decades.

Q16. How does railcar fleet maintenance affect Company operations?

A16. It is important for ensuring railcar regulatory compliance and meeting the Company's coal delivery requirements to regularly maintain railcars. The railroad industry is highly regulated with governing agencies including the Surface Transportation Board (STB), Federal Railroad Administration (FRA) and American Association of Railroads (AAR) to ensure a safe system. Accordingly, the railroads have implemented a rigorous inspection protocol for the railcars operating on their railroad system. The inspections can unilaterally remove defective railcars from service due to the attendant operating risks, which would require the Company to procure an equivalent amount of railcars to meet its delivery requirements, likely at greater expense. The Company's capital program is designed to limit and/or avoid repairs to structural aspects of the railcar and other components, including the wheels and bearings, and the costs incurred for such repairs.

Q17. What is the planned future of the railcar fleet?

A17. The Company plans to move up the retirement date of the railcar fleet to 2032, consistent with the planned retirement of the two remaining coal fired units at MPP as explained in the Case No. U-21193 IRP case.

Part II – MERC and Fuel Supply Capital Investments

Q18. Can you explain the nature of MERC's capital expenditures and how declining coal delivery volumes affect the economics?

A18. The MERC capital expenditures are for the operation of the coal terminal that processes rail shipments of LSW coal for lake vessel delivery to DTE Electric's power generation plants in southern Michigan. MERC is a large industrial facility and has unavoidable fixed costs such as rail tracks and conveyor belts to move coal, and with high volumes can take advantage of economies of scale. The decline in the amount of coal being transshipped necessarily results in a higher dollar per ton cost metric compared to higher volume periods, as unavoidable fixed costs can't be lowered without risk to safe and reliable operations. The Company expects MERC to transship similar volumes in 2023 and 2024 compared to the amount in 2022, with a slight decrease in volume during the projected test period ending December 31, 2025. This decrease will result in lower total cost as discussed below.

Q19. How does the amount of MERC capital expenditures change from the historical year ended December 31, 2022 through the projected test period ending December 31, 2025?

A19. The amount of capital expenditures decreases almost 90% for MERC, from $1.2 million in 2022 to only $154 thousand in 2025. It should be noted that capital spending is significantly reduced each of the projected years of this general rate case. The reduction is about $300 thousand in 2023 for total spend of $926 thousand. The reduction for year ending December 2024 is roughly $600 thousand for a total spend of $290 thousand. The diminished amounts are a result of continued evaluation of spending, limiting expenditures to only critical items that could stop operations if not addressed, and considering the transition from coal generation addressed in the Case No. U-21193 IRP Order.

Q20. What does the capital program for the railcar fleet entail, what is the spending plan, and why is it important for the Company's customers?

A20. The capital program for the Company's railcar fleet addresses two key components of the railcars; the truck and the draft systems. The truck system is a chassis or framework-like structure underneath a railroad car to which wheel axles (and, hence, wheels) are attached through bearings. The draft system is an assembly behind the couplers at each end of the car to manage the compression and tension forces between the cars of the unit train. These railcar components are subject to significant physical forces, weighing about 21 tons unloaded and 141 tons loaded with coal, incur wear and tear over time and need to be replaced. The railcar industry recommendation is that the truck and draft assembly be rebuilt after 1 million miles of operations. The Company's capital program focuses on those cars with over 1 million miles of operation and allocates one million dollars per year to replacing components on these railcars. The program was implemented almost a decade ago and is expected to be completed in 2025. This program is important to our customers, since it is designed to limit and/or avoid repairs to structural aspects of the railcar and other components, including the wheels and bearings, and the costs incurred for such repairs. The program work accomplished proactively by the Company at private shops also lowers expenditures by avoiding costlier repairs performed at the railroad shops after inspection and directives from railroad personnel.

Line No.

Q21. How does the transition from coal-fired generation at BRPP and MPP affect the railcar capital investment program?

A21. As mentioned earlier, the capital investment program the Company implemented is scheduled to be completed at the end of 2025. The Company will use the railcars through the life of MPP, therefore it is reasonable and prudent to complete the capital program. It should be noted the program is focused only on the railcars that will still be required through the life of MPP. The Company expects to have no capital expenditures from 2026 - 2032 for the railcar fleet. The Company is confident of this end date because a "teardown" of a sample of railcars was performed at the end of 2023 to inspect components. Based on this independent assessment of the condition of the railcars, DTE Electric's capital program was determined to be effective and no more capital program spending should be required after 2025 to keep the fleet in safe operating order. The inspector's assessment indicated that the Company's railcar fleet was well maintained and, in his opinion, should have minimal issues continuing in service through 2032.

Q22. What does Exhibit A-12, Schedule B5.2 show?

A22. Exhibit A-12, Schedule B5.2 shows capital expenditures for MERC and Fuel Supply for the historical test period 2022, as well as forecasted capital expenditures for the 24-month projected bridge period (January 1, 2023 through December 31, 2024) and the 12-month projected test year ending December 31, 2025.

Q23. What is the rationale for MERC and Fuel Supply capital expenditures shown on Exhibit A-12, Schedule B5.2?

A23. All the expenditures described in Q24 – Q26,for the period of January 2022 through December 2025 are related to maintaining safety, meeting environmental requirements, operating reliably, and/or replacing end-of-life equipment. These expenditures are not avoidable and are reasonable and prudent and necessary for MERC's coal transshipment capabilities to BRPP and Fuel Supply railcar availability.

Q24. What are the capital expenditures for MERC and Fuel Supply for the historical test year 2022 included on Exhibit A-12, Schedule B5.2, column (b), lines 9 and 12, respectively?

A24. The total capital expenditures for both entities in 2022 were $2.2 million, as detailed on lines 2 through 8, and 11 of the Exhibit. The total MERC expenditures on line 9 of $1.2 million consists of $0.56 million for conveyor belting to replace damaged belting needed to keep coal moving through the facility from train unloading to vessel loading, $0.3 million for the D11 Caterpillar dozer needed to move and form coal piles at the facility and other heavy movements, $0.15 million for a 85' man lift in order to safely complete necessary work on elevated components at the facility, and $0.21 million for various capital projects that are each less than $100,000.

For Fuel Supply, as described earlier, there is a program to rebuild railcar trucks and draft system components. The railcar capital program extends the trucks and draft systems useful life and operability consistent with expected operations and mitigates future potential railcar repair costs. The costs for these railcar truck and draft system rebuilds during the January 2022 through December 2022 period were $1.0 million as shown on Exhibit A-12, Schedule B5.2, line 11, column (b).

Line No.

Q25. What are the projected capital expenditures for MERC and Fuel Supply for the 24 months from January 2023 through December 2024 as reflected on Exhibit A-12, Schedule B5.2, column (e)?

A25. The total capital expenditures for January 2023 through December 2024 are estimated to be $2.9 million in total, line 13 column (e). MERC total capital expenditures for this period are projected at $1.21 million, line 9 column (e) which is a $1.78 million and 59% reduction from Case No. U-21297. The Company has identified and removed avoidable expenditures since the Case U-21297 filing. MERC capital spend will focus on safety initiatives and replacement of equipment that becomes obsolete or fails and is necessary for continued operations. There are no plans to spend capital on items that are not critical to continued safe, environmentally compliant, and reliable operations consistent with MERC's planned retirement. As detailed on lines 2 through 8 of the Exhibit, the capital projects at MERC for the 24 months ending December 31, 2024 consist of $0.11 million for conveyor belting and associated structures to replace end-of-life equipment, $0.36 million for large mobile equipment components to replace engines and transmissions per manufacturers' recommendations, $0.12 million for facility roadways and railroad tracks for safe operations, $0.16 million for 750KVA & 1500KVA transformers to replace end-of-life equipment, and $0.46 million for capital projects that are less than $100,000 each to address based on historical operations and small emergent required capital projects related to maintaining reliable and safe operations.

As reflected on line 11 of the Exhibit, Fuel Supply continues the project to rebuild railcar trucks and draft system components on cars to extend the trucks' and draft

Line No.

systems' useful life and operability consistent with expected operations and to mitigate future potential railcar repair costs. Fuel Supply is projected to spend $1.7 million on this truck and draft system rebuilding project over the 24-month period January 2023 through December 2024.

Q26. What are the projected capital expenditures for MERC and Fuel Supply for the projected test period, January 1, 2025, through December 31, 2025, as reflected on Exhibit A-12, Schedule B5.2, column (f)?

A26. The total capital expenditures for January 1, 2025, through December 31, 2025, for both entities are estimated to total $1.2 million. MERC total capital expenditures for this period are projected at $0.15 million, as detailed on lines 2 through 8. Capital projects currently planned at MERC in the projected test period consist of $0.05 million for large mobile equipment components to replace engines and transmissions per manufacturers recommendations and $0.1 million for capital projects that are less than $100,000 each to address based on historical operations and small emergent required capital projects related to maintaining reliable, safe, and environmentally compliant operations.

As reflected on line 11 of the Exhibit, Fuel Supply completes the capital program to rebuild railcar truck and draft systems on railcars to extend their useful life and operability consistent with expected safety regulations, industry norms, reliability, and to mitigate future potential railcar repair costs and unsafe operations. Fuel Supply is projected to spend $1.0 million on this truck and draft system rebuilding project during the 12-months ending December 31, 2025. As described above, based on expected coal deliveries it is reasonable and prudent to continue the railcar

Line No.

capital program of $1 million per year through 2025 but the program will cease after that year.

The projected test year capital amount represents a significant reduction from the historical test year, with each projected year being lower than the prior year, as described in Q & A 19.

<u>Part III – Fuel Supply and MERC Operations and Maintenance Expenses</u>

Q27. Can you explain the nature of Fuel Supply and MERC operations and maintenance expenditures and how declining coal delivery volumes affect the economics of those operations?

A27. Fuel Supply's expenditures are primarily for the planning, procurement, and contract administration of the fossil fuel commodities including transportation to plants and the costs to maintain the Company's railcar fleet. The MERC expenditures are primarily for the operation of the coal terminal that processes rail shipments of western coal for lake vessel delivery to DTE Electric's power generation plants in southern Michigan.

The decline in the amount of coal being transshipped at MERC results in a higher dollar per ton cost compared to higher volume periods because the reduced fixed operational costs are not being reduced to the extent the tonnage is being lowered.

Q28. What does Exhibit A-13, Schedule C5.2, show?

A28. Exhibit A-13, Schedule C5.2, shows historical and projected operation and maintenance (O&M) expenses associated with the Fuel Supply department, on lines 1 through 7, and MERC Fuel Handling, on lines 8 through 15.

Line
No.

Q29. What were Fuel Supply and MERC's adjusted historical O&M expenses for 2022 as shown on Exhibit A-13, Schedule C5.2?

A29. Fuel Supply and MERC Fuel Handling adjusted historical O&M expenses for 2022 totaled $8.3 million as shown in column (f), line 16. This is comprised of $4.5 million for Fuel Supply in column (f), line 7, and $3.8 million for MERC Fuel Handling in column (f), line 15.

Fuel Supply O&M expenses include $0.6 million for operation supervision and engineering, $0.2 million for miscellaneous steam power expenses, $0.1 million for maintenance supervision and engineering, and $1.3 million for maintenance of miscellaneous steam plant in column (f), as well as a Fuel Handling Reclass to O&M of $2.2 million in column (d) for the Fuel Supply department's portion of Fuel Handling O&M expense recorded in Fuel Account 501.

MERC's Fuel Handling expenses charged to Fuel Account 501 are shown on lines 9 through 14, column (d), which reflect components of fuel handling costs that are reclassified to other expense categories on DTE Electric's adjusted historical financial statements, as explained by Witness Uzenski (see Exhibit A-3, Schedule C.16). Therefore, an adjustment is made in column (e) to remove these cost items from O&M. The remaining amount of $3.8 million in column (f), line 15 is the total MERC Fuel Handling expenses included in O&M.

Line
No.

Q30. What are Fuel Supply and MERC's Fuel Handling projected O&M expenses for the projected test period ending December 31, 2025, as shown on Exhibit A-13, Schedule C5.2?

A30. The total projected test period O&M expense is \$8.1 million, comprised of \$4.9 million for DTE Electric's Fuel Supply in column (l), line 7, and \$3.2 million for MERC's Fuel Handling in column (l), line 15. These amounts were based on the adjusted historical 2022 O&M expenses adjusted for inflation. The inflation adjustment factors of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025 are supported by Company Witness Ms. Uzenski.

Q31. Were any adjustments made to derive the January 1, 2025, through December 31, 2025 projected test period O&M expense ?

A31. Yes, there is an almost \$1 million dollar reduction of the expected O&M for MERC Fuel Handling represented in column (j) line 9. This 23% reduction of MERC's O&M expense, based on the as-adjusted historical test period plus 3 years of inflation (line 15), is a result of the expected savings and avoided costs from decreased transshipment activities (primarily reduced labor and supplies as coal volumes decrease). As with capital, the \$3.2 million of MERC fuel handling O&M represents the minimum expense required to operate the facility safely, reliably, and in an environmentally compliant manner, which helps ensure that critical coal deliveries are made to the Company's power plants.

Q32. What are your thoughts regarding the Company's MERC and Fuel Supply programs and expenditures?

Line
No.

A32. I believe that the Company's MERC and Fuel Supply programs and expenditures are reasonable and prudent and properly balance the circumstances involved in DTE Electric's transition from coal-fired generation. The Company has reasonably and prudently minimized its MERC and Fuel Supply expenditures to those necessary to maintain safe, reliable, and environmentally compliant operations consistent with its future generation plans.

Q33. Does this complete your direct testimony?

A33. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

PANKAJ SHARMA

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF PANKAJ SHARMA

Q1. What is your name, business address and by whom are you employed?

A1. My name is Pankaj Sharma (he/him/his). My business address is One Energy Plaza Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC (LLC), as Director – Information Officer within the Information Technology Services (ITS) organization.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I have a master's degree in Computer Application from University of Rajasthan, India. I have a Bachelor of Science in Mathematics from Agra University, India.

Q4. What work experience do you have?

A4. I have worked for DTE Energy or one of its regulated utilities for over 22 years in various Information Technology (IT) positions. I am currently the IT Director of Infrastructure Operations for DTE Energy, LLC as well as supporting the DTE Electric and the DTE Gas Companies. Prior to my current position, I was the Director – Information Protection & Security within the Information Technology Services (ITS) organization.

Q5. Do you hold any certifications or are you a member of any professional organizations?

Line No.

A5. I am a member of Project Management Institute (PMI) Org[1] since 2002 and have maintained a Project Management Professional (PMP) Certification[2] since 2005. I have been an active member of the Information Systems Audit and Control Association® (ISACA[3]) since 2019 and maintain ISACA's Certified Information Security Manager (CISM)[4] certification. In my professional career I have been certified in ITIL Foundation, a leading industry standard and global framework for IT service management and delivery. The ITIL framework offers a detailed set of practices for managing and delivering IT services.

Q6. What are your current duties and responsibilities?

A6. As the IT Director of Infrastructure Operations, I am responsible for all aspects of ITS Operational matters as well as being the infrastructure owner for all DTE Shared ITS assets and asset classes. My department designs, integrates, and operates all the common ITS assets including, but not limited to, the DTE Corporate Network, DTE Energy Data Centers, Server and Storage assets and Endpoint Devices. My department also supports other Company IT related assets such as Operational Technologies (OT) used by various business units to operate the gas and electric distribution networks located in dispersed facilities and locations. Examples of this would include technology at power plants, substations, service center locations, dedicated field sites and data centers.

---

[1] Project Management Institute (PMI) is the leading professional association for project management, and the authority for a growing global community of millions of project professionals (Ref : https://www.pmi.org/about) accessed 11/17/22

[2] The Project Management Professional (PMP)® is the world's leading project management certification. (Ref: https://www.pmi.org/certifications/project-management-pmp). accessed 11/17/22

[3] https://www.isaca.org/why-isaca/about-us/history accessed 11/17/22

[4] https://www.isaca.org/credentialing/cism. accessed 11/17/22

Line
No.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I have sponsored testimony in the following cases:

U-20836	2022 Electric Rate Case
U-21297	2023 Electric Rate Case

Line No.

Part I. Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my direct testimony is to:

- Describe the IT Capital investment framework and planning process that drives prioritization of both single and multi-year projects and programs.
- Discuss overall IT O&M spend as well as O&M spend supporting the capital investments.
- Specifically support the reasonableness of DTE Electric's IT capital expenditures in the amount of $224.3 million for the historical test year ended December 31, 2022, $314.6 million in the bridge period (for the 24 months ending December 31, 2024), and $145.7 million for the projected test period ending December 31, 2025; and
- Discuss the variance of actual 2022 capital spend compared to 2022 capital spend approved in, MPSC Case No. U-21297. Additionally, provide explanation for projected budget differences in 2023 and 2024 (as compared to U-21297) for projects that meet the requirement established in U-20162 final order.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.7	Projected Capital Expenditures - Information Technology
A-12	B5.7.1	Corporate Applications
A-12	B5.7.2	Customer Service (Sharma)

A-12	B5.7.4	Plant & Field
A-12	B5.7.5	Information Technology for IT (IT for IT)
A-12	B5.7.6	Information Protection Security (IPS)
A-12	B5.7.7	Infrastructure Operations
A-12	B5.7.8	Enterprise Data & Analytics
A-12	B5.7.9	Innovations
A-24	N1	IT Business Cases – Executive Summaries
A-24	N2	Historical Spend Variance Summary
A-24	N3	IT Capital Investments with Additional Project Details
A-13	C5.13	Projected Operation and Maintenance Expenses - Information Technology

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were. I co-sponsor Exhibits A-24, Schedules N1, N2, and N3 with Company Witness Hatsios.

Q11. How is your testimony organized?

A11. My testimony consists of four parts:

Part I	Purpose of Testimony
Part II	Investment Framework
Part III	Portfolio Details
Part IV	Historical Spend Variance

Line No.

Q12. Can you describe the requirements provided by the Commission in previous orders?

A12. Yes, in Case U-18238, the MPSC set forth seven requirements directly related to the highest cost Top 25 IT and OT projects in the projected test year. These requirements can be found in Part III filing. The Part III requirements were further revised in the updated order dated May 18, 2023, to include additional information in a spreadsheet and readable PDF format. In Case U-20162, the MPSC requested the Company to provide a breakdown of both O&M and Capital cost into two or three sub-categories, nine additional requirements for projects greater than $0.5 million addressing scope, schedule, cost, and alternatives.

Recently in the final order in U-21297, the Commission directed the Company to provide an exhibit outlining IT O&M spend which is included as Exhibit U-21534 IT O&M Exhibit A-13 Schedule C5.13.

Q13. What is the process used by the Company in identifying and prioritizing IT Investment projects?

A13. DTE's Annual Planning Cycle (APC) is how the Company refines its investment strategies, establishes financial targets, and sanctions work. This approach also applies to IT investments. The business units come together annually to review, prioritize, and authorize the next two years of IT investments, aligned with the assigned capital targets, as shown in Figure 1. This process is detailed in the DTE Five-Year IT Plan 2021-2025 filed in Docket No. U-20561.

Figure 1 DTE IT APC Cadence

The business unit project sponsor, with support from their IT liaisons, submits a business case into the IT APC process that documents the opportunity, functionality, or capability sought, the value proposition, related key output measures, key objectives, alternative analysis, and cost estimate. A Project Prioritization Score (PPS) is then applied to the project based on the alignment of the investment to the Company's strategies and goals.

The IT organization utilizes PPS to prioritize investments. Once the PPS is applied, the business case enters the enterprise IT Investment prioritization model where it is evaluated against execution capacity to ensure that there is a high degree of confidence the projects will be executed as planned. The model then optimizes the number of projects to be implemented by the Company. The Company's IT investment plan is reviewed and approved by the Company's executive Technology Investment Committee (TIC). The business case executive summaries are provided in Exhibit A-24 Schedule N1.

Q14. Can you further explain how the project benefits are evaluated using the Project Prioritization Scoring model?

A14. The Company completed benchmarking on industry best practices in investment prioritization. As a result, the Company hired an industry consulting firm to apply these best practices to establish a framework used to evaluate, score, and prioritize projects. This framework is similar to what market leading IT research recommends. For reference, Gartner research[5] also helped enabling companies to establish a model that will prioritize digital investments that maximize business value. These business value outcomes include revenue and cost, but also focus on risk reduction, efficiency, and value. Based on this informed research and best practices, the Company's prioritization model considers both qualitative and quantitative benefits across seven weighted benefit categories when considering IT Enhancements and Strategic investments for prioritization of discretionary funding, as shown in Figure 2. The result of this benefit analysis is a Project Prioritization Score (PPS). This PPS score is used as a standardized scoring and ranking methodology to bring consistency to how projects across multiple investment portfolios are assessed. Non-discretionary Regulatory/Compliance, Sustainment, and Return-to-Health projects are considered "must do" and therefore do not require a benefit analysis. The non-discretionary projects are assigned a standard score based on the associated investment category. The PPS score was introduced into the APC prioritization starting with the 2023 investment planning, so all 2023 and beyond, business cases will include the PPS score. Scoring categories and weighting are subject to change to ensure ongoing alignment with the priorities the Company believes are in the best near-term and long-term interest of its customers.

[5] Gartner Research Article - 'Prioritize Digital Investments That Maximize Business Value', Published 18 April 2022 - ID G00752285.

Figure 2 Project Prioritization Score Criteria

	Strategic Fit			Financial Impact		Operational Impact		Total
Scoring Category	Strategic Alignment	Customer Experience	Employee Engagement	Affordability & Growth	Benefit/Cost	Operational Reliability	Foundational Capability	Weight
Weighting Scale	10%	30%	10%	20%	10%	15%	5%	100%

Part II - Investment Framework

Q15. What are the Company's IT Capital Expenditures - Summary Exhibit A-12 Schedule B5.7?

A15. Exhibit A-12 Schedule B5.7 focuses on IT Capital projects which reside in the IT portfolios as defined in DTE Five-Year IT Plan 2021-2025 filed in Docket No. U-20561. These projects span across the historical year (2022), bridge year (24 months ending 12/31/2024) and the projected test year (12 months ending 12/31/2025) periods by category.

Q16. Can you describe the capital cost and the corresponding O&M costs for IT Projects?

A16. The capital costs reflected in Exhibits A-24 Schedule N-3 and A-12 Schedule B5.7 presented is only the portion of IT costs allowed to be capitalized in accordance with DTE's accounting policies such as hardware costs, software costs, and software development costs. These policies define the scope and phases of a project that can be capitalized and the scope and phases of the project that should be expensed. According to these policies the O&M cost is considered Cost To Achieve (CTA). The O&M costs reflected in Exhibit A-24 Schedule N-3 represent the total O&M cost to achieve each project and are provided for informational purposes only.

Q17. Can you provide a more detailed description of other IT O&M cost?

A17. Yes, in addition to CTA expense, in order for the ITS organization to operate within the Company the ITS operating expense includes operational labor support (Base Operate) and software maintenance cost (License Management & Maintenance). The IT Operational support cost represents IT resources that support hardware and software defect remediation (e.g. Office 365 not working as expected, Password Reset Support, MFA failure and access requests), business support services (e.g., IT Help Desk, Data Center Operation), and IT administration. Commercial software maintenance and support represents IT O&M expense include software maintenance and license for use fees for on premise and cloud solutions for certain specific contracts.

To support the Commission requirement to provide more detail supporting IT O&M, I have provided the following exhibit: U-21534 IT O&M Exhibit A-13 Schedule C5.13. The 'A&G Capitalized' on line 7, reflects the transfer (allocation) of A&G costs to capital as an overhead. The amount of A&G transferred (allocated) is based on the percentage of total direct labor charged to capital.

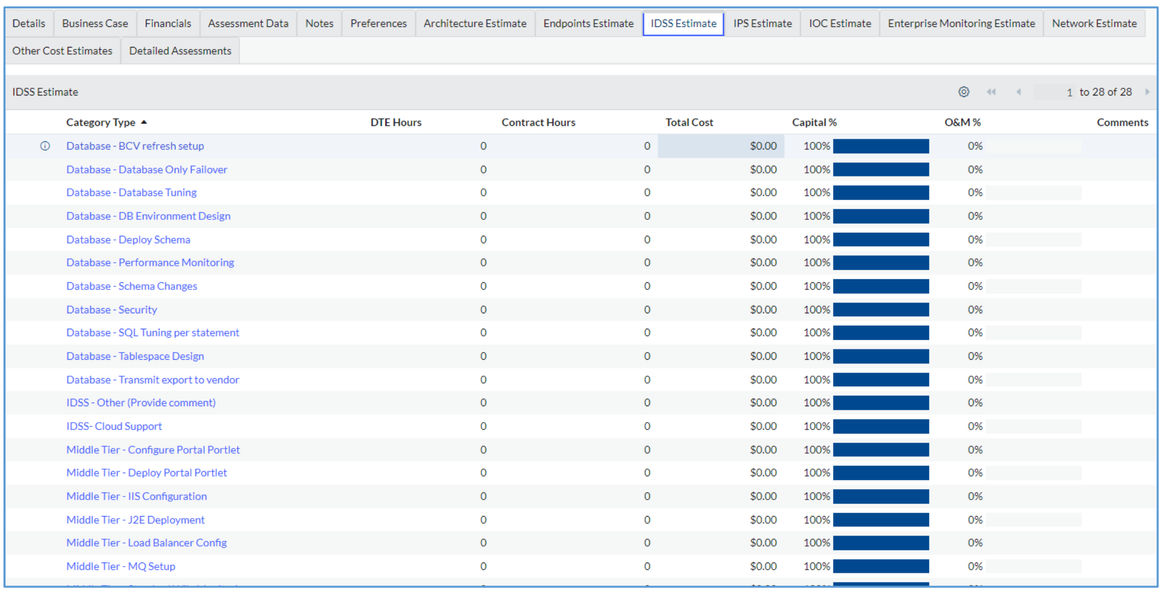
Q18. Can you describe how IT projects are estimated?

A18. Yes, IT projects approved through the ITS Annual Planning Cycle are processed through a thorough, detailed estimation process. This is enabled through ServiceNow demand management module utilized for planning IT investments. The Demand manager estimates project labor by phase of the project, and for any

Line No.

oversight/governance or project management cost. The demand management team is also responsible for obtaining and providing any associated vendor or solution estimates. In addition to these project level cost estimates, each demand has 28 discreet tasks generated to seven different workstreams (Architecture, Endpoints, IDSS, IPS, IOC, Enterprise Monitoring, & Network) to provide requirement and deliverable based estimation and analysis, as seen in Figure 3 below. There are a total of 169 discreet project elements available to estimate on any given project as applicable, which are required to support project execution.

Figure 3 IT APC Estimation Table Example



Details | Business Case | Financials | Assessment Data | Notes | Preferences | Architecture Estimate | Endpoints Estimate | IDSS Estimate | IPS Estimate | IOC Estimate | Enterprise Monitoring Estimate | Network Estimate | Other Cost Estimates | Detailed Assessments

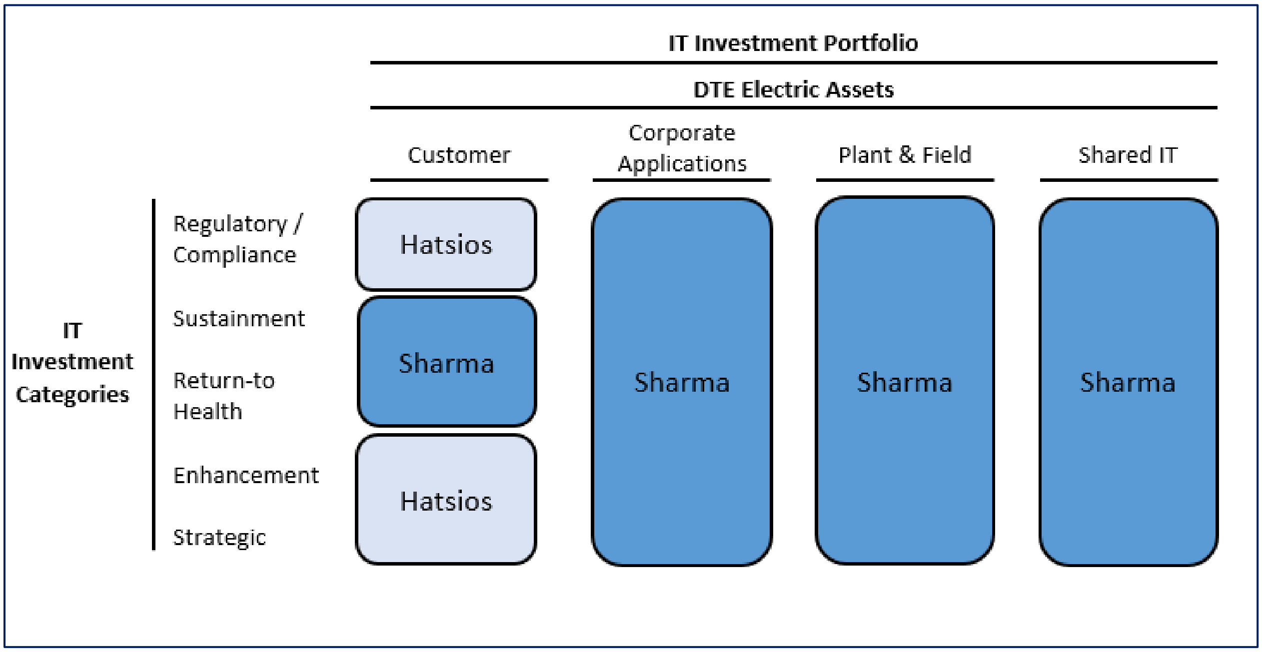
IDSS Estimate — 1 to 28 of 28

Category Type	DTE Hours	Contract Hours	Total Cost	Capital %	O&M %	Comments
Database - BCV refresh setup	0	0	$0.00	100%	0%	
Database - Database Only Failover	0	0	$0.00	100%	0%	
Database - Database Tuning	0	0	$0.00	100%	0%	
Database - DB Environment Design	0	0	$0.00	100%	0%	
Database - Deploy Schema	0	0	$0.00	100%	0%	
Database - Performance Monitoring	0	0	$0.00	100%	0%	
Database - Schema Changes	0	0	$0.00	100%	0%	
Database - Security	0	0	$0.00	100%	0%	
Database - SQL Tuning per statement	0	0	$0.00	100%	0%	
Database - Tablespace Design	0	0	$0.00	100%	0%	
Database - Transmit export to vendor	0	0	$0.00	100%	0%	
IDSS - Other (Provide comment)	0	0	$0.00	100%	0%	
IDSS- Cloud Support	0	0	$0.00	100%	0%	
Middle Tier - Configure Portal Portlet	0	0	$0.00	100%	0%	
Middle Tier - Deploy Portal Portlet	0	0	$0.00	100%	0%	
Middle Tier - IIS Configuration	0	0	$0.00	100%	0%	
Middle Tier - J2E Deployment	0	0	$0.00	100%	0%	
Middle Tier - Load Balancer Config	0	0	$0.00	100%	0%	
Middle Tier - MQ Setup	0	0	$0.00	100%	0%	

Q19. What is the portfolio structure within the DTE IT organization, and how is it reflected in your testimony?

A19. The DTE Five-Year IT Plan introduces both Portfolio and Category as lenses through which all DTE IT investments can be seen. This matrix can be visualized as seen in Figure 4.

Figure 4 IT Investment Portfolio



Q20. How are alternate solutions explored for each project or initiative in the Investment Planning process?

A20. The Company has adopted a Platform Strategy for its technology decisions over the last several years, where applicable, as reflected in the 5-Year Plan and in recent rate cases. For each new investment represented in my testimony, DTE has considered standard alternatives including moving the investment into the Cloud[6], foregoing or delaying the investment, or looking outside of the platform for an alternative that has an advantage for our customers or the business unit. In addition to many references of these alternatives throughout my testimony, the Company also addresses alternatives in the business cases themselves. The standard alternatives are:

[6] Cloud instances are IT infrastructure provided as a service instead of the Company purchasing and maintaining it ourselves. This includes components such as servers, racks, data centers, etc.

- "Do nothing" within the instant rate case period and defer the activity to a future period.
- Revert to a manual process rather than updating or replacing the existing system, where applicable or possible.
- Select different/competitive/complimentary technology to implement in place of the existing solution.

Q21. Can technology changes impact multiple investments?

A21. Yes. Some technology changes impact many areas. One example is the large-scale effort involved in accommodating a remote workforce that needs collaboration and communication technology to be successful. Because these types of changes cross multiple areas, I have not included them as one large project. Instead, I will mention them as a component of multiple projects that span various areas but are all impacted in varied ways by larger scale change. These will thus appear multiple times throughout my testimony because the obstacles they present are pervasive.

Q22. What are the investment categories reflected in the Capital Expenditures - IT Summary Exhibit A-12 Schedule B5.7?

A22. The IT investments are categorized into one of the five investment categories, summarized below in Figure 5:

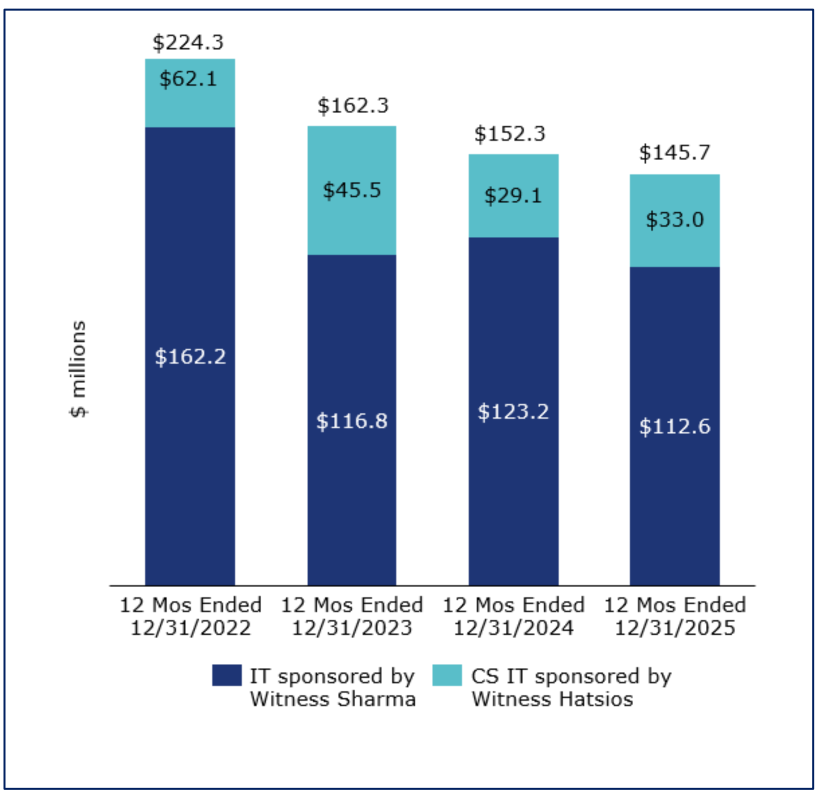
Line
No.

Figure 5 IT Investment Categories

Regulatory/ Compliance	Required spend due to regulatory requirements
Sustainment	Required spend to 'run' the organization (e.g., basic internal labor, base operating and system maintenance costs)
Return-to-Health	Required investments to update systems that are in critical health or have reached end of life
IT Enhancements	Discretionary capacity/capability performance upgrades to core platforms (e.g., SAP, IT) determined by business needs which are not required for 'keeping the lights on'
Strategic	Strategic spend to unlock a new business capability that can realize value for the organization (e.g., customer satisfaction, increased revenue to offset rate increases, etc.)

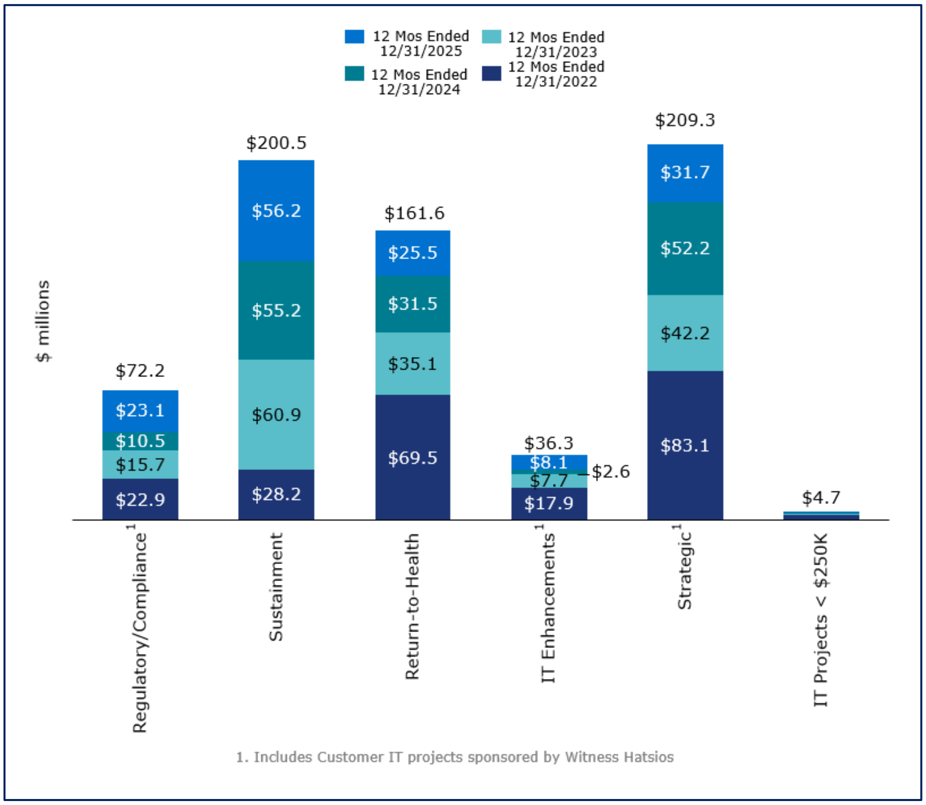
Using this nomenclature, I can summarize DTE IT capital both by year and by category as seen in Figures 6 and 7 below.

Figure 6 DTE Electric IT Capital Expenditure by Period



Line No.

Figure 7 DTE Electric IT Capital Expenditure by Category



Q23. Are there any common causes in variance from the prior rate case?

A23. Yes. The IT Department may need to adjust scope and/or re-sequence (adjust schedule) to address high-priority items based on other emerging and higher priority needs. My explanations of historical spend will reflect this prioritization as I explain changes between investment years. The re-sequencing of the scope of an entire project should not be interpreted as the investment is no longer necessary; it is simply a reflection of the operational reality of making investments when there are finite IT resources.

<u>Part III- Portfolio Details</u>

Q24. How is Part III organized?

Line
No.

A24. The Part III is intended to provide a detailed overview of IT capital investments organized into the eight IT portfolios that I discuss in my testimony, as reflected below:

1. Corporate Applications
2. Customer Service (Sustainment and Return-to-Health)
3. Plant & Field
4. Information Technology for IT (IT for IT)
5. Information Protection Security (IPS)
6. Infrastructure Operations
7. Enterprise Data Analytics
8. Innovations

Within the portfolios, the investments are organized by the investment categories and appear in the same order as they do in the corresponding capital Exhibit A-12 B5.7.1 through B5.7.9.

Q25. How does your overall testimony tie to your exhibits?

A25. My testimony presents projects which are traced to corresponding exhibits as outlined below:

- Exhibit A-12 Schedule B5.7 is a summary view of IT capital cost by portfolio and by investment category.
- Exhibits A-12 Schedules B5.7.1 through B5.7.9 present the capital spend in the historical, bridge, and projected test periods within each portfolio. I have structured my testimony to address IT projects, under the portfolio they support, in the same order we present the portfolios and projects in these exhibits, for each project more than $250,000.

- Exhibit A-24, Schedule N1 presents the executive summaries for each business case associated with each project over $250,000. Exhibit A-24, Schedule N1 tracks to the same order of projects as Exhibit A-12 Schedules B5.7.1 through B5.7.9. I also provide the corresponding business cases for each project in my workpapers.
- Exhibit A-24 Schedule N3 provides a greater level of detail in the format requested by Commission Staff, as set forth in new filing requirements adopted in the May 18, 2023 Order in Case No. U-18238. Each of these IT projects is presented by year and then in portfolio/project order.
- All variance commentary provided within the testimony will reconcile to Exhibit A-12 Schedules B5.7 - B5.7.9. Where additional recovery is being requested, please refer to Exhibit A-24 Schedule N2.

Q26. Are there any IT projects that have already been approved for cost recovery in previous rate cases with no additional spend being requested in the instant case?

A26. Yes, the following projects in Table 1, for which I provided testimony, and which were approved for cost recovery in Case Nos. U-21297 & U-20836, are not described further in my testimony in the instant case.

Table 1 IT Projects Approved in U-21297 & U-20836

Project Name	Portfolio	Category	U-21534 Exhibit Reference	Previous Exhibit Reference
Enterprise Applications Health	Corporate Applications	Sustainment	Line 4, A-12 B5.7.1	Line 3, A-12 B5.7.1, U-21297
Core ERP Data Archiving	Corporate Applications	Return-to-Health	Line 10, A-12 B5.7.1	Line 9, A-12 B5.7.1, U-21297
SOTeria Safe Worker Observations (SWO)	Corporate Applications	IT Enhancements	Line 13, A-12 B5.7.1	Line 12, A-12 B5.7.1, U-21297
PowerPlan Upgrade	Corporate Applications	IT Enhancements	Line 12, A-12 B5.7.1	Line 11, A-12 B5.7.1, U-21297

Line
No.

Enterprise Automation	Corporate Applications	Strategic	Line 15, A-12 B5.7.1	U-20836 A-12 B5.8, Line 8 Sponsored by witness Uzenski.
Distributed Generation Upgrades	Customer Service	Return-to-Health	Line 22, A-12 B5.7.2	Line 22, A-12 B5.7.2, U-21297
Migrate IVR to the Cloud	Customer Service	Return-to-Health	Line 23, A-12 B5.7.2	Line 18, A-12 B5.7.3, U-21297
Systems, Applications, and Products (SAP) Enhancement Program	Customer Service	Return-to-Health	Line 24, A-12 B5.7.2	Line 23, A-12 B5.7.2, U-21297
Network Reliability and Monitoring	Plant and Field	Sustainment	Line 11, A-12 B5.7.4	Line 9, A-12 B5.7.4, U-21297
Cable Routing Application (CRA) Replatform	Plant and Field	Return-to-Health	Line 18, A-12 B5.7.4	Line 17, A-12 B5.7.4, U-21297
DO Business Warehouse (DOBW) Replacement	Plant and Field	Return-to-Health	Line 20, A-12 B5.7.4	Line 20, A-12 B5.7.4, U-21297
Fuel Supply-Plant Fuel Management System	Plant and Field	Return-to-Health	Line 23, A-12 B5.7.4	Line 20, A-12 B5.7.4, U-21297
Meter Data Management (MDM) Consolidation	Plant and Field	Return-to-Health	Line 25, A-12 B5.7.4	Line 22, A-12 B5.7.4, U-21297
P3M Heat Rate Calculation and GADS Reporting Functions	Plant and Field	Return-to-Health	Line 26, A-12 B5.7.4	Line 23, A-12 B5.7.4, U-21297
Plant & Field Document Repository	Plant and Field	Return-to-Health	Line 27, A-12 B5.7.4	Line 24, A-12 B5.7.4, U-21297
Replace DO Lines – SOC Radio	Plant and Field	Return-to-Health	Line 28, A-12 B5.7.4	Line 25, A-12 B5.7.4, U-21297
ESRI Application Health	Plant and Field	Return-to-Health	Line 22, A-12 B5.7.4	Line 18, A-12 B5.7.4, U-21297
Fermi Enhancements	Plant and Field	Strategic	Line 30, A-12 B5.7.4	Line 28, A-12 B5.7.4, U-21297
Integrated Information Resource (I2R) Replacement	Plant and Field	Strategic	Line 32, A-12 B5.7.4	Line 30, A-12 B5.7.4, U-21297
Maximo Engineering Process Automation	Plant and Field	Strategic	Line 33, A-12 B5.7.4	Line 31, A-12 B5.7.4, U-21297
Maximo HSE Support	Plant and Field	Strategic	Line 34, A-12 B5.7.4	Line 32, A-12 B5.7.4, U-21297
Primavera Modernization	Plant and Field	Strategic	Line 35, A-12 B5.7.4	Line 34, A-12 B5.7.4, U-21297

Line
No.

IT for IT Tools	IT for IT	IT Enhancements	Line 2, A-12 B5.7.5	Line 10, A-12 B5.7.5, U-21297
Application Portfolio Management- APM	IT for IT	Strategic	Line 3, A-12 B5.7.5	Line 11, A-12 B5.7.5, U-21297
IT Service Management Tool	IT for IT	Strategic	Line 5, A-12 B5.7.5	Line 27, A-12 B5.7.5, U-21297
Automating Database Event Log Monitoring	Infrastructure Operations	Regulatory / Compliance	Line 1, A-12 B5.7.7	Line 1, A-12 B5.7.5, U-21297
Ashley Mews Closure and Relocation	Infrastructure Operations	Sustainment	Line 3, A-12 B5.7.7	Line 2, A-12 B5.7.7, U-21297
Virtual Desktop Infrastructure (VDI)	Infrastructure Operations	Return-to-Health	Line 29, A-12 B5.7.7	Line 20, A-12 B5.7.7, U-21297
Afaria Upgrade / Replacement	Infrastructure Operations	IT Enhancements	Line 31, A-12 B5.7.7	Line 8, A-12 B5.7.5, U-21297
Wide Area Network Redesign Session Initiation Protocol (SIP) Backhaul	Infrastructure Operations	IT Enhancements	Line 34, A-12 B5.7.7	Line 21, A-12 B5.7.7, U-21297
Network Operations Center (NOC) Automation	Infrastructure Operations	Strategic	Line 46, A-12 B5.7.7	Line 30, A-12 B5.7.5, U-21297

<u>**Corporate Applications**</u>

Q27. Can you describe the Corporate Applications portfolio?

A27. The Corporate Applications portfolio encompasses assets used by the enterprise to execute critical internal business functions. It supports business units such as Human Resources, Finance and Controller, Legal, Supply Chain, Fleet & Facilities, and IT assets used by the entire enterprise. In addition, Corporate Applications portfolio provides Enterprise Automation solutions for the enterprise. The investments within Corporate Applications span the 5 investment categories outlined/described above and the specific projects are detailed in the section below.

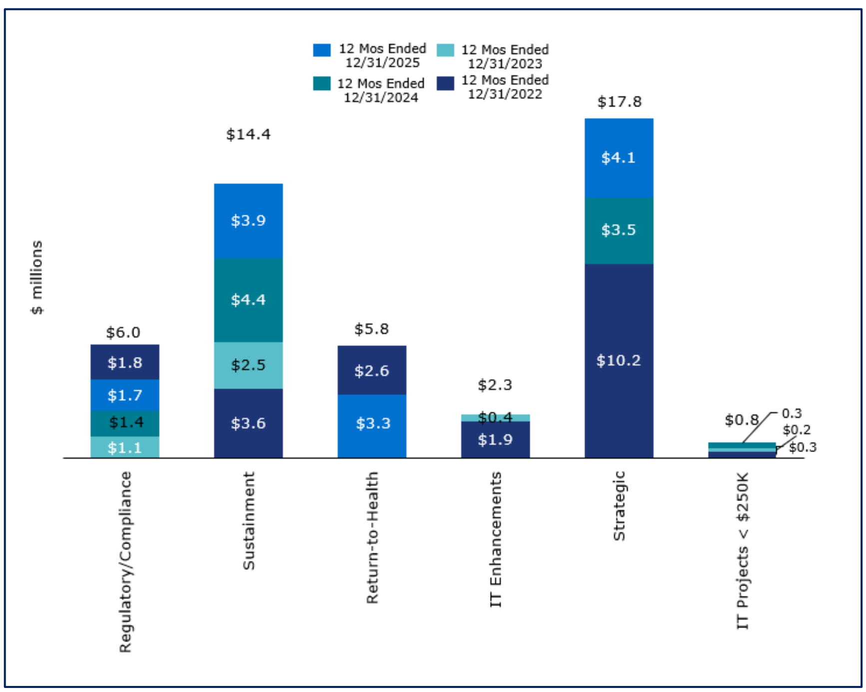
Q28. What are the projected costs for investments in the Corporate Applications Portfolio?

Line
No.

A28. As reflected on Line 2 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures for Corporate Applications total $17.1 million for the historical test year ended December 31, 2022, $17.7 million in the projected bridge period 24 months ending December 31, 2024, and $12.4 million for the projected test period ending December 31, 2025.

The individual initiatives that fall into this area appear in Exhibit A-12 Schedule B5.7.1. The synopses below provide the total spend for each line item the Company requests in the instant case, and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in Exhibit A-12 Schedule B5.7.1, in columns d, g and h, respectively. Figure 8 represents a high-level view of capital allocation within the portfolio.

Figure 8 Corporate Applications – IT Investment



Regulatory/Compliance

Q29. Can you explain in detail the Corporate Applications investments in the Regulatory and Compliance category?

A29. The portfolio will invest $4.9 million in the Regulatory/Compliance category in the project described below:

Core ERP Stacks and Packs

- The Company will invest $4.9 million in the **Core ERP Stacks and Packs** project over the course of 36-months ending December 31, 2025, and has a historical spend of $1.1 million as shown on line 1 of Exhibit A-12 Schedule B5.7.1.

  The Core ERP Stacks and Packs project is a recurring annual investment to ensure the Core Enterprise Resource Planning platform is up to date with the latest required support packs and stacks. The Enterprise Resource Planning system (ERP) is a core platform that supports all resource planning processes and systems supported through the SAP platform for the Corporate Services, Human Resources (HR), and Finance organizations. Examples of critical processes that are supported are Financial Close, Financial Asset Management, Financial Reporting, Time Management, Payroll Processing, Purchasing, and Tax Management. There are also critical integrations that support Customer Billing and Asset and Work Management. The system must be upgraded with the latest Human Resources updates from vendor SAP in order to run year-end payroll, produce W-2s and comply with mandatory State, local, and Federal reporting.

  The annual investment from 2022 to 2024 was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 4 for additional project details for the 2025 spend.

Sustainment

Q30. Can you explain in detail the Corporate Applications investment in the Sustainment category?

A30. The portfolio will invest $10.8 million in the Sustainment category over the course of 36-months ending December 31, 2025, as shown in line 2 through line 8 of the Capital Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are primarily across projects discussed further below:

Corporate Services Application Health

- The Company will invest $2.1 million in the **Corporate Services Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.5 million in 2022, as shown on line 2 of Exhibit A-12 Schedule B5.7.1.

Corporate Services Application Health is an ongoing and annual investment to upgrade applications running on unsupported infrastructure and operating systems to ensure the health and stability of a suite of 36 applications within the portfolio to support organizations such as Supply Chain, Environmental Management and Safety, and the overall health, reliability, and security of our corporate services applications such as mail services, fleet and fuel management, and emissions monitoring. The Company will continue to invest in the 36 applications, making the necessary system changes required by the business units, implementing hardware and environment upgrades, continuing information security enhancements, and implementing vendor software changes. This ongoing annual investment ensures IT assets avoid outages or disruption to business processes that may occur due to IT component failure, security issues, incompatibility with newer components, and appropriate vendor support is maintained.

The annual investment from 2022 to 2024 was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 8 for additional project details.

Documentum (EDM) Application Health

- The Company will invest $0.9 million in the **Documentum (EDM) Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 3 of Exhibit A-12 Schedule B5.7.1.

  This project represents the year over year investment that will be required in the Documentum platform including yearly capital investments to account for security vulnerability remediation, system upgrades, value added enhancements, and organic system growth (sizing). A Document Management Governance Board has been established to define an aligned strategy that addresses gaps in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged.

  This investment will ensure that the system meets the operational and availability goals for which it was implemented and remains secure and available to meet document repository objectives. These objectives will support our defined document management strategy which spans across business units.

  The Company reflects a variance of $0.1 million less in the 12 months ending December 31, 2024, than was approved for cost recovery in U-21297. This cost reduction was a result of decreased external labor cost with the new vendor.

  The investment from 2023 to 2024 was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 811 for additional project details.

Enterprise Resource Planning

- The Company will invest $2.9 million in the **Enterprise Resource Planning** project over the course of 36-months ending December 31, 2025, and has a historical spend of $1.2 million in 2022 as shown on line 5 of Exhibit A-12 Schedule B5.7.1.

  The Enterprise Resource Planning system (ERP) is a core platform that supports all resource planning processes and systems supported through the SAP platform for the Corporate Services, Human Resources, and Finance organizations.

  This investment supports the non-regulatory and compliance requirements such as monthly releases to upgrade end-of-life systems, complete required critical system failover testing, and enhance associated applications with changing business processes in each of these organizations.

  The annual investment from 2022 to 2024 was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 18 for additional project details.

Financial Applications Health

The Company will invest $0.8 million in the **Financial Applications Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022 as shown on line 6 of Exhibit A-12 Schedule B5.7.1. This project represents periodic updates which include significant capital investment in environment upgrades to maintain the health, reliability, and security of our financial systems and covers 21 unique applications under the financial applications portfolio. The Company reflects a variance of $0.3 million more in the 12 months ending December 31, 2024, due to an additional $298K spend in 2022 to support PowerPlan Uplift vendor fees.

The annual investment from 2022 to 2024 was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 22 for additional project details.

Human Resources Applications Health

- The Company will invest $0.9 million in the **Human Resources Applications Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.6 million in 2022, as shown on line 7 of Exhibit A-12 Schedule B5.7.1.

Human Resources Applications Health investment is annual and ongoing to ensure the health and stability of applications within the Human Resources portfolio, such as the SuccessFactors Platform, OpenText, and Oracle backends. This project will cover the required upgrades on these applications to ensure they are running on supported infrastructure and that operating systems are replaced as required. SAP requires yearly upgrades and SuccessFactors require bi-annual upgrades to ensure each platform is current and operating with the latest functions and features to support business processes. This project also supports the application configuration changes to be built, tested, and deployed through monthly change release to support HR business process requirements.

The Company reflects a variance of $0.4 million more in the 36 months ending December 31, 2024, than was approved for recovery in U-21297. This is primarily due to the additional spend in 2022 as explained below.

In 2022 this project required additional scope to deliver the following functionality in the HR SuccessFactors:

- Enhanced Learning Management System reporting allows updated reporting and analysis to ensure employees have the timely training and skills to perform their jobs.

Line No.

- Preferred name implementation
- Employee file management improved DTE's ability to manage larger volumes of workforce-related records, while maintaining compliance with document retention, deletion regulation, and allowing searches on all personnel activities and processes to be performed more efficiently.

The annual investment from 2022 to 2024 was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 26 for additional project details.

Production Growth

- The Company will invest $2.2 million in the **Production Growth** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.5 million in 2022, as shown on line 8 of Exhibit A-12 Schedule B5.7.1.

The Production Growth project addresses the ongoing increase in the size and capability of our computing environment as our on-premise Corporate Application systems expand to meet the demands of our business. This investment primarily covers server and storage capacity needed by existing business systems. The annual server storage, capacity, and memory growth for the Corporate Application portfolio, for example, in 2020 was approximately 11 TB storage and 16 GB of memory across all environments (test and development). The annual budget for these increases is based on the historical consumption performance and growth. In 2022, the growth was approximately 8 TB storage, 16 GB of memory and 1.1 GHz CPU across all environments.

The annual investment from 2022 to 2024 was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 30 for additional project details for the 2025 spend.

Line No.

Return-to-Health

Q31. Can you explain in detail the Corporate Applications investment in the 'Return-to-Health' category?

A31. The portfolio will invest $5.8 million in the Return-to-Health category over the course of 36-months ending December 31, 2025, as shown in lines 9 to 11 of the Capital Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are spread across projects that are as discussed below:

Cloud Health and Safety

- The Company will invest $3.1 million in the **Cloud Health and Safety** project over the course of 36-months ending December 31, 2025, as shown on line 9 of Exhibit A-12 Schedule B5.7.1.

The current DTE Energy safety reporting systems are not integrated and contain minimal workflow capabilities resulting in lagging safety information which is used for internal metrics. To return the Company's safety reporting capabilities to health the Company will design, configure, test, and deploy a Software as a Service (SaaS) SAP solution. The SAP solution will improve reporting on near-miss and unsafe working conditions along with consolidating multiple systems for recording Potential Serious Injury and Fatality (PSIFs) into a single system. It will further improve security role compliance/access by minimize the potential for human error on entering data into multiple systems. The solution will support monitoring which enables the company to efficiently detect data security threats, secure data for HIPAA regulations, and mitigate potential sources of data breaches by having a single system to safeguard access. The solution will also enable dynamic form entry which both employees and contractors can access.

The 2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines 31-32 for additional project details.

Source to Pay (S2P) Transformation

- The Company will invest $2.0 million in the **Source to Pay (S2P) Transformation** project over the course of 12 months ending December 31, 2025, as shown on line 11 of Exhibit A-12 Schedule B5.7.1.

This project will replace the existing SAP SRM outdated software with cloud-based technology that directly integrates with ECC and the S4 Hana application. SAP has not invested in their current purchase to pay (P2P) functionality Supplier Relationship Manager (SRM) product in nine years. The purchasing business process and system required to support our customer commitments, storm activities and power distribution and generation operations are relying on old technologies such as email, fax and manual created reports or dashboards to measure and maintain the materials and services to keep our organization running. In 2027, the SAP support for our current Enterprise Resource Planning Central Component (ECC) financial system and SRM purchasing system will expire. The two-year effort to replace the purchase to pay system and implement modernized process should be completed prior to the upgrade of the SAP ECC financial to reduce risk. See Exhibit A-24 N3 Line 34 for additional project details.

IT Enhancements

Q32. Can you explain in detail Corporate Applications investment in the IT Enhancements category?

A32. The portfolio will invest $0.4 million in the IT Enhancement category over 36-months ending December 31, 2025, as shown in lines 12 to 14 of the Capital

Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are across projects that are as discussed further below:

SuccessFactors Program

- The Company will invest $0.3 million in the **SuccessFactors Program** project over the course of 12-months ending December 31, 2024 and has a historical spend of $0.2 million in 2022 as shown on line 14 of Exhibit A-12 Schedule B5.7.1.

The multi-year program involves the gradual release of features/modules in the SuccessFactors platform in multiple areas.

The Company will implement the SuccessFactors Cross board and Peoplesoft queries, which provides a streamlined business process for the HR business partner to hire (onboard), terminate (offboard) and internally transfer (cross-board) employees. In today's environment, the HR process to internally transfer or terminate an employee is managed outside of the SuccessFactors platform and is not tied to the existing employee records. This results in HR being unable to monitor process timing and number of employees impacted.

The Company reflects a variance of $0.1 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297 as explained below.

In 2022, the project re-sequenced work to ensure business process development was completed in advance of technology implementation of Employee Central (EC) Shared Service Center scope. This schedule adjustment has been reflected in the projected spend completing in 2023.

The 2022, 2023 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines 39-40 for additional project details.

Line No.

<u>Strategic</u>

Q33. Can you explain in detail Corporate Applications investment in the Strategic category?

A33. The Company will invest $7.6 million in the Strategic category over the course of 36-months ending December 31, 2025, as shown in lines 15 through 20 of the Capital Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are primarily across projects that are as discussed further below:

Enhanced Document Management Capability

- The Company will invest $4.2 million in the **Enhanced Document Management Capability Projects** project over the course of 36-months ending December 31, 2025, as shown on line 16 of Exhibit A-12 Schedule B5.7.1.

  This project will begin in 2024 and address significant functional improvements in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged. The areas of focus are automation of document workflow to streamline business processes consistently and integration of documents to work management tools & other systems. Defining a common document management strategy that can span across all Plant & Field BU's and addresses gaps in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged. These changes will impact all plant and field employees in Fossil Generation, Renewables, DO, and Gas. Expected time savings estimated at 200,000 man-hours a year. These efficiency gains are expected to be achieved by all business department users.

  The Company reflects a variance of $2.0 million less in the 12 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to a schedule and cost shift from 2024 to 2025, to an adjusted implementation plan start project in 2024 with a project completion in 2026.

See Exhibit A-24 N3 Lines 42-43 for additional project details.

Organizational Management Optimization

- The Company will invest $0.5 million in the **Organizational Management Optimization** project over the course of 12-months ending December 31, 2024, as shown on line 17 of Exhibit A-12 Schedule B5.7.1.

In 2017, the Company implemented Success Factors (SF) and integrated the solution with SAP on Premise. In order to keep cost down for the initial implementation in 2017, the replication of data between the two systems was required to be completed manually. Since 2017, this has required 1 Full Time Equivalent dedicated to manual replication and has impacted the productivity of HR staffing in replication downstream process impacts. In order to optimize operating cost and meet customer affordability targets the Company must invest in streamlining all business processes. In response to these challenges, this project will optimize organization management process within SuccessFactors by removing the manual replication requirements between SuccessFactors and SAP on premise, resulting in 100% reduction in replication errors and data mismatches of 500 or more per month, 30% efficiency in downstream process improvements and achieve productivity gains of 2 full time equivalents.

See Exhibit A-24 N3 Line 44 for additional project details.

SAP Employee Central Payroll

- The Company will invest $0.9 million in the **SAP Employee Central Payroll** project over the course of 12-months ending December 31, 2025, as shown on line 18 of Exhibit A-12 Schedule B5.7.1.

  This project will implement the SAP Employee Central Payroll application to replace the current SAP ERP payroll system implemented in April 2007. Our current SAP ERP application houses a built-in Payroll application; however, SAP is phasing out SAP ERP application and replacing it with SAP S4 Hana application by 2027. However, SAP S4 Hana does not have a built-in payroll system. Therefore, SAP SuccessFactors Payroll, an eighteen-month initiative, requires implementation starting in 2024 as a predecessor project, to avoid delaying the start of the S4 Hana implementation. It is prudent for the Company to make this investment at this time as the future S4 Hana implementation project, which will take 2 years to implement (requiring the same environments and resources to implement), to ensure critical business processes are still operating on a supported platform by SAP S4 Hana in 2027. The cloud-based SAP Payroll application will be configured, tested, and integrated with multiple business unit interfaces, external interfaces, and our third-party business systems.

  The Company reflects a variance of $0.8 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to a schedule change from original project start 2024 and original project finish 2025 to revised project finish date in 2026 in order to align with Time Entry project dependencies. Employee Time entry is the practice of monitoring and documenting the hours that each employee works. The Company tracks work hours by requiring employees to enter time in the SAP time management system which sends information to SAP payroll. Aligning this project with Time Entry allows will optimize integration and capability testing and deployments.

See Exhibit A-24 N3 Line 45 for additional project details.

Talent System Optimization

- The Company will invest $0.3 million in the **Talent System Optimization** project over the course of 12-months ending December 31, 2025, as shown on line 19 of Exhibit A-12 Schedule B5.7.1.

The Talent Management Optimization has several benefits: it builds a high-performance workplace by improving Diversity, Equity and Inclusion engagement score from 4.1 to 4.3, and a 5% increase in the adoption of learning programs; it fosters a learning climate; it adds value to the employer brand, and it improves diversity. The talent management module will enable a connection for employee development throughout the SuccessFactors system, allowing employees to see a clear career path including opportunities for learning, assignments and skill and competency assessments.

The Company's IT (SuccessFactors modules) systems are currently set up to work independently of one another, not connecting an individual's skills and competencies with learning, career pathing, or any other talent process. In today's competitive talent environment, it is important for the Company to invest in talent management because employees expect a clear development plan for their career aspirations. The optimization of the system will be more effective in attracting and retaining talent. With the system fully optimized, the Success Factors platform will be able to provide this functionality.

See Exhibit A-24 N3 Line 46 for additional project details.

Transparency Electric Data

- The Company will invest $1.8 million in the **Transparency Electric Data** project over the course of 12-months ending December 31, 2024, as shown on line 20 of Exhibit A-12 Schedule B5.7.1.

  The electric grid has seen an increased strain from severe weather events leading to customer outages. The Company's customers and stakeholders are increasingly seeking more robust data on both grid reliability and planned investments. Importantly, customers and stakeholders have expressed a desire to have this data provided in a localized manner, so that customers or communities can understand circuit(s) performance and investments in their neighborhoods. To meet this need in a way that allows our customers and stakeholders ready access to localized data on grid performance and grid investments, the project sets out to accomplish the following:

  1. Design and develop an improved intuitive, easy-to-find, and customer-friendly Electric Grid Investment Map. This will offer our customers and community stakeholders readily accessible and hyper-localized visibility into the investments the Company is making to improve grid reliability. Customers will have improved visibility into the types of work being done in their neighborhood as well as the projected timelines for that work's completion. In addition, customers will have access to localized reliability data that will help customers and stakeholders easily assess the relative performance of their circuit(s).
  2. Design and develop an easy-to-use, flexible, "one-stop shop" platform that simplifies reliability and investment data access between internal business units. This enables easy and quick capability for internal personnel to use

readily available data for community stakeholder engagement. This also ensures data is accurate, current, and consistent so that it meets the needs of our customers and stakeholders.

See Exhibit A-24 N3 Line 47 for additional project details.

Customer Service

Q34. Can you describe the Customer Service Portfolio?

A34. The Customer Service Portfolio is made up of key systems integrating with the Company's SAP Customer Relationship and Billing (CR&B) platform. Investments in the Customer Service portfolio directly impact the Company's interactions with our customers. I will discuss the IT capital investment in Sustainment and Return-to-Health categories in my testimony below. Company Witness Hatsios discusses the capital investments in the Regulatory/Compliance, IT Enhancements and Strategic categories in detail in his testimony in the instant case.

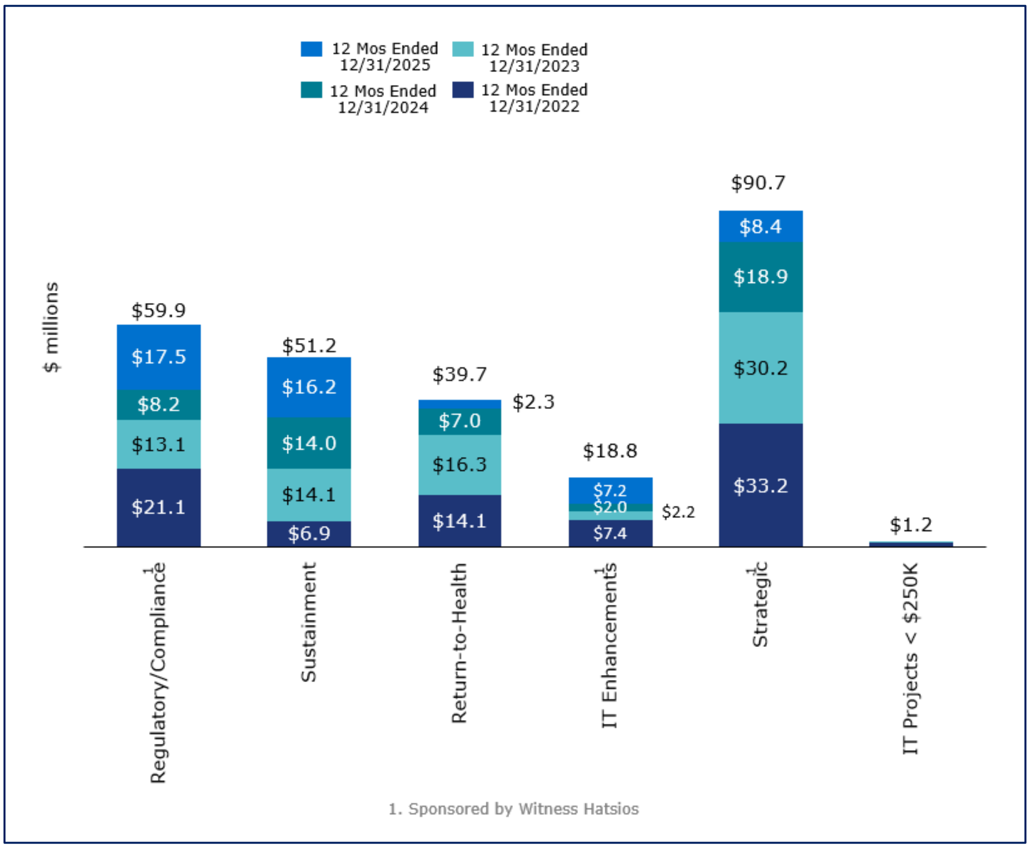
Q35. What are the projected costs for investments in the Customer Service Portfolio?

A35. As reflected on line 3 of Exhibit A-12 Schedule B5.7, page 1, capital costs for the Sustainment and Return to Health category investments in Customer Service Portfolio total \$21.6 million for the historical test year ending December 31, 2022, \$51.5 million in the bridge period (for the 24 months ending December 31, 2024), and \$18.5 million for the projected test period ending December 31, 2025.

The individual initiatives that fall into this area appear in Exhibit A-12 Schedule B5.7.2. The synopses below provide the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in Exhibit A-12 Schedule B5.7.2, in columns d, g and h, respectively. Figure 9 represents a high-level view of capital allocation within the portfolio.

IT dollars depicted in Exhibit A-12 Schedule B5.7.3 are in support of the Customer Service Organization and reflect investments discussed by Witness Hatsios.

Figure 9 Customer Service– IT Investment



<u>Sustainment</u>

Q36. Can you explain in detail Customer Service investments in the Sustainment category?

A36. The Company will invest $44.3 million in the Sustainment category over the course of 36-months ending December 31, 2025, as shown in lines 1 through 14 of the

Capital Expenditures Exhibit A-12 Schedule B5.7.2. The planned costs are across projects that are as discussed further below:

Automated Application Monitoring Health

- The Company will invest $1.1 million in the **Automated Application Monitoring Health** project over the course of 36-months ending December 31, 2025 and has a historical spend of $0.6 million in 2022, as shown on line 1 of Exhibit A-12 Schedule B5.7.2.

Today, the Company has deployed several modules from the SAP Solution Manager application. These modules provide visibility across multiple systems, SAP Process Integration, SAP Customer Relationship Management, SAP Industry solution for utilities, SAP Business Warehouse etc. These modules do not have a built-in solution to support operational monitoring of potential system failure points. This project will add Solution Monitoring, End User Experience Monitoring, Dynatrace Monitoring, and SAP Solution Manager. These features will provide additional Monitoring, Optimize Alerting & Notifications, Improve Standard Operational Procedures, Data Volume Management, and Analytics and Dashboards. It will provide precise visibility across systems. The SAP Solution Manager systems also require ongoing operational asset health upgrades to maintain the overall reliability and availability of the infrastructure hosting the application. These upgrades provide foundation for application changes due to evolving business processes and security compliance updates.

The Company reflects a variance of $0.3 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is partially due to $0.17 million increase in 2023 as a result of the first quarter catastrophic storm which required an increased scope to improve monitoring and resiliency of core critical applications (Customer Relationship Management, Industry Solution for Utilities, and Process Orchestration) related to outage management.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 51 for additional project details.

Business Planning and Development (BPD) and Electric Sales & Marketing (ESM) Application Health

- The Company will invest $2.4 million in the **Business Planning and Development (BPD) and Electric Sales & Marketing (ESM) Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 2 of Exhibit A-12 Schedule B5.7.2.

  The BPD and ESM project supports annual refresh of 12 IT assets that support the operations of Corporate Energy Forecasting, Integrated Resource Planning, Demand Response, Community Lighting, Joint Use, and Customer Choice. These departments and the associated applications support the Company's ability to effectively forecast system load for planning purposes and provide customers with alternative rates and products that assist them with managing their energy usage. This project provides the resources and services to complete required application software upgrades and hardware replacements, the development, testing and deployment of enhancements to improve functionality and performance required by business process changes, and end of life replacement of legacy operating systems, hardware, and cloud based virtual systems. Finally, investments in mitigation of security vulnerabilities are planned for as required.

  The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 55 for additional project details.

Line No.

Contact Center Application Health

- The Company will invest $3.8 million in the **Contact Center Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $1.1 million in 2022, as shown on line 3 of Exhibit A-12 Schedule B5.7.2.

  The Contact Center IT portfolio includes 17 IT-supported applications across the contact center telephony and interactive voice response (IVR) functions, four of which are critical, and approximately 210 technology components consisting of servers (both physical and virtual), operating systems, and databases that are required to run day-to-day activities. This portfolio of systems allows customers to call DTE's main 1-800 phone number, interact with the IVR system for self-service if desired, and be properly routed to a Contact Center customer representative (CR) with the ability to resolve the customer's inquiry or process their request / order when needed. In addition, this portfolio provides the tools and support for the Contact Center to manage and administer both the IVR and call handling systems.

  The Company reflects a variance of $3.6 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297.

  In 2024, this project included scope to renew the Avaya Telephony contract. However, through the Migrate IVR to the Cloud project it was determined that in 2024 the Company will be replacing the Avaya solution and will no longer be required to extend the licenses purchase resulting in the variance above.

  The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 59 for additional project details.

Closed Loop COCL Application Health

- The Company will invest \$1.6 million in the **Closed Loop COCL Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 4 of Exhibit A-12 Schedule B5.7.2.

  This project will utilize agile delivery to roll out incremental improvements for customer transactions on the web such as billing, usage, payments, outage, program enrollment, Collections Closed Loop, and MIMO (Move-In/Move-Out) Closed Loop process improvements. In support of the Digital Experience Team, the project team will provide Azure APIM (API Management) including Network configuration, Firewall configuration, access management and managing the API gateway in support of web services, and awareness in system health insight. Additional Dynatrace licenses will be utilized for integrating Azure with Dynatrace and will provide the ability to monitor the customer experience and make necessary adjustments.

  The Company reflects a variance of \$0.4 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to cost savings initiatives associated with service providers supporting the projects.

  The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 63 for additional project details.

Cloud Platform Enterprise Agreement

- The Company will invest \$0.8 million in the **Cloud Platform Enterprise Agreement** project over the course of 12-months ending December 31, 2024, as shown on line 5 of Exhibit A-12 Schedule B5.7.2.

The project is to cover a 3-year capital cost for the Cloud Platform Enterprise Agreement (CPEA) which is a business model that allows for the consumption of cloud credits based on actual usage. This agreement originated with the Meter Data Management (MDM) project and its need for SAP FIORI. SAP Fiori is a design system that enables you to create business apps with a consumer-grade user experience, turning casual users into SAP experts with simple screens that run on any device. By using the SAP Fiori design guidelines DTE can easily build and customize our own apps that are consistent with what we use SAP S/4HANA and our other enterprise software solutions. As a result of this service MDM was able to utilize the SAP FIORI Launchpad as an entry point to our back-end SAP system (SAP ISU). Additionally, this platform has been utilized for other critical projects such as Agency Website (an agency portal for assisting customer energy needs), Damage Claim and Document Signature lending the capability to use the Business Technology Platform services available under the CPEA. These services are key and critical to the continued success of the technical solution and architecture design in which they are based upon.

This investment covers implementation support for hardware and environment upgrades, security vulnerability remediation, and the adoption of both major and minor software releases. Also included in this effort is the support for the user base as they respond to new business needs, continuous improvements, and process changes to improve their productivity.

See Exhibit A-24 N3 Line 64 for additional project details.

Customer Digital Channels and Self-Service Program

- The Company will invest $7.8 million in the **Customer Digital Channels and Self-Service Program** project over the course of 36-months ending December 31, 2025 and has a historical spend of $1.6 million in 2022, as shown on line 6 of Exhibit A-12 Schedule B5.7.2.

Significant portions of the DTE Web and mobile digital customer transactions continue to run on legacy platforms. The customer mobile applications run on frameworks and foundational code that was written in 2013-2014. Substantial portions of the customer web experience run on IBM WebSphere Portal (version 8), which IBM no longer supports. The Company is investing in a 5-year transformational agenda to move off these aging platforms, however continued investments are needed to maintain and make improvements to the existing assets, until such time as they can be retired. This Customer Digital Channels and Self-Service Program is comprised of capital business cases that will deliver ongoing enhancements to the Web and Mobile App that allow the Company to maintain key customer transactions and improvement in digital self-service metrics (e.g., Web Digital Engagement Rate (DER), Web Completion Rates), while the transformation efforts are in progress.

See Exhibit A-24 N3 Line 68 for additional project details.

Customer Information Technology (CIT) Configuration Management

- The Company will invest $3.6 million in the **Customer Information Technology (CIT) Configuration Management** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.5 million in 2022, as shown on line 7 of Exhibit A-12 Schedule B5.7.2.

This project provides streamlined configuration, release, compliance and audit management processes for the Customer and Business Planning and Development (BPD) portfolio of assets. It assists the operational team in configuring, building, and deploying planned functional release for all assets of the portfolio.

Configuration, build, and deployment support is in alignment with the needs of the application teams, the business partners, and customers.

See Exhibit A-24 N3 Line 72 for additional project details.

Customer Legacy Application Health

- The Company will invest $1.6 million in the **Customer Legacy Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 8 of Exhibit A-12 Schedule B5.7.2.

The Company reflects a variance of $0.2 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to additional spend in 2023 as explained below.

In 2023, previously unsupported applications were incorporated into the revised support agreement with the strategic vendor partner. Incorporation of these applications was needed to ensure their resiliency and availability to customers; and 2) The sourcing strategy also increased the depth of application support coverage within the Customer IT portfolio. The additional resources will also increase the availability and resiliency of applications.

Systems that are not core billing systems or self-service channels are called Legacy applications. These applications include Agency Web Site (AGW), Interactive Voice Recognition (IVR), old billing systems in read-only mode (CSB, KCS) and the Enterprise Service Bus (ESB) and are some of the important systems that fall in this category.

AGW is the agency website application that our partners like Salvation Army and others use to help our low-income customers. The IVR is a recognition system key to our customers calling Contact Center. Per compliance, the Company is maintaining legacy billing systems, CSB/KCS (Residential and Commercial), in read-only mode for inquiries. ESB is middleware software that communicates between the core billing system (CR&B) and the channels (Web, Mobile, IVR and Kiosk). It is critical that these system function for customers to complete their transactions. Hence, these customer systems require regular production releases to support daily operations and the effective delivery of service to our customers. This includes vulnerability management and deployments of required capabilities or functionality.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 76 for additional project details.

Customer Relationship and Billing Program

- The Company will invest $4.2 million in the **Customer Relationship and Billing Program** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 9 of Exhibit A-12 Schedule B5.7.2.

The CR&B Platform is a fully implemented system. The CR&B production environment needs to be regularly maintained to ensure the health, compliance, and strategic alignment of the SAP CR&B Platform while providing a high level of availability with accurate data to meet the business needs of the Customer Service, Billing and Metering, Distribution Operations, Energy Optimization, Treasury, Controller, Gas Operations, and Electric and Gas Sales and Marketing organizations. These are all part of our ongoing customer excellence efforts.

The 2023 through 2025 scope of this investment will support achieving sustained and improved performance of CR&B Platform while furthering strategic alignment with the platform vendors (e.g., SAP, OpenText). Included in this effort is the strategic oversight for the CR&B Platform including the development and delivery of the Technology Platform Plan.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 80 for additional project details.

Hybris Application Health

- The Company will invest $3.9 million in the **Hybris Application Health** project over the course of 36-months ending December 31, 2025, with a historical spend of $2.0 million in 2022 as shown on line 10 of Exhibit A-12 Schedule B5.7.2.

  Hybris Software Solution, an e-commerce delivery platform that will allow the Company to design and deliver non-metered products[7] (e.g., Surge Protection Program, TreeGuard Assurance, Smart Savers, and Smart Currents) in conjunction with existing metered offerings. These systems require regular production deployments to support daily operations and the effective delivery of service to our customers. There are 12 monthly scheduled releases annually to accommodate deployments.

  The current version of Hybris platform is 2005 with an end-of-life date by the providing vendor of March 2023. In 2023, this project completed the upgrade to the supported version 2211 of SAP Commerce Cloud and SAP Marketing Cloud.

  The Company reflects a variance of $3.2 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to the project adding scope to upgrade the Sales and Service platform and created the required interface between Cloud Platform and DocuSign and OpenText, in 2022. The configuration, testing and deployment of the upgrades and

[7] Non-metered products are products that do not require a meter for billing purposes

interfaces was delivered over 6 months. In 2023, we had to perform 3 upgrades to the SAP Commerce Platform to bring the platform to be compliant with SAP recommendation. Also, for the regulatory requirement of rate change, we updated the commerce platform configuration and content for renewable energy programs. During the 2023 storms, SAP Marketing Cloud platform faced significant performance issues resulting in a redesign of the architecture to consolidate notification workflows so that the platform can send notifications to the customers on time. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 84 for additional project details.

MIGreenPower Program Stabilization

- The Company will invest $4.7 million in the MIGreenPower Program Stabilization project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 11 of Exhibit A-12 Schedule B5.7.2.

  The Company reflects a variance of $1.1 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to a scope addition of backlog enhancements to include Commerce cloud, Marketing and Analytics cloud components to the scope of the project resulting in an updated forecast for 2024. This allowed for the line items and credits to be appropriately reflected on Customer Renewable Energy bill.

  The intent of this project is to sustain and support the MIGreenPower applications in production by modifying application configuration as projects are completed as necessary to maintain a stable platform, completing minor enhancement request to support business process changes and required application updates. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 88 for additional project details.

Powerley Customer Platform Application Health

- The Company will invest $7.2 million in the **Powerley Customer Platform Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 12 of Exhibit A-12 Schedule B5.7.2.

Powerley has developed and supports several systems used by DTE's external customers (e.g. DTE Insight, Energy Bridges, Bill Management). These systems need to be maintained and upgraded to support new mobile operating systems otherwise DTE's external customers will lose the capabilities they are paying for. DTE does not maintain the internal expertise or staffing levels to support Powerley Cloud systems and needs to provide the required support services to maintain the solutions provided by Powerley. Also enhancing the Bill Management web site to include various new features to assist customers to understand their usage, rates, their current and forecasted bill / usages.

Powerley provides services including all necessary architecture components and cloud computing services (i.e. Amazon Web Services) that are utilized to maintain the user-facing functionality as expected for:

• DTE Insight iOS and Android Mobile application, with ongoing software updates as required by respective operating systems

• Energy Bridges, including ongoing firmware support for real-time usage data from AMI meters and Zigbee and Z-Wave connected devices

• Bill Management (billmgmt.dteenergy.com) enhancements, with ongoing software updates and resolve defects(O&M) and provide updates as required

• Powerley Portal (portal.pwly.io), with support for all currently provided functionality, including customer management, energy usage visualization, bill impact information, content management, budget/rate calculator support, and all Demand Response capabilities.

See Exhibit A-24 N3 Lines 89-91 for additional project details.

Service Cloud Product Support for Customer Document Submission

- The Company will invest $0.8 million in the **Service Cloud Product Support for Customer Document Submission** project over the course of 36-months ending December 31, 2025, as shown on line 13 of Exhibit A-12 Schedule B5.7.2.

  This project was previously approved in U-21297 and reflects a variance of $0.2 million more in the 36 months ending December 31, 2024, than was approved for cost recovery due to the 20% disallowance from the Commission.

  The Customer Service Organization is seeking a long-term solution for external customers to submit documents for review and approval by DTE businesses during various customer service scenarios where document verification is required (i.e., Contact Center, Revenue Management and Protection (RM&P) and Collection Exceptions). The document submission portal is the only secure way for the Customer Service organization to obtain documents from DTE customers. When the document submission process is broken, it has an operational impact on customers trying to complete MIMO transactions, enrollment into payment programs such as low-income, obtain medical holds, etc.

  See Exhibit A-24 N3 Line 92 for additional project details.

Supporting Capabilities Test data and Test Data Mgmt.

- The Company will invest $1.0 million in the **Supporting Capabilities Test Data and Test Data Mgmt** project over the course of 36-months ending December 31, 2025, as shown on line 14 of Exhibit A-12 Schedule B5.7.2.

Line
No.

This project was previously classified as an IT Enhancement in U-21297 and supported by Company Witness Hatsios (U-21297 Capital Exhibit A-12 Schedule B5.7.3 (Hatsios), Line 22).

Currently the CR&B application team has a process to generate any type of test data to help self-service channels, Assisted Channel, and Training with their Sustainment and project testing activities. The team also needs to coordinate regression and performance test with the vendors. Vendors maintain the regression scripts and ensure the scripts are run every month to ensure there are no issues identified before production launch. In the instance where the solution is customer facing, the vendor ensures the customer facing website and its corresponding backend can handle the load under certain significant events like Outage, Move in Move out, etc.

See Exhibit A-24 N3 Lines 93-94 for additional project details.

Return-to-Health

Q37. Can you explain in detail Customer Service investments in the 'Return-to-Health' category?

A37. The Company will invest $25.6 million in the Return-to-Health category over the course of 36-months ending December 31, 2025, as shown in lines 15 through 24 of the Capital Expenditures Exhibit A-12 Schedule B5.7.2. The planned costs are primarily across projects that are as discussed further below:

Agency Web Site AGW Rebuild

- The Company will invest $1.8 million in the **Agency Web Site AGW Rebuild** project over the course of 12-months ending December 31, 2023, and has a historical spend of $2.7 million in 2022 as shown on line 15 of Exhibit A-12 B5.7.2.

Line No.

The Agency Website (AGW) was designed in 2004 to support the online interface between human service agencies and DTE. The need to rebuild is the result of requirement changes due to State and Federal guidelines year over year and introduction of new programs and new technology availability. The new system will allow external agencies the ability to track special program enrollments and review data related to bill payment assistance for customers-based program provided funding.

This project was previously approved for cost recovery in U-21297, and the Company reflects a variance of $1.6 million more in the 36 months ending December 31, 2024. This is primarily due to additional scope in 2023 to handle Customer Payments, Payment refund, Chargebacks on a nightly basis. The scope also includes to validate customer collection status, disconnect status before handling any payments. The 2022 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 96 for additional project details.

Archive and Purge

- The Company had a historical spend of $1.5 million in the **Archive and Purge** project over the 24 months ending December 31, 2023, as shown on line 16 of Exhibit A-12 Schedule B5.7.2.

Data archiving and purging refers to the saving of customer transactional data (e.g., invoices, meter reads) and correspondence data (e.g., emails, letters) and makes the data available for retrieval for a specified period, after which it will be purged from the CR&B system.

With the implementation of the Company's C360 billing system, the current SAP CR&B platform was sized to retain three years of transactional data and 13 months

Line No.

of customer correspondence. Retention policies for customer correspondence have been internally reviewed and require the Company to produce such documentation for customers for up to seven years. Retaining this level of historical data within the transactional system will degrade performance and overrun the system design size.

The Company reflects a variance of $0.4 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. During the design phase for data storage, it was determined that the optimal solution would be to build upon cloud data storage rather than on premise data storage to remediate / eliminate dependency to CR&B. This would further reduce data volume management challenges in CR&B. This required outside vendor services to support the implementation which resulted in the increased spend.

See Exhibit A-24 N3 Lines 97-98 for additional project details.

Contact Center Infrastructure

- The Company will invest $0.7 million in the **Contact Center Infrastructure** project over the course of 12-months ending December 31, 2023, with a historical spend of $1.8 million in 2022 as shown on line 17 of Exhibit A-12 B5.7.2.

Contact Center infrastructure includes all the hardware and software that enables the Contact Center's telephony and IVR systems to operate. The infrastructure includes a combination of servers (both physical and virtual), databases, applications, and vendor appliances. The current telephony systems were initially installed in 2017 while the current IVR systems were put into service between 2018-2019.

This work is critical to remain within vendor supported versions to receive future support as new vulnerabilities arise. In addition, investing in upgrades to this core infrastructure will provide the required foundation for future projects such as the Migrate IVR to the cloud project.

See Exhibit A-24 N3 Lines 99-100 for additional project details.

Customer Bill Print and Archive Software

- The Company invested $0.7 million in 2022 in the **Customer Bill Print and Archive Software** project in the historical period, which was not included in U-21297, as shown on line 18 of Exhibit A-12 Schedule B5.7.2.

DTE Electric and DTE Gas used two OpenText products – StreamServe and Extended Enterprise Content Management (xECM). This project upgraded StreamServe which the vendor had deemed end-of-life and no longer providing support as of March 2020. These products support the Customer Bill Print and Archive business processes. Stream Serve is used to convert the raw data files from the SAP Customer Relationship and Billing (SAP CR&B) system and converts them into customer bills and correspondences. DTE sends approximately 156 types of correspondence to customers ranging from outage alerts, payment plan changes, Choice enrollment notifications, bankruptcy deposit requests, home heating tax credit, letter of credit, etc. Every day, approximately 150,000 bills and 20,000 correspondences are sent and running operations which directly affects our customers and DTE on an unsupported platform was unacceptable. Extended xECM stores and archives transactional data and correspondences by customers for retrieval in the digital channels by the Customer Representatives (CRs) in the Customer Relationship Manager application. CRM is a Customer Relationship Management application, a front-end SAP tool used by CRs to support customer requests.

See Exhibit A-24 N3 Line 101 for additional project details.

Line No.

Customer Experience Suite

- The Company will invest $0.5 million in the **Customer Experience Suite** project over the course of 12-months ending December 31, 2023, and has a historical spend of $2.6 million in 2022, as shown on line 19 of Exhibit A-12 Schedule B5.7.2.

  In 2022, the Company implemented the Adobe Experience Cloud product. This scope included architecture design, creation of content templates, population of digital assets, data layer creation for analytics, and migration of approximately 400 static content pages from our legacy IBM Web Content Management platform to the new Adobe platform.

  This project was approved for cost recovery in U-21297, and the Company is seeking recovery of the $0.6 million more spend projected in the 36 months ending December 31, 2024, for reasons described below.

  The spend in 2023 was not planned and reflects an extension of the schedule and the labor cost to remediate vulnerabilities identified during system testing, prior to production release resulting in the incremental spend.

  See Exhibit A-24 N3 Lines 102-103 for additional project details.

Customer Service Infrastructure Landscape & Growth

- The Company will invest $5.9 million in the **Customer Service Infrastructure Landscape & Growth** project over the course of 12-months ending December 31, 2023, as shown on line 20 of Exhibit A-12 Schedule B5.7.2.

  The Company reflects a variance of $2.1 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to an increase in hardware cost and the increase in labor cost to resolve pre-production deployment issues.

Currently, DTE uses the SAP CR&B platform to provide customer relationship management, customer billing, customer master data management, business data management and application process orchestration. These functions are performed by the SAP CR&B applications Customer Relationship Manager (CRM), Industry Solutions Utility (IS-U), Business Warehouse (BW) and Process Orchestrator (PO). These applications and the associated databases are hosted on DTE premises on physical hardware and infrastructure. The current physical hardware and infrastructure was purchased and installed prior to SAP CR&B go-live in 2017. All hardware and infrastructure for the CR&B platform will reach end-of-life (EOL) at the end of 2022. This project refreshed the entire CR&B platform with hardware and infrastructure that is appropriately sized and supported for an additional five years.

See Exhibit A-24 N3 Line 104 for additional project details.

Digital Channels Transformation Program

- The Company will invest $10.5 million in the **Digital Channels Transformation Program** over the course of 36-months ending December 31, 2025, with a historical spend of $0.5 million in 2022, as shown on line 21 in Exhibit A-12 Schedule B5.7.2.

While the Company has made measurable improvements in providing customers with the ability to interact with DTE on the digital Web and Mobile customer channels for the five key customer transactions (MIMO, Outage, Collection, Billing and Payment). These digital platforms are aging, run on fragmented technologies, and, in some cases, unsupported. The core DTE website runs on a platform (IBM WebSphere Portal) that is unsupported, and no longer owned by the original supplier (IBM). This presents an operational risk to the channel and could lead to

Line
No.

the inability to serve DTE customers through the Web. The DTE iOS and Android Mobile applications have benefited from functional enhancements, however the foundational codebases for both applications were written in 2013-2014. Apple and Google continuously enhance and improve mobile phone application platforms, releasing new major versions annually. The aging DTE mobile codebase makes releasing new features and functionality to customers complex and in some cases not possible. During storms in 2021-2022, customers regularly experienced reliability issues with the mobile applications due to aging code, leading to difficulties reporting problems with service and receiving restoration updates.

While the Company has made measurable investments to improve the digital web and mobile customer channels and begin moving to the cloud, digital platforms are aging, run on fragmented technologies, and in some cases, unsupported technology platforms. The core DTE website runs on a platform (IBM WebSphere and IBM WebSphere Portal) that is unsupported, and no longer owned by the original supplier (IBM). This is an operational risk to channel and could, leading to inability to serve DTE customers on web channel. Additionally, architecture is consistently one-off, caused by app code duplication that can be resolved by building a standardized shell to eliminate waste/redundancy in excessive application code.

In 2025 this project will modify the separate and distinct Payments and Outage single-page applications to become web components that can reside within the architecture that will be established in 2023-2024.

The project will design, build, and test the current functionality of Guest Pay, Manage Payment Methods, Authenticated Payments page to the newer architecture hosted in the new platform. The project will also design, build, and test the current functionality of Report Outage, Down Wire, Get Status, Report outage by Police and Fire, Street Lighting to the newer architecture hosted in the new platform.

Alternatives considered included utilizing off the shelf solutions and continuing with the current approach of building multiple single page applications and was rejected because if we need to utilize off the shelf solutions, it will require to build a common foundational architecture and build the interfaces to integrate with the backend.

A do nothing alternative was rejected because without a common foundational architecture, product teams will continue to build separate single page applications for each transaction, driving up costs and increasing customer friction. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Lines 108 for additional project details.

Plant & Field

Q38. What is included in the Plant & Field Portfolio?

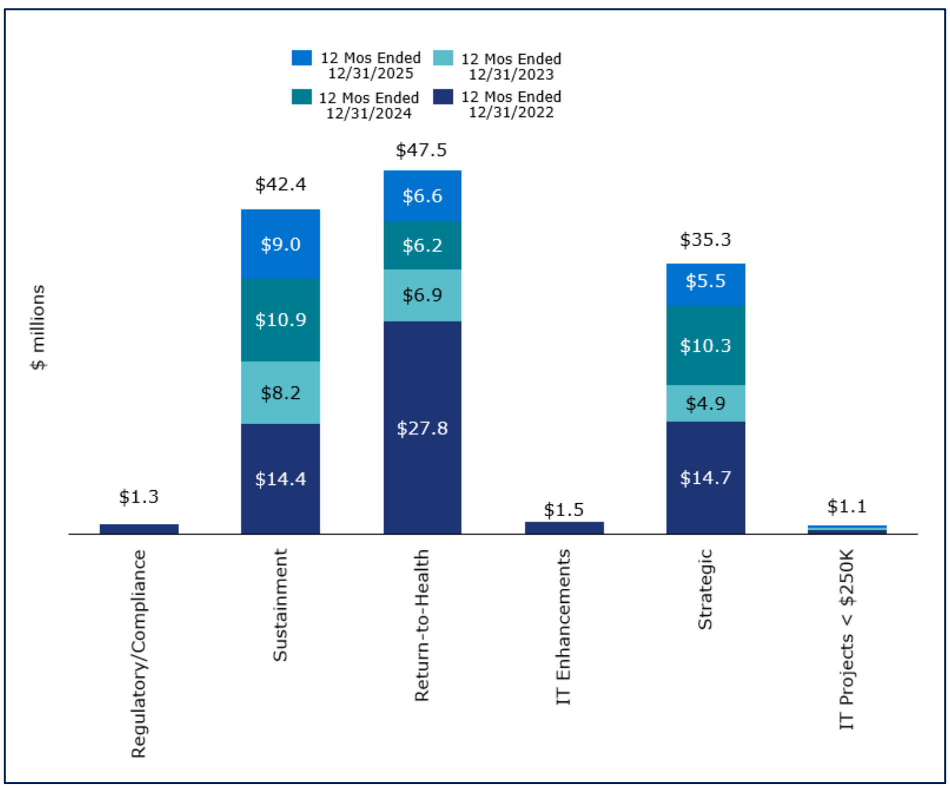
A38. The Plant & Field Portfolio supports IT business systems used by organizations such as Distribution Operations (DO), Energy Supply (ENS), Generation Optimization (GenOpts), and Fermi. Business systems in this area include core organization-spanning technologies such as the Work and Asset Management system, as well as department-focused systems such as Outage Management, equipment Tagging[8], Mapping, and other similar technologies.

Q39. What are the projected costs for investments in the Plant & Field Portfolio?

[8] for maintenance and authorized use

A39. As reflected on Line 5 of Exhibit A-12 Schedule B5.7, page 1, capital costs for Plant & Field total $58.9 million for the historical test year ended December 31, 2022, $47.7 million in the bridge period (for the 24 months ending December 31, 2024), and $22.6 million for the projected test period ending December 31, 2025. The individual initiatives that fall into this area appear in Exhibit A-12 Schedule B5.7.4. The synopses below provide the total spend for each line item involved in the Company's request for recovery in this rate case. with details regarding breakout by historical period, projected bridge period, and projected test period laid out in Exhibit A-12 Schedule B5.7.4, in columns d, g and h, respectively. Figure 10 represents a high-level view of capital allocation within the portfolio.

Figure 10 Plant & Field – IT Investment



Line No.

Regulatory/Compliance

GenOpts-FERC Order 841 Compliance

Q40. Can you explain in detail the Plant and Field investment in the Regulatory Compliance category?

A40. Yes, the Company will invest $1.3 million in the **GenOpts-FERC Order 841 Compliance** Project over the course of 12-months ending December 31, 2025, as shown on line 1 of Exhibit A-12 Schedule B5.7.4.

Federal Energy Regulatory Commission (FERC) Order 841 sets out electric storage resource regulations as well as the broader participation model associated with all involved entities. The Company's investment is both to comply with FERC Order 841[9] and to enable Electric Storage Resources (ESR) interconnected to the DTE Distribution System to participate in the Wholesale Power Market. This will provide functionality allowing any DTE Electric customer to install an ESR and start directly transacting wholesale power with the Midcontinent Independent System Operator (MISO)[10]. To accomplish these goals, DTE must (1) make appropriate adjustments to meter configuration to exclude wholesale power from billing calculations and (2) establish a wholesale distribution customer rate to compensate for distribution services provided to wholesale market participants.

The Company reflects a variance of $1.1 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This project was rescheduled to 2025, and there is no change to planned scope or cost.

See Exhibit A-24 N3 Line 114 for additional project details.

[9] Order No. 841 Order No. 841 | Federal Energy Regulatory Commission (ferc.gov) accessed 01/04/23

[10] MISO is an independent, not-for-profit, member-based organization focused on (1) Managing the generation and transmission of high-voltage electricity across 15 U.S. states and the Canadian province of Manitoba, (2) Managing the energy markets in the MISO region, and (3) Planning the grid of tomorrow

Line No.

Sustainment

Q41. Can you explain in detail Plant & Field investment in the Sustainment category?

A41. The Company will invest $28.1 million in the Sustainment category over the course of 36-months ending December 31, 2025, as shown in lines 2 through 16 of the Capital Expenditures Exhibit A-12 Schedule B5.7.4. The planned costs are primarily across projects that are discussed further below:

Advance Metering Infrastructure Application Health

- The Company will invest $5.0 million in the Advance Metering Infrastructure Application Health project over the course of 36 months ending December 31, 2025, and has a historical spend of $0.8 million in 2022, as shown on line 2 of Exhibit A-12 Schedule B5.7.4.

  Currently, Advanced Metering Infrastructure (AMI) has 2.5 million electric and 1.3 million gas meters. The electric AMI meters are integral to Distribution Operations (DO) storm management, interruptible service/demand response, electric power quality, long-term load planning, and customer billing accuracy. Planned investment in this area will address the servers and related Oracle databases that are either currently end-of-life or as scheduled to be end-of-life per the Original Equipment Manufacturers, referred to as OEM. The core AMI systems require ongoing operational asset health upgrades to maintain the overall reliability and availability of the infrastructure hosting the application and data. This investment also will provide further code development and AMI Portal configurations which will enable the required functionality within the AMI system for reporting on interval reads, tracking disconnects and reconnects, enable automatic failover between data centers to allow for full redundancy and other data management functions.

The Company reflects a variance of $0.8 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to the 20% disallowance from the commission, which resulted in a shift in project timing. The underspend from 2023 represents capital work shifted into 2024. The 2024 overspend is this additional capital work plus the funds needed to successfully execute the restructured scope.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 118 for additional project details.

ClickSoft Application Health

- The Company will invest $1.1 million in the **ClickSoft Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 3 of Exhibit A-12 Schedule B5.7.4. The project has a historical spend of $0.002 million in 2022.

  ClickSoft provides increased visibility of crews by dispatchers, availability of real time status at the point of activity to customers, and increased visibility into business and crew requests for improvements. This project manages the ClickSoft application health and associated infrastructure through triaging, tracking, resolution of issues, and prioritizing business requests for improvements & upgrades.

  The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines 119-122 for additional project details.

Line
No.

Distribution Operations Application Health

- The Company will invest $3.5 million in the **Distribution Operations Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $1.8 million in 2022, as shown on line 4 of Exhibit A-12 Schedule B5.7.4

  This project covers 50 IT supported applications impacting field crew assignment/management, central dispatch communication systems in support of field workers, grid management/distribution engineering, tree trim vegetation management, and public protection for storm additions. These applications are key operational assets fundamental to our primary business functions – making the ongoing required support a non-discretionary investment.

  The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 126 for additional project details.

DTE Electric Generation Capacity Application Health

- The Company will invest $1.7 million in the **DTE Electric Generation Capacity Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.7 million in 2022, as shown on line 5 of Exhibit A-12 Schedule B5.7.4.

  This project was previously approved in U-21297 and reflects a variance of $0.4 million more in the 36 months ending December 31, 2024, than was approved for cost recovery due to the 20% disallowance from the Commission.

  For the duration of 2023-2025, there will be an annual project spend to fund regularly scheduled releases to our Generation Supply Management System (GSMS) platform, which the Company uses to effectively calculate which generation plants it will offer into the MISO market, which in turn contributes to

Line No.

the selection of plant capacity running per the MISO market schedule. Specifically, the GSMS vendor targets a quarterly release schedule, which the Company must adopt to remain compliant with MISO regulations such as the determination of how a plant is offered to the market and the need to remain current with MISO Shadow Billing (the method used to settle charges and revenue with the Company). When the Company is not current with the application release schedule, the Company loses its ability to understand and prepare accordingly for our financial exposure in this market as our calculations would not match current MISO calculation rules.

In addition, there will be the required investment associated with the changes MISO is making to its back-end system. These changes will jeopardize the way the Company's GSMS system connects to, and interacts with, MISO's system.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 130 for additional project details.

DTE Electric Utility Network (UN)

- The Company will invest $0.7 million in the **DTE Electric Utility Network (UN)** project over the course of 36-months ending December 31, 2025, as shown on line 6 of Exhibit A-12 Schedule B5.7.4.

  This project was previously approved in U-21297 and the Company reflects a variance of $0.1 million more in the 36 months ending December 31, 2024, than was approved for cost recovery due to the 50% disallowance from the Commission.

  DTE currently uses the ESRI ArcMap platform GIS (Geographic Information System) for geospatial data and analysis. This data includes information such as the distribution of electrical assets. ArcMap, however, will no longer be supported by Q1 2025. To account for this adjustment and maintain our current-state capabilities, the DTE Electric Utility Network project will implement the new ESRI

UN product in the cloud. This product replacement will increase availability, recoverability, scalability, and security while enabling business process efficiency. The initiative will leverage the latest technology on location data, business intelligence, and integrated systems to drive enterprise system automation and business performance for our public-facing and internal IT systems. It will improve safety in the field, improve reliability metrics and outage information, reduce customer complaints, and improve overall customer satisfaction.

See Exhibit A-24 N3 Lines 131 -132 for additional project details.

ESRI Application Health

- The Company will invest $0.9 million in the **ESRI Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 7 of Exhibit A-12 Schedule B5.7.4.

This project was previously approved in U-21297 and the Company reflects a variance of $0.1 million more in the 36 months ending December 31, 2024, than was approved for cost recovery due to the 20% disallowance.

ESRI application health supports enhancements to the Company's automated mapping system (Geographic Information System or GIS) that supports all GPS mapping data including operating maps and customer-facing outage maps. This investment includes procuring additional user licenses, IT labor cost associated with testing/installing service packs and security vulnerability remediation as part of regularly scheduled release enhancements. Failure to deploy GPS releases would result in inaccurate mapping data. Additionally, the investment is required to improve the management and sharing of data via workflow automation.

See Exhibit A-24 N3 Lines133-134 for additional project details.

Line No.

Fuel Supply Application Health

- The Company will invest $1.3 million in the **Fuel Supply Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 8 of Exhibit A-12 Schedule B5.7.4.

  This project will deliver the non-discretionary scope to manage key applications used by Fuel Supply. These applications are as follows:

  - AAR: Automated Rail Receipt is a solution used by Corporate Fuel Supply to manage inputs of coal, petcoke, and oil used by DTE's generation fleet. This system interfaces with data hosted by the vendor application Envision, which provides the location data of coal rail cars used by Corporate Fuel Supply.
  - GenMart: This data repository holds information related to the generation fleet and is utilized by Generation Optimization (GenOpts) and Corporate Fuel Supply (CFS). Fuel Inventory and Consumption reports for CFS allow DTE to build cost models and run cost-based scenarios for the purpose of market management, logistics decision making, and rail fleet optimization. It enables optimization and the ability to combine delivered fuel cost, plant variable cost, and dispatch cost to develop an optimized generation solution. This repository includes rail car maintenance analytics, aggregated data used by GenOpts for analytics on load components, information on Net System Output, and MISO Residual Load Adjustment data. Additionally, it serves as an archive database for all generation and load meters as well as emissions data.

  Beginning in 2021, the Power Cost Inc. Energy Trading and Risk Management (ETRM) application was implemented, delivering functions to plan natural gas purchasing, transportation, inventory management, nominating, and scheduling for the DTE gas fueled generation units. Starting in 2022, quarterly vendor releases to

Line No.

ETRM and AAR systems were tested and deployed. These upgrades are required to remain current under vendor support and provide new product capabilities to end users who were included in upgrades.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines 135-138 for additional project details.

ITS-SRS Application Health

- The Company will invest $1.6 million in the **ITS-SRS Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 9 of Exhibit A-12 Schedule B5.7.4.

The ITS-SRS staff supports the ADMS, GMS and eSCADA application portfolios. The requirements of supporting critical systems that ensure the safe and reliable operation of the electrical grid demand a high level of support. This demand covers the resource costs to support the ongoing operation of these applications. To ensure high availability and optimal performance, the system requires annual capital investment for regular upgrades and enhancements to the software products, servers, infrastructure, and workstations as well as accompanying expense for patching, compliance efforts, and maintenance to ensure that these systems are running at their best and can handle the demands placed on them.

See Exhibit A-24 N3 Lines 139-140 for additional project details.

ITS ADMS Application Health

- The Company will invest $2.1 million in the **ITS-ADMS Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 10 of Exhibit A-12 Schedule B5.7.4.

The ITS ADMS Application Health Program covers a suite of applications in use at DTE for safe and effective operation in the Electric System Operations Center (ESOC) and for Distribution Operations Dispatch. These include the following:

- OMS (Outage Management System) is used to manage and respond to outages in the power grid.
- DMS (Distribution Management System) is used to manage the distribution of power on the grid.
- EMS (Energy Management System) is used to monitor and control the generation and transmission of power.
- GMS (Generation Management System) is used to manage the generation of power, typically at a power plant or other large facility.
- SOM (System Operations Management) is used to manage the overall operation of the power grid.

The ADMS application portfolio is critical in safely supporting the electrical grid through use of these systems, which each require their own level of enhancements, upgrades, and support as well as licensing. The ADMS team is responsible for supporting and updating these applications as well as for integration infrastructure (ESB or Enterprise Service Bus) that connects all aspects of ADMS to DTE legacy systems. Without the proper enhancements, upgrades, and maintenance, there is a risk of system failure or malfunction, which can have serious consequences on the safe and reliable operation of the electrical grid.

See Exhibit A-24 N3 Lines 141-142 for additional project details.

Nuclear Generation Business Systems Replacement

- The Company will invest $2.0 million in the **Nuclear Generation Business Systems Replacement** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.5 million in 2022, as shown on line 12 of Exhibit A-12 Schedule B5.7.4.

Nuclear Generation has 36 key and critical applications that exist to satisfy regulatory, safety or business process requirements. The business unit has historically had between 3 and 6 critical and key applications that need to be updated each year. These include software, hardware and/or database environment upgrades or replacement each year due to regulatory changes, obsolescence, security vulnerabilities and continued protection from the risk of system failure and possible cyber-attack. Nuclear Generation has 36 applications which require regular security vulnerability remediation.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines 145-148 for additional project details.

Production Growth

- The Company will invest $4.3 million in the **Production Growth** project over the course of 36-months ending December 31, 2025, and has a historical spend of $9.1 million in 2022, as shown on line13 of Exhibit A-12 Schedule B5.7.4.

This project is to support the annual growth resulting from the ongoing increase in data and business processing needs. This will be accomplished by provisioning Just-In-Time computing power, storage capacity, database availability, and middle-tier infrastructure. As technology products approach the end of the product lifecycle, the Company must continue to make investments for supportability to ensure that software and hardware is operational to run the business. This project also enables IT business operations to perform within prescribed CPU-capacity, storage thresholds, system response times, and availability.

The Company reflects a variance of $9.0 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297.

In 2022, the company spent $7.7 million more than previously approved for cost recovery. This additional spend supported the purchase and deployment of infrastructure components supporting the ADC, DDC and various service centers, the purchase of 3-year software licenses to support the ADMS application, and the supporting labor costs to deploy the purchased components. The existing appliances were reaching end-of-life (EOL) at the end of 2022 and were planned for replacement. The devices procured had more capacity and capability than the infrastructure that was already in place and reduced the overall operational cost of maintaining the existing infrastructure as the new purchase included warranty.

In 2023, new capabilities were implemented as planned, and an overspend of $0.8million was invested to install the additional purchased hardware from 2022. The in-scope capabilities are related to outbound SMS features for Electric Damage Claims, execution of SRS Red Hat 3-year license agreement, OSI GMS license upgrade and proof of concept around gathering additional insights into possible power outages by leveraging data to provide periodic status report data for active Energy Bridges.

See Exhibit A-24 N3 Lines 149-152 for additional project details.

Renewable Operations Application Health

- The Company will invest $0.4 million in the **Renewable Operations Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.1 million in 2022, as shown on line 14 of Exhibit A-12 Schedule B5.7.4.

The Renewable Energy Operations organization performs monitoring, operations, and maintenance of all Company-owned wind and solar assets. Operations include predictive analytics on turbine health data, case management, work scheduling, and work tracking. This project is to perform work to support sustainment of DTE renewable assets and business processes. Renewable assets include IT infrastructure, applications, and systems for the existing ten wind and seven additional solar parks.

The scope of this investment includes required upgrades, new reports, interface changes, and release management. Systems impacted include GE Digital, Wind-SCADA, E-SCADA and GE connect adapter. The incremental changes needed for monitoring and managing wind parks will support business process improvement goals. Infrastructure work includes maintaining asset health for telecommunication at all wind and solar parks, such as firewalls, routers, switches, and domain controllers. Additionally, maintaining Renewable data center asset health such as software upgrades and vendor support.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines153-156 for additional project details.

Supervisory Control and Data Acquisition (SCADA) System Improvement

- The Company will invest $1.4 million in the **Supervisory Control and Data Acquisition (SCADA) System Improvement** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.6 million in 2022, as shown on line 15 of Exhibit A-12 Schedule B5.7.4.

DTE maintains critical applications which must comply with NERC-CIP regulation, cyber security standards, and requirements for controlling, monitoring, and supporting the electrical grid. SCADA monitors and controls the electrical system continually, supports Energy Management System (EMS) and Generation Management System (GMS) applications, and in the instance of an outage, provides rapid solutions.

An objective of this initiative is to adhere to regulatory and security standards by maintaining a safe cyber security posture. Additionally, the project will seek to apply the latest vendor updates required to ensure uninterrupted functionality.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines 157-160 for additional project details.

System for Fossil Generation for Coal and Gas

- The Company will invest $1.2 million in the **System for Fossil Generation for Coal and Gas** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 16 of Exhibit A-12 Schedule B5.7.4.

Several of the Energy Supply applications such as Power Plant Performance Management (P3M), the Laboratory Management System (LMS), PlantView and the Overtime Management System (OTM), all require monthly releases as well as hardware and software upgrades in alignment with accommodating vendor releases. Frequently, we also need updates to the Generating Availability Data System (GADS) reporting process, especially to reduce manual workarounds and transition manual entry into automated or programmatic features. Data validity is essential on this system as it not only affects operations but is also reviewed by MISO and federal regulatory agencies such as the Federal Energy Regulatory Commission (FERC). Therefore, failure to install required updates presents an unacceptably high risk of data inaccuracy. The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Lines161-164 for additional project details.

Return-to-Health

Q42. Can you explain in detail Plant & Field investment in the 'Return-to-Health' category?

A42. The Company will invest $19.8 million in the Return-to-Health category over the course of 36-months ending December 31, 2025, as shown in lines 17 to 28 of the Capital Expenditures Exhibit A-12 Schedule B5.7.4. The planned costs are primarily across projects that are discussed further below:

Advance Metering Infrastructure Field Collection System

- The Company will invest $4.6 million in the **Advance Metering Infrastructure Field Collection System** project (AMI) over the course of 36-months ending December 31, 2025, and has a historical spend of $2.1 million in 2022, as shown on line 17 of Exhibit A-12 Schedule B5.7.4.

The AMI Collection Engine (CE) requires updates to remain on vendor supported technology as well as operate within established security standards. To support the AMI Collection Engine SR7 project this return-to-health project will continue through 2025 to ensure that the test environment and production environments are upgraded to supported versions the addition of Collection Engine Application Servers, as well as Collection Engine Database Servers. The project includes purchasing new hardware and virtual components, including software, as well as the required labor hours for testing, configuration, and development. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line168 for additional project details.

Line No.

Corporate Instance - Maximo Application Suite Upgrade Phase 1

- The Company will invest $3.8 million in **Corporate Instance - Maximo Application Suite Upgrade** project over the course of 12-months ending December 31, 2025, as shown on line 19 of Exhibit A-12 Schedule B5.7.4.

  The corporate instance of Maximo Suite supports the Work Asset Management function for the following several key business units at DTE, including Distribution Electric Operations work and asset management. This asset and platform is critical to serve the needs of our customers and service the grid. The current version of Maximo 7 is scheduled to end vendor support in September of 2025. The newer version of Maximo is more than just a traditional upgrade and it requires a complete re-platforming as the underlying hardware and technical architecture is new. This new platform is aligned with the latest technology and security standards and will provide DTE a supported work and asset management platform. In 2025, the company will complete the planning and design phases. The complete design and finalized architecture design will support the future needs of the enterprise and incorporate the resiliency and agility to respond to the needs of the future.

  See Exhibit A-24 N3 Line 170 for additional project details.

DO Equipment Engineering Transformer Database

- The Company will invest $0.4 million in **DO Equipment Engineering Transformer Database** project over the course of 12-months ending December 31, 2024, as shown on line 21 of Exhibit A-12 Schedule B5.7.4.

  Currently at DTE, the DO Equipment Engineering Transformer Database holds key data related to our Engineering Transformers. This database uses old technology and is not in alignment with the company efforts to invest in the strength and reliability of our Distribution Operations assets through maximization of corporate platform solutions. We need to invest in upgrading this asset to continue vendor support, as well as migrate to the Maximo system for Asset and Work Management functionality. This project will invest to first upgrade the current systems' underlying technologies including the Operating system and Database Tooling to the minimum extent that will enable currently supported functionality. Second, we will work to migrate transformer assets to Maximo to track transformer data attributes and maintenance activities. This will enable us to leverage Maximo Asset Management and Work Management Processes.

See exhibit A-24 N3 Line 172 for additional project details.

Maximo Platform Program

- The Company will invest $4.7 million in the **Maximo Platform Program** project over the course of 36-months ending December 31, 2025, and has a historical spend of $4.1 million in 2022, as shown on line 24 of Exhibit A-12 Schedule B5.7.4.

IBM is the vendor for Maximo which is the Work and Asset Management solution. It provides functionalities such as procurement of assets, preventative maintenance of assets, install and replacements of assets, work order management, timekeeping, and materials management. The Maximo system (version 7.6.0) was initially implemented in 2015.

This project will implement configuration changes, new feature enhancements, mobile enablement, and automated business processes for Work and Asset Management.

The Company reflects a variance of $3.7 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. In 2022, $2.2 million additional spend associated with the Work and Asset Management portion of the Platform was required to support the upgrade of two end-of-life servers (hardware), and Oracle Licenses and the required labor to build, test and deploy. In 2023, the incremental $1.6 million was approved to meet demand of the business units for configuration changes, new feature enhancements, mobile enablement, and automated business processes for Work and Asset Management for across multiple business units, Distribution Operation, Gas Operations, Energy Supply, Renewables, Fleet and Facilities. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Lines 176 -179 for additional project details.

IT Enhancements:

DTE Electric Generation Capacity Enhancements

Q43. Can you explain in detail Plant & Field investment in the IT Enhancements category?

A43. Yes, the Company invested $1.5 million in the **DTE Electric Generation Capacity Enhancements** Project over the course of 12-months ending December 31, 2022, as shown on line 29 of Exhibit A-12 Schedule B5.7.4.

Under circumstances where available generation is unable to meet load demand, the Company will communicate the need to customers under Interruptible Agreements [11]that their load must be reduced. This load is either curtailed by the Company directly, or by the customer, depending on the agreement. For both agreement types, there are communication requirements that must be met prior to the Company-initiated curtailment, or the customers risk a penalty for not initiating their own load reduction. In either case, the Company risks being assessed high

[11] Interruptible Agreements are offered to /signed by large customers to reduce their load during high demand situations at DTE's request in turn for a better rate, in this case D8.

market penalties and loss of capacity credit when load reduction does not occur within the required timeframe. Due to lower energy reserves in the market, the potential for the frequency of these event has increased.

To address this growing need, the Company implemented a solution to manage the required communication process to ensure successful communication with the customer. The current process is a manual process shared between two business units. Major Account Services (MAS) manages the customer account data, and Generation Optimization (Gen Opts) manages the communication process to enrolled customers. This process is time consuming for both business units to manage, execute, and validate. The manual process is also vulnerable to human error, which may result in corporate financial penalties.

See Exhibit A-24 N3 Line 187 for additional project details.

Strategic

Q44. Can you explain in detail Plant & Field investment in the Strategic category?

A44. The Company will invest $20.6 million in the Strategic category over the course of 36-months ending December 31, 2025, as shown in lines 30 through 37 of the Capital Expenditures - Exhibit A-12 Schedule B5.7.4. The planned costs are primarily across projects that are discussed further below:

Field Service Management- ClickSoft for EFO (Electric Field Operations)

- The Company will invest $0.5 million in the **Field Service Management- ClickSoft for EFO (Electric Field Operations)** project over the course of 12-months ending December 31, 2023, and has a historical spend of $1.1 million in 2022, as shown on line 31 of Exhibit A-12 Schedule B5.7.4.

Line
No.

The vendor (ABB) supporting our field service work management system (Service Suite) communicated in 2019 that their product would no longer be supported. This system was originally implemented in 2007 and implemented its last upgrade in 2014. The end-of-life (EOL) classification by a vendor means they would no longer provide critical security vulnerability remediation to ensure the software remains safe from new cyber threats or support business process changes. Due to Service Suite limitations, we are also unable to adapt to improvements in service management requirements. This investment is critical to the Company's Distribution Operations Field Service Management staff to provide a reliable and secure business process application.

Aligned with the Company's cloud strategy, this project will implement a new field management product, ClickSoft. This is a cloud-based product which enables configuration within the product as opposed to the server. It optimizes automatic routing of requests and changes for electric field operations and has an appointment book functionality. Overall scope includes Timesheet functionality, development of an additional 15 UI (User Interface) screens, Appointment Book, optimization of crew routes, automatic assignment of work and system interfaces between ClickSoft, Maximo, SAP CRM, and the Outage Management System. Additionally, the Data Lake Platform effort will continue to move data from ClickSoft to the Company data platform.

The project reflects a variance of $0.5 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This increase was primarily due to the delay and required integration with the ADMS project which extended the resources over a longer period going through March 2023. Specifically, the new product was required to interface with Service Suite as part of standard migration activity, but also needed to successfully integrate with ADMS as the new and advanced ADMS/OMS systems would send orders to the new product after completing migration away from ServiceSuite. Alignment between these two projects was critical. The 2022 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 190 for additional project details.

Storm Data Lakehouse

- The Company will invest $2.0 million in the **Storm Data Lakehouse** project over the course of 12-months ending December 31, 2025, as shown on line 36 of Exhibit A-12 Schedule B5.7.4.

Situational awareness is paramount during storms that impact our service territory and result in customer outages. DTE emergency headquarters and storm roles need timely and reliable access to customer, storm, job, and damage assessment information to effectively manage crew resources and provide our customers with accurate restoration information. The Storm Data Lakehouse will build upon our current enterprise data lake infrastructure to provide a performant, unified access layer for storm data and storm analytics needs.

This is provided today by having four separate databases in Azure to support the user load requirements. By implementing the Storm Data Lakehouse, we can reduce the number of databases and achieve cost optimization of cloud hosted database charges.

Build on current enterprise data lake infrastructure (hosted in Azure cloud) to implement a purpose-built Storm Data Lakehouse that provides a performant, unified access layer for storm datasets and storm analytics needs. This will provide fast, concurrent querying on large data volumes and provide the building blocks for visualizations such as system outage screen (SOS) and situational awareness reports. The Storm Data Lakehouse will provide data ingestion, data storage, metadata, data and report visualization, and a data consumption layer that is purpose built meet the needs for storm analytics, storm reporting, and situational awareness of storm restoration efforts.

These benefits of this investment will provide timely and reliable data for outages, regions, and customers impacted which will enable improved decision making for storm restoration and enable better estimates for our customers.

This project is supporting the Company's storm response investments discussed in Company Witness Hill's testimony (please refer to Q&A 17) and the customer interaction improvements as discussed in Witness Hatsios' testimony (please refer to Part 6).

See Exhibit A-24 N3 Line 198 for additional project details.

Storm Simulation Lab

- The Company will invest $10.0 million in the **Storm Simulation Lab** project over the course of 24-months ending December 31, 2025, as shown on line 37 of Exhibit A-12 Schedule B5.7.4.

From 2021 through 2023, DTE experienced 13 severe weather-related events each exceeding 110,000 unique customer outages, averaging 274,000 customers impacted. These particularly impactful periods of outage are known within the Company as "Catastrophic" or CAT Storm. During these CAT Storms, failures in our IT systems such as Outage Management result both Customer and Operational impact occurred 60% of the time. The average duration for CAT storm IT system related outages is 6.8 hrs. During these events, customers may not have been able to report outages, wire down events, hazards, etc. and could also experience delayed or incorrect communications related to their restorations. Field crews would also lack the ability to restore power, working quickly and efficiently from paper with manual processes to plan, schedule, dispatch, and provide statuses of necessary work. Analyzing the data from our IT major incidents shows that, during 60% of those events, these kinds of system failures are directly caused by high load that is beyond the design capacity of the related and interconnected systems. While the Company has remediated these issues and corrected the system designs in reaction to these storm events, we have no ability to identify these failure points before they impact our customers and our employees.

The Storm Simulation Lab will identify the maximum throughput that each system's design can handle and allow us to proactively make the necessary design changes before a storm situation. After implementing the Storm Simulation Lab, the number of IT major incidents incurred due to high load will be drastically reduced with a target of 10% overall reduction in the frequency of IT outages caused by load-related system issued during CAT Storm events. To address this opportunity, the Company will invest in building a Storm Simulation Lab beginning in 2024. The lab will provide:

- **Identify and build the "testing harness"** for storm critical systems – This refers to the suite of tools and related environments required to conduct focused and largely automated end-to-end testing for the subset of systems identified as being critical during Storm events.
- **Execute the initial end-to-end test**: the Company will define the approach, collect available data, and conduct the end-to-end tests needed to promote the resiliency of our critical Storm systems. From this the Company can identify

the issues/ risks from the tests and translate these into actions for the appropriate application teams

The Storm simulation lab will add the capability to test the end-to-end capabilities of DTE's customer and outage systems fully proactively before each storm season as well as after any significant changes to the associated IT systems.

The project aligns with DTE's priorities of ensuring the safe and reliable operation of the electrical grid, restoring customers within 48 hours, and continuing to reduce the frequency and duration of electric outages.

This project is supporting the Company's storm response investments discussed in Company Witness Hill's testimony and the customer interaction improvements as discussed in Witness Hatsios' testimony.

See Exhibit A-24 N3 Lines 199-200 for additional project details.

<u>Information Technology for Information Technology (IT for IT)</u>

Q45. Can you describe the IT for IT Portfolio?

A45. The Information Technology for IT Portfolio consists of capital projects that represent investments made within IT for the enterprise as a whole or that enable the functioning of the IT Department in support of the overall Company. These capital project investments represent initiatives that are more periodic in nature than ongoing year over year asset replacements or that bring significant new capabilities to the IT department.

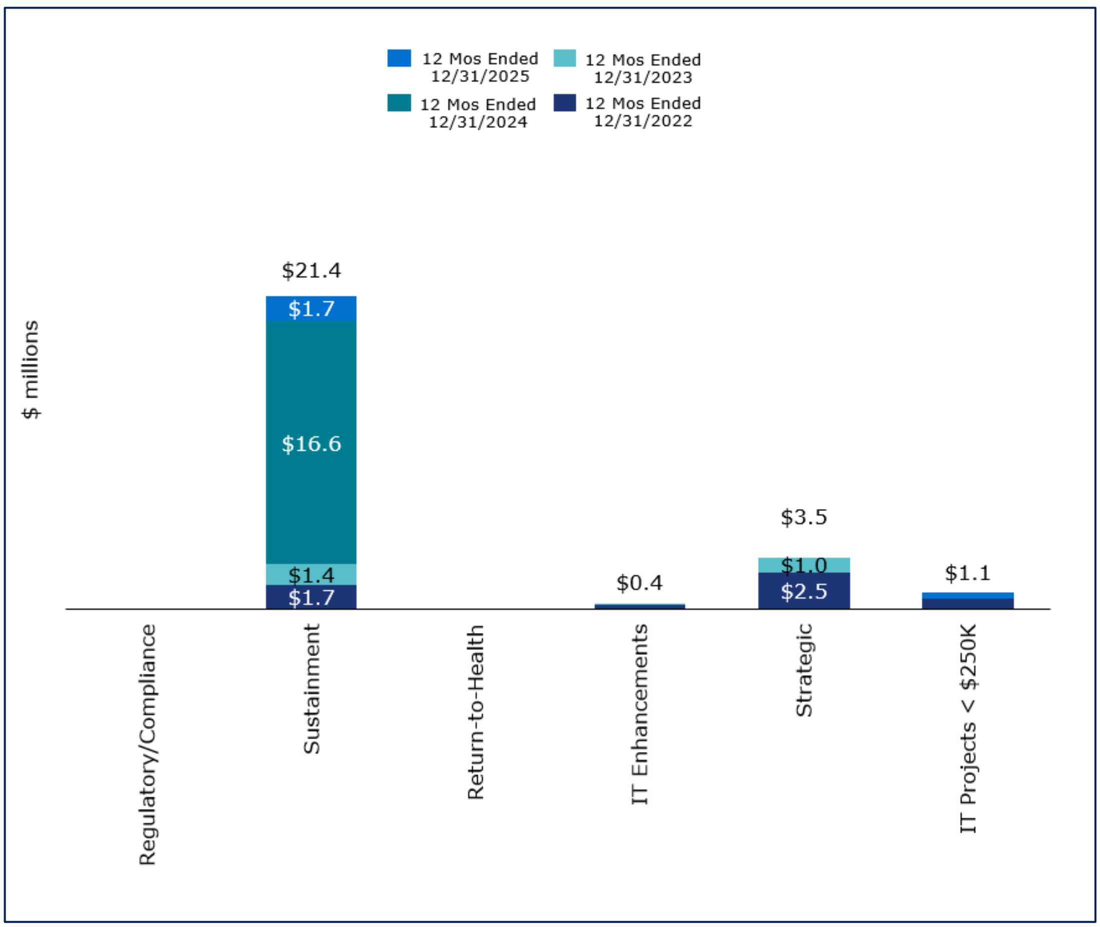
Q46. What are the projected costs for investments in the IT for IT Portfolio?

A46. As reflected on line 6 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures for IT for IT total $5.2 million for the historical test year ended December 31, 2022,

$19.1 million in the bridge period (for the 24 months ending December 31, 2024), and $2.1 million for the projected test period ending December 31, 2025.

The individual initiatives that fall into this area appear in Exhibit A-12 Schedule B5.7.5. The synopses below generally provide the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in Exhibit A-12 Schedule B5.7.5, in columns d, g and h, respectively. Figure 11 represents a high-level view of capital allocation within the portfolio.

Figure 11 IT for IT Investment



Line No.

Sustainment

IT for IT Application Health

Q47. Can you explain in detail IT for IT investment in the 'Sustainment' category?

A47. Yes, the Company will invest $19.7 million in the **IT for IT Application Health** project over the course of 36-months ending December 31, 2025, and has a historical spend of $1.7 million in 2022, as shown on line 1 of Exhibit A-12 Schedule B5.7.5.

This project includes the production upgrades for IT Services Platform in 2022-2025, including ServiceNow, GitHub, and Azure Devops. This ensures that applications do not go out of support provided by the vendor and provides regular application upgrades to mitigate security vulnerabilities. Yearly, we complete version upgrades (two annually for ServiceNow, other applications as made available by providing vendors). This project enhances workflows to improve efficiency, adds new items to the service catalog to take advantage of the ServiceNow solution to improve efficiency, enables automations, extends discovery and event management to reduce unplanned outages, and manages vulnerability identification and remediation. ServiceNow is essential to the company's IT governance and control and critical tool for supporting SOX and PCI testing. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 204 for additional project details.

Strategic

Q48. Describe IT for IT investment in the Strategic category.

A48. The Company will invest $1.0 million in the Strategic category over the course of 36-months ending December 31, 2025, as shown in lines 3 to 5 of the Capital

Expenditures - Exhibit A-12 Schedule B5.7.5. The planned costs are primarily across projects that are discussed below:

Cloud Management (Service Now)

- The Company invested $0.6 million in **Cloud Management (Service Now)** project in the historical year ending December 2022, with a credit of ($.065) in 2023, as shown on line 4 of Exhibit A-12 B5.7.5. This project was approved for cost recovery in U-21297, and the Company is seeking no additional recovery in this instant case. The project reflects a variance of $0.2 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297 due to a credit from the vendor.

<u>Information Protection & Security</u>

Q49. Can you describe the Information Protection & Security Portfolio?

A49. Information Protection & Security (IPS) investments focus on the reliability of security infrastructure as well as improving the Company's overall Security posture in Information Technology (IT) and Operational Technology (OT). The Company is seeking to improve the combined risk posture across IT and OT by implementing a unified approach to security governance, covering both areas while still acknowledging that security requirements and risk appetite may be different across the two domains. Traditionally OT systems are more likely to be secure due to air gap (limited or no external connectivity), protocols, and specialized functions - while IT systems are all interconnected and use common protocols, standard interfaces, and APIs. As the world moves to more interconnected systems, both domains rely on the same infrastructure such as Windows, or Linux, both use the same hardware, and connect via the same Transmission Control Protocol/Internet

Protocol networks. As a result, both systems face many of the same threats and vulnerabilities. An IT system exploit can lead to OT system compromise just as it can lead to an IT system compromise, so the Company's cybersecurity investment uses a balanced approach to keep cybersecurity infrastructure healthy and appropriately updated to address emerging threats, while we increase our focus on maturing cybersecurity controls in the OT domain. The Company has established this risk-based framework to apply uniform standards across both technologies.

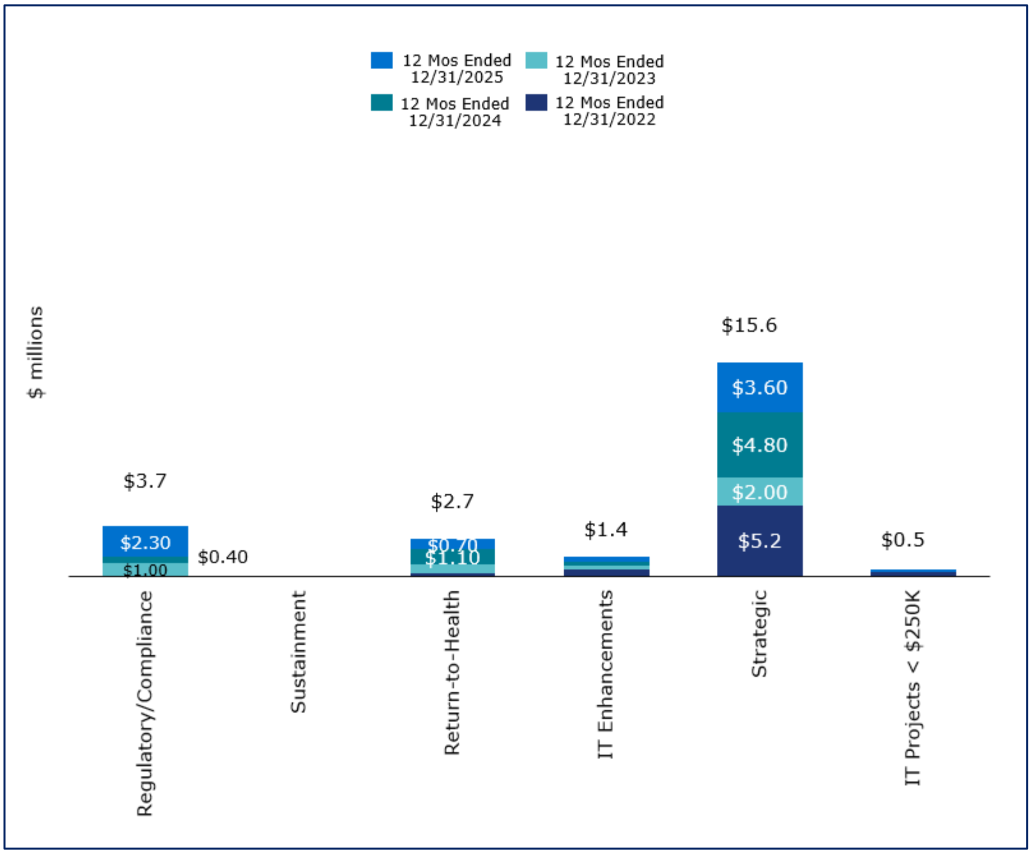
Q50. What are the projected costs for investments in the IPS Portfolio?

A50. As reflected on line 7 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures for IPS total $6.1 million for the historical period ended December 31, 2022, $10.6 million in the bridge period (for the 24 months ending December 31, 2024), and $7.2 million for the projected test period ending December 31, 2025.

The individual initiatives that fall into this area appear in Exhibit A-12 Schedule B5.7.6. The synopses below generally provide the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in Exhibit A-12 Schedule B5.7.6 in columns d, g and h, respectively. Figure 12 represents a high-level view of capital allocation within the portfolio.

Line No.

Figure 12 IPS– IT Investment



<u>Regulatory/Compliance</u>

Q51. Can you explain in detail IPS investment in the 'Regulatory/Compliance' category?

A51. Yes. The Company will invest $3.7 million in the Regulatory/Compliance category over the course of 36-months ending December 31, 2025, as shown on line 1 to 4 of Exhibit A-12 Schedule B5.7.6.

Cloud Privilege Access Management

- The Company will invest $0.9 million in the **Cloud Privilege Access Management** project over the course of 36-months ending December 31, 2025, as shown on line 1 of Exhibit A-12 Schedule B5.7.6.

  This project will complete the migration of the legacy on-premise CyberArk solution to SaaS based model. The scope of work will include the identification of all privilege accounts across the Company in IT and OT[12] environments. The CyberArk solution will be integrated with SailPoint for Identity Governance lifecycle processes, ServiceNow ITSM, ServiceNow CMDB for automation, and SEIM solution for alerting/monitoring. All secure privileged accounts on critical assets across the enterprise IT and OT environment will be onboarded.

  This project was previously approved in U-21297 and reflects a variance of $0.4 million less in the 36 months ending December 31, 2024. This project was put on hold and will resume in 2025, reflecting only a schedule shift in the project. The 2023 spend was approved for cost recovery in U-21297.

  See Exhibit A-24 N3 Line 213 for additional project details.

Security Information & Event Management (SIEM) End of Life Replacement

- The Company will invest $1.0 million in the **SIEM End of Life Replacement** project over the course of 12-months ending December 31, 2025, as shown on line 2 of Exhibit A-12 Schedule B5.7.5.

  The current Security Information & Event Management (SIEM) will be at end of life and unsupported by the vendor at the end of 2025. The SIEM performs real-time monitoring and analysis of security events, generates security alerts for investigation, and logs security data for compliance and auditing purposes such as

[12] Operational Technology

North American Electric Reliability Corporation (NERC), Payment Card Industry (PCI), Security Exchange Commission (SEC), Sarbanes-Oxley (SOX), and Transportation Security Administration (TSA).

The above regulations mandate the logging of security events. Without an operational SIEM, the logging would not occur, placing the Company at risk for non-compliance. Additionally, the SIEM is used to monitor and detect cyber security threats. Undetected cyber incidents could result in significant financial, reputational, and customer data integrity risks to DTE.

See Exhibit A-24 N3 Line 214 for additional project details.

Vendor Onboarding for DTE

- The Company will invest $0.8 million in the **Vendor Onboarding for DTE** project over the course of 12-months ending December 31, 2025, as shown on line 3 of Exhibit A-12 Schedule B5.7.5.

  This project was previously approved for cost recovery in U-21297. The project reflects a variance of $0.6 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is due to the project being rescheduled to 2025.

Vulnerability Scan Tool

- The Company will invest $1.0 million in the **Vulnerability Scan too**l project over the course of 36-months ending December 31, 2025, as shown on line 4 of Exhibit A-12 Schedule B5.7.5.

  This project was approved for cost recovery in U-21297. The project reflects a variance of $0.6 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This primarily due to a schedule change, shifting the project start to 2025 and carrying over the implementation into 2026. There is no change to planned scope or cost.

Return-to-Health

Q52. Can you explain in detail IPS investment in the 'Return-to-Health' category?

A52. The Company will invest $2.5 million in the Return-to-Health category over the course of 36-months ending December 31, 2025, as shown in lines 5 to 7 of the Capital Expenditures – Exhibit A-12 Schedule B5.7.6. The planned costs are primarily across projects that are discussed further below:

Cloud Security

- The Company will invest $1.2 million in the **Cloud Security project** over the course of 36-months ending December 31, 2025, as shown on line 5 of Exhibit A-12 Schedule B5.7.6.

This investment will deliver asset monitoring and improve our cloud security disposition. Monitoring today is reactive which creates delays in our response to cyber security- related events. The solution to be implemented will provide proactive monitoring capabilities that allows DTE to respond faster to security events – thereby reducing risk and lowering impact to DTE systems. This will also allow DTE to address unmonitored assets (applications and servers). The recommended solution is aligned with the Company's platform roadmap. The 2023-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 220 for additional project details.

Cyber Security Defense Center (CSDC) Growth and Lifecycle Management

- The Company will invest $1.0 million in the **Cyber Security Defense Center (CSDC) Growth and Life Cycle Management** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.2 million in 2022, as shown on line 6 of Exhibit A-12 Schedule B5.7.6.

This project will enable cyber security monitoring capabilities and hardware life cycle to maintain detection of and defense against threats to DTE cyber assets. DTE will continue to expand cyber defense & intelligence monitoring to meet the ever-growing threats. This project will utilize existing tools and processes to maintain our ability to monitor and respond to threats and incidents more effectively. It will entail the purchase of additional licenses for the Security Information and Event Monitoring (SIEM) to accommodate increasing security log volume, purchase of additional licensing for existing threat intelligence feeds to accommodate increasing security alerts, and management of the hardware life cycle of packet capture hardware. The investment will also cover network taps, and sensors that ensure network monitoring remains operational.

The 2022-2024 spend for this project was approved for cost recovery in in U-21297 and will conclude in 2025.

See Exhibit A-24 N3 Lines 221-224for additional project details.

IPS Operations PAWS and DC Replacement

- The Company will invest $0.3 million in the **IPS Operations PAWS and DC Replacement** project over the course of 12-months ending December 31, 2024, as shown on line 7 of Exhibit A-12 Schedule B5.7.6.

Cyber Operations maintains and supports several cyber assets that reach end of life each year. To maintain security operations for DTE identities, key and critical assets for these systems require hardware, software replacements/upgrades, additional capabilities added to the platforms to support security growth, maintain a healthy risk posture, and minimize risks from insider/outsider threats. This supports the Company's best operated strategy and aligns with our Cyber Security Strategy. Two such assets are Privileged Access Workstations (PAW) and Domain Controllers (DC).

See Exhibit A-24 N3 Line 225 for additional project details.

IT Enhancements

Endpoint Protection

Q53. Describe IPS investment in the IT Enhancements category.

A53. The Company invested $0.9 million in the **Endpoint Protection** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.5 million in 2022, as shown on line 8 of Exhibit A-12 Schedule B5.7.5.

This project was previously approved in U-21297 and reflects a variance of $0.2 million more in the 36 months ending December 31, 2024, than was approved due to the 20% disallowance from the commission.

DTE uses Endpoint Protection as a standard tool of choice to secure end user workstations as well as Windows based servers. It provides the last layer of protection to prevent malware and malicious attacks, as well as to provide remediation and investigation capabilities. The 2022-2024 spend was approved for cost recovery in U-21297.

See exhibit A-24 N3 Line 229 for additional project details.

Line No.

Strategic

Q54. Can you explain in detail IPS investment in the Strategic category?

A54. The Company will invest $10.4 million in the Strategic category over the course of 36-months ending December 31, 2025, as shown in lines 9 to 17 of the Capital Expenditures – Exhibit A-12 Schedule B5.7.6. The planned costs are primarily across projects that are discussed further below:

Automated Provisioning

- The Company will invest $3.9 million in the **Automated Provisioning** project over the course of 36-months ending December 31, 2025, and has a historical spend of $1.6 million in 2022, as shown on line 9 of Exhibit A-12 Schedule B5.7.5.

This planned investment will include the work needed to replace the Oracle Waveset system with SailPoint because the current product went out of support by the vendor in 2019. An unsupported product cannot be updated to keep up with the pace of changing technology, cyber security, or regulatory requirements. Migration to the SailPoint system will provide commensurate features, with the added ability to integrate role-based access control, and scalability in support of future need.

This project was previously approved in U-21297 and reflects a variance of $1.1 million more in the 36 months ending December 31, 2024, than was approved for cost recovery due to the $0.7 million (20%) disallowed by the Commission. The balance of $0.4 million was spent in 2022 to pull ahead 10 applications from 2023 into 2022 and the incremental cost associated with the increase labor cost to support this scope pull ahead. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 233 for additional project details.

Azure Active Directory Federation Implementation

- The Company will invest $1.2 million in the **Azure Active Directory Federation Implementation** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.06 million in 2022, as shown on line 10 of Exhibit A-12 Schedule B5.7.6

  The existing on-premise multifactor authentication (MFA) solution limits our ability to update user authentication without manual intervention. This project will implement/configure AD to support internet facing systems and Software as a Service (SaaS) cloud applications. As the Company increases its use of cloud computing, it is imperative that it continues to ensure authentication is enabled for all Company applications, including cloud-based solutions. With the implementation of Active Directory for cloud applications, single sign-on for external facing applications will be enabled, ensuring password security and ease of use. The 2022-2024 spend was approved for cost recovery in U-21297.

  See Exhibit A-24 N3 Line 237 for additional project details.

Cyber Excellence Plan (CEP) Program

- The Company will invest $0.9 million in the **Cyber Excellence Plan (CEP) Program** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.3 million in 2022, as shown on line 11 of Exhibit A-12 Schedule B5.7.6.

  The Company established the CEP program to build a cross-business-unit collaborative team to identify and address cyber security issues that expose the Company's operational technology infrastructure at its facilities.

  In March 2022, DTE hosted an Edison Electric Industry (EEI) Culture of Security (COS) Peer Review with the intent to receive and share best practice

Line No.

recommendations with industry peers regarding the DTE cyber and physical security landscape. Given the recommendations, DTE elected to focus the Cyber Excellence program on (1) the cyber security metrics collection process and presentation enhancements during 2023, in addition to (2) continued expansion of the DTE cyber security monitoring capability for Operational Technology during 2023-2024.

The project cost was approved for recovery in U-21297 through 2024 and is seeking recovery for 2025 spend projected in the current case. In 2025, additional network sensors will be purchased and installed in specific critical electric generation OT network locations prioritized by electric generation capacity. Deploying these network sensors will aid in early detection of malicious cyber security events in these critical networks. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line241 for additional project details.

Enterprise Mobility Management

- The Company will invest $0.5 million in the **Enterprise Mobility Management** project over the course of 36-months ending December 31, 2025, shown on line 12 of Exhibit A-12 Schedule B5.7.6.

The Company is placing increased emphasis on mobility and the ability to work from anywhere, which includes the planned introduction of a personal device policy. The provisioning and management of the increasing number of Company and personal devices accessing our networks will require a more capable enterprise mobility management platform. DTE has deployed Enterprise Mobility Management (EMM) platform, a Microsoft solution, for managing devices that will process, store, or transmit DTE data on Company-owned devices and "Bring Your

Own Devices" (BYOD). The continuing investment will support securing corporate owned devices and executive level devices. This includes securing them and bringing advanced capabilities to increase end user experience. This project will provide a system and associated set of policies to manage and secure all mobile devices accessing Company resources and data.

This project reflects a variance of $0.4 million less than approved for cost recovery in U-21297 due to late project start due to limited resources and project priorities at the start of the year in FY23 and a transfer of 340k to the Mobile Device Management demand to support deploying EMM policies and processes to all DTE owned mobile devices. The 2023 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 243 for additional project details.

Network Access Control

- The Company will invest $1.8 million in the **Network Access Control** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.2 million in 2022, as shown on line 13 of Exhibit A-12 Schedule B5.7.6.

  Due to the heightened global cyber security risk, this project continuation is required. This investment will provide increased network security when these devices attempt network access, and will unify endpoint security technology, user and system authentication, and network security enforcement.

  This project was approved in U-21297 through the bridge period and reflects a variance of $1.7 million less than approved for cost recovery in U-21297. This reflects a schedule shift of the project implementation from 2023-2024 to 2024-2025. The 2022-2024 spend was approved for cost recovery in U-21297.

  See Exhibit A-24 N3 Line 247 for additional project details.

Line No.

Ransomware Protection

- The Company invested $2.5 million in the **Ransomware Protection** project over the course of 12-months ending December 31, 2022, as shown on line 14 of Exhibit A-12 Schedule B5.7.6.

  This project reflects a variance of $2.2 million more than approved for cost recovery in U-21297. In 2022, the Company was required to respond to the TSA mandate to implement the additional protection actions in support of the mandate which is reflected in the increased spending.

  The Ransomware Protection project will advance cyber security recovery capability by means of automated data isolation security analytics, and recovery/remediation to protect against ransomware attacks. Ransomware attacks are becoming more common and sophisticated, and the Company's cyber security must mitigate these risks to protect Company data. This investment provides data to make evidence-based decisions and will allow the Company to proactively prevent, detect, and respond quickly to ransomware attacks threatening our organization.

  Technology was purchased including Data Vault Domain for hosting our Critical Applications and from which related data can be recovered in case of a Ransomware attack as part of a Cyber Recovery Plan. This separate isolated, air-gapped, infrastructure will serve as a vault with separation preventing ransomware from traversing across the network and locking systems.

  Initial infrastructure is required to build out the vaulting capability along with first year of storage. Then, year-over-year storage for the vault will be purchased in subsequent years.

  See Exhibit A-24 N3 Line 248 for additional project details.

Ransomware Recovery

- The Company will invest $1.4 million in the **Ransomware Recovery (previously called Ransomware Protection)** project over the course of 36-months ending December 31, 2025, as shown on line 15 of Exhibit A-12 Schedule B5.7.6.

  Ransomware attacks are becoming more sophisticated and DTE Cyber security must mitigate these risks to protect DTE Energy data. Furthermore, the TSA has mandated Cyber security controls requiring offline storage for recovery solutions.

  This project was approved for cost recovery in U-21297 through 2024 and the 2025 scope reflects the continuation of this project, for which the company is seeking recovery in the current case. The 2023-2024 spend was approved for cost recovery in U-21297.

  See Exhibit A-24 N3 Line251 for additional project details.

Recovery Manager for AD- Disaster Recovery Edition

- The Company will invest $0.7 million in the **Recovery Manager for AD- Disaster Recovery Edition** project over the course of 12-months ending December 31, 2024, as shown on line 16 of Exhibit A-12 Schedule B5.7.6.

  This project will advance the Company's position as part of our cyber defense with respect to disaster recovery. The implementation of DRE can reduce recovery time to within 24-48 hours. This is critical to the Company's operations as 95% of operating applications depend on Active Directory (AD) for authentication, as do all Windows servers and systems.

  This project will procure and implement a modern solution for disaster recovery.

  Ransomware attacks are a growing threat, with the global average downtime due to such attacks being 21 days in 2020; taking an average of 287 days for businesses to fully recover from these attacks. Given the crucial role that AD plays in the

Company's operations, an attack on AD could have severe implications for the Company and our customers.

See Exhibit A-24 N3 Line 252 for additional project details.

Threat Intel Module

- The Company will invest 0.043 million in the **Threat Intel Module** project over the course of 24-months ending December 31, 2024, and has a historical spend of $0.5 million in 2022, as shown on line 17 of Exhibit A-12 Schedule B5.7.6.

Threat intelligence is information about cyber threats and malicious actors and can come from several sources including governmental sources, peer companies, open source, and from the dark web. DTE currently receives threat intel from vendors, government authorities (DHS, DOE, FBI, etc.), Information Sharing and Analysis Centers, peer companies, and DTE's internal sources. DTE will establish a threat intelligence platform integrated with our cyber event ticketing system to aid in reducing cyber risk by quickly associating shared threat intel with internal cyber alerts generated by our security monitoring systems. This effort will automate the intake and handling of threat intelligence data to mitigate new cyber threats against our computing environment. Automation of this data means that we are not only aware of potential threats, but we are able to more efficiently ingest and handle threat data to make decisions that will ensure cyber resilience.

This project was approved for cost recovery in U-21297. The project reflects a variance of $0.6 million less in the 36 months ending December 31, 2024. This is due to external resource labor savings with AI capabilities available in the Palo Alto XSOAR solution.

Line No.

<u>Infrastructure Operations</u>

Q55. Can you describe the Infrastructure Operations Portfolio?

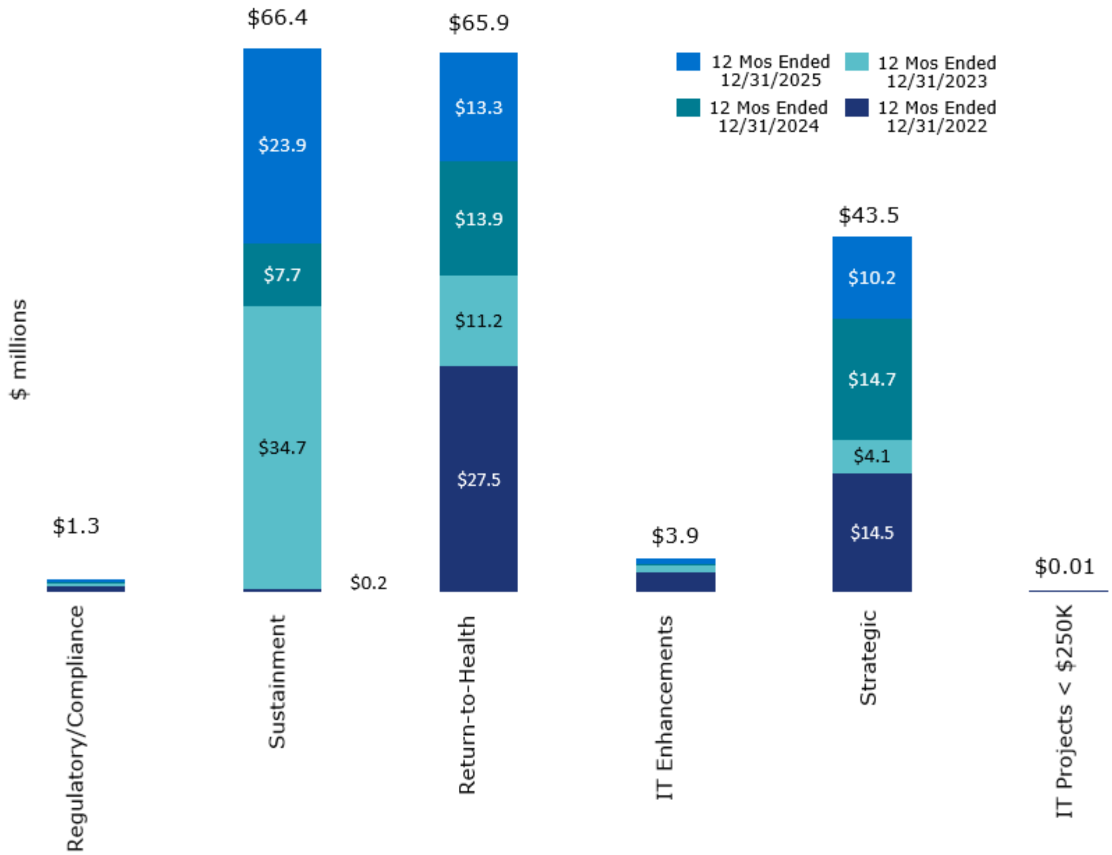
A55. The Infrastructure Operations Portfolio is responsible for the design, implementation, and secure operation of the Company's overall IT Infrastructure. This includes all the Company's physical IT assets (datacenters, servers, computers, network devices, and the licensed software that supports those assets). This portfolio is responsible for the day-to-day operation of these assets, the overall health of the assets (including operational growth, capacity, and availability standards), and from a project perspective, the enhancement of these assets to meet project requirements.

Q56. What are the projected costs for investments in the Infrastructure Operations Portfolio?

A56. As reflected on Line 8 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures for Infrastructure Operations total $45.1 million for the historical test year ended December 31, 2022, $87.8 million in the bridge period (for the 24 months ending December 31, 2024), and $48.3 million for the projected test period ending December 31, 2025.

The individual initiatives that fall into this area appear in Exhibit A-12 Schedule B5.7.7. The synopses below generally provide the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in Exhibit A-12 Schedule B5.7.7, in columns d, g and h, respectively. Figure 12 represents a high-level view of capital allocation within the portfolio.

Figure 13 Infrastructure Operations – IT Investment



<u>Regulatory/Compliance</u>

Q57. Can you explain in detail the Infrastructure Operations investment in the Regulatory/ Compliance category?

A57. The Company will invest $0.7 million in the Regulatory/Compliance category over the course of 36-months ending December 31, 2025, as shown on lines 1 & 2 of the Capital Expenditures – Exhibit A-12 Schedule B5.7.7.

Tower and Lighting Inspections and Repairs

- The Company will invest $0.7 million in the **Tower and Lighting Inspections and Repairs** project over the course of 36-months ending December 31, 2025, with a

Line No.

historical spend of $0.3 million in 2022, as shown in line 2 of Exhibit A-12 Schedule B5.7.7.

The Tower and Lighting Inspections and Repairs project is an annual effort that evaluates the integrity of both the physical towers that carry the DTE network telecommunications lines and the real estate upon which the towers are built. These towers are used to provide reliable, efficient, and redundant network systems that are used by DTE IT and DTE Business Units in support of our customers. The FCC regulations ensure the capability, security, and safety of these lines in the transmission of DTE data. The Commission approved this program in previous rate case, and the capital spend included in this case is incremental and builds upon work/spend approved previously. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Lines 260 for additional project details.

Sustainment

Q58. Can you explain in detail the Infrastructure Operations investment in the Sustainment category?

A58. The Company will invest $66.2 million in the Sustainment category over the course of 36-months ending December 31, 2025, as shown in lines 3 to 14 of the Capital Expenditures – Exhibit A-12 Schedule B5.7.7. The planned costs are primarily across projects that are discussed further below:

Backup Environmental Growth

- The Company will invest $1.2 million in the **Backup Environmental Growth** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.2 million in 2022, as shown on line 4 of Exhibit A-12 Schedule B5.7.7.

The Backup Environmental Growth Project for 2022 through 2024, will ensure that the information technology devices that maintain the business data of DTE have the appropriate amount of capability necessary to create and securely store the backup data.

The project reflects a variance of $0.6 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This reduction in planned spend was prioritized for the renewal of Dell Licenses, as discussed in Server Engineering Support Services project further below. The Dell License purchase included the required backup environmental requirements to support this project as planned. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 265 for additional project details.

Collaboration Application Health

- The Company will invest $24.8 million in the **Collaboration Application Health** project over the course of 36-months ending December 31, 2025 with a historical spend of $0.7 million in 2022, as shown on line 5 of Exhibit A-12 Schedule B5.7.7. This project was previously approved in U-21297 and reflects a variance of $4.7 million more in the 36 months ending December 31, 2024, than was approved for cost recovery due to 20% disallowance by the Commission.

The collaboration platform is a group of systems that enable employee productivity through collaborative communications, meetings, email, calendaring, instant messaging, co-authoring, and calling. Foundational Microsoft 365 upgrades/migrations authorized and implemented in years past made this possible.

Line No.

Ongoing application and collaboration enhancement enable DTE's workforce model.

In addition to infrastructure enhancements, we have added tools and intelligence to the investment and have implemented solutions such as Hive, which enables an Enterprise-Wide Live Meeting and was not possible prior to this implementation. This software allows our Company's senior leadership to conduct live meetings with all employees at one time, in an interactive environment. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Lines 269 for additional project details.

Dell Storage Hardware Refresh

- The Company will invest $0.3 million in the **Dell Storage and Hardware Refresh** project over the course of 24-months ending December 31, 2024, as shown on line 6 of Exhibit A-12 Schedule B5.7.7.

  The existing lease for storage infrastructure is expiring end of 2023. In order to maintain enterprise storage services, a new agreement must be executed. This impacts the Company's storage capabilities that supports all servers and enterprise-wide applications hosted on these servers.

  See Exhibit A-24 N3 Line 270 for additional project details.

Endpoint End of Life Electric Support Services

- The Company will invest $2.7 million in the **Endpoint End of Life Electric Support Services** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.6 million in 2022, as shown on line 7 of exhibit A-12 Schedule B5.7.7.

Line No.

To meet the organizational and business driven needs assigned to Endpoint engineering services or functions, IT partnered with a third-party service provider to provide the necessary labor support to meet demand. This spend reflects the capital labor portion of endpoint engineering services the Company uses for the deployment of the capital assets purchased under the Endpoint EOL program. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 274 for additional project details.

Enterprise Monitoring Licensing

- The Company will invest $5.0 million in the **Enterprise Monitoring Licensing** project over the course of 36-months ending December 31, 2025, as shown on line 8 of Exhibit A-12 Schedule B5.7.5.

The project reflects a variance of $3.4 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This was due to pull ahead of the Dynatrace licensing purchase to 2022 prior to expiration date.

This project will provide visibility into the IT ecosystem along with contextual and situational awareness of the health of all IT assets and services. The Company has implemented Dynatrace and NetScout to support monitoring of DTE's internal and external facing applications. Specifically, this technology allows for predictive alters to mitigated unnecessary application interruptions or unplanned outages.

See Exhibit A-24 N3 Line 275 for additional project details.

Enterprise Monitoring Strategy Operational Growth

- The Company will invest $2.2 million in the **Enterprise Monitoring Strategy Operational Growth** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.5 million in 2022, as shown on line 9 of Exhibit A-12 Schedule B5.7.7.

Investment in Enterprise Monitoring Operational Growth expands the monitoring of critical applications, infrastructure, security, services, and user experiences. This expanded monitoring provides increased ability to extract and present data logs, implement real-time decision-making dashboards, provide analysis of application infrastructure, security, inter-connectivity, services, and proactively respond to increased demand on the IT infrastructure from processing business systems and user load.

See Exhibit A-24 N3 Line 279 for additional project details.

Field Communications Network (FCN) Growth and Upgrade

- The Company will invest $1.1 million in the **Field Communications Network (FCN) Growth and Upgrade** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 10 of the Exhibit A-12 Schedule B5.7.7.

  The FCN Growth project is a continuing program designed to provide redundant communication and control functionality for the Company's field devices (Routers, Switches and Hubs) that monitor and control the operation of the bulk-electrical-system network. This program replaces devices that are reaching the end of useful life, adds devices to accommodate load or geographical growth, and adds functionality, automation, and redundancy to the alternate System Operations Center location. Annually, this effort in both hardware and labor requires investment of $0.4M to ensure the communication hardware requiring replacement, upgrade, or reconfiguration meets the requirements of the business and our customers. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 283 for additional project details.

Network Hardening and Operations

- The Company will invest $1.7 million in the **Network Hardening and Operations** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.6 million in 2022, as shown on line 11 of Exhibit A-12 Schedule B5.7.7.

  The Company intentionally does not maintain the internal staffing levels required to meet the growing demands (both project and operational) of Network Engineering services/functions across the enterprise. To meet the organizational and business driven needs assigned to network engineering for projects or operational system upgrades, Infrastructure and Operations partnered with a third-party service provider to provide the necessary labor support to meet demand. This spend reflects the capital labor portion of Network Engineering services the Company uses for the deployment of the capital assets purchased under the Network EOL program.

  This project reflects a variance of $0.8 million more than was approved for cost recovery in U-21297. In 2022, a contract renewal of Infloblox was required. Infoblox is a critical communication infrastructure used by the entire company. This infrastructure allows all wired and wireless users to connect to the Company's network, obtain IP address assigned, query and connect to internal and external devices. Without this agreement in place the Company's employees would be unable to communicate on DTE's networks.

  In 2023, the spend was $0.5 million more than approved due to hardware purchases made in 2022 that were unable to be received until 2023 due to vendor supply chain issues. The 2022-2024 spend was approved for cost recovery in U-21297.

Line No.

See Exhibit A-24 N3 Line 287 for additional project details.

Palo Alto Capital License Purchase

- The Company will invest $5.5 million in the **Palo Alto Capital License Purchase** project over the course of 12-months ending December 31, 2025, shown on line 12 of Exhibit A-12 Schedule B5.7.7.

  The Company utilizes Palo Alto solution to ensure functionality and supportability of network security assets required for the Company's IT and OT/Control networks. The current support agreement will expire in 2025 requiring a 3-year license purchase. External and internal security threats continue to increase and evolve throughout DTE's IT and OT/Control networks. DTE leverages Palo Alto based security infrastructure for securing our network and providing the needed threat protection.

  This is a mandatory investment for the Company to ensure security infrastructure up to date and supported.

  See Exhibit A-24 N3 Line 288 for additional project details.

Server Engineering Support Services

- The Company will invest $16.2 million in the **Server Engineering Support Services** project over the course of 36-months ending December 31, 2025, and has a credit of -$3.5 million in the historical period ending December 31,2022, as shown on line 13 of Exhibit A-12 Schedule B5.7.7.

  To meet the organizational and business driven needs assigned to server engineering for projects or operational system upgrades, IT partnered with a third-party service provider to provide the necessary labor support to meet demand. The planned spend

Line No.

reflects this capital labor supporting the deployment of the capital assets purchased under Server and Database Engineering & Operations.

The project reflects a variance of $2.2 million more in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. In 2023, the Company executed the multi-year Dell Storage agreement resulting in variance to previously requested and approved spend. The software and hardware provided by this agreement supports enterprise applications, user storage, and backup and disaster recovery. Not renewing this agreement would mean enterprise and customer facing applications would eventually cease to function and our ability to recover from data loss or app failures would be severely impeded if not impossible. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 292 for additional project details.

VMWare License Purchase

- The Company will invest $5.6 million in the **VMWare License Purchase** project over the course of 12-months ending December 31, 2025, as shown on line 14 of Exhibit A-12 Schedule B5.7.7.

  VMware is a virtualization and cloud computing software for IT infrastructure like Vrealize operations, Vrealize automation, VMWare Hypervisor and vCenter Server and vSphere Client. The Company uses these to run over 150 critical applications including customer facing apps such as CR&B.

  See Exhibit A-24 N3 Line 293 for additional project details.

Return-to-Health

Q59. Can you explain in detail the Infrastructure Operations investment in the 'Return-to-Health' category?

A59. The Company will invest $38.4 million in the Return-to-Health category over the course of 36-months ending December 31, 2025, as shown in lines 15 to 30 of the Capital Expenditures Exhibit A-12 Schedule B5.7.7. The planned costs are primarily across projects that are discussed further below:

Compute and Storage Cache Refresh

- The Company will invest $0.5 million in the **Compute and Storage Cache Refresh** project over the course of 24-months ending December 31, 2024, as shown on line 15 of Exhibit A-12 Schedule B5.7.7.

  This project includes increasing storage capacity to support on-premise infrastructure and will be implemented by the IDSS team in collaboration with DELL/EMC. The current storage infrastructure in use at our primary data center is running at an average 80% capacity to accommodate existing and new applications demands. This project will reduce system overloads and improve the efficiency of application performance. A 30% increase in storage and compute will allow us to accommodate an anticipated 20% increase in the application workload.

  The project reflects a variance of $0.3 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. In 2023, this scope was deprioritized to support the cost for the Dell Storage Agreement as discussed within testimony of Server Engineering Support Services page PS-107, lines 4-12. The 2023-2024 spend was approved for cost recovery in U-21297.

Conference Room Audio Video Support

- The Company will invest $1.4 million in the **Conference Room Audio Video Support** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.3 million in 2022, as shown on line 16 of Exhibit A-12 Schedule B5.7.7.

The Company intentionally does not maintain the internal specialized staffing levels required to meet the growing demands (both project and operational) of Endpoint Engineering Conference Room and Audio-Visual (A/V) support services/functions across the enterprise. This allows the Company to flex staffing models as necessary and respond timely to changing use/needs given the remote work reality.

This project reflects a variance of $0.3 million more than approved for cost recovery in U-21297.In 2022, incremental audio video equipment failures occurred requiring more equipment procurement and labor than estimated for the year. In 2024 and 2025, additional conference rooms have been added to the plan to meet the demand of the Company. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 299 for additional project details.

Data Center Modernization and Optimization

- The Company will invest $3.8 million in the **Data Center Modernization and Optimization** project over the course of 36 months ending December 31, 2025, and has a historical spend of $1.1 million in 2022, as shown on line 17 of Exhibit A-12 Schedule B5.7.7.

Four Uninterruptible Power Supplies (UPS) that provide the necessary power redundancy in our core data centers have reached or exceeded their serviceable end-of-life of 20 years per the OEM. These units must be replaced to maintain the security of having appropriately modulated power in the case of a data center power outage. A UPS is an industry standard solution which is core to every data center

Line No.

and ensures that power will continue to be provided to critical IT equipment while the emergency generators start up and begin to provide power.

The Company relies on the ability of our technology to meet the computing demands of daily operations. Much the same as these assets require modulated power to function within specification, they also need to have the necessary redundant power to function in the case of a data center outage. The replacement of the UPSs provides this insurance and ensures the capability of the business processing needs in the case of a data center power outage.

Six strings of batteries that work in conjunction with the UPSs, will also be replaced. The normal lifespan of our batteries is three to five years and each one of these battery strings is over five years old. The batteries will be upgraded at the time of replacement to a newer technology that will double the expected lifespan and reduce the annual maintenance by 50%.

Delaying the replacement of these end-of-life assets increases the risk of loss of redundant power to the infrastructure assets that we use to host our business applications and customer data. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 303 for additional project details.

Digital Worker Experience Electric EOL

- The Company will invest $8.3 million in **Digital Worker Experience Electric EOL** (previously called Endpoint End of Life Electric) over the course the 36-months ending December 31, 2025, and has a historical spend of $7.9 million in 2022, as shown on line 18 of Exhibit A-12 Schedule B5.7.7.

This project was previously approved in U-21297 and reflects a variance of $5.6 million more than was approved for cost recovery. This was due to the $0.9 million

(20%) disallowance from the Commission in U-21297, and $3.9 was incremental spend in 2022 for the procurement of 350 mobile device terminals (MDT) to replace those that had a high failure rate and were past EOL, and 336 marginal devices that did not meet the hardware requirements for ADMS. Finally, incremental labor was required for the deployment of these devices began in support of ADMS. The majority of these MDT's are vehicle based requiring additional Docks, cabling harnesses, and installation costs.

Annually, the Company issues, supports, and maintains over 14,000 Company-owned endpoint devices (desktop computers, laptops, tablets, smart devices, and ruggedized field computers) throughout the business. This annual project replaces 20% of these devices each year to maintain the asset refresh rates of 95% devices greater than 5 years old (refer to the Table 2 below). The plan also takes into consideration adding 25 units per year due to new hires and replacement of 100 units per year that are damaged or destroyed through normal use. To meet the change in the workforce model from onsite to remote, the Company requires replacement of onsite desktop towers with laptops as well as the additional labor required to deploy the devices in a timely manner.

Table 2 Endpoint Devices Replaced by Year

Device Type	Refresh Year		
	2023	2024	2025
Laptop	617	800	700
Desktop	1	100	185
Monitors	180	100	100
Tablets	25	40	28

See Exhibit A-24 N3 Lines 304-307 for additional project details.

End of Life Asset Replacements

- The Company will invest $1.5 million in the **End of Life Asset Replacements** project over the course of 36-months ending December 31, 2025, and has a historical spend of $6.8 million in 2022, as shown on line 19 of Exhibit A-12 Schedule B5.7.7.

The EOL Asset Replacement project will replace servers, storage, databases, and operating licenses that are at end of their serviceable life which means they are no longer capable of accepting operating system or security vulnerability remediation, capacity has reached the upper threshold of processing ability, or the technology will no longer interact with newer components within the architecture. These assets located within our corporate data centers or major secondary sites are reliant upon continuous upgrades to ensure that security, capacity, or operating parameters are capable of meeting business requirements (see Table 3).

Table 3 Device Lifecycle Management Standards

Component	Lifecycle
Servers	5 Years
Storage	3 Years
Operating Systems	Annual Upgrades
Databases	Annual Upgrades

This project reflects a variance of $6.5 million more in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297, as explained below. In 2022, $6.1 million was required to support a 3-year license purchase for VMWare. This was critical to ensure service continuity to our customers. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 311 for additional project details.

Line No.

Field Worker Device End of Life

- The Company will invest $1.8 million in the **Field Worker Device End of Life** project over the course of 36-months ending December 31, 2025, as shown on line 20 of Exhibit A-12 Schedule B5.7.7.

  This project will establish and execute the annual EOL replacement cycle for the enterprise MDT devices. Mobile Data Terminal is a computerized device used on mobile devices (devices in transit or devices that are mounted on systems that are always on the move) to communicate with a centralized control system. Mobile data terminals are equipped with technology to provided maps and information systems regarding geographic locations and other information relevant to the tasks and actions performed by the devices they are mounted on. These capabilities allow field workers to resolve customer issues and provides input to customer service representatives so they may effectively respond to customer queries.

  The lifecycle of the current Mobile Data Terminal (MDT) fleet has been stretched to the point that field crew are experiencing multiple device and connectivity failures. This impacts the crew's ability to gain insight into customer issues and outages, provide updates to leadership and customer service, communicate resolution and closure of customer concerns in a safe and efficient way.

  See Exhibit A-24 N3 Lines 312-313 for additional project details.

Load Balancer Asset Health and Re-Engineering

- The Company will invest $0.5 million in the **Load Balancer Asset Health and Re-Engineering** project over the course of 12-months ending December 31, 2025, as shown on line 21 of Exhibit A-12 Schedule B5.7.7.

  This project will replace the hardware load balancers that will be deemed end of life by 2025 with modern virtual load balancers. Virtual load balancers are virtualized application delivery controller software that helps to distribute network traffic load amongst backend servers. Virtual Load Balancers are software-based load balancing solutions that help manage load effectively while still offering exceptional performance and scalability. Having unsupported load balancers would increase security vulnerabilities to approximately 4000 URL's required for applications to function to support operations.

See Exhibit A-24 N3 Line 314 for additional project details.

Microwave End of Life

- The Company will invest $1.2 million in the **Microwave End of Life** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.5 million in 2022, as shown on line 22 of Exhibit A-12 B5.7.7.

This project reflects a variance of $0.2 million more in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297, primarily due to the 20% disallowance of $146 thousand from the commission and the balance was due to higher contractor cost from MCE, (Motor City Electric).

The Company owns and operates its own set of microwave communications installations. As the network grows from business-driven requirements, the Company must replace aging assets as well as add components as we strengthen, tune, and optimize the system. This investment includes replacement of microwave paths, enhancements to stabilize the microwave ring, and support changes mandated by the FCC in deregulation of the 6 gigahertz (Ghz) frequency. These efforts provide overall improvements to infrastructure redundancy, availability, capability, and security. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 318 for additional project details.

Line No.

Modernize Disaster Recovery Tools

- The Company will invest $0.5 million in the Modernize Disaster Recovery Tools project over the course of 36-months ending December 31, 2025, as shown on line 23 of Exhibit A-12 Schedule B5.7.7.

  DTE has a custom-built solution for disaster tolerance and recovery that supports SAP, Maximo and AMI systems that support field operations. This legacy solution was implemented in 2006. These applications and data support critical business processes must be able to recover from a data center disaster (weather, water damage, facility damage) or event. The existing Disaster Tolerant High Availability (DTHA) solution is built on now obsolete technology and infrastructure and last upgrade available in 2017.

  This technology (DTHA Commander) has become increasing difficult and expensive to maintain due to outdated programing language maintenance and gap in industry of skilled resources required to support it. The security risk has increased as it is no longer supported by the operating system vendor. This system must be modernized in order to maintain the capability to withstand and recover from unplanned system failures that impact the Company's computing infrastructure. This project scope will design, test, and deploy a modern disaster recovery solution onto DTE's private cloud platform ensuring operational reliability of core operational systems within the Company.

  See Exhibit A-24 N3 Line 319 for additional project details.

Network Advanced Metering Infrastructure Support

- The Company will invest $6.5 million in the **Network Advanced Metering Infrastructure Support** project over the course of 36-months ending December

31, 2025, and has a historical spend of $2.4 million in 2022 as shown on line 24 of Exhibit A-12 Schedule B5.7.7.

The Network AMI Support project sustains the network and connected devices that the Company uses to enhance and support the AMI mesh. This network infrastructure is responsible for transporting the meter information needed to accurately bill customers for service and to control/monitor the metered usage for our 2.6 million electric customers. There are over 10,000 assets installed in the field as of this filing. As DTE expands the AMI mesh via direction from the business, the Company projects the annual cost based on previous year deployments to ensure that the business priorities are met.

Without this investment there would have been unplanned hardware outages that would adversely affect data related to customer power outages and accuracy of billing. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 323 for additional project details.

Network Data Center End of Life

- The Company will invest $1.9 million in the **Network Data Center End of Life** Project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 25 of Exhibit A-12 Schedule B5.7.7.

Annually key data center networking assets that have achieved end of serviceable life must be replaced. The Company continually monitors the age and capability of these devices and connections along with information from the OEM to identify which of these assets must be replaced and estimate the costs for investments for the coming year. This effort will replace data-center core switches, routers, and include the installation of new components to allow the Company to increase the connection bandwidth between its two data centers. Business applications with a requirement of failover and backup capabilities rely on the operability of these devices to ensure continuity in the event of an unplanned outage. The Company continuously monitors the latest technologies available from its vendors. Through this analysis determinations are made as to interoperability, capability, impact to the architecture, business impact, and cost analysis. Replacing the existing core switches and routers with alternative products would cost the Company $5-$10 million.

This project reflects a variance of $0.4 million more in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297 due to a $0.2 million (20%) disallowance from the MPSC in U-21297, along with an increase in spend in 2023 to accommodate supply chain equipment receipt deferrals from 2022 into 2023. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 327 for additional project details.

Network End of Life Electric

- The Company will invest $2.3 million in **the Network End of Life Electric** project over the course of 36-months ending December 31, 2025, and has a historical spend of $0.4 million in 2022, as shown on line 26 of Exhibit A-12 Schedule B5.7.7.

  This project is an ongoing program to replace EOL network hardware that is not physically located in either of the corporate data centers. These updated solutions will address the components that have reached their end of designed and serviceable life, as well as provide additional network expansions to meet business-partner requirements, expectations, and demand (see Table 4).

Line No.

Table 4 Network Devices Replaced by Year

Year	2022	2023	2024	2025
Assets Replaced	110	50	100	100

The Network EOL – Electric project will annually fund only those devices within the purview of Infrastructure and Operations. This investment will maintain the core foundation for upcoming investments needed for new customer rates like Time of Use billing, and accounts for planned data loads as new electric-grid-control systems come online. It will further increase the size and capacity of existing equipment as key electrical-control points for required security upgrades. Examples of these enhancements are support for perimeter intrusion detection and streaming real-time video surveillance at locations that are deemed critical or high. This updated infrastructure will provide improved stability and supportability across the network. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 331 for additional project details.

Security Infrastructure Growth and EOL

- The Company will invest $4.2 million in the **Security Infrastructure Growth and EOL** project over the course of 36-months ending December 31, 2025, and has a historic spend of $7.4 million in 2022, as shown on line 27 of Exhibit A-12 Schedule B5.7.7.

  This ongoing program covers annual investment replacing 15% to 20% of security infrastructure equipment. These systems average a life span of five to seven years based on OEM. As reflected in Table 5 below, these systems have the following equipment replacement cycle to ensure they remain within vendor supportable life:

Line
No.

Table 5 Security Asset Lifecycle

Asset	Lifecyle
System Baselining	4 years
Firewalls	5 years
DNS	6/7 years
Vulnerability Tool	6 years
Web Proxy	5 years
DataPower	4 years
Windows server hardware/software	5-7 years

This plan addresses annual upgrade of firmware and hardware and increasing capacity to manage growth in IT and OT environments. While the Company wants to remediate every potential cyber security and operational risk, this goal is unrealistic given the volume, variability, and constantly evolving nature of risks. To manage and prioritize Cyber Risk Management, the Company uses a multi-layer, risk-based approach that assesses risk, criticality, and controls.

This project reflects a variance of $5.7 million more in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297. In 2022, the Company required the purchase of the Palo Alto license and cybersecurity specialized hardware resulting in the $6M increased spend from the amount approved in U-21297. The Company has since planned for the purchase of Palo Alto licenses as a separate capital project which will reoccur in 2025. The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 335 for additional project details.

Wide Area Network and Wireless Local Area Network Expansion

- The Company will invest $2.6 million in the **Wide Area Network and Wireless Local Area Network Expansion** project over the course of 36-months ending December 31, 2025, as shown on line 28 of exhibit A-12 Schedule B5.7.7.

This project reflects a variance of $0.9 million less in the 34 months ending December 31, 2024, than approved for cost recovery in U-21297. This is due to $0.6 million (20%) disallowance by the Commission in U-21297, along with the deferral of equipment receipt planned for 2022 which could not be received until 2023 due to vendor supply chain issues.

The Wide Area Network (WAN) MPLS is the core network equipment responsible for the telephony service at most of the Company's office locations. This technology ensures that our communications network can support voice interactions between ourselves, our customers, and other businesses. The replacement of SIP Trunks is necessary to harden the ConnectUs Teams investment and will allow DTE Employees to continue work activities remotely without interruption. The current state of the Wireless Local Area Network (WLAN) requires expansion to cover new locations and additional points of activity to ensure connectivity for field and knowledge workers at DTE locations. The devices that support the daily business operations have reached the end of their serviceable life and are unable to be kept viable to meet the requirements of the business. Corporate WLAN expansion is needed to support the increased number of devices and network coverage. The current wireless components comprising the network at many DTE locations are not optimal as wireless requirements have changed since their original installation. The 2023-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 338 for additional project details.

Virtual Desktop Infrastructure End of Life

- The Company will invest $1.5 million in the **Virtual Desktop Infrastructure Asset Health** project over the course of 36-months ending December 31, 2025, as shown in line 30 of Exhibit A-12 Schedule B5.7.7.

  The current virtual desktop hardware including virtual desktops and virtual application clusters is reaching end of life by the end of 2023. This hardware provides secure virtual network connectivity to approximately 7000 users across the enterprise and without the necessary replacement there would be loss connectivity for all end users on utilizing the Virtual desktop and application infrastructure which would impact their ability to perform daily operations.

  See Exhibit A-24 N3 Lines 341- 342 for additional project details.

<u>IT Enhancements</u>

Q60. Can you explain in detail the Infrastructure Operations investment in the IT Enhancements category?

A60. The Company will invest $1.6 million in the IT Enhancement category over the course of 36-months ending December 31, 2025, as shown in lines 31 to 35 of the Capital Expenditures – Exhibit A-12 Schedule B5.7.7. The planned costs are primarily across projects that are discussed further below:

Network Segmentation (phase 2+) emergent extension

- The Company will invest $1.2 million in the **Network Segmentation (phase 2+) emergent extension** project over the course of 36-months ending December 31, 2025, as shown on line 32 of Exhibit A-12 B5.7.7.

Cyber threats continue to rise, and it has become increasingly important to add additional cybersecurity countermeasures to the Company's networks.

Cisco Application Centric Infrastructure (ACI) technology restricts traversing the DTE network. There are multiple legacy Cisco network switches which are currently end of life and are no longer compatible with current versions of the N9K FX3 version of network switches and configuration of the Cisco ACI technology. This has impacted the installation and use of firewalls to isolate applications running on obsolete operating systems.

See Exhibit A-24 N3 Lines 345-347 for additional project details.

Self-Healing Endpoint Automation

- The Company will invest $0.3 million in the **Self-Healing Endpoint Automation** project over the course of 12-months ending December 31, 2025, as shown on line 33 of Exhibit A-12 Schedule B5.7.7.

  This project will utilize Microsoft InTune, an existing platform within the IT technology landscape, for endpoint (desktops, laptops, MDT, iPADs, Androids, etc) management of function and security requirements. Endpoint management today is a manual process requiring labor resources to build and image endpoints, ship endpoints, and manage functional requirements such as hard drive spacing, CPU memory performance management.

  Microsoft Intune will be used along with Autopilot and Microsoft PowerShell scripting will automate these services. InTune will enable remote endpoint builds, remote endpoint imagining and application delivery, and remote device wiping and patching.

Autopilot will enable direct shipment of endpoints to the Company's end users. And finally, PowerShell scripting will enable employees to manage endpoint functional self-healing of hard drives and CPU memory performance management. See Exhibit A-24 N3 Line 348 for additional project details.

Wireless Local Area Network Expansion

- The Company invested $1.3 million in the **Wireless Local Area Network Expansion** project over the course of 12-months ending December 31, 2022, as shown line 35 of Exhibit A-12 Schedule B5.7.7.

  This project reflects a variance of $0.2 million more in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297, this is due to increased demand from external project dependencies for wireless LAN requirements.

  The benefits of this investment are targeted to reduce the number of wireless incidents reported by ~20% and increase employee productivity by the increased wireless coverage with a targeted network utilization across the Company locations at ~80%.

  The consideration of alternative providers or asset types were rejected since they would impose an undue burden due to the reconfiguration required.

  The "do nothing" alternative would not allow us to meet the requirements of the business, reduce connectivity availability, and delay the collaboration capabilities in service and therefore was rejected.

  See Exhibit A-24 N3 Line 351 for additional project details.

Strategic

Q61. Can you explain in detail the Infrastructure Operations investment in the Strategic category?

A61. The Company will invest $29.1 million in the Strategic category over the course of 36-months ending December 31, 2025, as shown in lines 36 through 47 of the Capital Expenditures Exhibit A-12 Schedule B5.7.7. The planned costs are primarily across projects that are discussed further below:

ConnectUs Teams

- The Company will invest $1.0 million in the **ConnectUs Teams** project over the course of 11-months ending November 30, 2023, and has a historical spend of $1.9 million in 2022 as shown on line 36 of exhibit A-12 B5.7.7.

  This is a continuation of the project the Commission approved for inclusion in rates in both Case No. U-20162 and Case No. U-20561. The Company has adopted an increasingly electronic collaboration method through Microsoft Teams and its connected services/products, formerly referred to as Skype for Business Conversion (to Teams). Ongoing investment in this conversion is the continuation of a multi-year implementation of infrastructure and software updates to enhance our security, simplify support efforts, drive collaboration, and enable our workforce to effectively work remotely. The work in 2022 for Teams calling we successfully enabled 36 sites.

  This project reflects a variance of $1.9 million more in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297 primarily due incremental Microsoft licensing purchased to support the enterprise.

  The benefits of this investment will be in reduced O&M cost to maintain physical assets. The Company has been able to reduce teleconferencing expenses by 80%

Line No.

(comparing 2020 actuals to 2022 actuals) to date with the rollout of Teams calling capability as shown in Table 6 below.

Table 6 Teleconferencing Actuals by Year

Spend Category	2020	2021	2022	2023
COM NETWORK SERVICES	159,194.15	52,355.77	36,229.55	8,988.79
TELECONFERENCING	173,595.46	37,957.32	30,416.21	0.00
Grand Total ($)	**332,789.61**	**90,313.09**	**66,645.76**	**8,988.79**

The 2022 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 353 or additional project details.

Data Power Replacement

- The Company will invest $0.6 million in the Data Power Replacement project over the course of 12-months ending December 31, 2023, as shown on line 37 of Exhibit A-12 Schedule B5.7.7.

The Company uses DataPower to provide security services for applications that are externally exposed as well as for the applications that are externally hosted. The services include authentication/authorization of or the users to access applications based on need, as well as provide layered protection to prevent unauthorized access. It is also used as an identity provider for some of our cloud hosted applications. Today, this identity provider capability resides on physical servers in our data centers. This project adopted industry standard cloud technology aligning with the Smart Cloud guidance and security best practices.

See Exhibit A-24 N3 Line 354 for additional project details.

Data Power Replacement Phase 2

- The Company will invest $0.7 million in the Data Power Replacement Phase 2 project over the course of 12-months ending December 31, 2024, as shown on line 38 of Exhibit A-12 Schedule B5.7.7.

  The DMZ DataPower Gateway capability resides on physical servers in our data centers and provides security services for applications that are externally exposed. The services include authentication/authorization for users to access applications based on need, layered protection to prevent unauthorized access, and provision of identity for some cloud hosted applications. This project will move current functionality away from physical data centers and into the cloud–- specifically Microsoft application proxy in the Azure cloud. The project will replace Data Power identity management capabilities for the targeted applications, with an optimal solution including reverse proxy provision as well as identity provider capabilities.

  As a foundational capability all DTE business unit applications will utilize the new cloud-based application gateway platform to provide secure access to employees and customers. And finally provide the increased application capacity to be hosted by Cloud Application Gateways, since the current systems are at capacity and unable to support more applications.

  See Exhibit A-24 N3 Line 355 for additional project details.

Digital Infrastructure and Services

- The Company invested $6.4 million in the **Digital Infrastructure and Services** in the historical period ending December 31, 2022, as shown on line 39 of Exhibit A-12 Schedule B5.7.7. This project reflects a variance of $2.2M less than approved for cost recovery in U-21297. The remaining $2.2 million is included in the spend for the Tree Trim Risk Prioritization Model project shown on line 24 of the Exhibit A-12 Schedule 5.4. The Company is not seeking any additional recovery for this IT project in the current case. Please refer to the testimony of Witness Steudle for the detailed business benefits. See Exhibit A-24 N3 Line 356 for additional project details.

DTE Private Cloud Infrastructure as a Service

- The Company will invest $0.6 million in the **DTE Private Cloud Infrastructure as a Service** project over the course of 24-months ending December 31, 2024, and has a historical spend of $0.4 million ending December 31, 2022, as shown on line 40 of Exhibit A-12 Schedule B5.7.5.

DTE Cloud infrastructure management and provisioning currently requires 3 full time resources annually to manage. The implementation of various cloud management tools and automating processes will reduce the manual processing, reduce provisioning and deployment cycle time, enable the application teams to estimate infrastructure costs directly, reduce operational costs due to virtualization, and allow tight integration with the IT work management system (ServiceNow).

As of October 2022, DTE has approximately 44 Windows 2003 servers, 97 Windows 2008 servers, and 703 Windows 2012 servers that are out of support or soon to be out of support and will have the opportunity to be migrated to the Azure IaaS private or public Cloud. Beginning in 2023, the project started application deployment and migrate workloads onto the infrastructure.

This project reflects a variance of $0.5 million less in the 36 months ending December 31, 2024 than approved for cost recovery in U-21297. In 2022, the Company spent $0.4 million less than approved for cost recovery in U-21297, this was primarily a result extended Microsoft Licensing negotiations that delayed purchasing all the 2022 planned licenses. Final negotiations resulted in a savings to the required spend of $0.4 million due to bundling multiple licenses into one agreement. The 2022-2023 spend was approved for cost recovery in U-21297.

Endpoint Operating System and Hardware Upgrade

- The Company will invest $6.9 million in the **Endpoint Operating System and Hardware Upgrade** project over the course of 24-months ending December 31, 2025, as shown on line 41 of Exhibit A-12 Schedule B5.7.7.

  This project is planned for the necessary upgrade of 9,700 machines from Windows 10 to Windows 11 in 2024, as well as replacement of 1,000 machines during that timeframe[13], with a total of 15,000 devices being upgraded at project completion in 2026.

  Windows 10 extended support includes updating the operating system and this support officially ends October 2025. Updating endpoint operating systems will reduce DTE's exposure to operating-system-based vulnerabilities within the DTE network. This three-year project further supports the strategic direction to upgrade to Windows 11 for the entire organization across roughly 10,000 devices.

  This project reflects a variance of $0.6 million less in the 36 months ending December 31, 2024 than approved for cost recovery in U-21297. This is due to the deferment of purchase and installation of 425 devices to 2025. This deferment will free up the resources to work on higher priority projects to sustain operational reliability. The 2024 spend was approved for cost recovery in U-21297.

  See Exhibit A-24 N3 Line 360 for additional project details.

[13] DTE endpoint devices that have antiquated technology and operating systems will no longer be supported through Microsoft's standard support process, rendering the user unable to perform job responsibilities.

Enterprise Monitoring Strategy Implementation

- The Company invested $5.0 million in the Enterprise Monitoring Strategy Implementation project during the 24 months ending December 31, 2023, as shown on line 42 of Exhibit A-12 Schedule B5.7.7.

  This project reflects a variance of $4.5 million more in 2022 than approved for cost recovery in U-21297 due to the pull ahead of Dynatrace monitoring software license purchase by one month (originally planned in January of 2023 but contracted in December of 2022 to avoid possible service interruption and accommodate growth in the extent of our enterprise monitoring deployment.

  The 2022-2023 spend was approved for cost recovery in U-21297.

External Secure File Transfer Replacement

- The Company invested $0.4 million in the **External Secure File Transfer Replacement** project during the 36-month ending December 31, 2025, as shown on line 43 of Exhibit A-12 Schedule B5.7.7.

  This project reflects a variance of $0.2 million less in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297. This was due to scope reductions due to company's financial constraints in 2023.

Firewall Threat Protection

- The Company will invest $2.1 million in the **Firewall Threat Protection** project over the course of 36-months ending December 31, 2025, as shown on line 44 of Exhibit A-12 Schedule B5.7.7. This project reflects a variance of $1.8 million less than approved for cost recovery in U-21297. The Palo Alto License agreement purchase in 2022 provided additional features for Threat Protection, this reduced

Line No.

the estimated cost for procurement and deploying additional hardware planned for this project.

External and internal threats to DTE cyber security continue to increase and evolve for both IT and OT/Control networks. This will require the Company to build additional protection, detection, and response capabilities to protect DTE's assets. To achieve this, there is a strategic need to deploy firewalls that can provide added capacity as well as advanced capabilities for real time threat protection. Some of the business areas where this is anticipated include Customer Payments, Energy Supply control networks, AMI, Gas and Electric SCADA, and substation networks. The solution is a centralized repository to retain threat intel received from vendors, government agencies (DHS, DOE, FBI, etc.), Information Sharing and Analysis Centers (E-ISAC, DNG-ISAC), peer companies, and from DTE's internal sources. The 2023-2024 spend was approved for cost recovery in U-21297.

Mobile Device Management (MDM)

- The Company will invest $0.8 million in the **Mobile Device Management (MDM)** project over the course of 24-months ending December 31, 2024, as shown on line 45 of Exhibit A-12 Schedule B5.7.7.

This project reflects a variance of $0.2 million more than approved for cost recovery in U-21297 due to combining scope from Enterprise Mobility Management demand into the Mobile Device Management demand and adding onsite resources to support field crew with their assigned device migration to DTE's new Mobile Device Management platform from Microsoft at various DTE facilities. During the migration, extended support is required as part of the hyper care resulting in the additional spend. The 2023-2024 spend was approved for cost recovery in U-21297.

Line
No.

See Exhibit A-24 N3 Line 368 for additional project details.

Storm Cloud

- The Company will invest $16.0 million in **Storm Cloud** project over the course of 36-months ending December 31, 2025, as shown on line 47 of Exhibit A-12 Schedule B5.7.7.

DTE has suffered several technology related challenges during storms which drive costs to restore and impact customer satisfaction. System resiliency for our cloud-based applications has become an issue impacting our customers. Over the last few years DTE has faced multiple storms where application resiliency issues hindered the restoration effort and impacted customer satisfaction. In 2022 and 2023, DTE weathered 6 catastrophic storms, impacting 2.1M customers. At several points during the storms DTE's IT infrastructure experienced performance degradation in applications critical in servicing our customers and aiding restoration efforts. Customers were unable to review or report outages in our mobile apps. Tools used in restoration efforts were not functioning properly, requiring field workers to use manual alternatives, increasing recover times. Patterns emerged around overloaded IT systems and failing integrations between apps, many of which are housed in the Azure Cloud. The objective of this project is to "meaningfully move the needle" on two aspects of how IT can improve its performance and hence better support DTE during its storm efforts. This will also establish an automated scalability without manual intervention. The overall impact can be measured in terms of operational reliability (and hence reduced downtime for crews when system outages happen) as well as improved customer satisfaction from an improved ability to serve customers. During catastrophic storms in 2022 and 2023, nine IT infrastructure outages affecting an average of 270k customers each, directly related to overloaded applications occurred on internal and customer facing applications. Each outage saw degraded or unavailable applications and services for several hours during critical periods, affecting hundreds of internal users dedicated to restoration efforts and thousands of customers using the tools to communicate and manage their outage.

This project is supporting the Company's storm response investments discussed in Company Witness Hill's testimony and the customer interaction improvements as discussed in Witness Hatsios' testimony.

See Exhibit A-24 N3 Lines 371-372 for additional project details.

<u>**Enterprise Data Analytics**</u>

Q62. What is the Enterprise Data and Analytics (EDA) Portfolio?

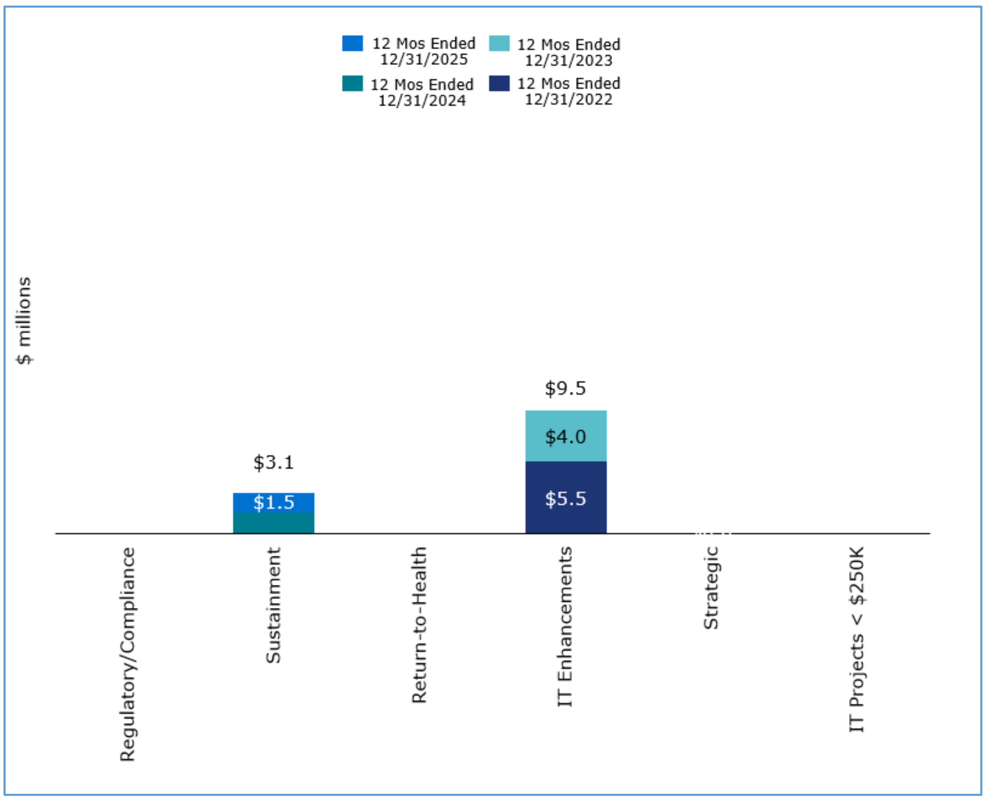
A62. The Company continues to build a cloud-based and on-premise data platform to enable analytics to drive business value. This requires a data platform for data storage and processing along with software to manage the data and usage. To support our data users, the Company created a team to enable the infrastructure, build integrations to source systems, and subsequently organize, describe, and document the data available on the platform. EDA's mission is to dependably deliver timely, secure, high-quality data to business partners throughout DTE.

Q63. What are the projected costs for investments in the Enterprise Data & Analytics Portfolio?

A63. As reflected on line 9 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures for Enterprise Data & Analytics total $5.5 million for the historical test year ended December 31, 2021, $5.6 million in the bridge period (for the 24 months ending

December 31, 2024), and $1.5 million for the projected test period ending December 31, 2025. The synopses below in Figure 14 provide the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are laid out in Exhibit A-12 Schedule B5.7.8, in columns d, g, and h.

Figure 14 Enterprise Data and Analytics – IT Investment



<u>Sustainment</u>

Q64. Can you describe the investment in Enterprise Data Analytics in the IT Sustainment category?

Enterprise Data Platform Application Health

A64. Yes, the Company will invest $3.1 million in the **Enterprise Data Platform Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 1 of Exhibit A-12 Schedule B5.7.8. This project reflects a variance of $1.1 million less than what was approved for cost recovery in U-21297. These actual charges for the software licenses and services were accrued and charged to the Advance and Enhance the Data Platform project listed below.

The Enterprise Data Platform Application Health project is primarily to secure 3-year commitments for licenses and Azure services which allows for reduced costs over the pay-as-you-go pricing. On average, the Company will save 60% by reserving the use of Azure assets for a three-year period. As the cloud-based data platform grows we can add additional reservations each year to take advantage of more savings.

See Exhibit A-24 N3 Lines 373-374 for additional project details.

IT Enhancements

Q65. Can you describe the investment in Enterprise Data Analytics in the IT Enhancements category?

Advance and Enhance the Enterprise Data Platform

A65. The Company invested $4.0 million in the **Advance and Enhance the Enterprise Data Platform** project over the course of 12-months ending December 31, 2023, and has a historical spend of $5.5 million in 2022, as shown on line 2 of exhibit A-12 Schedule B5.7.8.

DTE's cloud-based data platform continued to grow in its fourth full year in operation.

This project reflects a variance of $7.5 million more in the 24 months ending December 31, 2024, than approved for cost recovery in U-21297.

In 2022, this project incurred the $3.5 million related to Enterprise Data Platform Application Health licenses (Alteryx, VM Reservations) and services renewals and supporting labor.

In 2023, which was not included in U-21297, this project added the capability to bring near real-time data to support both operational and historical analytics use cases (projects CODS and ADMS). Additionally, this project developed and implemented a data catalog and data validation capability. These solutions and additional capabilities will enable quicker response time to customer queries, improved decision making, and increased satisfaction. Additionally, EDA was responsible for the 2023 Azure cost for all the business units using Azure Cloud. See Exhibit A-24 N3 Lines 375-376 for additional project details.

Innovations

Q66. Can you describe the Innovations Portfolio?

A66. To address customer and business challenges that cannot be solved with traditional approaches, DTE applies innovation to deliver rapid value with shorter development cycles and time to value. We have proven the ability to boost reliability by expanding how DTE services and maintains the Company's IT assets and accelerate access to decision-making tools for customer and employee use. Further value is found in gaining new insights by thinking differently about pressing business challenges.

Q67. Can you summarize the Innovation investments?

A67. The Company seeks recovery of its $2.8 million spend in Innovation investments over the course of 12-months ending December 31, 2022, as shown in line 1 of the Capital Expenditures - Exhibit A-12 Schedule B5.7.9.

Q68. Can you provide additional detail for the Innovation project?

A68. Yes. The DTE Applied Innovation Team provides both capability and capacity from a team comprised of in-house DTE leaders and subject matter experts, and external consultants with key technology, entrepreneurial, innovation management, and communications expertise. With this unique capability, the team can staff key projects that DTE needs to work on, but has not yet defined, and is able to rapidly respond to new business challenges identified and prioritized by executives. Innovation is a support function for the entire organization and does not introduce changes to core systems of record or assets. The management of assets live within the business and are not owned by the innovation team.

The following solutions were developed through the Applied Innovation Project and were in direct support of the Company's strategic priorities in 2022:

- **Supervisor Super Dashboard (Crew Tool Use Visualization)**

Historically, over 100 Distribution Operation Business Unit's supervisors and managers utilized several web pages/locations to see compliance-related and safety performance data of more than 2000 field crew members. This includes pre-job brief completion data, vehicle idling, driving events and due dates for required training and equipment expiration. This data is all housed in various disparate databases (source systems) and accomplished through complex integrations and security access passing. Innovation performed a "Go and See" to evaluate the time needed to complete this daily task by observing a sample set of 12 supervisors and found that the task required an hour to complete per supervisor. The solution created by DTE Innovation via PowerBI allowed these data points to be brought into a single page dashboard for safety, dependability, efficiency, and employee engagement. Data included focused on safety and compliance - driving data, safety procedure completeness and more.

Line No.

As a result, the affected DO leadership pool productivity improves by approximately 83 hours daily by ability to view and process the same data from a single application page in 10 minutes or less. This allows them to see all the compliance data they use to plan their day/week and where field observations may help improve their team's performance.

- **DO - CBC-8000 Automated Service Now Tickets from Maximo**

Historically, the process to connect DO Work Management and IT Work Management systems to enable CBC-8000 installations was done manually. DO engineering utilizes Maximo for issuing work orders for the installation of capacity controls by region. This work requires IT network engineering task to be generated from ServiceNow.

The Innovation process was designed to improve the CBC-8000 installation by automating ServiceNow tickets from Maximo via an Application Programming Interface. There are 3000-5000 CBC-8000 devices expected to be deployed and all deployments will utilize this newly developed efficiency and quality measure. The new process integrates Maximo work orders into ServiceNow IT tickets allowing the two systems to communicate. When a workorder is created in Maximo, a ServiceNow request is triggered, and updates are communicated between the two systems.

The new process can be utilized for any small or large-scale SCADA Devices deployment in the future which represents more than 3000 devices annually that will utilize this newly developed efficiency and quality measure. Considering an example of 3000 devices, approximately 15 minutes per request saves 45,000 minutes (750 hours). This also saves 10% manual entry errors, preventing 300 errors for 3000 devices. This solution aligns with DTE's service keys by increasing efficiency and dependability, due to removal of human error and decreasing the time it takes to manually enter ServiceNow tickets from Maximo.

See Exhibit A-24 N3 Line 377 for additional project details.

<u>Projects < $250K</u>

Q69. What is included in the "Projects less than $250,000" category?

A69. Workpaper titled "IT Projects <$250K", shows spend for projects in IT with estimated spend less than $0.25 million in the projected bridge and test periods. The investment in of these projects occurred in 2022, and we have implemented the projects. These projects span the portfolios and are necessary investments to collectively support DTE.

<u>Part IV – Historical Spend Variance</u>

<u>2022 Spend Variance</u>

Q70. How much did the Company spend in 2022 on total IT capital projects compared to what the Commission authorized for inclusion in rates in Case No. U-21297?

A70. The Company spent $224.3 million of capital on IT projects in 2022 compared to the $165.0 million approved by the Commission in Case No U-21297, as shown in line 18 of Exhibit A-24 Schedule N2, which is $59.3 million more than was authorized for inclusion in rates.

Q71. What were the reasons between the 2022 actual capital spend versus the spend the Commission authorized for inclusion in rates in Case No. U-21297 capital spend?

Line No.

A71. Exhibit A-24, Schedule N2, labeled as 2022 Historical Spend Variance Recovery, shows the comparison for projects greater than $0.5 million with a variance exceeding 20% and where additional recovery is being sought. The variance in these projects is discussed in the corresponding project prose in the sections above as referenced in Table 7.

Table 7 Variance Testimony Reference by Project

Description	Portfolio	Variance Testimony Reference
Production Growth	Plant and Field	PS-67-68
Maximo Platform Program	Plant and Field	PS-73-74
Automated Provisioning	Information Protection Security	PS-91
Ransomware Protection	Information Protection Security	PS-95
Digital Worker Experience Electric EOL	Infrastructure Operations	PS-110 –111
End of Life Asset Replacements	Infrastructure Operations	PS-112
Security Infrastructure Growth and EOL	Infrastructure Operations	PS-118-119
Enterprise Monitoring Strategy Implementation	Infrastructure Operations	PS-129
Advance and Enhance the Enterprise Data Platform	Enterprise Data Analytics	PS-134 -135

For the remaining variance recovery, please refer to Company Witness Hatsios' testimony 2022 Historical Project Spend Variance.

Other Variance

Q72. Were there any other projects that had variances that you have not yet discussed?

Line No.

A72. Yes. There are eight projects listed below that were not completed in 2022, 2023 nor are planned to be completed in 2024 as previously approved and included in rates in Case No. U-21297.

- Environmental Air Regulation Management: This project is currently being rescheduled and upon approval of reschedule the Company will submit plan in future rate case.

- Business Continuity Plan Automation: This project has been rescheduled to 2026.

- Time Entry: This project is currently being rescheduled and upon approval of reschedule the Company will submit plan in future rate case.

- Tool and Inventory: This project is currently being rescheduled and upon approval of reschedule the Company will submit plan in future rate case.

- Cloud Insight: This project has been deferred until DTE's annual spend/usage on cloud infrastructure are significantly large enough to benefit from potential cost savings which can be identified by deploying the Cloud Insight's demand.

- Cyber Security for OT and ICS: This project shall be deferred to complete the OT and ICS Cyber Security Assessment and developed specific recommendations to be implemented in order to meet security requirements and risks identified by the assessment/

Line No.

- FWWW IPS: This project is no longer being pursued because DTE moved employees to remote work during Covid, basically achieving the benefits which were targeted through the Future of Where We Work.

- Vulnerability Managements tools for key systems: This project was originally a separate initiative to address a number of IT systems and applications vulnerability risk. After further review of the demand objectives and requirements, it was determined that vulnerability management requirements in asset specific projects would be incorporated where required.

Q73. Does this complete your direct testimony?

A73. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JASON E. SPARKS

Line
No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Jason E. Sparks (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from Central Michigan University with a Bachelor of Science in Business Administration and a Master of Business Administration Degree.

Q4. What is your work experience?

A4. I have worked at DTE Energy since 2006, in several positions of increasing responsibility. From 2006 until 2013, I worked in the Controller's Organization performing many diverse tasks including processing journal entries, consolidating budgets, and providing operational support and compliance work. Since 2014, I have worked in the Customer Service Organization; first as a manager (in Revenue Management & Protection and then the Call Center), the Director of the Metering, Billing, and Exceptions teams, and now as Director of Revenue Management and Protection.

Q5. What are your current duties and responsibilities?

A5. As Director of Revenue Management and Protection (RM&P) group for DTE, I am responsible for the overall direction, strategy, leadership and management collection, theft mitigation, and low-income programs for DTE. The RM&P group is responsible for driving reduced uncollectible expense for DTE Electric and DTE Gas as well as optimizing the Energy Assistance funding for low-income customers. I am updated weekly on operational performance measures for all of Customer Service and receive updates on financial performance and strategic plans to improve all areas of the Customer Service Business.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following cases:

U-17999	2016 DTE Gas General Rate Case
U-18014	2016 DTE Electric General Rate Case
U-20836	2022 DTE Electric General Rate Case
U-21297	2023 DTE Electric General Rate Case
U-21291	2024 DTE Gas General Rate Case

Line No.

Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to:

- Explain the details of the Company's Energy assistance program
- Provide details of DTE's Low Income Self-sufficiency Plan (LSP)
- Provide details of DTE's Low-Income Assistance (LIA) credits
- Provide details on the Rate Schedule D1.6 rate provision change
- Provide details of DTE's Residential Income Assistance credits (RIA)
- Provide details of DTE's Payment Stability Plan (PSP) pilot
- Explain and support the $50.9 million of projected uncollectible expense

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-13	C5.8	Projected Operation and Maintenance Expenses Uncollectible Accounts
A-32	W1	Assistance Disconnect Rates

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

Energy Assistance Programs

Q10. What energy assistance programs does the Company provide to its customers?

A10. The Company provides energy assistance programs to both low-income and non-low-income customers. The Company's energy assistance programs include the Affordable Payment Plan (APP), which is known as the Low-Income Self Sufficiency Program (LSP), and Residential Income Assistance and Low-Income Assistance (RIA and LIA) credits. For non-low-income customers, we provide energy assistance through a 25% match of the Low-Income Home Energy Assistance Program (LIHEAP) Direct Support program administered by the Michigan Department of Health and Human Services (MDHHS) as well as Energy Waste Reduction (EWR) services. Additionally, to further understand and meet the energy affordability needs of our customers, we have implemented the Payment Stability Plan (PSP) pilot approved in the Case No. U-20929 Order. I will discuss all these programs in further detail in my testimony.

Q11. What is the goal of the Company's energy assistance programs?

A11. DTE Electric's energy assistance programs are structured with several primary goals in mind:

Sustained Energy Access: The foremost objective is to ensure that customers, particularly those with low incomes, have continued access to essential energy services. These programs strive to prevent service interruptions and help customers maintain a reliable source of energy for their households.

Arrears Reduction: The programs aim to alleviate customer arrears, which are outstanding or overdue payments. By providing assistance to reduce accumulated arrears, the burden on customers is eased, enabling them to manage their financial obligations more effectively.

Payment Habit Encouragement: DTE Electric's initiatives are designed to promote responsible payment behaviors among participants. By offering affordable monthly payments, these programs assist customers in establishing a habit of regular bill payments.

Consumption Reduction: Another goal is to encourage customers to reduce excessive energy consumption. Through education, incentives, and awareness campaigns, the programs seek to curb wasteful energy practices, thereby benefiting both customers and the environment.

Short-Term Assistance: While aiming for long-term sustainability, the programs provide short-term assistance to help customers bridge the gap during periods of financial strain. This assistance is intended to alleviate immediate challenges while participants work toward self-sufficiency.

Empowerment and Self-Sufficiency: Ultimately, the programs aspire to empower customers to become self-sufficient in managing their energy-saving practices. By guiding participants toward better financial management and energy-saving practices, the programs equip customers with the tools to afford the actual costs of their energy consumption over time.

Community Collaboration: Collaboration with external entities, such as social service agencies, government departments, and community organizations, is a central aspect of these programs. This collaboration helps identify eligible participants, tailor assistance strategies, and generate effective solutions for present and future energy challenges.

In summary, DTE Electric's energy assistance programs encompass a comprehensive range of goals that collectively aim to ensure energy access, alleviate energy burden, reduce arrears, and create pathways to energy assistance that address crisis situations.

Q12. What efforts has DTE Electric taken to maximize the benefits available to the greatest number of its most vulnerable low-income customers?

A12. The Company understands the challenges facing our low-income customers and utilizes both external and internal resources to proactively identify and assist our customers. Collaborating with social service agencies, government departments like MDHHS, and community action groups is a strategic priority. These partnerships provide valuable insights, resources, and expertise to better understand the needs of low-income customers and design effective assistance programs. Internal engagement focuses on continually improving how to engage and guide our customers toward energy assistance options. This integrated approach can yield sustainable solutions that benefit both the Company and its low-income customers. While these strategies have the potential to make a positive impact not only on our customers, but the broader community, they also can address changing circumstances and evolving customer needs.

Q13. What external collaborations are working to maximize benefits to low-income customers?

A13. As mentioned above the Company collaborates with community action agencies such as The Heat And Warmth Fund (THAW), Salvation Army, and United Way and Community Economic Development Association of Michigan (CEDAM). The Company also collaborates with the Energy Affordability and Accessibility Collaborative (EAAC) subcommittee recommendations for streamlined energy assistance applications and a standardized partnership with the state to leverage data-sharing similar to the process utilized with MDHHS during the LIHEAP direct support initiative. This allows DTE Energy and other utilities to identify income qualified households and proactively provide pathways to energy assistance like RIA credits and EWR services more efficiently.

Q14. What actions is the Company taking to ensure that customers are aware of available energy assistance?

A14. The Company continues to inform customers of available energy assistance through the standard channels such as 2-1-1, a free service that connects Michigan residents with help and answers from health and human services agencies and resources in their communities, and information provided through digital channels. In addition, the following accessibility strategies have been implemented:

- Outbound call campaign to SPP customers for SER application assistance
- Automated letter campaign to motivate potential energy assistance eligible customers to seek assistance early to avoid service interruption
- Email blasts to past recipients of SER funding
- Email outreach to customers receiving Notice of Intent (NOI) letters

Accessibility strategies focus on expanding the SER application process and leveraging community partnerships, involving virtual webinars to raise awareness and virtual Customer Assistance Days (CAD)s to promote MEAP and other energy assistance. Understanding the possible mail delivery delays through the United States Postal Service (USPS), the proactive NOI email initiative will notify customers more quickly and will help to prevent service interruption.

Low Income Self-Sufficiency Program (LSP)

Q15. What does the Company consider its key Affordable Payment Plan?

A15. LSP is the Company's APP. It is a 2-year payment plan for vulnerable families at or below 150% Federal Poverty Level (FPL) to make affordable monthly payments based on income and energy usage. The Company partners with social service agencies and the State of Michigan to further support and promote LSP. The LSP program provides comprehensive support that helps eligible customers afford their utility service. The comprehensive support includes wrap-around services from agency partners in the form of education, energy efficiency, and other self-sufficiency services over the course of their participation. While participating in the plan, customers have the benefit of sustained energy. The plan eliminates any future late payment charges, and past due energy charges are frozen while the customer receives a monthly arrears forgiveness credit. Additionally, a dedicated team of customer advocates within the Company are ready to assist customers while enrolled in LSP.

Q16. How long has the Company offered LSP to its customers?

A16. Public Act 615 of the Michigan Public Act of 2012 established the Michigan Energy Assistance Act requiring the MDHHS to administer the Michigan Energy

Assistance Program (MEAP). For just over a decade the MEAP funds have supported LSP. In addition to DTE, CMS, UPPCO, and SEMCO offer APPs.

Q17. Have there been recent changes to LSP?

A17. Yes, in 2023, the MPSC took measures to align utilities on eligibility and the administration of APPs. As a result, several changes were made to LSP. See the table below.

Table 1

Affordable Payment Plan Alignment Update - Changes to LSP

Components	Existing LSP – Fixed Customer Payment	New LSP – Modified Budget Billing Plan
Plan Length	24 Months	24 Months
Federal Poverty Level (FPL) Tiers	• 20-75 % • 76-110% • 111-150%	• 1-19%[1] • 20-75 % • 76-110% • 111-150%
Consumption Cap	• $1,600 for Electric Only • $2,150 for Gas Only • $3,750 for a Dual Commodity	No cap as the customers plan amount is reflective of their unique usage.
Arrears Forgiveness	• Arrears are frozen at the time of enrollment and paid off monthly. • $3,000 arrears cap	• Upfront arrears forgiveness payment of up to $600. • A 2nd Arrears payment of up to $600 at 12 months. • A final arrears payment of $1,800 at the completion of the plan. • No arrears cap.
Monthly Gap Payment	A credit is provided to offset the difference between the actual billed usage and the customer's plan amount.	• A flat monthly credit is provided to subsidize the customer's plan amount to make it more affordable than a traditional budget billing plan. • A reconciliation credit will be provided at the 12-month settlement to avoid additional customer burden.
Plan Calculation	• The customer's plan amount is based on the customer's FPL and usage but is not unique to the customer. • The customer's plan amount is set at enrollment and only changes if the customer moves.	• The customer's plan amount is based on their average monthly consumption and reduced by an agency credit chosen based on the customer's FPL. • The customer's plan amount is re-evaluated every 6 months and can change based on the customer's consumption behavior.

1. FPL Customers between 1-19% FPL requires MPSC approval in the existing LSP format.

Q18. How does the Company measure success for the current LSP program?

A18. In the current LSP program, a household is considered successful when completing the fiscal year without being removed for non payment.

Q19. Will the Company change how it measures success of the modified LSP?

A19. Yes. The Affordable Payment Plan Alignment subcommittee is working towards providing new metrics to define success of the modified LSP. This will include the definition of graduation and plan success over multiple fiscal years.

Q20. What are the Year Over Year (YOY) success metrics for LSP since its implementation?

A20. Table 2 depicts the metrics for LSP since its inception in 2013. This measure is customers avoiding disconnect due to missed payments.

Table 2 LSP Success Rate 2013-2022

LSP Yr	2013	2014	2015	2016	2017	2018	2019*	2020**	2021	2022
Success Rate	80%	81%	92%	88%	91%	89%	67%	85%	82%	81%

*First year State Emergency Relief was required as part of the LSP enrollment eligibility

** First year of 24 month LSP due to APP Alignment changes

Line No.

Q21. How many households that graduated from LSP returned to the program?

A21. Throughout the program an average of approximately 16% of graduates return to the LSP program as shown in Table 3.

Table 3 LSP Graduate Metrics

LSP Yr	Enrolled	Grad	Grad Percentage	Number Returned	Return %	Eligible for Graduation
2015-16	35,089	4,474	13%	1,189	27%	35,089
2016-17	40,049	4,278	11%	1,315	31%	40,049
2017-18	34,344	1,881	5%	93	5%	34,344
2018-19*	36,109	4,877	14%	573	12%	36,109
2019-20**	16,306	-	0%	-	0%	N/A
2020-2021	23,511	1,756	67%	178	10%	2,642
2021-2022	26,097	5,631	74%	611	11%	7,578
2022-2023	23,750	3,174	62%	354	11%	5,079

*First year SER was required as part of the LSP enrollment eligibility

**Excluded due to first year of moving from a 48 month to 24-month LSP payment plan due to APP Alignment changes

Q22. What ways are customers eligible for graduation from current LSP?

A22. Prior to the 2019-20 fiscal year LSP graduates were selected based on their account balance at the end of the fiscal year and not based on their time on the program. In the current program format in addition to customers achieving a zero balance for graduation status, customers are provided 24 months of eligibility on the program and graduation can occur for those customers who complete the 24 months even with a balance.

Q23. Why is it important to provide pathways to self-sufficiency for households such as those who have graduated from LSP?

Line No.

A23. After discontinuing the support of LSP, customers often encounter difficulties in maintaining consistent monthly payments, leading to potential crises. This challenge is particularly pronounced for individuals on fixed incomes, such as seniors, retirees, and minimum wage workers, who struggle to meet their financial obligations. For instance, a single minimum wage earner in Michigan, earning $10.10 per hour in 2023, would have an Adjusted Gross Income of $19,401 after accounting for Social Security and Medicaid taxes.

Considering the 2023 Federal Poverty Level (FPL) for a single-person household is $13,590, the 150% of FPL threshold stands at $20,385. However, according to the Massachusetts Institute of Technology Living Wage Calculator, the living wage for an individual in the Detroit – Warren – Dearborn area is $33,705[1]. This indicates a significant gap between minimum wage earnings and the income required for a basic standard of living.

Moreover, if we apply the Bureau of Labor Statistics' 2020 estimate that approximately one percent of full-time workers nationwide earn federal minimum wage or less to DTE's customer base, at least one percent of customers may lack the income necessary to cover all living expenses in the area [2]. This includes not only those below the poverty line but also individuals earning up to approximately 250% of the FPL.

---

[1] Living Wage Calculator - Living Wage Calculation for Detroit-Warren-Dearborn, MI (mit.edu) available at https://livingwage.mit.edu/metros/19820 accessed on January 17, 2023.

[2] Characteristics of minimum wage workers, 2020 : BLS Reports: U.S. Bureau of Labor Statistics available at https://www.bls.gov/opub/reports/minimum-wage/2020/home.htm accessed on January 17, 2023.

Line No.

The economic improvements in Michigan from 2010 to 2019, as indicated by reduced unemployment, GDP growth, and slight wage increases, did not alleviate financial struggles for a significant portion of households. In 2019, 38% of Michigan's households still faced challenges. While 13% were living below the Federal Poverty Level, a larger segment—26%—comprised ALICE households: Asset Limited, Income Constrained, Employed. These households earned above 150% of the FPL but fell short of meeting essential household needs.[3]

These circumstances underscore the importance of exploring payment options that extend beyond the conventional 24 months and surpass the 150% FPL requirements. Such solutions are crucial for customers facing long-term financial constraints.

Q24. What is the Payment Stability Plan (PSP) pilot?

A24. The PSP pilot is a percentage of income-based program directed at low-income customers at or below 200% FPL. PSP is a 2-year pilot that started in the first quarter of 2022. The pilot focuses on the importance of affordable energy as it relates to energy burdens for low-income customers. Customers who receive either gas or electric utility service from DTE Gas or DTE Electric have a flat bill payment equivalent to 6% of the household gross income. Customers who receive both gas and electric utility service from the Companies have a flat bill payment equivalent to 10% of the household gross income. PSP enrollees were also contacted to receive EWR education services and provided partner agency information to receive wrap

[3] ALICE In Michigan: A Financial Hardship Study, Live United 2021 Michigan Report, pg. 1, available at https://www.unitedforalice.org/michigan, accessed January 17, 2023.

around services such as financial literacy, housing and food assistance, job and education development, children and family services, and transportation.

Q25. What are the early observations of the PSP pilot?

A25. Participants in the PSP pilot exhibited a 21% enhancement in on-time and in-full payments, resulting in an average reduction of arrears by 43%. Moreover, a noteworthy improvement in service interruption was observed when compared to eligible households not enrolled in PSP.

Q26. What are the next steps for the PSP pilot?

A26. The Company remains committed to conducting a thorough analysis of data, with the intent of sharing valuable insights with key stakeholders to assess the long-term viability of the pilot. The Commission's directive to the MPSC EAAC subcommittees to delve into the effectiveness of offering Percentage of Income Payment Plans (PIPP) to Michigan households is a central focus for 2024. This underscores a proactive commitment to addressing energy affordability for vulnerable households.

Q27. Why is it important to expand energy assistance to households with FPL's greater than 150%?

A27. As stated earlier, the ALICE population, households above the 150% FPL still face financial challenges and are vulnerable to energy insecurity. Offering assistance to this group helps prevent them from falling into financial distress, reducing the risk of falling into crisis resulting in service interruption.

Residential Income Assistance and Low-Income Assistance Credits

Q28. What other methods of assistance are there for low-income customers?

A28. Another key program addressing energy sustainability for our low-income customers is the RIA and LIA assistance credits.

Q29. What are the current key features of the RIA credit?

A29. The RIA credit offers low-income electric customers $8.50 per month credit on their bill. To be eligible, the total household income cannot exceed the 150% FPL, as verified by an authorized State or Federal agency. The credit is renewed annually based on the eligibility requirements. Customers may not receive both an electric RIA and electric LIA credit at the same time.

Q30. How can a customer become enrolled to receive the electric RIA credit?

A30. Customers who receive energy assistance in the form of a Home Heating Credit (HHC), State Emergency Relief (SER), or one time assistance are automatically enrolled to receive the RIA credit.

Q31. How is a customer who is not a recipient of the above-mentioned energy assistance able to enroll to receive the RIA credit?

A31. Households that do not receive energy assistance in the form of HHC, SER, or one time assistance by an agency may provide documentation validating their eligibility and be manually enrolled.

Q32. How does DTE Electric reach out to households not automatically enrolled for the RIA credit?

Line No.

A32. The Company has several ways that it reaches customers who may have a need for the assistance. The Company distributes the "Payment Assistance Programs" brochure annually, as required by the Commission. This brochure includes several options for energy assistance and payment plans. Additionally, the brochure is also available on the Company's website for quick access. Customer Resource Events also assist customers by providing a variety of options to lower energy burden and provide pathways to EWR resources to lower monthly payments. In addition to these communication touch points, our call center analysts are trained to inquire and guide our customers to the best options for them to sustain energy through our Agent Assist Tool, which is highlighted later in my testimony.

Q33. In 2023 how many DTE Electric customers received the RIA credit?

A33. Over 160,000 unique electric customers received the RIA credit in 2023 with an annual monthly average of 75,522.

Table 4 2020-2023 Electric RIA Customer Counts

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	40,841	31,153	42,712	36,033	34,226	37,229	38,366	40,914	40,240	42,742	42,660	51,284	39,867
2021	49,353	47,625	59,867	59,242	56,920	70,009	60,730	60,095	57,133	54,675	52,637	54,668	56,913
2022	55,273	52,472	77,861	64,098	71,279	76,710	70,158	80,906	75,554	77,992	76,119	83,522	71,829
2023	83,898	67,558	84,225	68,573	79,637	74,767	71,061	80,429	77,502	77,240	70,466	70,910	75,522

Note: Customer counts are billing period end of month snapshots and year end variances to Part III reporting due to timing.

Q34. How many RIA customers is the Company including in its projected test year?

A34. In the projected test year, the Company is forecasting the RIA credit enrollment monthly average of 83,000 customers.

Line No.

Q35. What is the key feature of LIA Credit?

A35. The LIA credit (contained in Rate Schedule D1.6) offers qualifying low-income electric customers a $40 per month credit on their bill.

Q36. What currently makes a customer qualified to receive the LIA credit?

A36. To qualify for this rate an electric customer must have a total household income at or below 150% FPL.

Q37. Can any qualifying low-income customer currently be eligible to receive the LIA credit?

A37. Yes, though the Company prioritizes customers who are enrolled in the Company's APP or already receiving the RIA credit.

Q38. How many DTE Electric customers are currently enrolled and receiving the electric LIA credit?

A38. Over 38,000 unique households receive the electric LIA credit with an annual monthly average of 32,125.

Table 5 2020-2022 Electric LIA Customer Counts

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	25,038	20,297	24,597	22,928	23,337	26,073	26,551	26,296	26,268	26,431	23,998	28,748	25,047
2021	25,896	24,025	29,348	27,369	26,226	30,633	27,769	29,214	27,950	26,250	27,888	33,852	28,035
2022	33,841	28,554	36,381	31,150	32,757	34,291	30,513	33,697	31,136	31,126	29,700	32,852	32,167
2023	32,991	28,434	35,831	29,326	34,622	32,927	30,851	35,128	34,227	32,492	28,972	29,703	32,125

Note: Customer counts are billing period end of month snapshot and year end variances to Part III reporting fall within 5%.

Q39. What is the enrollment process for the LIA credit?

A39. There are several ways a customer may receive the LIA credit.

1. Customers who become enrolled in the LSP program are also enrolled to receive the LIA credit.
2. Graduates of LSP may continue to receive the LIA credit if maintaining their low-income eligibility status.
3. At the Company's discretion, customers receiving the RIA credit can transition to LIA when there is availability.

Aligning the LIA credit with LSP helps our most vulnerable customers move toward self-sufficiency. Though non-LSP customers may also receive the LIA credit, experience has shown that applying the low-income credit first towards a long-term program yields the highest self-sufficiency and assists in preventing missed payments.

Q40. What would be the impact if the LIA credit was applied randomly instead of strategically paired with customers enrolled in the LSP program?

A40. In previous case filings the Commission has agreed with the Company and determined that random application of the LIA credit is not as effective as when customers are partnered with the LSP Program. Random application results in higher disconnect rates amongst those customers who do not have the additional support of an affordable payment plan such as LSP. Overall, customers receiving the LIA credit without the pairing of LSP have twice the disconnect rate as those receiving both LIA and LSP. See Exhibit A-32 Schedule W1. Lines 2,5,7, and 8, which depict disconnect rates for non-LSP households receiving some type of assistance, such as Michigan Energy Assistance Payment (MEAP), HHC, and RIA.

Line No.

LSP households receiving LIA represent a significant decrease in the number of disconnects.

Q41. Is the Company proposing any changes to the LIA program?

A41. Yes. As described in the testimony of Company Witness Willis, the Company is proposing to eliminate Rate Schedule D1.6 and to expand the availability of the credit to all base residential rate schedules. This change will have no substantive impact on the credit and will bring it in line with how the electric RIA is managed. In addition, the Company is proposing to increase the LIA credit from $40 to $50.

Q42. Why is the Company proposing to increase the LIA credit from $40 to 50?

A42. In its December 11, 2015, Order in Case No. U-17767, the Commission approved the creation of Rate Schedule D1.6, which included the $40 LIA credit. The LIA credit has remained the same since its creation at $40. At the time of implementation, the LIA credit represented an approximate 43% credit to an eligible low income customer's bill compared to what the bill would have been without the credit. Based on the current Rate Schedule D1.6 rates approved by the Commission in Case No. U-21297, the current $40 LIA credit represents an approximate 34% credit to a low income customer's bill. The proposal to raise the credit to $50 aims to align the financial support provided to low-income customers receiving LIA with the originally approved credit offset as a percentage of their bills. The adjustment seeks to ensure that the credit amount is more in line with the intended assistance for customers facing financial challenges, providing a more consistent and impactful measure of relief.

Q43. What is LIHEAP Direct Support?

A43. The LIHEAP Direct Support assists eligible low-income households with their heating and cooling energy costs, bill payment assistance, energy crisis assistance, weatherization, and energy-related home repairs. In 2023, in partnership with MDHHS and as part of the Coronavirus Aid, Relief, and Economic Security (CARES) Act, the Company used match-funding to reduce the arrears in the amount of $1.9 million for over 3,500 low- and moderate-income households. The total LIHEAP Direct Support program supported over 18,000 households and provided over $9 million in energy assistance. This collaboration required swift action in defining and identifying eligible customers as well as a team effort in the coordination of communication and system enhancements.

<u>Uncollectible Expense</u>

Q44. What is Uncollectible Expense?

A44. Uncollectible expense is the income statement impact of recognizing a reserve for the portion of accounts receivable that is considered uncollectible.

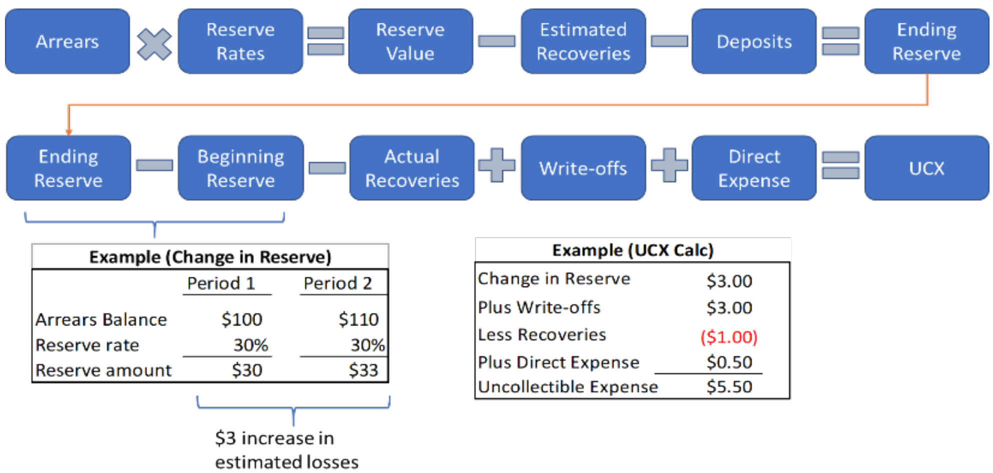
Q45. How is uncollectible expense determined?

A45. Uncollectible expense is determined by a review of individual arrearage accounts for the Company, recorded separately based on actual uncollectible performance and as a reserve against accounts receivables.

Q46. How does DTE Electric determine the accounts receivable (AR) reserve for uncollectible accounts?

A46. DTE Electric uses a balance sheet method. The 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 Uncollectible Expense Calculation is shown in Figure 1.

Figure 1 Uncollectible Expense Calculation



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.

Q47. How does the Company account for uncollectible expense?

A47. Uncollectible expense is recorded in the income statement to reflect the change in the AR reserve. In any given month, this expense is calculated as the increase/decrease in the AR reserve, plus accounts that were written-off during the month, minus accounts that were recovered (on previously written off accounts) during the month, plus write-offs of customer credits applied that are not expected to be reimbursed to DTE Electric by agencies through the Low-Income Self - Sufficiency Plan (LSP). Figure 1 is an illustration of the uncollectible expense calculation process.

Q48. What are the Company's write-off procedures?

A48. 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.

Q49. How is uncollectible expense projected in this case?

A49. To be consistent with prior rate making approvals, in this case the Company is utilizing a historical three-year average of actual net write-offs plus direct expense for 2020-2022 and adjusted for revenue growth, resulting in a $50.9 million of uncollectible expense. This amount is calculated on Exhibit A-13, Schedule C5.8 and shown on line 1, column (g) of that same exhibit.

Line No.

Q50. Is this the same methodology the Company used in its last rate case, Case No. U-21297?

A50. No. In this case, the Company is adopting the historical 3-year average of net write-offs, similar to Staff's methodology from Case No. U-21297. In that case, the Commission adopted and approved Staff's methodology, which is the same methodology the Company is using in this case.

Q51. In accordance with the Case No. U-21297 Order, is the Company providing a report to the Commission Staff on any debt sale within the past 5 years?

A51. The Company is not providing a report as it has not conducted any debt sales within the past 5 years.

Q52. Does the Company plan to complete a debt sale in the project test year?

A52. No, the Company does not anticipate any debt sale in the projected test year.

Q53. Does this complete your direct testimony?

A53. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

RACHEL C. STEUDLE

Q1. What is your name, business address and by whom are you employed?

A1. My name is Rachel Steudle, Director of Tree Trimming, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company, known simply as DTEE.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from Skidmore College with a Bachelor of Art in Economics and Environmental Studies in 2012. I completed a Master of Art in Applied Economics, and a Master of Science in Energy Systems from the University of Michigan in 2015.

Q4. What is your work experience?

A4. I began my career with DTEE in 2015 and have been employed there since. I joined DTEE in the Corporate Strategy team and spent four years supporting a broad range of strategic projects, primarily focused on the DTE Electric company. I concluded my time with Corporate Strategy as an Associate, responsible for leading and managing projects with minimal oversight. In 2019, I was promoted to Manager, Tree Trimming where I was responsible for leading the tree trim scheduling process, managing the program's budget, and supporting strategic efforts. In mid-2020, I was promoted to the Strategy Manager role for Tree Trimming. In this position, I continued my previously stated responsibilities while taking responsibility for developing the annual and 5-year maintenance plans, leading all

Line
No.

regulatory activities, negotiating contracts with the trimming vendors and overseeing our planning and auditing field team. In March 2023, I accepted a new role in the Company's project management organization responsible for leading the long-term planning for distribution capital projects. In November 2023, I returned to the Tree Trimming team to assume the Director role.

Q5. What are your current job responsibilities?

A5. Currently, I am the Director of Tree Trimming. In this role, I am responsible for the strategy and execution of the Tree Trimming Program. This includes contract negotiations, strategy, planning, auditing, execution, outage restoration trimming, customer satisfaction, workforce development and scheduling.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. No, I have not.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. As referenced in Witness Kryscynski's description of the distribution witnesses, the purpose of my testimony is to:

- Discuss the importance of and progress made in DTE Electric's vegetation management ("Tree Trimming") program.
- Provide details related to the Company's Tree Trimming Surge Program that will deliver on the reliability goals established in the Company's Distribution Grid Plan (DGP).
- Describe the customer benefits of the Company's Tree Trimming Surge Program to date.
- Support the Operations and Maintenance (O&M) expenses related to tree trimming efforts for the historical test period ending December 31, 2022, and the projected base O&M expenses and the Tree Trimming Regulatory Asset Surge funding amount for January 1, 2025, to December 31, 2025.
- Request approval of incremental Surge funding for 2025.
- Discuss the future of the Tree Trimming program once the Surge is completed.
- Address the additional requests from Case No. U-21297.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures – Distribution Plant
A-13	C5.6.1	Projected Tree Trimming Expenses
A-22	L1	Projected Value of Tree Trimming Surge Program

Line No.

A-31	V1	2023 Tree Trimming Annual Report

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

Outline of Testimony

Q10. How is your testimony organized?

A10. My testimony is organized as follows:

- Overview of the Company's Tree Trimming Program and the Surge
- Discussion of the final years of the Surge
- Strategy and Vision for Post-Surge
- Additional Requests from the Order in Case No. U-21297

Part I: Overview of the Company's Tree Trimming Program

Introduction

Q11. Can you please describe the Company's Tree Trimming Pillar of investments within the Distribution Grid Plan (DGP)?

A11. The Tree Trimming Pillar focuses on keeping vegetation (trees, brush, vines) clear of our overhead electrical equipment, including poles, wires, transformers, etc. The objectives of these investments are to reduce tree-related safety hazards and to reduce the volume of tree-related trouble cases, thereby increasing customer reliability. All vegetation management investments are made through the Company's Tree Trimming Program.

Q12. What is the biggest root cause of outages?

A12. As discussed in the Company's 2023 DGP (Case No. U-20147), tree interference remains one of the leading drivers of customer outages. Historically, tree-caused outages accounted for two-thirds of the time that customers spent without power. The Company's Tree Trimming Program reduces the frequency of tree contact with the distribution system, mitigating impact. The ongoing, successful execution of this program allows DTEE to continuously improve the overall reliability of electric service.

Q13. What is the best way to reduce tree-related outages?

A13. A robust Tree Trimming Program improves system reliability, including a reduction of the volume and duration of outages, wire-downs, and other non-outage trouble events. Achieving customers' desired level of reliability requires that the program be funded to maintain a tree-trim cycle that permits the trimming of a circuit to prevent vegetation interference with the Company's wires and become hazards.

Q14. What is the Company's Tree Trimming Program?

A14. Beginning in 2016, the Company has executed a robust program to address tree interference by trimming to an enhanced specification known as the Enhanced Tree Trimming Program, or ETTP. The ETTP specification is designed to reclaim right of ways, remove or reduce vegetation hazards from distribution infrastructure, and properly define trim specifications for vegetation encroachment. In addition to introducing this new specification, the Company proposed the Tree Trim Surge (the Surge) in 2018 in Case No. U-20162. The purpose of the Surge was to secure the necessary funding to trim all circuit miles to the ETTP specification by the end of

2025. The Company proposed maintaining a 5-year cycle (3-year cycle for Subtransmission) for all miles, including those trimmed in the early years of the Surge. This means a circuit trimmed to the ETTP specification in 2016 or later would be maintained on a 5-year cycle length while the Company addressed additional off-cycle miles in the later years of the Surge.

Q15. How long did the Company forecast the Tree Trim Surge would take?

A15. The Company forecasted the Surge would span seven years, or 2019 through 2025.

Q16. How much did the Company project the Surge would cost in Case no. U-20162?

A16. In Case No. U-20162, the Company projected that the Surge would cost $1,131 million; $721 million treated as base O&M and $410 million booked as a regulatory asset.

Q17. Has the Commission supported the Tree Trimming Surge?

A17. Yes, the Commission approved the first three years of regulatory asset treatment in Case No. U-20162. In subsequent rate cases the Commission has continued to support the Tree Trimming Surge, approving incremental years of regulatory asset treatment and the requested base O&M increases.

Q18. What is the progress towards completing the Surge as of the end of 2023?

A18. The Company trimmed 5,299 miles in 2023, bringing the system to 83% on-cycle. Our goal is to be 100% on-cycle by the end of 2025.

Line No.

Q19. What does on-cycle mean?

A19. On-cycle means that the circuit miles have been trimmed to the ETTP specification at least once and are on a maintenance trimming cycle for future years.

Q20. What is the Company's maintenance cycle for on-cycle miles?

A20. The Company distinguishes cycle-length based on the voltage of the circuit. For subtransmission circuits (24 and 40kV) the cycle length is three years. For distribution circuits (4.8, 8.3 and 13.2 kV) the target cycle length has been five years. The Company is introducing a variable, risk-based cycle for distribution circuits, which would mean some circuits have a longer or shorter cycle length based on certain criteria. This approach is discussed in detail later in this testimony.

Q21. What does reclaim miles mean in this context?

A21. Reclaim miles are circuits that have not been trimmed to the ETTP specification and are considered off-cycle. These circuits have not been trimmed since at least 2015.

Q22. Have the ETTP specifications been applied consistently throughout the Surge?

A22. Yes. The ETTP tree-trimming specifications are applied consistently throughout the Company's service territory. The Company trims and removes trees to maintain circuit clearance for one five-year cycle worth of growth, which, on average, necessitates ten feet of clearance to the outermost conductor. The required clearance is species-specific. The specification is focused on clearing vegetation within the right-of-way. In addition, while trimming a circuit the Company identifies priority trees outside the right-of-way that could pose a risk and attempts

Line No.

to mitigate this risk. All circuits are inspected post trimming by either DTE foresters or an independent third-party contractor to ensure the specifications have been met. Any deviation from specification is corrected by the tree contractor who performed the work at no additional cost to the Company. Further discussion of the inspection process is included at the end of my testimony.

<u>Tree Trimming Surge Effectiveness</u>

Q23. Has the Company measured the effectiveness of the Surge program thus far?

A23. Yes, the Company has developed a methodology to measure the performance of on-cycle circuits trimmed to the ETTP specification relative to reclaim circuits.

Q24. Can you elaborate on the methodology?

A24. The Company uses the methodology outlined in Case No. U-20561 as well as in the Tree Trimming Annual Reports submitted in the Case No. U-20162 docket. The 2023 Tree Trimming Annual Report has been submitted as Exhibit A-31, Schedule V1 for reference. The report, and results mirrored below, include outage and event data through the end of the 2023 calendar year.

The methodology used to calculate ETTP Performance for all distribution circuits uses the average of three years of pre-trim ETTP tree-outage events and compares it to each year post trimming. All post-trim year results of the same year were then summed to increase the sample size (as an example, all post-trim year 1 results are summed). The difference between the before trimming performance and the post trimming performance was used to create the "% Change in Outage Event Reduction for ETTP circuits". To create a control group for comparison, the same

Line No.

methodology was used for the remainder of circuits not trimmed ETTP[1] (Non-ETTP circuits), which is identified as "% Change in Outage Event Reduction for Non-ETTP circuits". To account for natural weather variation, the performance of the control group is subtracted from the ETTP circuit performance to provide an accurate representation of the true impact of the ETTP.

Q25. What has been the improvement in outage events on circuits trimmed to the ETTP compared to the non ETTP control group?

A25. The difference in outage events on ETTP circuits compared to the balance of the system not trimmed to ETTP is 54.0% in post-trim year 1, 36.8% in the second year, 43.8% in the third year, and 11.1% in the fourth year. The actual reduction for Years 1-4 post ETTP trim are depicted in Table 1.

[1] This group consists of circuits that have not been trimmed to the ETTP specification and are considered off-cycle

Line
No.

Table 1 ETTP Tree-Related Outage Event Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Reduction
1 Year Post Trim	2063	-22.0%	32.0%	**-54.0%**	-57.0%
2 Years Post Trim	1442	-12.8%	49.6%	**-36.8%**	-57.0%
3 Years Post Trim	974	9.9%	53.7%	**-43.8%**	-50.0%
4 Years Post Trim	491	58.1%	69.2%	**-11.1%**	-37.0%

Q26. How does this reduction compare to results under the prior trimming practice?

A26. As discussed in Case No. U-20162, (3T 202) the past practice of trimming a "clearance circle" around conductors provided only a 13% reduction in tree-related events in the year following trimming as compared to the average number of events in the three years preceding trimming.

Q27. Do you see similar differences for customer interruptions and the number of customer minutes of interruption on ETTP vs. non-ETTP circuits?

A27. Yes. Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a

57.9% difference in Year 1, 59.3% difference in Year 2, 48.6% difference in Year 3, and 40.7% difference in Year 4. These results are shown in Table 2. Customer minutes of interruption, shown in Table 3, also show significant improvements. Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP circuits show a 32.4% difference in Year 1, 8.1% difference in Year 2, -22.4% difference in Year 3, and -6.4% difference in Year 4.

Table 2 Post ETTP Tree-Related Customer Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customers Interrupted for ETTP circuits	% Change in Customers Interrupted for Non-ETTP circuits	**Difference in % Change in Customers Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Reduction
1 Year Post Trim	2063	-38.8%	19.1%	**-57.9%**	-57.0%
2 Years Post Trim	1442	-28.0%	31.2%	**-59.3%**	-57.0%
3 Years Post Trim	974	-24.1%	24.6%	**-48.6%**	-50.0%
4 Years Post Trim	491	-14.3%	26.4%	**-40.7%**	-37.0%

Line No.

Table 3 Post ETTP Tree-Related Customer Minutes of Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customer Minutes Interrupted for ETTP circuits	% Change in Customer Minutes Interrupted for Non-ETTP circuits	**Difference in % Change in Customer Minutes Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Reduction
1 Year Post Trim	2063	-27.0%	5.3%	**-32.4%**	-57.0%
2 Years Post Trim	1442	16.4%	24.5%	**-8.1%**	-57.0%
3 Years Post Trim	974	10.5%	-11.9%	**22.4%**	-50.0%
4 Years Post Trim	491	1.3%	-5.2%	**6.4%**	-37.0%

Q28. What has been the reduction in wire-down events post-ETTP trimming?

A28. Wire downs on the circuits that have been trimmed as part of the ETTP are significantly lower in the years after trimming compared to Non-ETTP circuits. The Year 1 difference is 55.4%, Year 2 is 56.8%, Year 3 is 39.8% and Year 4 is 15.3%. Reductions are shown in Table 4.

Table 4 Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year After Trimming	2063	-65.5%	-10.1%	**-55.4%**
2 Years After Trimming	1442	-64.8%	-8.0%	**-56.8%**
3 Years After Trimming	974	-58.3%	-18.5%	**-39.8%**
4 Years After Trimming	491	-52.7%	-37.4%	**-15.3%**

Q29. Does the Company plan to change the way it measures effectiveness of the Tree Trimming Program as the Surge finishes?

A29. Yes. The Company recognizes the usefulness of this methodology is beginning to diminish with the majority of circuits now trimmed to the ETTP specification. The remaining non-ETTP population is becoming too small to be an effective comparison to ETTP trimmed circuits. Moving forward the Company is exploring alternative methodologies to measure tree related reliability and plans to propose an alternative methodology to the Commission in a future case.

Other Components

Q30. What are the other key components of the Tree Trimming Program?

Line No.

A30. Other key components of the program include reactive trimming, herbicides, and spot trimming.

Q31. What is reactive trimming?

A31. Reactive Trimming includes work outside of normal maintenance, storm, or construction. This trimming is driven by trees that are causing an outage/non-outage event and trees considered a hazard to the Company's equipment or public safety.

Q32. What is the herbicide program?

A32. The Company uses EPA-regulated herbicides to replace mechanical removal of vegetation from the right-of-way with a chemical treatment, which will only control the tree species with the potential to grow into electrical wires. The Company has created the program using industry best practices that were collected and developed through benchmarking and by working with an outside consultant. The Company uses herbicides that include foliar herbicide treatment, basal herbicide treatment, and dormant stem treatment.

Q33. What are the benefits of the herbicide program?

A33. The herbicide treatment will reduce the future cost of maintenance trimming in the right-of-way by reducing tree density. There are other advantages besides realizing cost savings. As tree density and brush height decreases, the electrical system becomes more reliable, and the right-of-way becomes more accessible. Also, because grasses and shrubs are not affected by the herbicide treatment, the area will become a habitat for pollinators, birds, and small mammals. The treatment will also target invasive plant species, limiting their spread.

Q34. What is spot trimming?

A34. Spot trimming is focused on poor performing circuits, typically not yet trimmed to the ETTP specification, that have a high number of sustained and/or momentary outages. Spot trimming involves targeted trimming at select trouble locations to address ongoing emergent issues. ETTP trimming addresses the entire circuit and the full trim specification.

Part II – Final Years of the Surge

Q35. Does the Company have a projection for percentage of circuit miles that will be on-cycle at the end of 2024?

A35. Yes, at the end of 2024 the Company projects that ~90% of circuit miles will be on-cycle.

Q36. When was the Tree Trimming Surge originally proposed to be completed?

A36. In Case No. U-20162 the Company proposed trimming the full system to the ETTP specification and maintaining on-cycle miles to a 5-year cycle (3-year cycle for subtransmission) by the end of 2025. With that goal in mind the Company expects to have 10% of its system to reclaim in 2025.

Q37. Does the Company foresee any challenges with completing the Surge based on the funding levels and timeframe originally proposed in U-20162?

A37. As the Company has entered the final years of the Surge, we have identified a funding gap to complete all reclaim miles *and* maintain on-cycle miles at the intended 5-year cycle.

Q38. How much did the Company forecast the Surge would cost in Case No. U-20162?

A38. Case No. U-20162 stated the Surge would cost $1,131 million, $721 million treated as O&M and $410 million booked as a regulatory asset.

Q39. Does the Company have an updated forecast on the total cost of the Surge?

A39. Yes. Based on actuals for 2019-2023, negotiated contracts for 2024, and assumed costs for 2025, the Company estimates the full cost of the Surge will be $1,383.2 million. This is $251.2 million more than forecasted in Case no. U-20162.

Q40. When did the Company understand the magnitude of the change in cost?

A40. While the program has navigated a changing landscape and impacts to the cost since the beginning of COVID, the magnitude of the change in cost emerged at the end of 2023. This was due to the largest driver of the variance being the cost of on-cycle work[2] being higher than originally projected. The ETTP specification was implemented in 2016 and the circuits trimmed in 2016 returned for their first "on-cycle" trim in 2021. Subsequently we also had "on-cycle" miles in 2022 and 2023. The Company has been closely monitoring the cost of these circuits relative to their historical cost each year, but recognized there could be year-to-year variations.

[2] Referring to distribution miles trimmed to the ETTP spec and due for their next trim – sub transmission has been on-cycle and costs related to that work are not the driver for the new cost projection.

With the conclusion of 2023, the Company had three years' worth of on-cycle actuals to project future costs of the program.

Q41. Can the Company breakdown the drivers of the $251.2 million incremental cost?

A41. Yes – below is a summary of the drivers.

Drivers	$ Millions
Higher On-Cycle Costs	$133.6
Increased Outsource Premium	$69.7
Programmatic Additions	$30.5
Inflation	$17.4
Total	**$251.2**

Q42. Can you elaborate on the higher on-cycle costs driver?

A42. In Case No. U-20162, the Company prepared a forecast for the seven-year Surge. The Company modeled the cost to reclaim miles and cost to maintain on-cycle miles in the latter years of the Surge. A key assumption of this model was that there would be a 40% savings once circuits were on-cycle. For example, if a circuit cost $1 million dollars to reclaim to the ETTP specification, the next time we trim it the circuit would cost $600,000 (not adjusting for inflation). The Surge model used the 40% savings assumption along with historical cost data to forecast the average cost per mile for reclaim and on-cycle miles each year of the Surge.

Actuals for reclaim miles have totaled $28 million less than the forecasted cost in the Surge model. However, actuals for the on-cycle miles have totaled $162 million more than the forecasted cost in the Surge model. In net, the cost of the miles has been $134 million more expensive than the Surge model forecast.

Q43. Where did the 40% cost savings assumptions come from?

A43. The 40% cost savings assumption was based on a work study completed by ECI, a third-party consultant, between 2015 and 2017. The goals of the work study were to assess use of industry management best practices within the utility, address general opportunities for program enhancements, and assess program performance. The work study included a field review of vegetation conditions and opportunities. Through this review, ECI identified that our average density was 228 trees per mile, 48% of the tree work is in the backlot/in-accessible by equipment, and 42% of trees were good removal candidates.

ECI recommended a maintenance program with a 5-year to 6-year cycle. Based on the characteristics above and the recommended maintenance program, ECI forecasted that once on-cycle the program would be 40% less than relative to the reclamation period.

Q44. Why have actual savings been less than the 40%?

A44. The variance in on-cycle savings is driven by differences in ECI's assumptions and the actuals we have observed in the field.

Line No.

Table 5 Comparison of ECI Assumptions and Actuals

Key Assumptions	ECI	Actuals	Commentary
Density (trees per mile)	228	242	• Actual density has been ~5% higher than assumed
Backlot Work (%)	48%	80%	• Significant discrepancy in the assumed percentage of backlot work • Backlot work is majority manual climbing, which is more expensive and requires skilled trimmers
Removals Rate	42%	15%[3]	• ECI assumed 100% of good removal candidates would be removed

The difference in work location and removal rates means that complexity and volume of work for on-cycle trimming is higher than originally assumed, resulting in lower savings.

Q45. Why were ECI's assumptions on removal rates and work location notably different from actuals?

A45. ECI sampled the territory to identify total trees, good removal candidates, and work location. For removal rates, ECI assumed all trees identified as good removals would be removed during the first trimming to the ETTP specification. Customer approval is required for all removals on property. This would have meant the Company had 100% acceptance by customers to remove all these trees. At the time of study, the ETTP specification was relatively new, and the Company had limited data to understand the customer approval rate with respect to removals.

[3] Removal rate for just trees, the Company's removal rate for all vegetation (trees, vines and brush) is 28%.

For front vs. back lot, ECI identified trees as accessible or inaccessible. This was done by surveyors who determined whether the tree could be addressed by a bucket truck or other mechanized equipment. Accessibility of equipment is dependent on physical ability to maneuver equipment to the tree, but also customer willingness to allow for the equipment on their property, soil condition, weather and other factors.

Q46. Does the Company have improved ways to track data on removal rates and mix of work location to assist in improved cost projections for the future?

A46. Yes, the Company leverages a robust work management tool during maintenance trimming in which we capture all vegetation touched as part of our annual maintenance plan. For each unit (e.g., tree, brush, vine) that is addressed, we document whether it is in the backlot vs. front-lot, parcel address, species, and whether it's a trim or removal. Effectively, the Company is cataloging the vegetation system as it is trimmed for the Surge. The work management tool was implemented in 2019 and we plan to have our full system catalogued at the conclusion of the Surge.

Q47. Can you elaborate on the increased outsource premium cost driver?

A47. To complete the volume of trimming needed in the Surge, the Company recognized the need to pay a premium to attract outsource crews to work in the Company's service territory. This premium was made up of per diems and crew overtime. In Case No. U-20162, the Company forecasted the cost for the outsource premium, however, actuals have exceeded the forecasted cost because we have required approximately 100 more outsource trimmers annually to supplement the local workforce not growing at the forecasted rate.

Q48. Can you elaborate on the programmatic additions?

A48. Yes. There are two additions to the program that were not included in Case No. U-20162's forecasts. As discussed earlier in my testimony, the Company performs spot trimming on poor performing circuits that have a high number of sustained and/or momentary outages. In addition, the Company created the Tree Trim Academy to support growth of our local workforce and create a pipeline within the City of Detroit. Operation of the Tree Trim Academy was interrupted in 2020 due to the COVID-19 Pandemic but resumed in 2022. Cost impact for both programs is shown in Table 6.

Table 6 Cost of Programmatic Additions ($ millions)

Spot Trimming	$26.1
Detroit Tree Trim Academy	$4.3
Total	**$30.4**

Q49. Can you elaborate on the inflation impact?

A49. The Surge model assumed an annual inflation rate of 3%. Actual costs have been driven by the labor rates negotiated between IBEW Local 17 and tree trim contractors. The annual labor increase for line clearance tree trim contracts ranges from 4%-6% through the life of the Surge. This difference equates to $13.6 million. In addition, deferring filing a rate case for two years caused the Company to forego

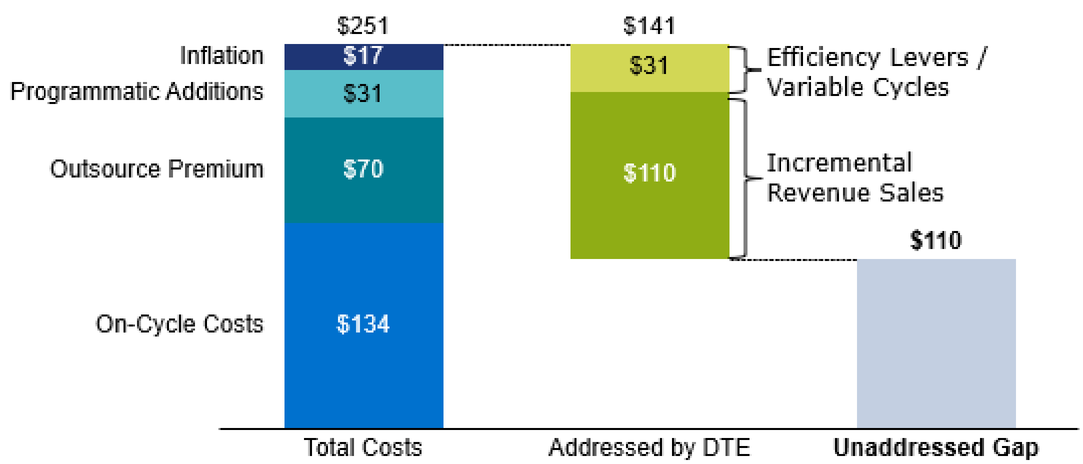
Line No.

$3.8M in inflation-related increases in our base O&M. The Surge model assumed the Company would engage in annual rate cases and the base O&M would increase each year.

Q50. How has the Company addressed the total $250 million variance?

A50. As shown in Figure 1, the Company has addressed a substantial portion of the higher costs by utilizing extra revenues collected from customers when sales were above projections and introducing variable, risk-based cycles. However, we forecast a remaining $110 million needed to complete the Surge in totality, which equates to a 10% variance to the original cost projections for the Surge.

Figure 1 Cumulative Cost Impact of the Surge ($ millions)



Q51. Can you elaborate on the incremental sales revenue?

A51. A substantial portion ($90 million) of the $110 million incremental sales revenue is associated with non-weather-related electric sales patterns resulting from the coronavirus (COVID-19) pandemic. Certain directives issued in response to the COVID-19 pandemic impacted electricity usage patterns of the Company's

Line
No.

customers resulting in a net increase to margin compared to expectations under normal circumstances. The Company proposed refunding this margin to rate payers in the form of additional tree trim surge investments. The intent being to advance the Company's Tree Trimming efforts while avoiding future customer expense for those investments, thus providing an affordability benefit to customers. The Company proposed creating a onetime regulatory liability that would be debited for incremental tree trim expenses that occurred between 2021 and 2023. To the extent the Company did not spend the full $90 million by the end of 2023, the Company would provide refunds to customers via bill credits. In Case No. U-21128, the Commission approved the Company's proposal.

Q52. How was the additional tree trim surge investment utilized?

A52. The additional tree trim surge investment was leveraged as an immediate response to the severe storm events in summer of 2021. In 2022, the Company spent $85.8 million of the incremental $90 million investment. This additional investment allowed the Company to complete an extra 1,700 off-cycle miles in 2022 and lead the system to be 79% on-cycle at year end. These miles were focused in poor reliability areas and trimming was completed prior to the 2022 storm season. The remaining $4.2 million was committed to spot trim high-risk areas that were not on the 2023 maintenance plan. In total, the Company invested $89.4 million of the $90 million, the balance of which will be credited to customer bills as proposed.

Q53. How does the Company propose to address the remining funding needed?

A53. The Company proposes to address the $110 million through a combination of incremental regulatory asset in 2025 ($87 million) and increasing the base O&M

($23 million) in 2026. The regulatory asset would be required to address the remaining reclaim miles needed to complete the Surge. The increase in base O&M is to fund trimming on-cycle miles based on the new projections. Increasing the O&M for the first year post-Surge would set the appropriate baseline budget for a fully on-cycle system into the future. There is further discussion of the strategy for post-Surge and the opportunity to move to a risk-based, variable cycle in Part IV of my testimony. Table 7 summarizes the annual funding for the final years of the Surge and the first year post-Surge.

Table 7 Proposed Incremental Funding to Complete the Surge ($ millions)

Funding Source	**2024**	**2025**	**2026 (Post Surge)**
Base O&M	$106	$109	$112
Incremental O&M	*-*	*-*	*$23*
Regulatory Asset	$53	$44	
Incremental Regulatory Asset		$87	
Total Annual Funding	**$159**	**$240**	**$135**
Total Incremental		$87	$23

Q54. How much cost is the Company expecting to recover outside of base rates?

A54. The Company is proposing to defer Surge costs up to $183.4 million above base rates from 2024 through 2025.

Q55. How has the Company proposed to recover the program costs above base rates?

Line No.

A55. The Company proposed, and the Commission approved, regulatory asset treatment for the incremental costs through 2024 totaling $365.8 million, $156.9 million of which were securitized in March 2022 pursuant to the Commission's June 23, 2021 order in Case No. U-21015. Witness Lepczyk discusses how the Company proposes to recover future Surge costs until they can be securitized.

Q56. Why is the Company proposing to securitize the costs?

A56. As previously discussed, the Surge investment is intended to lower future reactive costs that would be incurred given the current state of vegetation near or on the distribution system. Securitization funding recognizes the long-term nature of the program. As the costs are incurred up front and the full savings will not be realized until after the program has matured, recovery over a longer period provides a better matching of costs with the anticipated savings, minimizing the cost impact to customers.

Q57. What happens if the Commission does not approve the incremental $87 million requested of regulatory asset?

A57. Without the incremental funding, one of two scenarios will likely occur for 2025:

1) Scenario 1: Prioritize the reclaim miles with available funding, which will limit the Company's ability to address circuits trimmed to the ETPP specification that are due for their next maintenance trim. The Surge would be completed, however, there is a risk of historically on-cycle miles (trimmed to the ETTP specification) going past their optimum next trim date which could lead to

Line No.

reliability problems and the cost to retrim those miles will be more expensive in the future.

2) Scenario 2: Prioritize maintaining miles due for on-cycle trimming with available funding, which results in a portion of reclaim miles not to be trimmed in 2025 and carryover to 2026. The Company would continue to trim the remaining reclaim miles as funds allowed but would prioritize maintaining on-cycle miles.

Q58. Can you provide more details on the impact of either of these options to the Tree Trimming Program and electrical reliability.

A58. Yes - we have identified the following adverse impacts:

1) Scenario 1 – Approximately 3,200 on-cycle miles that are due for trimming would not be addressed. This would cause trimming expense to increase by 20% the following year. Further, an impact to reliability performance would result for circuits identified as fast growth archetypes.

2) Option 2 – Based on the 2024 plan, approximately 2,600 reclaim miles will remain at the beginning of 2025. If the Company prioritizes on-cycle miles with the current funding, we estimate being able to address up to 700 of the remaining 2,600 miles of reclaim. The reliability impact to the 1,900 miles unable to be trimmed would be increased by approximately 20%. The average age since last trim of these miles in 2025 would be 11.5 years. In addition, the Company would need to defer ~500 on-cycle miles that are due in 2025, to 2026.

Part III – Post-Surge (2026 and beyond)

Q59. Can you define "post-Surge"?

A59. As DTEE enters 2024, the penultimate year of the Surge, the Company is beginning to plan for what the Tree Trimming Program will look like once it is fully on-cycle, beginning in 2026, defined as the "post-Surge" period. This definition assumes that DTEE completes all the reclaim miles by the end of 2025.

Q60. What funding level does the Company forecast the program will need post-Surge?

A60. The Company forecasts the program will require approximately $135 million annually (not adjusted for inflation) to maintain the Surge's investment and keep all miles on-cycle.

Q61. How does this funding level compare to the forecast from prior cases?

A61. As shown in Table 8, the DTEE forecasts the Tree Trim Program will cost an incremental $23 million annually relative to the amount that the Company originally forecasted in Case No. U-20162. In Case Nos. U-21297 and U-20836, the Company submitted exhibit A-22 Schedule L1. This exhibit is an output of the Surge model which projects the future O&M needs of the program – the exhibit indicated expected O&M for the program after the Surge was trending higher than the projections from Case No. U-20162. As discussed previously, the full magnitude of the increased costs were not fully understood until last Fall.

Table 8 Forecasted O&M Post-Surge ($ millions)

Source of Projection	2026	2027	2028
U-20162	$112	$116	$119
U-20836/U-21297	$126	$130	$133
Current Projected Costs	**$135**	**$139**	**$142**

Q62. Why will the post-Surge program cost more than originally forecasted?

A62. As discussed previously, the Company has determined that the on-cycle cost of trimming is more than it forecasted in Case No. U-20162.

Q63. Beyond requesting incremental O&M, how does the Company plan to address the on-cycle cost pressures?

A63. In Case No. U-21297, the Company introduced its effort to develop a risk-based, variable cycle model. The model was developed to elevate the Company's maintenance trimming cycle to be more targeted than the current 5-year standard.

Q64. Why is the Company exploring a risk-based, variable cycle currently?

A64. As the Company enters the final years of the Surge, the Company recognizes that there are opportunities to adjust the target cycle for different parts of the system utilizing technology such as LiDAR. Adjusting cycle lengths based on tree species' growth rates, risk of outages, and cost of trimming will further improve trimming efficiencies and provide reliability benefits to customers. With the acquisition of LiDAR tree density and encroachment data combined with tree species data the Company has acquired over the course of the Surge program, DTE Electric has the necessary information to make data-driven improvements to the program.

Furthermore, the idea of variable cycles was raised by intervenors and the Commission in Case No. U-20836. In Case No. U-20836 (p.487), the Commission ordered the Company to continue to explore efficiency improvements, and benefits from a variable cycle for the Tree Trimming program and the Company is complying with that directive.

Q65. What is LiDAR and why is it beneficial to the Tree Trimming program?

A65. LiDAR (Light detection and ranging) is a remote sensing method that measures the distance to Earth of different objects, such as trees and utility equipment. LiDAR enables the development of a 3D image of an area with accurate measurements between objects and the ground. In recent years, LiDAR has emerged as a valuable tool for vegetation management programs to digitalize assets and assess risk to the system.

Q66. Does the Company have experience with LiDAR technology?

A66. Yes. The Company has developed a risk-based, variable cycle model that leverages the LiDAR data to help identify optimal trim cycles and emerging hot spots. LiDAR technology provides advanced data on the Company’s tree density, growth patterns and emerging cycle-buster trees. This data can also provide significant value to the Tree Trimming program in the form of assisting in scoping and estimating costs for maintenance work.

Q67. How is a risk-based cycle different from a 5-year cycle?

Line No.

A67. A fixed-year cycle (i.e., 5-year cycle) has been the industry standard until recently. The emergence of remote sensing and advanced data analytics for vegetation programs allows companies to begin considering variable cycles.

Moving towards a variable, risk-based cycle would be a refinement to the Company's maintenance trimming program. The 5-year cycle is based on the **average** growth rates and tree densities across the entire system and their expected **average** spatial relation to the conductor. There are areas across the territory with higher tree densities and faster growing species that grow back into the wires prior to five years, in other words there are variances to the averages discussed. Conversely there are areas with slower growing species that could go longer between maintenance trims before interfering with the conductor. Moving towards a risk-based cycle would move higher risk areas to a shorter-cycle, and lower risk areas to a longer-cycle, instead of uniformly trimming every area on a 5-year cycle.

Q68. Do other utilities use a risk-based cycle?

A68. Yes. Based on my understanding of benchmarking and other information, the Company has identified other utilities in the industry exploring or introducing variable, risk-based variable cycles.

Q69. What does the Company foresee as the benefit from this shift?

A69. The Company expects that moving towards a risk-based cycle will result in trimming efficiencies and improved reliability for high-risk areas. Based on the nature of variable cycle programs, the Company anticipates the need to trim high-risk areas more frequently, and low-risk areas less frequently, resulting in an overall

Line
No.

more efficient use of resources. In addition, more frequent trimming in high-risk areas should provide reliability benefits to customers, without sacrificing reliability in low-risk areas.

To best understand the benefits and potential tradeoffs from a variable, risk-based cycle, in 2024 the Company identified approximately 2,000 miles of on-cycle circuits that could go a year past the 5-year cycle based on the results of its risk-based model. This sample of variable cycle circuits will allow the Company to measure the potential benefits of risk-based cycles such as improved trimming efficiencies, lower annual trimming costs and improved reliability. In addition, the Company will be able to identify potential challenges, develop countermeasures, and adjust the model.

Q70. How did the Company determine the length of a risk-based cycle?

A70. The Company developed a risk prioritization model that leverages remote sensing data (e.g., LiDAR), advanced analytics, and machine learning to estimate the probability of vegetation-driven failures and determine optimal trim cycles for an area.

Q71. What was the investment for the risk prioritization model?

A71. The direct capital investment for this model is approximately $6.3 million.

Q72. Is the Company seeking recovery for this investment?

A72. Yes. The Company is seeking recovery for this investment as shown in Exhibit A-12, Schedule B5.4, Page 17, line 24 ($6.9 million).

Q73. Are there other elements of the model?

A73. Yes. Beyond identifying optimum trim cycles for different areas, the model will provide key improvements to the Company's annual planning and execution of the maintenance plan.

(1) This model will expand and enhance the cost modeling the Company has already done using LiDAR data and circuit system data. This information together can identify efficiency opportunities through mechanization identification in accordance with trim location[4].

(2) The model identifies where trimming work for overlapping distribution and sub transmission lines can be optimized to drive efficiencies and optimize trim cycles in areas with multiple classes of distribution assets.

(3) The model will improve the process for developing the annual plan by automating the balance of work across the territory to ensure capacity of work is within control limits[5].

Q74. Will the use of the risk-based cycle reduce the Company's forecasted funding needs post-Surge?

A74. Yes, the Company's forecasted need of $135 million annually assumes that the Company will be on a risk-based, variable cycle. If the Company does not move to a risk-based cycle, then the cost of maintaining the program at a 5-year cycle will be higher. We assume risk-based cycles will yield a minimum of a 5% savings annually during initial transition to variable cycles.

---

[4] In this context *mechanization identification* refers to the practice of employing equipment, such as backyard buckets or Jarraffs, in areas that historically used manual climbing.

[5] Control Limits is a point of reference for balancing volume of work based on service center, resources, budget, and other operational constraints.

Line No.

Part IV: Additional Requests from Order Case No. U-21297

Q75. Has the Company been Ordered to consider other changes to the Tree Trimming program?

A75. Yes, in Case No. U-21297 (December 1, 2023, Order, page 353) the Commission directed the Company to consider a future residential service drop Tree Trimming pilot and to work with the Staff to develop such a pilot to be considered in the Company's next rate case.

Q76. What is a service drop?

A76. Generally, a service drop is the term used for an overhead secondary conductor running from a utility pole, across a customer's property, to a meter installed on a home (for a typical residential customer).

Q77. How does a service drop differ from other types of overhead distribution wires?

A77. Most overhead distribution wires run from one utility pole to another, whereas service drops run from pole to a customer's structure. Utilities typically have a right of way (ROW) for the areas surrounding their pole-to-pole wires that permits them to trim vegetation near those conductors. The Company does not have the same right of way for service drops.

Q78. Does the Company have a service line Tree Trimming maintenance program for service drops?

A78. No, the Company does not.

Line No.

Q79. Is the Company developing a pilot to trim services?

A79. Yes. The Company is working with Staff and at least one intervenor to develop a pilot utilizing the expedited pilot process.

Q80. Were there additional tree trim related directives in the December 1 Order in Case No. U-21297?

A80. Yes, in Case No. U-21297 (Page 353) the Commission adopted Staff's recommendations regarding tree-trimming audits (inspections) and an analysis of more aggressive trimming in zones 2 and 3.

Q81. Does the Tree Trimming Program include auditing (inspections)?

A81. Yes. The Tree Trimming program performs quality inspections on all maintenance work to ensure compliance to specifications outlined by the ETTP.

Q82. How is the inspection conducted and to what standards?

A82. An inspection is conducted to quality standards determined by ISA and ANSI300A trimming guidance against the trim plan for that specified work completed on a circuit. The inspection is performed by a certified arborists who are either internal to the Company or a 3rd party vendor who is not associated with the Tree Trimming vendors.

Q83. When does inspection take place?

A83. Inspections are conducted typically less than 30 days from the time the entirety of the work for all circuits from a substation is completed. Once all the work is reviewed and approved by the arborist the closure of that work is approved.

Line
No.

Q84. What happens when a non-compliant result is discovered?

A84. Any non-compliance of a tree trim task according to plan against the standard is provided to the trimming vendor to be remediated within 30 days, at no additional cost to the Company. An auditor then inspects the area again to ensure the remediation is performed in a satisfactory manner.

Q85. How does the Company track tree work associated with the maintenance program and the quality inspections?

A85. The Company has a work management system that is used for the planning, execution, and inspection of all maintenance trimming. This program allows for planners to identify specific tasks (trims or removals by tree / brush) on a property, which the trimmers reference and use for their work plan execution. The inspection team uses the same system to identify the work that was completed and inspect the tasks for potential defects. Inspection results are then accessible to the contractor through the work management system. This process allows for streamlined plans, electronic records of work completed, and a database of tree work for the Company to leverage for future planning and analysis.

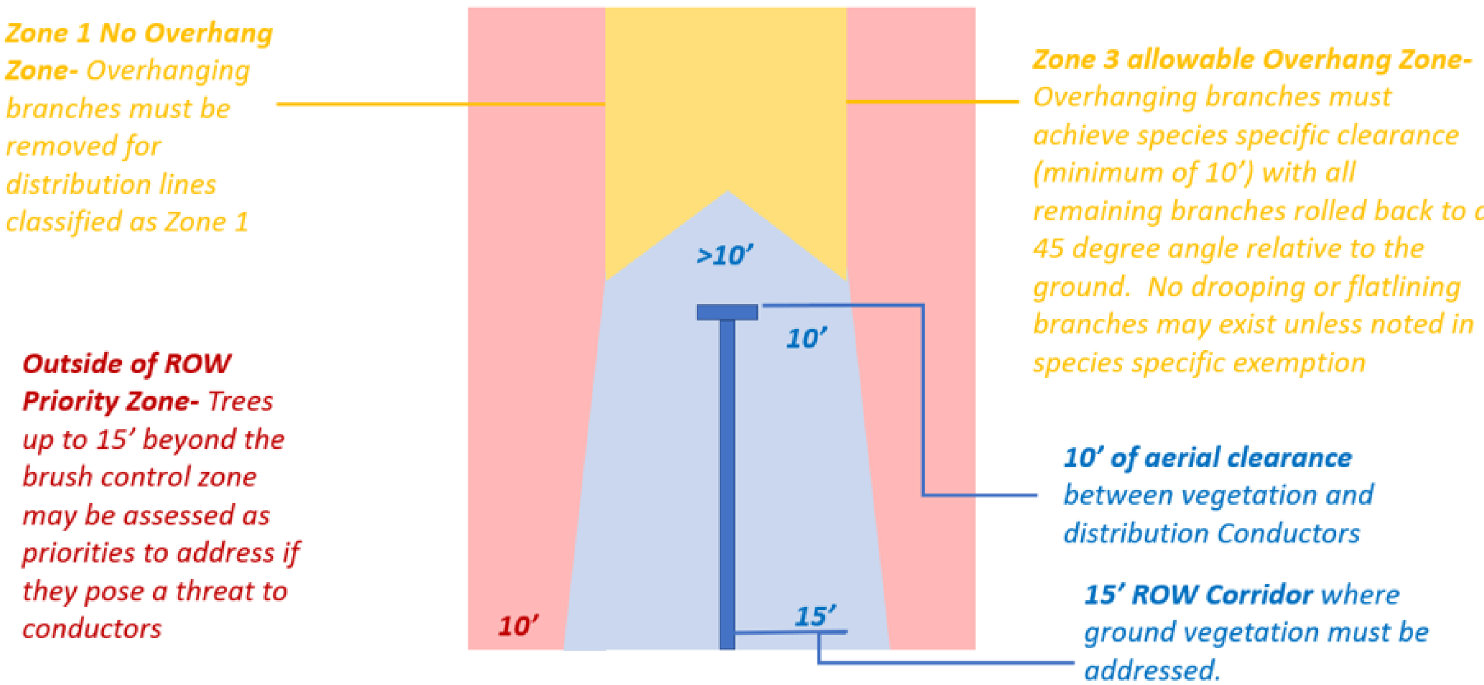
Q86. What is Zone 2 and Zone 3 and how do they differ from Zone 1 from a trimming specification?

A86. The Company divides the overhead electrical system into three zones. In Zone 1, the portion of the circuit from the substation to the first protective device or drop down, the Company removes all branches overhanging the conductors. In Zone 2, the portion of the circuit from the first protective device or drop down[6] to the fused

[6] Drop Down is designated as a location on the circuit where a voltage drop or a multiple direction split in distribution power takes place.

lateral, and in Zone 3, the fused laterals, the Company removes all softwood and hardwood branches overhanging the conductors at less than a forty-five-degree angle. The difference in specification is illustrated in Figure 2.

Figure 2 Trimming Specification for Zone 1 compared to Zone 2/3



Q87. What would more aggressive trimming of Zone 2 and Zone 3 look like from a specification perspective?

A87. If the Company were to trim these zones more aggressively, it would be trimming all areas to the Zone 1 specification, which requires removing all overhang.

Q88. Could the Company pilot the impact of more aggressive trimming in Zone 2 and Zone 3?

A88. While the Company could perform a pilot, the appropriate timeframe to fully understand the costs and benefits of this type of change would be to track a subset

Line No.

of circuits for 4-5 years after trimming to fully measure reliability benefit relative to circuits trimmed to our current maintenance specification. If we were to pilot trimming all zones to the same specification on several circuits this year (2024), we would need to compare those circuits' performance through 2029 to fully measure the potential reliability benefit.

Q89. Does the Company have an alternative methodology to study the incremental benefit and cost of expanding the trimming on Zone 2 and Zone 3?

A89. The Company proposes comparing circuits trimmed on our regular maintenance program (control group) to circuits trimmed for construction projects (test group). The Company has a small subset of circuits that have been trimmed to a more expansive specification, with all overhang removed, in preparation for construction projects. The Company can compare the cost and reliability of these two groups to understand the impact of potentially changing the specification.

Q90. Are there other considerations beyond cost and reliability if the Company were to change the specification for Zone 2 and Zone 3?

A90. Yes:

1) The Company anticipates customer sentiment would be impacted negatively by pulling overhang on Zone 2 / Zone 3. Typically, the portion of the overhead line that runs through a customer's backyard / property is Zone 2 / Zone 3. Comparatively, Zone 1 is often referred to as the backbone and may be along the roadside or in a less residential setting, therefore less direct impact to customers.

2) Pulling additional overhang would require more skilled climbing trimmers and acquisition of specialty trim equipment in areas where large mature trees are present.
3) By trimming overhang, that historically hasn't been removed, undergrowth and brush will be exposed to additional sunlight, expediting existing growth and creating new vegetation growth under the wires. This could lead to further maintenance costs and interfere with anticipated reliability improvement.

Conclusion

Q91. Does this complete your direct testimony?

A91. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF THERESA M. UZENSKI

Line
No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Theresa M. Uzenski (she/her/hers). I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy). My business address is One Energy Plaza, Detroit, MI 48226.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I have a Bachelor of Science in Accounting from the University of Detroit and a Master of Business Administration with a concentration in Finance from Wayne State University.

Q4. What is your work experience and what position do you currently hold at DTE Energy?

A4. I have worked for DTE Energy or one of its affiliated regulated utilities for over thirty-four years in various accounting, finance, and management positions. I am currently the Manager of Regulatory Accounting for DTE Electric Company as well as DTE Gas Company.

Q5. Do you hold any certifications or are you a member of any professional organizations?

Line
No.

A5. 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.

Q6. What are your current duties and responsibilities?

A6. As Manager of Regulatory Accounting, I am responsible for the development and management of regulatory accounting policies and practices and 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 implementation. My department also supports other Company expert witnesses in various proceedings before the MPSC by preparing financial exhibits and other financial analyses.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. I have sponsored testimony in the following cases:

U-11222	Michigan Consolidated Gas Company (MichCon) Depreciation
U-13898	MichCon UETM
U-14702	Detroit Edison 2006 PSCR Plan
U-15160	Detroit Edison Enhanced Security Cost Recovery
U-15244	Detroit Edison Choice Incentive Mechanism Reconciliation
U-15259	Detroit Edison Pension Equalization Mechanism
U-15417-R	Detroit Edison Pension Equalization Mechanism

U-15806-EO	Detroit Edison Energy Optimization
U-15768	Detroit Edison UETM
U-15890	MichCon Energy Optimization
U-16009	Complaint Case against Detroit Edison
U-16246-R	Detroit Edison 2009 RETM Reconciliation
U-16246-R	Detroit Edison 2010 RETM Reconciliation
U-16356	Detroit Edison 2009 REP Reconciliation
U-16472	Detroit Edison 2010 Rate Case
U-16574	Detroit Edison 2010 UETM Reconciliation
U-16582	Detroit Edison 2014 REP Plan
U-16769	MichCon Depreciation
U-16952	Detroit Edison 2014 CIM Reconciliation
U-16956	Detroit Edison 2014 RETM Reconciliation
U-16964	Detroit Edison 2014 UETM Reconciliation
U-17302	DTE Electric Company 2017 REP Plan Update
U-17437	DTE Electric Company Transitional Cost Recovery Mechanism
U-17767	DTE Electric Company 2014 Rate Case
U-17999	DTE Gas Company 2015 Rate Case
U-18014	DTE Electric Company 2018 Rate Case
U-18122	DTE Electric Company Customer 360 Program Accounting
U-18255	DTE Electric Company 2017 Rate Case
U-18419	DTE Electric Company Certificates of Necessity
U-18999	DTE Gas Company 2018 Rate Case
U-20106	DTE Gas Company Tax Cut & Jobs Act – Credit A
U-20105	DTE Electric Company Tax Cut & Jobs Act – Credit A

Line No.		
1	U-20162	DTE Electric Company 2018 Rate Case
2	U-20298	DTE Gas Company Tax Cut & Jobs Act – Credit C
3	U-20561	DTE Electric Company 2019 Rate Case
4	U-20642	DTE Gas Company 2019 Rate Case
5	U-20940	DTE Gas Company 2021 Rate Case
6	U-21015	DTE Electric Company 2021 Securitization
7	U-20836	DTE Electric Company 2022 Rate Case
8	U-21193	DTE Electric Company 2022 Integrated Resource Plan
9	U-21297	DTE Electric Company 2023 Rate Case
10	U-21291	DTE Gas Company 2024 Rate Case

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to support DTE Electric's financial statements for the historical test year ended December 31, 2022, the interim forecast period and a twelve-month projected test period ending December 31, 2025, with certain adjustments necessary for presenting the financial information in the appropriate format for ratemaking purposes. My testimony supports the development of the projected test year adjusted Electric operating income based on forecasted changes from the normalized historical Electric operating income. I will discuss how costs recovered from other mechanisms are excluded from the financial statements in this case including Renewable Energy Program (REP) and Energy Waste Reduction (EWR). I will support the Corporate Staff Group (CSG) capital and Operations and Maintenance (O&M) expenses for the historical and forecasted periods and explain the function of this group including the method for allocating costs to DTE Electric and other DTE subsidiaries through the Shared Asset charge.

I also explain the accounting treatment of the Monroe regulatory asset and amortization over 15 years. Witness Vangilder supports the revenue requirement. In addition, I request regulatory asset and liability accounts for the Company's proposed storm cost sharing mechanism supported by Witness Foley.

Q9. What exhibits are you sponsoring in this proceeding?

A9. I am supporting the following exhibits for the historical period:

Exhibit	Schedule	Description
A-2	B2	Historical Utility Plant
A-2	B3	Historical Depreciation Reserve
A-2	B4	Historical Working Capital
A-2	B5	Historical 13-Month Average Adjusted Balance Sheet with Classifications
A-2	B5.1	Historical Year-End Adjusted Balance Sheet with Classifications
A-2	B6	Historical Adjusted Balance Sheet – Year Ended and 13-Month Average
A-2	B6.1	Historical Year-End Adjusted Balance Sheet
A-2	B6.2	Historical 13-Month Average Adjusted Balance Sheet
A-2	B7	ARO & Nuclear Decommissioning Trust Fund
A-3	C1	Historical Adjusted Net Operating Income
A-3	C1.1	Adjustments to Historical Net Operating Income
A-3	C3	Historical Operating Revenue
A-3	C4	Historical Fuel and Purchased Power
A-3	C5	Historical Operation and Maintenance Expenses
A-3	C6	Historical Depreciation and Amortization Expenses
A-3	C11	Historical Allowance for Funds Used During Construction
A-3	C14	Historical Corporate Membership Adjustment
A-3	C15	Historical Advertising Adjustment
A-3	C16	Historical MERC Net Operating Income

A-3	C17	Historical Power Supply Cost Recovery Items
A-3	C18	Eliminate Nuclear Surcharge
A-3	C19	Historical Executive Incentive Compensation Adjustment
A-3	C20	Historical Employee Incentive Plan Normalization Adjustment
A-3	C21	Historical Weather Normalization Adjustment

I am also supporting the following exhibits for the projected test year:

Exhibit	Schedule	Description
A-12	B2	Projected Utility Plant
A-12	B3	Projected Depreciation Reserve
A-12	B4	Projected Working Capital
A-12	B4.1	Projected Average Balance Sheet with Classification
A-12	B4.2	Projected Balance Sheet
A-12	B4.3	Common Equity Reconciliation
A-12	B4.4	Monroe Regulatory Asset - Projected Balance
A-12	B4.5	Monroe Regulatory Asset - Calculation
A-12	B5	Projected Capital Expenditures – Summary
A-12	B5.8	Projected Capital Expenditures – Corporate Staff
A-13	C1	Projected Net Operating Income
A-13	C1.1	Projected Net Operating Income Adjustments
A-13	C3	Projected Operating Revenue
A-13	C5	Projected O&M Expense – Summary
A-13	C5.6.2	ADMS Regulatory Asset Amortization

Line
No.

A-13	C5.9.1	Charging Forward Regulatory Asset Amortization
A-13	C5.9.3	ACPP and TOD Regulatory Asset Amortization
A-13	C5.10	Projected Administrative and General Expenses
A-13	C5.10.1	Incentive Deferral Mechanism
A-13	C5.15	Inflation Factors
A-13	C5.17	PERC (Nuclear Projects) Regulatory Asset Amortization
A-13	C6	Projected Depreciation and Amortization Expense
A-13	C11	Projected Allowance for Funds Used During Construction
A-13	C11.1	AFUDC Ratemaking Adjustment
A-13	C12	Projected Amortization of the Loss on Reacquired Debt
A-13	C13	Projected Other (Income) / Deductions

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How were your exhibits prepared?

A11. My team, under my direction, uses an Excel model to create historical and projected balance sheets and income statements, and the supporting exhibits. We also have models to capture historical and projected O&M and capital expenditures. The O&M and capital models feed into the financial statement model. Our models start with historical financial information from the MPSC Annual Report on Form P-521. I calculate most of the rate case normalizations and adjustments to the historical balance sheet and income statement, but other Company witnesses calculate the adjustments to the O&M and capital expenditures for the business unit costs that they support. In addition, Company Witnesses Vangilder and Wisniewski support certain adjustments to interest and taxes. I support the O&M and capital costs for the Corporate Staff Group other than Information Technology (IT).

After the normalizations and adjustments are made to the historical period, I use the adjusted amounts to develop the financial statements for the projected period. Again, the witnesses supporting their business unit costs provide the known and measurable adjustments to O&M expense and the details for the capital expenditures. Sales revenue and fuel and purchased power are calculated by Company Witness Willis. Income and property taxes are calculated by Witness Wisniewski. The data provided by these witnesses is captured in my models to create the consolidated financial statements for the projected period. My projected financial statement data is then used by Witness Vangilder to calculate the revenue deficiency.

Q12. Can you explain the history of the Transitional Recovery Mechanism (TRM)?

A12. Yes. The City of Detroit operated a 139 square mile public lighting department (PLD) serving approximately 115 retail electric customers and a street lighting system and decided to exit the electric distribution business. On July 11, 2013, the Commission issued an order in Case No. U-17427, authorizing DTE Electric to defer for accounting purposes, the net incremental revenue requirement associated with the disposition of the PLD electric distribution business and transfer of PLD customers to DTE Electric retail service. On May 13, 2014, the Commission issued an order in Case No. U-17437 approving a TRM and tariffs to recover the net deferred costs. The deferred net incremental revenue requirement has been reviewed in annual reconciliation cases starting with Case No. U-17761 covering the period ending December 31, 2014. The transition of the PLD electric retail service to DTE Electric was completed in 2022. Therefore, the deferral of the net revenue requirement for the former PLD customers (that were converted to DTE Electric's system) has ceased, and the revenues and costs are instead included in base rates effective with the Order issued in Case No. U-20836 on November 18, 2022. A final TRM reconciliation was filed on October 31, 2022, in Case No. U-21307 covering the period January 1, 2021 through October 31, 2022. On July 26, 2023 the Commission issued an Order approving the final reconciliation and ratemaking for the TRM.

Q13. How does the end of the PLD cost deferral and the TRM impact the exhibits and the revenue requirement in the instant case?

A13. Consistent with prior rate cases, I have removed the TRM surcharge revenue and the related regulatory asset because they are addressed in the TRM reconciliation process. The final under recovery of the TRM is addressed in the final reconciliation case filed on October 31, 2022.

Q14. Would you summarize the treatment of the TRM in this case?

A14. Consistent with Case No. U-21297, the rate base supporting the former PLD customers and the cost of service on that rate base are reflected in the historical and projected financial exhibits. It is necessary to include the rate base supporting the former PLD customers in this case because these costs are no longer recovered through the TRM surcharge effective November 1, 2022. Please refer to Exhibit A-2, Schedule B6.1, column (k). The only item being eliminated from the balance sheet is the TRM regulatory asset on line 43 representing costs incurred before November 2022. It is being recovered via a separate surcharge through February 2024.

Q15. What is the impact to the historical and projected income statements?

A15. The exhibits include the sales revenue from PLD customers along with the related base fuel and purchased power expense. Please see Workpaper TMU-6. The TRM elimination in the instant case reflects only the surcharge revenue and O&M costs that will not recur.

Historical Test Year

Q16. What information are you providing regarding the Historical Test Year ended December 2022?

A16. For the historical test year ended December 2022, I am providing the balance sheet and net operating income (NOI) 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

Q17. What historical test year balance sheet information are you providing?

Line No.

A17. Exhibit A-2, Schedules B2 and B3 provide the historical utility plant and depreciation reserves, respectively. Schedule B4 provides the historical 13-month average for working capital. Schedule B5 classifies the historical balance sheet information into the categories of net plant, working capital, and the various financing components adjusted to use a 13-month average. Schedule B5.1 provides the same classifications based on a historical year-end balance.

Exhibit A-2, Schedule B6 shows the historical balance sheet amounts on a historical year-end and 13-month average incorporating the adjustments detailed on schedules B6.1 and B6.2. Schedule B6.1 contains the historical test year balance sheet information on December 31, 2022. Schedule B6.2 is a 13-month average balance sheet for the periods December 2021 through December 2022. The columns for both schedules detail the same types of adjustments.

Schedules B6.1 and B6.2, column (b) values are from the MPSC Annual Report on Form P-521. Column (c) adds the balance sheet values for the Midwest Energy Resources Company (MERC), a wholly owned subsidiary of DTE Electric involved in low-sulfur western coal storage and transshipment operations. MERC has been incorporated in the preparation of all exhibits. Pursuant to the Commission's Order in Case No. U-5108, capital costs incurred by MERC, including depreciation and property taxes, administrative expenses, income tax, interest, and return on rate base are to be considered in the Company’s main electric ratemaking process. Column (d) is the consolidated balance on which I base my adjustments.

Line No.

Q18. What adjustments are you making to the consolidated historical period financial statements?

A18. Consistent with the treatment in past cases, I am reclassifying certain items, removing non-utility items, and removing balances that are being recovered or refunded via other mechanisms or surcharges including EWR, REP, and PSCR. 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. I am removing the Combined Operating License (COL) for ratemaking purposes. Additionally, I am removing the Tree Trim Regulatory Asset and Tier 2 plant assets that have been securitized.

The adjustments are shown on the balance sheets on Exhibit A-2, Schedules B6.1 and B6.2, columns (e) through (p). 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.

Q19. What is the adjustment for taxes?

A19. Column (e) nets the Accumulated Deferred Income Tax Asset on line 67 and the Investment Tax Credit (ITC) on line 114, with the Accumulated Deferred Income Tax Liability on line 113. The ITC amount reflected in the reclassification is supported by Witness Wisniewski.

Q20. What is the adjustment for Tier 2 Plants?

Line
No.

A20. The St. Clair and Trenton Channel "Tier 2" coal plants were retired in 2022 before the end of their respective lives. In the June 22, 2023 Order in Case No. U-21338, the Commission approved the securitization of $594.1 million of St. Clair and Trenton Channel net plant. The Commission also granted approval to classify these costs as a regulatory asset. Therefore, in column (f), I reduced the Tier 2 Plants regulatory asset by $594.1 million, which were the combined balances of St. Clair and Trenton Channel approved for securitization. The related capitalization of 50% debt and 50% equity is also removed. This approach is consistent with the Commission's Order in the 2023 Securitization Case No. U-21338, which required the balances related to the St. Clair and Trenton Channel generation sites to be removed on a gross basis, with no impact to accumulated deferred income taxes.

Q21. What is the elimination for Tree Trim?

A21. The Commission authorized the Company's Tree Trim surge program, allowing for regulatory asset treatment of costs above an approved base amount in O&M. The regulatory asset is not included in rate base because the balance through June 2021 of $156.9 million was securitized pursuant to the Commission's June 23, 2021 Order in Case No. U-21015. Additionally, the Company is planning a future securitization of the Tree Trim regulatory asset once the balance is large enough as described by Witness Lepczyk. Therefore, I removed the historical regulatory asset and related capitalization of 50% debt and 50% equity in column (g). The revenue requirement for the forecasted Tree Trim Surge regulatory asset, which represents the tree trim costs not yet securitized, is separately calculated and supported by Witness Vangilder on his Exhibit A-11, Schedule A1.1.

Q22. What is the adjustment for the COL?

A22. Per the Commission's Orders in Case Nos. U-18014 and U-17767, the COL asset is being amortized over twenty years, but the balance remaining must be excluded from rate base. Therefore, in column (h) I have removed both the COL asset reflected on the books of DTE Electric and the related capitalization of debt and equity at 50% each.

Q23. What are the adjustments for programs and recovery mechanisms in columns (i) through (k)?

A23. Column (i) eliminates DTE Electric's EWR program. Column (j) eliminates the REP, except for the regulatory liability, and column (k) eliminates the TRM related to the conversion of the City of Detroit's PLD customers to DTE Electric. The associated debt and equity eliminations are consistent with the capital structures authorized by the Commission for each program.

Q24. If the REP is excluded from base rates, then why are you not eliminating the associated regulatory liability?

A24. The regulatory liability generated from the REP program is not eliminated because it is being used as a source of financing for DTE Electric's general rate base. Therefore, I have reclassified the balance out of the regulatory liability on line 106 and reflected it as short-term debt on line 94.

Q25. Why are you showing the REP regulatory liability as a source of financing for general rate base instead of REP rate base?

Line No.

A25. Consistent with the Commission's Order in Case No. U-15806 the return embedded in the REP surcharge reflects DTE Electric's approved cost of capital, primarily long-term debt, and equity. However, because the REP revenue requirement was collected in a surcharge separate from base rates, the remaining liability generated from the previous surcharge is available to reduce DTE Electric's other short-term debt, as approved by the Commission in Case No. U-15806.

Q26. If DTE Electric is using the regulatory liability as a source of financing, then how are DTE Electric's customers compensated?

A26. The REP revenue requirement and surcharge is reduced by interest accrued on the regulatory liability.

Q27. What accounting adjustments are reflected in the Company's financial presentation for the historical test year in this case?

A27. This rate case reflects adjustments for Accounting Standards Codification (ASC) 842, Accounting for Right-of-Use Assets (Operating Leases); ASC 410, Accounting for Asset Retirement Obligations; and ASC 715, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, because the accounting impacts are excluded from the revenue requirement.

Q28. What is the adjustment for leases?

A28. The Financial Accounting Standards Board issued ASC 842, which requires operating leases to be recognized on the balance sheet effective for DTE Electric in 2019. GAAP financial statements now include operating lease right-of-use assets and liabilities. The Uniform System of Accounts does not include balance sheet accounts for operating leases. The FERC ruled that the new lease accounting standard cannot impact ratemaking, and operating lease expense must continue to be based on actual amounts paid and be recorded as rent expense. I eliminated the operating lease asset and related liabilities (short-term and long-term) in column (l) to ensure there is no impact to ratemaking resulting from this new accounting standard. Additionally, in column (l) I eliminated a deferred gain on the sale of land associated with a prepaid lease for a parking structure that is amortized below the line. In prior cases, the Commission ordered that this item was to be excluded from rate base.

Q29. What is the adjustment for asset retirement obligations?

A29. The accounting for asset retirement obligations (ARO) results in timing differences in the recognition of legal asset retirement costs for accounting purposes compared to the recognition of amounts the Company is currently recovering in rates. ARO accounting requires an up-front accrual for future legal removal costs as a liability. Utility accounting recognizes the removal obligation in accumulated depreciation and accrues it through depreciation expense over the life of the asset. The timing differences are deferred under ASC 980, Regulated Operations. The ARO liability is offset by a corresponding net plant Asset Retirement Cost and a regulatory asset, which results in no impact on the revenue requirements in this case. A regulatory asset does not offset the incremental liability related to the non-utility Fermi 1 site.

To ensure that there is no impact on revenue requirements from ARO accounting in the forecast years, I have removed all 2022 regulated balance sheet impacts on Exhibit A-2, Schedules B6.1 and B6.2, column (m). I also removed the ARO for

Fermi 1 and the related decommissioning trust fund asset. In addition, I have removed the decommissioning obligation and related trust fund assets for Fermi 2. The details of the balance sheet eliminations are shown on Exhibit A-2, Schedule B7.

Q30. What are the ARO and Nuclear Decommissioning Trust Fund eliminations shown on Exhibit A-2, Schedule B7?

A30. Exhibit A-2, Schedule B7 shows the components of ARO accounting as well as nuclear decommissioning that are included in the unadjusted historical balance sheet. The removal of the ARO items is consistent with DTE Electric's presentation that the Commission has reviewed and accepted in all the Company's rate cases beginning with Case No. U-15244.

Q31. Why did you eliminate the Fermi 2 Nuclear Decommissioning Trust Fund?

A31. The assets and related liabilities for Fermi 2 decommissioning net to zero with no impact to rate base. For transparency, I removed all the line items from the historical balance sheet consistent with the Company's presentation that was reviewed and accepted by the Commission in its rate cases beginning with Case No. U-18014.

Q32. Can you explain the adjustment for benefit plans?

A32. ASC 715 requires the recognition of the unfunded liabilities for defined benefit pension and other postretirement plans with a charge to other comprehensive income within equity. DTE Electric recorded a regulatory asset in place of the charge to other comprehensive income because the costs are included in rates consistent with when the expense is recognized in the income statement. Since the liability and offsetting regulatory asset result in no change to revenue requirements, Exhibit A-2, Schedules B6.1 and B6.2, column (n) eliminates the 2022 balance sheet impacts related to ASC 715. This treatment is also consistent with DTE Electric's presentation in all its rate cases starting with Case No. U-15244.

Q33. What are the working capital normalizations in column (o)?

A33. Customer Accounts Receivable is adjusted to remove the impact of weather. Accounts Receivable from Associated Companies is adjusted to remove non-utility balances. These adjustments decrease working capital by $2.5 million on Schedule B6.1 (year-end) and by $1.2 million on Schedule B6.2 (13-month average).

Q34. Why are you eliminating the items in column (p), Other?

A34. Column (p) eliminates an asset for PSCR ($420.8 million) that is reconciled in the PSCR mechanism, and provisions for rate refunds including the $30 million 2020 COVID regulatory liability that reversed during 2022 per the Commission's Order in Case No. U-20921 and the $90 million 2021 COVID regulatory liability that reversed in 2022 and 2023 per the Commission's Order in Case No. U-21128. It eliminates a software maintenance prepaid asset and the offsetting liability that net to zero in working capital. It reclassifies a current lease payable out of short-term debt to deferred credits. It eliminates a tax reserve that is recognized only for GAAP purposes and eliminates affiliate Notes Receivable/Notes Payable that are assumed settled in the projected period. It also removes non-utility amounts from DTE Electric's consolidated balance sheets including the Detroit Investment Fund. In prior cases, the Commission ordered that these items are to be excluded from rate base. Column (p) also reflects the write-off of certain plant balances resulting from the Order in Case No. U-21297, totaling $26.2 million for which the Company is no longer seeking recovery (primarily related to Information Technology investments).

Q35. What information is contained in column (q), on Exhibit A-2, Schedule B6.1?

A35. Column (q), "Total Electric" represents the DTE Electric balance sheet as of December 31, 2022, after adjustments. This Total Electric December 2022 balance sheet is used by Witness Vangilder in determining DTE Electric's year-end historical rate base and capitalization.

Q36. What information is contained in column (q), Total Electric, on Exhibit A-2, Schedule B6.2?

A36. Column (q), Total Electric, represents the DTE Electric balance sheet after the adjustments previously discussed. These 2022 Total Electric 13-month average balances are used by Witness Vangilder in determining DTE Electric's average historical rate base and capitalization.

Q37. What information is shown on Exhibit A-2, Schedule B6?

A37. Exhibit A-2, Schedule B6, page 1 is the Assets and Other Debits portion, and page 2 is the Liabilities and Other Credits portion of the DTE Electric Adjusted Balance Sheet for December 2022. Column (b) reflects December 31, 2022 balances while column (c) represents the 13-month average balances. Both columns are carried from column (q) of Exhibit A-2, Schedules B6.1 and Schedule B6.2, respectively.

Historical Income Statement

Q38. What information are you supporting on Exhibit A-3, Schedules C1 and C1.1, Adjustments to Historical Net Operating Income (NOI)?

A38. On Exhibit A-3, Schedules C1 and C1.1, DTE Electric's Adjusted Net Operating Income (NOI) for the year ended December 31, 2022 was determined by starting with the financial information reported on the Company's MPSC Annual Report Form P-521, page 114. Then I adjusted the reported financial information for certain exclusions and inclusions to get to a rate case filing level. The rate case filing level was further adjusted by normalizations to remove unusual or one-time events. I support the adjustments to NOI on Exhibit A-3, Schedule C1.1, except for line 27 supported by Company Witness Guillaumin; line 28 supported by Company Witness Kryscynski; line 33 supported by Company Witness Cooper; and lines 40 and 41, which are supported by Witness Vangilder.

Q39. What information is displayed in Exhibit A-3, Schedule C3, Historical Operating Revenue?

A39. Exhibit A-3, Schedule C3 provides the amounts as reported on MPSC Annual Report Form P-521 for retail, wholesale, refund provisions and miscellaneous revenues, underlying the total revenue for the 12-month period ended December 31, 2022 and is carried forward to line 1, column (c), of Exhibit A-3, Schedule C1.1.

Q40. What is the purpose of Exhibit A-3, Schedule C4, Historical Fuel and Purchased Power?

Line
No.

A40. Exhibit A-3, Schedule C4 provides the amounts as reported on the MPSC Annual Report Form P-521 for various accounts associated with power supply expenses for the 12-month period ended December 31, 2022 and is carried forward to Exhibit A-3, Schedule C1.1, column (d), line 1.

Q41. What information is displayed in Exhibit A-3, Schedule C5, Historical Operation and Maintenance Expense?

A41. Exhibit A-3, Schedule C5 provides the amounts as reported on the MPSC Annual Report Form P-521 for operation and maintenance expenses adjusted to exclude fuel and purchased power expense for the 12-month period ended December 31, 2022 and is carried forward to Exhibit A-3, Schedule C1.1, column (e), line 1.

Q42. What information is displayed in Exhibit A-3, Schedule C6, Historical Depreciation and Amortization Expenses?

A42. Exhibit A-3, Schedule C6 provides the amounts as reported on the MPSC Annual Report Form P-521 for various accounts related to depreciation and amortization expense for the 12-month period ended December 31, 2022, and is carried forward to Exhibit A-3, Schedule C1.1, column (f), line 1.

Q43. What information is contained on line 1 of Exhibit A-3, Schedule C1.1?

A43. Net Operating Income of $1,310.2 million is on line 1, column (m) and ties to the MPSC Annual Report Form P-521, page 114, line 26.

Q44. Why do you adjust Net Operating Income on Exhibit A-3, Schedule C1.1, lines 3 through 19?

Line
No.

A44. These adjustments reflect certain inclusions and exclusions to the reported Net Operating Income amount to arrive at an allowable rate case filing level. The inclusions for AFUDC, interest and dividend income, MERC operating income, customer interest, and amortization of loss on reacquired debt are allowable for ratemaking, but they fall below the calculation of NOI on the Income Statement. Conversely, the exclusions for certain corporate memberships and advertising, executive incentives, and regulatory assets and liabilities recovered under separate surcharges are not included for ratemaking, but they fall within the calculation of NOI on the Income Statement.

Q45. What adjustment to Net Operating Income did you make on line 3 on Exhibit A-3, Schedule C1.1?

A45. Line 3 reclassifies fuel handling from Fuel and Purchased Power to O&M.

Q46. What are the adjustments on lines 5 through 19?

A46. Exhibit A-3, Schedule C14, supports line 5, Excluded Corporate Memberships. This schedule calculates the removal of social and service organization membership expense for the year ended December 2022. All membership dues for Chambers of Commerce are excluded from customer rates. The portion of other membership dues related to political activities is also removed. Some organizations disclose the portion of dues paid related to political activities on the invoice. For those amounts recorded to an account excluded for ratemaking, no adjustment was necessary. If the entire invoice was recorded to operating expense, I removed the portion related to political activity, as disclosed on the invoice. The total adjustment decreases O&M expense by $0.4 million and increases NOI by $0.3 million.

Line 6, Excluded Advertising Expenses, is supported by Schedule C15, which classifies year ended December 2022 electric advertising expenses by categories as prescribed by the standard filing requirements. Advertising expenses included for ratemaking include public safety, conservation, and billing practices. This exhibit identifies the advertising expenses that have historically been accepted by the Commission and removes the remaining advertising expense. This adjustment results in a decrease in O&M expense of $5.7 million and an increase in NOI of $4.2 million.

Line 7, MERC NOI Adjustment, is supported on Schedule C16. MERC's net income is effectively included in DTE Electric's NOI on Schedule C1.1, line 1. This occurs in two ways. First, MERC charges DTE Electric for fuel handling and that charge is included in DTE Electric's fuel expense (account 501) on Schedule C1.1, line 1, column (d), which is then part of the fuel handling reclassification to O&M expense on line 3, column (e). Second, MERC's profit or loss is included in the PSCR. Third Party Revenues (consisting of Third-Party Dock Services plus Net Coal & Transportation Sales) are credited, and Net Site Operating Expenses are expensed to customers in the PSCR mechanism (through a change in the delivered cost of coal). This inventory change is embedded in Fuel and Purchased Power expense shown on Exhibit A-3, Schedule C1.1, line 1, column (d). These two items are shown on Schedule C16, page 1 of 2. The fuel handling charge of $9.4 million together with the PSCR inventory change of $7.1 million results in a net contribution to consolidated DTE Electric for ratemaking of $16.5 million as shown on Schedule C16, column (b).

Line
No.

I will now explain details of the adjustment on Schedule C1.1, line 7. First, a portion of the fuel handling charge recorded as O&M by DTE Electric is for MERC's depreciation, taxes, and interest. As detailed on Schedule C16, page 2 of 2, column (c), I subtracted out the $9.7 million fuel handling expense recorded by DTE Electric and replaced it with the same amount but in the detailed classifications shown in column (d). The total impact of the reclassification is shown on Schedule C16, page 2 of 2, column (e) and is carried forward to Schedule C1.1, line 7. The impact of this reclassification increases NOI by $0.5 million, representing MERC's interest expense. This net addition to NOI is necessary to offset the expense reflected in DTE Electric's consolidated interest expense, which includes debt for MERC. This ensures there is no impact to customers in base rates.

The Commission first authorized the above-described MERC accounting treatment in MPSC Case No. U-5041 (Accounting and Ratemaking for MERC), Order dated September 17, 1976, and reaffirmed its findings in MPSC Case No. U-5108 (General Electric Rate Case) Order dated May 27, 1977, as well as in MPSC Case No. U-8578 (Detroit Edison’s 1987 PSCR Plan Case), Order dated December 8, 1987.

Line 8, PSCR Offsets, is supported by Schedule C17, and details three adjustments between revenue and fuel and purchased power. The first adjustment eliminates the amount of revenues that are collected via the PSCR factor to reset historical revenue to the PSCR base level. The second adjustment is to eliminate interconnection and ancillary transmission revenues that are netted against PSCR costs. Since these amounts are credited to customers in the PSCR reconciliation,

Line
No.

they need to be eliminated from revenues in net operating income for base rates. The last adjustment is for steam revenue, which is included in net operating income, but the related fuel cost is not recovered in the PSCR. To make up for this shortfall, I reduced the revenue amount by the un-recovered cost. The sum of these three adjustments is a $547.3 million reclassification between revenue and fuel on Exhibit A-3, Schedule C1.1, line 8.

Line 9 eliminates the revenues and expenses included in the nuclear surcharge. Schedule C18 details the components supporting the $0.6 million net operating income adjustment.

Consistent with past practice, line 10 reduces incentive plan expense by $10.2 million to remove the incentive compensation for DTE Electric's top five executive officers. The adjustment is shown on Schedule C19.

Line 11, MGM Rent, supported by Workpaper TMU-4, is for an expense included in O&M related to DTE Energy's use of a parking deck. I removed this expense to match the treatment of a related gain on the sale of land underlying the parking deck that is classified below the line. This adjustment results in a decrease in O&M expense of $1.0 million and an increase in NOI of $0.7 million.

Line 12, Customer Deposit Interest, is supported by Workpaper TMU-5 and reduces NOI by $1.7 million recorded below the line as other interest in account 431. It is included as an operating expense in the Company's revenue requirement since Customer Deposits are not included in the Company's capital structure.

Line 13 eliminates the revenues and expenses from the TRM related to former City of Detroit PLD customers because it is recovered via a separate surcharge and is not a part of base rates. Workpaper TMU-6 details the components supporting the net income adjustment.

Line 14 eliminates the revenues and expenses from the EWR program because it is recovered via a separate surcharge outside of base rates. Workpaper TMU-7 details the components supporting the $28.1 million NOI adjustment.

Line 15 eliminates the revenues and expenses from the REP because they are included in the regulatory liability that is separate from the Company's base rates. Workpaper TMU-8 details the components supporting the $155.4 million NOI adjustment.

Line 16 eliminates revenues and expenses related to the Low-Income Energy Assistance Fund (LIEAF). This is a separate surcharge program, which has no income impact. This adjustment as shown on Workpaper TMU-9 is necessary so that the normalized NOI detail is comparable to the forecast period.

Line 17 eliminates miscellaneous event sponsorship expenses that are reclassified to Other Deductions.

Line 18, Regional Relations Political Advocacy, removes $314,000 of expense related to lobbying and political advocacy activities that was incurred in the historical test year, increasing NOI by $233,000. (Note that the expense related to

Line No.

federal and state activities was recorded to an account excluded from net operating income. Thus, an elimination of those costs is not required.)

Line 19 Energy Insurance Services (EIS) relates to the Company's investment for funding insurance. The Order in Case No. U-21297 requires the Company to include a forecast of the income from the insurance fund in projected operating income based on a five-year average in lieu of removing the EIS asset from working capital. The adjustment on line 19 includes the five-year average of an EIS loss in NOI.

Q47. Why are you making normalization adjustments to NOI as reflected on Exhibit A-3, Schedule C1.1, lines 23 through 41?

A47. Consistent with current Commission policy, DTE Electric developed a projected test year ending December 31, 2025, based on projected changes from the year ended December 31, 2022 historical or actual test year. The year ended December 31, 2022 historic test year was adjusted to reflect the same normal baseline as the twelve-months ending December 31, 2025 projected test year as far as rate levels, weather impacts and one-time revenue or expense impacts. All adjustments were made to the year ended December 31, 2022 reported NOI amount to arrive at a rate case filing level as the starting point to develop the twelve-months ending December 31, 2025 projected test year.

Q48. What is the employee incentive plan normalization adjustment on line 23 of Exhibit A-3, Schedule C1.1?

Line
No.

A48. Line 23, Employee Incentive Plan Adjustment, is supported by Schedule C20 and reduces 2022 incentives expense by $4.8 million. The Company applies the equity method to account for long-term Performance Shares; thus, any change in DTE Energy's share price between the grant date and payout date is generally reflected in DTE Energy's equity with no impact to expense. Long-term incentives in 2022 includes a $4.1 million accrual for an increase in expense for the 2019 through 2022 performance shares based on performance relative to 100% of the target. Since an incentives payout higher than the target may not recur, I have reduced that amount from the historical expense. 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 200% of the target, depending on actual results achieved. Short-term incentive expense in 2022 includes $1.4 million for amounts paid above the 100% target, offset by $0.6 million of prior period adjustments. Since payments above the target and prior period adjustments may not recur, I have removed those amounts.

Q49. What is the basis for the $24.3 million NOI Weather Normalization Adjustment you are supporting on Exhibit A-3, Schedule C1.1, line 24?

A49. The instant rate case assumes that for electric sales, historical normal weather will occur for the forecast period. Thus, for comparison purposes the historical test year must be adjusted to a normal weather basis. Weather was warmer than normal in 2022, increasing DTE Electric's pretax margin by $32.8 million, and NOI by $24.3 million, as shown on Schedule C21. Underlying the $32.8 million pretax margin increase was sales revenue of $42.5 million offset in part by an increase in power supply cost of $9.7 million. Company Witness Leuker discusses the weather impacts in more detail.

Q50. What are the adjustments to O&M expense on lines 25 through 34?

A50. Witness Kryscynski supports the adjustment on line 28 and I support the adjustment on line 30 for expense items not expected to recur in the projected period. Lines 31 and 32 normalize expenses using averages due to the volatility in cost levels. I support line 31, injuries and damages and line 32, environmental remediation, as shown on my Exhibit A-13, Schedule C5.10; and Witness Cooper supports line 33, benefits normalizations. I support line 34, Incentive Compensation deferral above base amount, which increases O&M expense by $856,000 and decreases NOI by $634,000. This normalization adjustment represents 2022 incentive compensation expense above the approved based amount established by the Commission's Order in Case No. U-20836.

Q51. What is the adjustment for the COVID-19 Voluntary Refund on line 35?

A51. In Case No. U-20921, DTE Electric was authorized to accrue a one-time $30 million regulatory liability in 2020 related to unusual sales patterns related to the COVID pandemic. Amortization of the entire $30 million regulatory liability took place in 2022 and was used to offset the cost of service related to new DTE Electric company plant.

Q52. What are the adjustments on lines 38 through 41?

A52. Line 38 adds $37.5 million of AFUDC income to offset the impacts of including construction work in progress (CWIP) in rate base. The federal, state, and local

Line
No.

income tax expense related to AFUDC and interest income is already included in the income tax expense displayed on line 1, columns (i) and (j) of Exhibit A-3, Schedule C1.1.

Line 39 represents Amortization of the Loss on Reacquired Debt. To reduce interest costs, DTE Electric has redeemed and refinanced long-term debt securities in prior years in advance of their scheduled maturities. The cost related to each of these early redemptions is amortized over the life of the new issue as prescribed by the Commission's Uniform System of Accounts. The year ended December 2022 amortization of the Loss on Reacquired Debt results in a decrease in net operating income of $3.3 million. This expense is displayed on a pretax basis since the tax expense is already included in net operating income.

Line 40, Income Tax Effect of Interest, and line 41, Interest Synchronization, are supported and explained by Witness Vangilder on Exhibit A-3, Schedules C12 and C13, respectively.

Q53. What is the Adjusted Normalized Year ended December 2022 NOI amount?

A53. Inclusion of the rate case adjustments and normalization adjustments supported by Company Witnesses Hatsios, Cooper, Vangilder, Guillaumin, Kryscynski, Wisniewski, and I result in an Adjusted Normalized year ended December 2022 NOI of $1,132.0 million. This amount is detailed on Exhibit A-3, Schedule C1.1, line 43 and is included in the historical revenue deficiency/ (sufficiency) calculation supported by Witness Vangilder.

Line No.

Forecast Period

Q54. How was the financial forecast for the projected period, twelve months ending December 31, 2025, prepared?

A54. Projected DTE Electric financial statements for the twelve months ending December 31, 2025 were based on projected changes from the adjusted normalized amounts for the year ended December 31, 2022. The projected period reflects an increase in revenue and higher net operating expenses. Revenue includes an increase in electric sales revenue and increased inter-company rent revenue. The revenue increases are offset by increased O&M, depreciation expense, income tax expense and property taxes. As previously discussed, regulatory assets recovered with surcharges are excluded from the forecast, so they will not impact base rate determination. I prepared the forecasted financial statements using inputs from numerous DTE Electric witnesses.

Electric Income Statement Forecast

Q55. What information is included in the forecasted electric income statement contained within this filing?

A55. The income statement shown on Exhibit A-13, Schedule C1, column (e), represents the projected DTE Electric NOI for the twelve-months ending December 31, 2025. DTE Electric's financial statements represent DTE Electric Company plus MERC. Exhibit A-13, Schedule C1.1 develops the twelve months ending December 31, 2025 DTE Electric operating income statement based on projected changes from the year ended December 31, 2022 normalized amount.

Line
No.

Q56. How did you develop the revenues reflected in DTE Electric's operating income?

A56. Line 1 of Exhibit A-13, Schedule C1, contains DTE Electric's revenues for the forecasted twelve-months ending December 31, 2025. Generally, these revenues were derived from the projected electric sales volumes provided by Witness Leuker multiplied by existing tariff rates, as calculated by Company Witnesses Willis and Bellini. These tariff rates include electric base tariff rates authorized in Case No. U-21297. Total revenues also include certain utility related Miscellaneous Revenues that I support. As shown on Exhibit A-13, Schedule C3, page 2, I have excluded Nuclear, Securitization, EWR, REP, IRM, and LIEAF surcharge revenues because they do not affect the revenue deficiency in base rates.

Q57. What is the projected change in revenues from the historical normalized period to the projected period?

A57. Exhibit A-13, Schedule C1, column (d) shows that the projected change in revenues is an increase of $288.4 million. Schedule C3, page 1, of this exhibit compares the 2022 normalized revenue amount to the twelve-months ending December 31, 2025 revenue amount.

Q58. Can you explain the revenue items on Exhibit A-13, Schedule C3?

A58. Line 1 of Exhibit A-13, Schedule C3, page 1, represents electric sales distribution revenue. These projected revenues include a full year of the increase in tariff rates authorized in Case No. U-21297 effective in December 2023 and reflect lower overall service area sales in the projected period. Sales are discussed by Witness Leuker. Line 2 is the revenue that recovers base fuel and purchased power. The

Line
No.

change in this revenue component is the same amount as the change in base fuel and purchased power expense, discussed in more detail below. Company Witnesses Willis and Bellini support the twelve-months ending December 31, 2025 tariff revenue in their testimonies and exhibits.

Line 5 is Other Operating Revenues primarily consisting of: late payment charges, miscellaneous service charges, real estate rentals, and inter-company shared asset charges. The increase in the inter-company shared asset charge is due primarily to additional information technology assets that support both Electric and Gas operations. Line 7 reflects Rider 2 revenues related to special purpose facilities supported by Company Witness Maroun.

Comparing the projected twelve months ending December 31, 2025 revenue of \$5,465.4 million to the 2022 normalized revenue of \$5,177.0 million, results in an increase in projected revenue of \$288.4 million as shown on page 1 of Exhibit A-13, Schedule C3, line 8.

Q59. How was the Fuel and Purchased Power Expense portion of DTE Electric's operating expense developed?

A59. Line 3 of Exhibit A-13, Schedule C1, contains DTE Electric's fuel and purchased power expense for the forecast period as supported by Witness Willis on Exhibit A-13, Schedule C4. The change in fuel and purchased power expense is due to a decrease in sales volumes, and lower MISO purchase prices for customers on rates R10 and R3, partially offset by non-capacity charges for customers on rate D13. This decrease in expense is offset by a decrease in projected revenue. As previously discussed, I adjusted the historical period to eliminate items captured in the PSCR as shown on Exhibit A-3, Schedule C17. Any actual under or over recoveries of fuel and purchased power will be reconciled in DTE Electric's annual PSCR filings.

Q60. How was the O&M Expense portion of DTE Electric's operating expense developed?

A60. To determine the projected test year O&M expenses for the instant case, DTE Electric started with actual year ended December 31, 2022 results normalized for unusual, non-recurring items and eliminations/reclassifications for ratemaking purposes. The normalized O&M amounts were then escalated for the effects of inflation and adjusted to reflect anticipated material changes. Line 4 of Exhibit A-13, Schedule C1, contains DTE Electric's O&M expenses for the forecasted period.

In addition to me, Witnesses Guillaumin, Milo, Davis, Kryscynski, Bellini, Steudle, Farrell, Hatsios, Sparks, Hartwick, Bennett, and Cooper support the O&M expenses and describe them in their direct testimony. These witnesses also support the changes from the historic to the projected period within their respective areas. I support the inflation rates used in their projections. I support the Corporate Staff Group forecast and will explain the details later in my testimony. I also developed Injuries and Damages expense and Environmental Remediation costs based on an historical average. I have summarized the development of the forecasted O&M expenses in Exhibit A-13, Schedule C5.

Q61. How did you develop the inflation rates?

Line
No.

A61. As shown on Exhibit A-13, Schedule C5.15, I have calculated a composite inflation rate based on a labor factor and a non-labor factor. The inflation rate of 3% for internal labor is supported by Witness Cooper. I assumed the same rate for contract labor since a portion of our contract workforce comes from the same unions as the DTE union employees. The inflation rate for non-labor costs is based on a consumer price index (CPI)-Urban published by S&P/IHS Markit. I used the labor and non-labor rates to calculate a composite rate of inflation for 2023, 2024, and 2025 as shown on line 15.

Q62. Why are you using a 3% inflation rate for labor rather than the CPI?

A62. As discussed by Witness Cooper, DTE Electric's labor costs are driven by either contracts that cover the Company's represented employees or market-based pay practices, and thus are not directly tied to CPI. To forecast future labor costs, it is more appropriate to use a specific and known wage factor rather than an overall measure of inflation.

Q63. What is the projected change in O&M Expense from the historic normalized amount to the projected period twelve-months ending December 31, 2025?

A63. Line 4 of Exhibit A-13, Schedule C1, column (d), shows the projected change in O&M increasing expense by $42.5 million. The increase is due primarily to inflation, uncollectible accounts expense, Blue Water Energy Center operations, and marketing programs. These are partially offset by reductions related to steam plant closings, lower nuclear project (PERC) expense and lower nuclear outage accruals.

Line
No.

Q64. Did you provide any inputs to the other DTE Electric witnesses' O&M projections?

A64. Yes. I am proposing that the deferral of negative Other Post Employment Benefit cost (OPEB) and Pension expense, as supported by Witness Cooper, be continued in this case, and support the amortization of previously deferred balances. I am also sponsoring the amortization of the PERC regulatory asset reflected on Witness Davis's O&M exhibit, the amortization of deferred Advanced Distribution Management System (ADMS) program costs on Witness Kryscynski's O&M exhibit, the amortization of the Advanced Customer Pricing Pilot (ACPP) and Time of Day (TOD) regulatory assets on Witness Hastsios's O&M Exhibit, and the amortization of deferred program costs for Charging Forward on Witness Bennett's O&M exhibit.

Q65. Can you explain the adjustment you made to Witness Cooper's forecast for OPEB costs?

A65. Yes. Witness Cooper has forecasted retiree health care costs including DTE Electric's traditional OPEB plan. Since OPEB costs have been negative, a deferral to a regulatory liability was approved by the Commission in Case Nos. U-17767, U-18014, U-18255, U-20162, U-20561, U-20836, and U-21297. I have reflected the continued deferral of the negative net OPEB expense on Witness Cooper's Exhibit A-13, Schedule C5.12.2, line 18, consistent with prior treatment. If net OPEB expense becomes positive in the future, then the expense will be charged against the regulatory liability. In addition, in Case No. U-21297, the Commission ordered that the Company must amortize the OPEB regulatory liability of $128.4 million as of the historical test year (December 2022) over a seven-year period. I

Line No.

have reflected the amortization of the OPEB regulatory liability on Witness Cooper's Exhibit A-13, Schedule C5.12.2 line 19.

Q66. Did you make an adjustment to Witness Cooper's forecast for pension costs?

A66. Yes. A pension expense deferral mechanism was approved by the Commission in Case Nos. U-20836 and U-21297. I have reflected the deferral of the negative net pension expense on Witness Cooper's Exhibit A-13, Schedule C5.12.1, line 20. If net pension expense becomes positive in the future, then the expense will be charged against the regulatory liability.

Q67. How does the capitalization of Pension and OPEB costs impact Witness Cooper's forecasted expense?

A67. Exhibit A-13, Schedules C5.12.1 and C5.12.2, sponsored by Witness Cooper, detail the components of Pension and OPEB costs. Each schedule has a reconciliation of total cost to expense. A portion of the service cost component is capitalized to CWIP/Plant based on the related labor capitalized. Effective in 2018, the non-service cost components cannot be charged to capital under GAAP. Instead, the non-service costs that would have been capitalized under the traditional accounting treatment (but expensed under GAAP) are being recorded to a regulatory asset (or liability if cost is negative) instead of plant. The regulatory asset or liability is depreciated using the prior year's composite depreciation rate for plant in service, with the expense recorded to a unique account within Depreciation and Amortization expense. This treatment, approved in Case No. U-18255, results in recognizing the same expense and rate base that would have occurred under the historical accounting and ratemaking method.

Q68. How does this impact Witness Cooper's exhibits?

A68. The regulatory treatment is reflected on line 18 and line 16 of Witness Cooper's Exhibit A-13, Schedules C5.12.1 and C5.12.2, respectively. The amount previously shown as capitalized to plant has been bifurcated into two lines. Line 17 of C5.12.1 and line 15 of C5.12.2 represents the capitalized service costs recorded to CWIP/Plant, and line 18 of C5.12.1 and line 16 of C5.12.2 represents the capitalized non-service costs which are now recorded to a regulatory asset or liability.

Q69. Can you explain the adjustment you made to Witness Davis's O&M forecast?

A69. Yes. The Commission previously approved the deferral of certain nuclear project (PERC) costs above a base amount of $15 million in Case No. U-20561. The base expense is shown on Witness Davis's Exhibit A-13, Schedule C5.3, line 21, along with $4.9 million of PERC amortization expense on line 22, which represents a decrease of $11.4 million from the historical period.

Q70. How did you calculate the adjustment to PERC amortization expense on Witness Davis's O&M exhibit?

A70. The calculation of the deferral and related amortization expense is shown on my Exhibit A-13, Schedule C5.17. Lines 2 through 4 show the difference between PERC actual and forecasted expenses and the $15 million base amount. The PERC deferral amounts on line 4 are amortized over the subsequent five years. Lines 7 through 14 show the annual expense for each vintage year and the total amortization that will occur in the projected period on line 15. The projected period amount of $4.9 million is carried to Witness Davis's Exhibit A-13, Schedule C5.3, line 22, column (n). The projection adjustment of $11.4 million in column (l) is simply the difference between the forecasted amortization expense and the actual historical expense.

Q71. Can you explain the adjustment you made to Witness Kryscynski's forecast?

A71. Yes. In Case No. U-20162, the Commission approved the deferral of certain O&M costs related to the ADMS software project to a regulatory asset. The deferred costs include consulting and process reviews, process development, training, and software fees while the system is under development, with the amounts shown on capital Exhibit A-12, Schedule B5.4, page 1, line 25, sponsored by Witness Hartwick. The regulatory asset will be amortized over a fifteen-year period beginning with the year after the system in-service date. The final components of the ADMS software project were placed in service in February 2023. As shown on Witness Kryscynski's O&M Exhibit A-13, Schedule C5.6, line 12, column (j), the amortization expense is expected to be $1.2 million in the projected test period. The calculation of the amortization expense is shown on my Exhibit A-13, Schedule C5.6.2.

Q72. What other change did you make to Witness Kryscynski's forecast?

A72. A forecast adjustment of $5.0 million related to a change in the Company's capitalization policy related to pole inspection costs is included within Witness Kryscynski's O&M Exhibit A-13, Schedule C5.6, line 20, column (j). (See exhibit footnote number 6.) As explained in Case No. U-21297, the Company has reviewed and updated its policy related to pole inspection and testing costs. Effective January 1, 2023, the Company no longer capitalizes pole inspection and testing costs. As a result, Witness Kryscynski has included a projection adjustment to Account 593 Maintenance of Overhead Lines in the amount of $5.0 million on Exhibit A-13, Schedule C5.6, line 20, column (j) to reflect inspection costs in O&M. This amount is supported by Witness Elliott Andahazy on Exhibit A-12, Schedule B5.4.8

Q73. To which programs does the $5.0 million adjustment relate?

A73. Pole inspection and testing costs have historically been included in Distribution capital expenditures on Exhibit A-12, Schedule B5.4, page 13, within the two programs "4.8 kV Hardening" (line 12) and "Pole and Pole Top Maintenance and Modernization (PTMM)" (line 13). Witness Elliott Andahazy has detailed the costs for these two programs including inspection and testing costs on Exhibit A-12, Schedule B5.4.8. The Hardening program includes $1.1M inspection and testing costs in 2025 on line 2, column (e). The PTMM program includes $3.9 million inspection and testing costs in 2025 on line 9, column (e). The amounts are being reclassified out of capital expenditures on line 6 and 14, column (e), and a projection adjustment for the same amount is included on Witness Kryscynski's Exhibit A-13, Schedule C5.6.

Q74. Can you explain the adjustments you made to Witness Bennett's forecast?

A74. Yes. In Case No. U-20162, the Commission approved the Company's original Charging Forward program intended to develop infrastructure related to electric powered vehicles and the costs for the program are to be deferred to a regulatory asset. In Case Nos. U-20935, U-20836, and U-21297 the Commission approved additional components to the Charging Forward program. Per the Order in Case

Line No.

No. U-20561, audited costs will be amortized over five years, beginning with their inclusion in base rates. Witness Bennett supports the costs for the program shown on her Exhibit A-12, Schedule B5.9. I show the calculation of the amortization expense on my Exhibit A-13, Schedule C5.9.1. Line 2 of my Exhibit shows the regulatory asset expenses supported by Witness Bennett. Lines 5 through 10 calculate the amortization by vintage year for the test period of $3.6 million. This amount is carried to Witness Bennett's O&M Exhibit A-13, Schedule C5.9, line 11, column (k).

Q75. Can you explain the adjustments you made to Witness Hatsios' forecast?

A75. In Case No. U-20162, the Commission approved the Company's Advanced Customer Pricing Pilot (ACPP) and authorized the deferral of up to $7.3 million of one-time implementation costs. Additionally, in Case No. U-20836, the Commission approved a request for regulatory asset treatment for certain implementation costs associated with the Company's Time of Day (TOD) rate offering effective in November 2022. The costs for these projects are supported by Witnesses Hatsios and Bennett on Exhibit A-13, Schedule C5.9.2. The deferred costs are being amortized over five years. I show the calculation of $1.3 million of ACPP amortization expense for vintage years 2019 through 2022 on my Exhibit A-13, Schedule C5.9.3, line 6. I show the calculation of $1.7 million of TOD amortization expense for vintage years 2022 through 2023 on line 7. The sum of the ACPP and TOD amortization costs of $3.0 million is carried to Witness Hatsios' O&M Exhibit A-13, Schedule C5.7, line 8, column (k).

Line
No.

Q76. How was the Depreciation and Amortization Expense portion of DTE Electric's operating expense developed?

A76. Line 5 of Exhibit A-13, Schedule C1, contains DTE Electric's depreciation and amortization (D&A) expenses for the forecasted period. D&A includes book depreciation, which is based on existing plant balances, plus new capital expenditures and assumed retirements, using a half year convention. Depreciation expense is calculated using the rates authorized by the Commission in Case No. U-18150.

Q77. What is the projected change in D&A Expense from the historic normalized amount to the projected period?

A77. Exhibit A-13, Schedule C1, column (d) shows the projected change in D&A, increasing expense by $210.1 million. Schedule C6 of this exhibit shows the development of the projected period ending December 31, 2025, D&A expense of $1,266.2 million from the 2022 normalized D&A expense of $1,056.2 million. Depreciation is projected to increase by $254.0 million for capital in-service movement across all tangible plant categories, with the largest drivers being distribution and general plant. The increase is also driven by approximately $47.6 million due to reclassifying $2.1 billion of Monroe generation net plant to a regulatory asset effective December 31, 2024. The increases are offset by $65.7 million from plant retirements, with the largest driver being steam plant. Additionally, software amortization decreases by $25.6 million in the projected period.

Line No.

Q78. Why are you reclassifying $2.1 billion of Monroe generation net plant to a regulatory asset?

A78. The Commission approved a settlement agreement in the Company's Integrated Resource Plan (IRP) in Case No. U-21193 by its Order dated July 26, 2023. Among other things, the Order requires the Company to securitize approximately $845 million after the retirement of the Monroe Power Plant, expected in 2032. The portion of the plant to be securitized will remain classified within plant in service until it is retired. The balance of the plant not being securitized is to be recovered as a regulatory asset over fifteen years. Therefore, approximately $2.1 billion will be reclassified from plant in service to a regulatory asset effective December 31, 2024.

Q79. Can you explain the $47.6 million impact from the Monroe regulatory asset?

A79. Yes. As shown on Exhibit A-13, Schedule C6, line 8, the amortization of the Monroe regulatory asset over a 15-year period is forecasted at $144.1 million. The amortization is separately calculated and supported on my Exhibit A-12, Schedule B4.4. This is partially offset by $96.5 million of lower depreciation expense included within line 2. The reduction results from the cessation of depreciation on $3.4 billion of gross plant reclassified to the regulatory asset. (As previously mentioned, the *net* plant balance being reclassified is $2.1 billion.) I will explain the derivation of the regulatory asset in the balance sheet forecast portion of my testimony.

Q80. What is the amortization of Demand Response (DR) on line 9 of Exhibit A-13, Schedule C6?

A80. The historical period reflects a credit for under-recovered 2019 DR costs approved by the MPSC in Case No. U-20793. In Case No. U-20836, the MPSC approved recovery of the $3.0 million DR 2019 regulatory asset over three years. As subsequently discussed regarding the regulatory asset on the balance sheet, the MPSC has also issued orders in the DR 2020 and DR 2021 reconciliation cases. The projected period reflects the amortization of the 2019, 2020, and 2021 balances over three years.

Q81. What is the amortization of Capitalized Pension and OPEB on lines 10 and 11 of Exhibit A-13, Schedule C6?

A81. As I previously discussed regarding Witness Cooper's exhibits, the non-service cost components of pension and OPEB costs are being charged to a regulatory asset or liability instead of to plant. These items are expensed using the composite depreciation rate for plant in service.

Q82. What plant retirements have been forecasted?

A82. Steam plant retirements are forecasted at $260.2 million from January 2023 to December 2025. Approximately $612.0 million of scheduled retirements of computer equipment and amortizable plant are assumed. I am also estimating approximately $467.1 million in annual routine retirements based on recent history of other depreciable plant.

Q83. How does DTE Electric account for the plant retirements?

A83. The original cost is credited out of plant in service and debited to accumulated depreciation. This treatment is prescribed by the Uniform System of Accounts Electric Plant Instruction number 10 (F) which states, "The book cost less net salvage of depreciable electric plant retired shall be charged in its entirety to Account 108, Accumulated provision for depreciation and amortization."

Q84. What is the projected change in Property Tax Expense?

A84. Line 6 of Exhibit A-13, Schedule C1, column (d) shows that the total projected change in property tax expense is an increase of $62.9 million due primarily to increases in plant balances. Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedule C7.1.

Q85. What is the projected change in Other Tax Expense?

A85. Line 7 of Exhibit A13, Schedule C1, column (d) shows that the total projected change in other tax expense is an increase of $4.0 million. Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedule C7.

Q86. What is the projected change in State and Local Income Tax expense?

A86. Line 8 of Exhibit A-13, Schedule C1, column (d) reflects a $5.4 million decrease in state and local tax expense, including Michigan Corporate Income Tax (MCIT) and municipal income taxes. Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedules C9 and C10.

Q87. What is the projected change in Federal Income Tax Expense from the historic normalized amount to projected period?

A87. The change in federal income tax increases expense by $80.4 million as shown on Line 9 of Exhibit A-13, Schedule C1, column (d). Witness Wisniewski explains the changes and supports the amount on Exhibit A-13, Schedule C8.

Q88. How did you compute Operating Income?

A88. Operating Revenues minus Operating Expenses yields Operating Income shown on line 12 of Exhibit A-13, Schedule C1. Operating Income is projected to increase due to higher revenues from a full year of new base rates in Case No. U-21297, effective December 2023. The increase in revenues is partially offset by increased O&M, depreciation and property taxes related to capital additions, and increased income taxes.

Q89. What information is contained on the income statement line items below Operating Income?

A89. Lines 14 and 15 on Exhibit A-13, Schedule C1, represent items that are includable for ratemaking, but fall below the calculation of NOI on the income statement. Line 14 reflects AFUDC related to capital expenditures carried from Exhibit A-13, Schedule C11. It has two components. The first is an AFUDC offset equal to the amount of AFUDC included in CWIP (line 6 of Schedule C11). The second component removes the return on the AFUDC embedded in CWIP (line 7 of Schedule C11). This additional credit results in a revenue requirement of zero for the AFUDC eligible projects within CWIP and is calculated on Exhibit A-13, Schedule C11.1.

Consistent with past practice, the loss on reacquired debt results from the early redemption of securities, which are refinanced with lower cost issues. Line 15 of Schedule C1 is the annual amortization of losses on debt reacquired in prior periods. The forecast does not reflect additional early redemptions. Finally, line 17 of Schedule C1 provides Adjusted Net Operating Income. Adjusted NOI is projected to decrease from the historical test period due to the factors that impact Operating Income, offset by higher AFUDC.

Q90. How does AFUDC impact the Company's revenue requirement and deficiency?

A90. AFUDC represents the financing costs incurred while projects are under construction. Such costs are added to the asset being constructed with a corresponding credit to the income statement. AFUDC is generally applied to projects greater than $50,000 and lasting more than six months. The accrual of AFUDC ceases once the asset is complete and placed in service. Including the credit to income from AFUDC offsets the impact of including CWIP in rate base and therefore, projects that do not go into service during the projected test period have no impact on the Company's revenue requirement and deficiency.

Q91. What impact should a disallowance of projects that do not go into service during the projected test period, on which AFUDC is accrued, have on the Company's requested rate relief?

A91. Such disallowances should not have any impact. To ensure that is the result, either the proposed disallowances for projects not going into service should be excluded from any reductions to rate base approved by the Commission, or a corresponding

Line No.

adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of the projects from approved rate base.

Q92. What is the projected period NOI amount shown in Exhibit A-13, Schedule C1?

A92. Line 17 displays the Company's projection of the twelve months ending December 31, 2025 NOI of $1,087.1 million.

<u>Corporate Staff Group (CSG) Costs</u>

Q93. What is the CSG?

A93. The CSG is a shared services organization, "DTE Energy Corporate Services LLC" (LLC), which includes corporate staff functions. This business model provides efficiencies, cost savings and enhanced governance and internal controls. Each organization within the CSG provides enterprise-wide services.

Q94. What organizations are included in the CSG?

A94. 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 Planning
- Tax
- Finance and Treasury
- Corporate and Governmental Affairs
- Communications
- Corporate Offices

Line
No.

- Supply Chain
- Corporate Fleet and Facilities
- Human Resources
- Information Technology
- Legal
- Regulatory Affairs
- Environmental Management and Safety
- Project Management Organization (PMO)

Q95. Does the LLC provide other services in addition to Corporate Services?

A95. 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 O&M expenses are sponsored by Witness Hatsios.

Q96. What type of O&M expense do you support for the CSG organizations?

A96. I support the CSG expense projections included in the A&G accounts on Exhibit A-13, Schedule C5.10.

Q97. Can you explain the rate case adjustments and normalizations reflected in columns (d) and (e), respectively on Exhibit A-13, Schedule C5.10?

A97. Column (d) shows rate case adjustments of $29.2 million including the elimination of costs recovered via the REP and certain excluded costs (advertising, corporate memberships, political advocacy, and MGM rent expense). In addition, line 3 includes a reduction of $10.2 million to remove the incentive compensation for

Line
No.

DTE Electric's top five executive officers. Column (e) on line 20 is an O&M net decrease of $10.7 million that includes a reduction for one-time consulting costs, an increase for injuries and damages, and a reduction in incentive expense as previously discussed.

Q98. What adjustment did you make to Injuries and Damages?

A98. Consistent with the method approved in Case No. U-21297 and prior cases, I used a historical average to determine the projected test year amount for injuries and damages to smooth out any year over year variance. The calculation is shown on page 3 of Exhibit A-13, Schedule C5.10.

Q99. What adjustment did you make to Environmental Remediation?

A99. I used a five-year historical average to determine the projected test year amount for environmental remediation costs consistent with the method applied in Case No. U-21297. The calculation is shown on page 3 of Exhibit A-13, Schedule C5.10.

Q100. What projected adjustments did you make to O&M as reflected in columns (g) through (j)?

A100. Increases based on the inflation rate were applied to the adjusted historical test period expenses for the period January 2023 through December 2025.

Q101. With these adjustments, what is the projected test period amount for Administrative and General O&M expense?

A101. Based on the adjustments described above, A&G expense is $198.2 million for the projected test period ending December 31, 2025.

Line
No.

Q102. What expenses are included in account 920 on line 3?

A102. Account 920 reflects internal labor costs that are allocated to DTE Electric for the CSG organization.

Q103. What type of expenses are included in account 921 on line 4?

A103. The largest cost items in line 4, Office Supplies and Expenses, are for software maintenance and telecommunications. Witness Sharma provides more detail on the O&M expenses for the IT organization. This account also includes bank fees, assessments, and utilities expense.

Q104. What is the negative expense in account 922 on line 5?

A104. Line 5 reflects the transfer of A&G costs to capital as an overhead. The amount of A&G transferred is based on the percentage of total direct labor charged to capital.

Q105. What is included in account 923 on line 6?

A105. The account for Outside Services primarily includes contract labor for IT. It also includes security services, janitorial services, external audit fees and consulting services.

Q106. What expenses are included in lines 7 through 18?

A106. These lines are for property insurance, injuries and damages, advertising, environmental remediation, rents, maintenance of general plant, and other miscellaneous expenses. The historical period for these items has been adjusted and normalized as previously discussed.

Q107. How are the CSG cost allocations to DTE Energy companies accomplished?

A107. CSG costs are first incurred and accumulated at the LLC. Each department within a corporate staff organization identifies products and services it expects to provide to legal entities and/or business units based on the corporate staff organization's scope of work. These products and services are then analyzed to determine the most appropriate measure, which represents a unit of work, to be used in determining the billing of products or services being provided to DTE Electric and other DTE entities, by the administrative function. This measurement mechanism is called a cost driver. The cost driver, in cost accounting terms, is the unit of work/output that is used to determine a formula for billing the products or services to DTE Electric and other DTE entities. As departments incur expenses during the year, they are accumulated in cost pools. The pools are distributed and billed to DTE Electric and other DTE entities pursuant to the appropriate cost driver.

Q108. How does this cost driver allocation process work?

A108. Cost drivers represent units of work that best reflect the content of the work performed. For example, the Company's payroll department within Corporate Services processes paychecks. Given the transactional nature of this work, the volumetric cost driver of "paychecks processed" provides the best indication of work performed by this group for a specific legal entity. This department provides services for DTE Electric and other DTE entities and thus, payroll processing costs are billed based on the volume of paychecks processed for DTE Electric during the year. Other examples within the CSG include invoices paid, number of system application users, and application support hours. Cost drivers are evaluated and established based on resource consumption. These cost driver standards and levels of support are periodically reviewed and updated to reflect actual experience.

Q109. Has this cost driver allocation methodology been reviewed by the Commission in prior rate cases?

A109. Yes. This is the same cost allocation methodology supported by DTE Electric and approved by the Commission in DTE Electric's general rate cases going back to Case No. U-13808, and DTE Gas's general rate cases going back to Case No. U-13898.

Q110. How has the Company billed costs for which no direct cost driver was discernable?

A110. While most costs have been billed to DTE Electric and its affiliated companies based on the direct cost drivers I have described, a limited number of administrative activities are shared across the enterprise that do not possess cost driver attributes (a unit of work directly attributed to a legal entity), or that are incurred on behalf of the parent, DTE Energy, that indirectly benefit DTE Electric. It is in these cases that the Company uses the commonly accepted cost allocation methodology traditionally referred to as the Massachusetts Formula (Mass Formula). The Mass Formula, which utilizes a three-factor formula of gross margin, net plant, and labor costs, is designed to measure relative size and complexity as a means of assessing the degree of support services attributable to each individual company, within the context of the broader enterprise.

Line
No.

Q111. Has the Commission approved the use of the Mass Formula in allocating common costs in prior cases?

A111. Yes. Consistent with the cost driver methodology, the use of the Mass Formula for the allocation of CSG common costs was approved by the Commission in DTE Electric's prior general rate cases as well as in DTE Gas's general rate cases. Examples of CSG costs that utilize the Mass Formula include certain Corporate Communication, Governmental Affairs, Investor Relations, Corporate Secretary activities, and DTE Energy Board of Director fees.

Information Technology O&M

Q112. What is included in Information Technology O&M?

A112. IT costs are included in A&G expense on Exhibit A-13, Schedule C5.10. IT O&M consists of expenses related to project work along with on-going and base operating expense not tied to specific projects. Non-project costs include software maintenance, software licenses, cloud computing fees, software as a service, hardware and software defect remediation, business support services, and IT administration. Witness Sharma provides additional information and an exhibit supporting IT O&M expenses.

Q113. Are O&M costs for Information Technology reflected by project in the Projected Period?

A113. No. The business cases for IT projects often reflect both capital costs and O&M costs so that the full cost can be reviewed when management is evaluating projects. For rate case purposes, the capital costs are identified by project and supported by Witnesses Sharma and Hatsios. O&M costs related to projects are provided for

Line No.

informational purposes in Exhibit A-24, Schedule N3, as requested by the Commission. O&M related to capital projects is a subset of the total O&M costs related to IT and are not specifically forecasted in the O&M projections. Rather, the O&M forecast assumes that as work related to historical projects ceases, it is replaced with work on new projects. Consistent with all other A&G expense, IT expense in the projected period is based on adjusted historical costs plus inflation.

Q114. How are Information Technology expenses differentiated from capital expenditures?

A114. DTE Electric follows the FERC Uniform System of Accounts (USoA), per Title 18 of the Code of Federal Regulations, for its capitalization policies, in accordance with the MPSC Order in Case No. U-14811. Costs which do not meet the criteria for capitalization are charged to expense. Items that are expensed include work during the preliminary project stage (resource allocation, performance requirements, vendor identification), and work during the post implementation stage (training and application maintenance); and upgrades and enhancements which do not result in significant, additional functionality (bug fixes, table changes, screen changes, routine logic changes). The IT capital projects supported by Witnesses Sharma and Hatsios reflect only the cost of the components eligible for capitalization under the Company's policy.

Corporate Staff Capital Expenditures

Q115. What is the nature of the capital expenditures incurred by CSG functions?

A115. These expenditures reflect the annual capital requirement investment levels required for CSG organizations to deliver services to DTE affiliates. The largest categories of capital expenditures relate to information technology, physical infrastructure, and fleet.

Q116. Why are these costs charged directly to DTE Electric?

A116. CSG capital costs are generally incurred on behalf of all DTE affiliates. (Any projects or costs specific to other entities are charged directly to that company.) Thus, DTE Electric records 100% of the shared asset capital expenditures for CSG organizations and then charges a capital usage fee (Shared Asset Charge) to DTE affiliates for each affiliate's proportionate use of these assets which are owned by DTE Electric and jointly used by the companies. For example, DTE Gas occupies space in buildings owned by DTE Electric (e.g., the headquarters complex). Additionally, the Corporate Services Group and Customer Service organization providing services to DTE Gas or other affiliates do not own any of the assets or infrastructure required to function; the assets are owned by DTE Electric. The charge is comprised of the return on the assets and the related depreciation incurred by DTE Electric. The capital usage fee (Shared Asset Charge) is included in other operating revenue.

Q117. How does the Shared Asset structure benefit utility customers?

A117. This structure minimizes duplication of costs that would otherwise be required at the individual utilities. By using the same building for multiple groups, space usage can be optimized by filling up the available offices with employees from a different company or department. This helps avoid having to own or rent additional buildings for DTE Gas or the LLC. The same idea applies to computer infrastructure and office equipment. Sharing infrastructure not only reduces

Line
No.

investment costs, but it also reduces operating and maintenance expenses (e.g., lighting, heating and cooling, water, janitorial services, repairs, computer equipment maintenance, security). Thus, overhead costs for DTE and the individual utilities are reduced.

Q118. How is the Shared Asset cost allocated from DTE Electric to affiliates?

A118. The CSG capital costs incurred by DTE Electric must be paid for by the companies that utilize those assets, based on each company's proportionate share, to ensure DTE Electric customers are not subsidizing costs for DTE Gas and other DTE affiliates. The shared asset charge from DTE Electric to each affiliate is based on cost drivers for each group of assets. Buildings and furniture are allocated based on the location of employees and the cost drivers associated with the functions performed by those employees. Similarly, computer systems are allocated based on user headcount and their related cost drivers. For example, Customer Service building and computer costs are allocated between DTE Electric and DTE Gas based on their respective number of utility customers.

Q119. How are expenditures underlying the shared asset charge reviewed for reasonableness and prudency?

A119. As outlined above, the capital investments are owned by DTE Electric; therefore, the total capital investment, including return on capital and the related depreciation; along with the reasonableness and prudency of the project, is reviewed in DTE Electric rate cases. The review of the shared asset investments in an Electric rate case also encompasses the shared asset charge (expense) to affiliates, including DTE Gas. Upon approval of the investment in a DTE Electric rate case, the DTE

Line
No.

Electric revenue requirement is reduced by the amount it receives from affiliates (Shared Asset charge), including DTE Gas, for use of the assets.

Q120. If a shared asset investment and the associated revenue credits are approved in a DTE Electric rate case, what should be the outcome with respect to the corresponding expense in a DTE Gas rate case?

A120. The corresponding expense should also be approved in a DTE Gas rate case as reasonable and prudent. As discussed above, the total cost of the assets and the shared asset charge (representing the proportionate use of the asset) to affiliates, including DTE Gas, are reviewed for reasonableness and prudence by the Commission in DTE Electric general rate cases. Shared asset capital projects undergo the same review process in Electric rate cases as all other capital projects. Once a project has been approved as reasonable and prudent in a rate case, it should not be relitigated in subsequent rate cases. A review of shared asset costs and related revenue credits previously approved in a DTE Electric rate case within a DTE Gas rate case would be redundant, an inefficient use of Company and Commission resources, and potentially result in contradictory determinations.

Q121. What are the required adjustments for Shared Asset investments that are disallowed by the Commission in this rate case?

A121. If the Commission disallows capital related to a shared asset project, DTE Electric must also reduce its projected revenue credit related to its affiliates' proportionate share of those disallowed costs.

Q122. What level of capital expenditures do you expect the CSG organizations to incur?

A122. Company Witness Sharma supports $460.2 million for IT projects in the bridge and projected periods on his Exhibit A-12, Schedule B5.7. I support Exhibit A-12, Schedule B5.8, which provides the capital projections for physical infrastructure, fleet, and other projects, totaling $355.9 million.

Q123. What capital expenditures are included on Exhibit A-12, Schedule B5.8, page 1, line 1, Vehicle Fleet?

A123. Line 1, Fleet, represents the cost of new vehicles and power operated equipment. Items such as cars, trucks, bucket trucks, trailers, and forklifts are replaced to provide safe and reliable equipment as the fleet ages. The Company uses a proprietary model which develops a comprehensive asset life cycle that optimizes total cost of ownership. Historic ownership costs and operational data are used to develop a replacement strategy specific to DTE Electric. Assets with the greatest reduction to maintenance and ownership costs are chosen for replacement.

Q124. What is Facilities Construction and Upgrade on line 2?

A124. Line 2, Facilities Construction & Upgrade, includes capital maintenance and replacement items such as roofs, facades, electrical, plumbing, heating and cooling equipment, office space updates, elevators, and cranes. Capital maintenance standards are applied to optimize life cycle costs and maintain safety. The capital projects for the historical, bridge and test periods are detailed on Exhibit A-12, Schedule B5.8, page 2.

Line
No.

Projects in the bridge and projected periods include $7.4 million to repair and replace elevators at various locations (lines 1 through 6 and 50); $17.7 million to complete the replacement of roofs at various buildings (lines 7 through 12 and 60); $4.4 million for required five-year façade inspection and restoration work on the Walker Cisler Building (WCB) and General Office Building and $2.2 million façade restoration for other various locations (lines 21, 22 and 53); $9.5 million to replace the substation and related distribution equipment at the Walker Cisler Building (line 13, previously approved in Case No. U-21297); $9.1 million to investigate and replace the substation and electrical distribution equipment that is used to power the downtown campus (line 14); $6.7 million for electrical work at various locations (lines 24, 25 and 49); $2.6 million for plumbing work at various locations (line 58); $4.8 million for overhead and pedestrian door replacements at various locations (line 48); $7.5 million for automotive lifts (line 45); $30.6 million for HVAC replacements at various locations including boilers, chillers, piping, air handlers, diffusers, variable air volume boxes, and other equipment (lines 16, 17 and 56); $5.1 million for updates to the fire suppression systems at the Warren Service Center and other locations (lines 19 and 54); and $5.1 million for the Warren Service Center Transformer Yard reorganization and infrastructure improvements (line 20, previously approved in Case No. U-21297).

Another project planned for 2023 and 2024 is office space updates at the downtown campus of $9.5 million (lines 28 through 33) to accommodate the mandatory three-day return to work standards for employees starting in 2024. The Company is purchasing chairs, monitors, keyboards, mice, and docking stations to re-outfit the workstations in the General Office (GO) and Service Building (SB). The prior workstation equipment in these buildings was made available to employees to accommodate working from home during the COVID-19 pandemic and generally continues to support remote work. We are also purchasing additional workstations as needed based on employee counts. Additionally, all huddle and conference rooms in the GO and SB will require audio visual equipment to be Microsoft Teams enabled. In addition, the 2023 period includes $4.8 million for renovation of the first floor of the Walker Cisler Building lobby, including adding conference and huddle rooms (line 27).

Furthermore, the 2023 and 2024 periods include $7.0 million for renovation at the Shelby service center (line 26) which includes asset preservation and infrastructure upgrades including a new roof, removal of a septic tank and connection to the city sewer system, mechanical equipment, bathroom/locker room replacement and interior renovations.

Finally, the projected periods include $21.7 million for other general construction and end of life repairs and replacements, including but not limited to, equipment, tools, overhead cranes, flooring, truck shelters, security, and windows.

Q125. What is Service Center Optimization and Modernization on line 3?

A125. Service Center Optimization and Modernization is a project to replace facilities that have exceeded their useful life by consolidating some sites and updating other existing sites to reduce the Company's overall footprint and reduce operating expenses by 2025. The Commission approved this project in Case Nos. U-20162, U-20561, U-20836 and U-21297. The capital projects for the historical, bridge and test periods are detailed on Exhibit A-12, Schedule B5.8, page 3. The older facilities have experienced increased costs due to aging infrastructure, and critical components such as HVAC and roofs have failed. Through the consolidation of locations, we will realize savings opportunities and increase efficiency within the sites.

The Warren Service Center (WSC) is DTE's largest service center, supporting Distribution Operations, Energy Supply, and other departments with over 300 people on 60 acres and 23 acres of parking lots and roadways. The WSC project, which was approved in previous cases as stated above, started in 2017 to address aging assets that are beyond their useful life and in a state of disrepair. It included consolidating activities from two buildings into one building and constructing a new lab on an existing DTE site. The WSC site work project involves improvements to the 60-acre site which contains over 1,000,000 square feet of paved roadways and parking lots. The site is experiencing sinkholes in the roadways, collapsed storm water catch basins, and degraded paving resulting in potholes and trip hazards along with inadequate site lighting to support 24/7 operations. The work includes replacing the main roadway, site lighting, and parking lot paving to improve safety for employees and visitors (line 2). The majority of the WSC site improvements were completed through 2023, with an additional $1.5 million projected in 2024. Another significant project at WSC is improving building "L" at a cost of $8.0 million, of which $6.6 million is projected from 2023 through December 2025 (line 3). Building L is an approximately 40,000 square foot automotive repair facility constructed in 1970. It is the largest automotive repair facility at DTE and is critical to ensuring Company vehicles are

Line
No.

available to support our customers. The facility is experiencing automotive lift failures, roof leaks, and HVAC system failures which affects the Company's ability to maintain company vehicles in an efficient manner and support its customers. As a result, work includes replacing the building exhaust system, five automotive lifts, electrical panelboards and electrical service, the roof, the fire alarm and suppression system, the HVAC system, as well as overhead doors, and lighting.

The Western Wayne Service Center (lines 7 through 10) will also be updated at a cost of approximately $24 million. The building was constructed in 1978 and many building systems such as lighting, plumbing, electrical, flooring, and ceilings are beyond their useful life and need replacing. The building renovation shown (line 7) costs approximately $14.4 million and was previously approved in Case No. U-21297. Phase 2 of this project includes expanding the fleet vehicle repair garage bay and improvements to the fleet garage and warehouse (line 8). Phase 2 also includes site improvements on line 9 for a parking lot expansion, stormwater management, site lighting, and a perimeter security fence. Total projected costs for Phase 2 (lines 8 and 9) are $7.6 million.

Another significant project, Waterford, is on line 11. The lease on the Northwest Planning Design office in Farmington was terminated in 2020 and the Pontiac Service Center will close in the second half of 2024 and will be moved to a larger location in Waterford. This project started in 2018 and was approved in Case Nos. U-20162, U-20561, U-20836 and U-21297.

Line
No.

The Company plans to invest $3.0 million in 2025 for storm water improvements at the Ann Arbor service center (line 12). This is a preservation project for an asset that is beyond useful life, at risk of failure, does not meet current municipal requirements, and requires improvements to deal with more frequent storm events and mitigate risk. The Ann Arbor SC parking lot has flooded various times over the past several years impacting DTE Electric crews' ability to utilize the parking lot.

The Company also plans to invest approximately $6.4 million for Service Center Automated Building Control Systems upgrades (lines 13 through 22). These upgrades are asset preservation projects to replace various building control systems such as heating, ventilation, and air conditioning (HVAC) and lighting control systems that do not meet current energy code, are beyond useful life and are at risk of failure due to their condition. Technology advancements have made these control systems obsolete, and the energy code requires any new design or renovation to improve energy efficiency and reduce energy loss. This project will provide more efficient management of these systems, reducing energy usage and utilizing technology to remotely monitor and control these building systems. This will enable our operations and maintenance team to remotely diagnose and address building issues without having to travel to these locations, reducing waste and improving response time.

Finally, the Company is also planning to invest $7.9 million in 2023 through 2025 (lines 23 and 24) for costs to update the technical development center in Westland, which is nearly 50 years old with many assets in need of repair. The scope of the repairs includes replacing the current storm water management system due to flooding which has affected training and property utilization; replacing parking lots; and replacing building systems including HVAC, roof, and electrical systems.

Q126. What are the projects in Security Measures on line 4 of Exhibit A-12, Schedule B5.8 page 1?

A126. Line 4 on page 1 is a project to reduce security related risks. It includes $7.2 million in 2025 for Phase III of a project started in 2019 to replace the existing physical access control system (PACS) with new technology. The new PACS will be combined with our logical access control system (LACS) to tie physical control at our various sites to our SAP identity system. Employees were issued new high assurance credential badges. Highly encrypted access control technology is being installed at sites ranked through our Security Governance Risk Model. The costs for this project include IT hardware and infrastructure, new badge readers, and system integration.

Q127. What items are included in line 5, Miscellaneous?

A127. Line 5 includes approximately $1.7 million in 2024 and 2025 for environmental management. The Company is evaluating and developing technologies and controls to provide cost effective solutions in meeting environmental compliance and energy requirements. The remaining balance is for minor capital items used in the Corporate Staff groups. These items are substantially offset by investment recovery salvage sales.

Q128. How much allowance for funds used during construction (AFUDC) is assumed in the projected test period for Corporate Staff?

A128. AFUDC for Corporate Staff is included on Exhibit A-12, Schedule B5.8 page 4. As shown, the Corporate Staff AFUDC is projected to be $1.8 million for the 12-month period ending December 31, 2025. A historical trend is used to estimate AFUDC on routine capital, such as the portion of Facilities, Design and Construction where the mix of eligible projects is consistent year to year, while AFUDC is calculated specifically on a project-by-project basis for eligible non-routine projects. The authorized cost of capital rate is 5.561% per the December 1, 2023 Order in Case No. U-21297.

Q129. What is provided on the schedule entitled Removal Costs, Plant in Service and CWIP on page 5 of Exhibit A-12, Schedule B5.8?

A129. This schedule provides a breakdown of plant activities which are used to forecast Plant in Service, Accumulated Depreciation and Construction Work in Progress (CWIP) on the projected balance sheet. Capital expenditures consistent with page 1 are summarized in columns (c) through (f). Column (b) includes a corresponding in-service assumption: “Annual” is indicated for categories of plant spend that are generally unitized within the year of spend, while a specific in-service date is used for projects that remain in CWIP for more than a year before moving into Plant in Service.

Column (g) includes an estimated percentage of removal costs that are included within the capital expenditures. Removal costs are charged to Accumulated Depreciation rather than Plant/CWIP and are therefore not depreciable. Removal cost of 10% based on historical trend of removals as a component of capital expenditures is applied to Electric Facilities Repairs and Replacements on line 2, Facilities Construction and Upgrade on line 4, and Service Center Optimization Projects on lines 8 through 32, except 100% is used for specific demolition projects on lines 12 and 15. Finally, Investment Recovery Salvage Sales are assigned 100% removal as these proceeds are credited directly to Accumulated Depreciation to offset removal charges.

Columns (h) through (j) reflect calculated removal costs based on projected Capital Expenditures in columns (d) through (f) multiplied by the removal cost percentage in column (g). The remaining Capital Expenditures will appear in Plant in Service columns (k) through (m) if in-service assumption is "Annual," or CWIP columns (n) through (p) until the date of in-service as indicated in column (b). At that time, cumulative spend including the historical period is transferred to in-service (excluding the removal cost estimate).

Balance Sheet Forecast

Q130. What projected test year balance sheet information are you providing?

A130. Exhibit A-12, Schedules B2 and B3 provide the projected 13-month average utility plant balances and depreciation reserves, respectively, compared to the historical period. Schedule B4 provides the projected 13-month average working capital compared to the historical period. Schedule B4.1 classifies the projected balance sheet information into the categories of net plant, working capital, and the various financing components.

Q131. Can you explain the DTE Electric balance sheet on Schedule B4.2?

A131. The electric balance sheet statement shown on Exhibit A-12, Schedule B4.2, represents the DTE Electric 13-month average balance sheet for the projected year. As previously stated, DTE Electric's financial statements represent DTE Electric Company plus MERC.

Q132. What are the major components making up the Assets and Other Debits reflected in Exhibit A-12, Schedule B4.2, page 1 of 2?

A132. Exhibit A-12, Schedule B4.2, page 1 of 2 has four major asset components:

1) Total Utility Plant and Property
2) Other Property and Investments
3) Current Assets
4) Deferred Debits

<u>Total Utility Plant and Property</u>

Q133. How did you develop the projected Utility Plant and Property amount in this case?

A133. Total Utility Plant and Property on Exhibit A-12, Schedule B4.2 (lines 4 through 13) is comprised primarily of Net Utility Plant (line 9), which is projected to increase each year resulting from annual capital expenditures being greater than the annual depreciation allowance charge, partially offset by the transfer of $2.1 billion to a regulatory asset related to the Monroe power plant as required by the Commission's Order in the Company's 2023 IRP proceeding, Case No. U-21193. These projections reflect substantial capital expenditures primarily related to distribution system replacements and reliability improvements, steam generation reliability and environmental projects, nuclear main unit generator replacement and maintenance projects, facility upgrades and maintenance, and information technology investments. Page 1 of Exhibit A-12, Schedule B5 provides a functional summary of DTE Electric's total projected capital expenditures. Further, the various operational witnesses provide details on the capital expenditures they are sponsoring.

Q134. How did you develop the projected capital expenditure amounts DTE Electric included in this case?

A134. To determine the projected test year capital expenditure levels for this case, DTE Electric started with historical amounts normalized for unusual, non-recurring items. In some cases, the routine capital expenditures were escalated for the effects of inflation. Capital expenditures for unique or one-time projects were individually forecasted. Capital expenditures are supported by Company Witnesses Guillaumin, Milo, Davis, Hill, Hartwick, Steudle, Deol, Elliott Andahazy, Bellini, Farrell, Bennett, Sharma, Hatsios and me. (Removal costs included in capital expenditures on the individual witness exhibits are reflected as a charge to the accumulated depreciation reserve.)

Q135. Will all the forecasted capital expenditures be unitized to plant in service by the end of the projected test period?

A135. No. The capital expenditure exhibits show which projects will not be in service during the projected test period. There is no depreciation expense projected for these projects, and the AFUDC credit on the income statement offsets the impact of reflecting the projects in rate base. In other words, there is no current revenue requirement for these projects.

Q136. What are Removal Costs?

A136. Pursuant to the Electric Plant Instructions in the Uniform System of Accounts (USOA), cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant. As part of Utility plant accounting, the Company's depreciation rates are set to recover both the original cost and estimated removal costs over the life of the asset. When removal costs are actually incurred, they are charged against the accumulated depreciation balance. Any over or under accrual is handled by updating depreciation rates in depreciation cases and applying the new depreciation rates prospectively when they are reflected in base rates.

Q137. What is included on page 2 of Exhibit A-12, Schedule B5?

A137. To calculate the projected balance sheet, the rate case model appropriately assumes the portion of capital expenditures related to removal work is charged as a debit to accumulated depreciation. These costs do not get charged to CWIP/Plant and are not depreciable capital expenditures. The schedule on page 2 of Exhibit A-12, Schedule B5, shows the amount of removal costs included in capital expenditures on page 1.

Capital expenditures from Page 1 are summarized on lines 1 through 13. Removal Costs included within those Capital Expenditures are provided on lines 15 through 27 which are assumed charged to Accumulated Depreciation. The difference on lines 29 through 41 represents the non-removal portion of capital expenditures initially charged to CWIP and moved to Gross Plant once placed in service.

Q138. What is provided on pages 3-4 of Exhibit A-12, Schedule B5?

Line
No.

A138. This schedule provides the Company Summary breakdown of plant activities used to forecast Plant in Service, Accumulated Depreciation and Construction Work in Progress (CWIP) on the projected balance sheet. Witnesses Guillaumin, Davis, Hill and I sponsor a similar schedule for Steam, Nuclear, Distribution and Corporate Staff, respectively, which is displayed on lines 1 through 31, and 46 through 47. On lines 33 through 43 of this summary schedule, I also provide the corresponding activity for Information Technology, MERC and Fuel Supply, Community Lighting, Demand Side Management, and Charging Forward based on assumptions provided by the sponsoring witnesses.

Capital expenditures consistent with page 1 are summarized in columns (d) through (f). Column (g) through (i) includes estimated removal costs that are included within those capital expenditures. To estimate cost of removal, the Company assumes a standard percentage of capital expenditures related to removal costs, unless the project is 100% related to removal or demolition or 0% removal related to technology projects. The remaining Capital Expenditures will appear in Plant in Service columns (j) through (l) if assumed in-service, or CWIP columns (m) through (o) until transferred to in-service.

Q139. What is the projected change in Total Utility Plant and Property?

A139. Exhibit A-12, Schedule B4.2, line 4, reflects a plant-in-service decrease from December 2022 to December 2024 of $356.7 million. This change is due to $3,830.1 million of base capital in-service movement less $3,422.0 million related to the Monroe regulatory asset reclassification, and $764.8 million of plant retirements transferred to the depreciation reserve. The plant-in-service change from December 2024 to December 2025 is $1,419.2 million. This change is due to $1,993.7 million of in-service movement less $574.5 million for plant retirements.

Plant held for future use on line 5 primarily reflects the FERMI 2 license extension in the historical and interim periods. The license extension becomes effective when the existing license expires on March 20, 2025, and is reclassified to intangible plant within Plant in Service. (See Exhibit A-13, Schedule C6, page 2, line 21.) The costs incurred to obtain the extension have been capitalized and include project management; engineering planning and design; and NRC required inspections of, and updates to, the physical assets. DTE Electric will incur additional costs through March 2025 to complete work related to commitments made to the NRC as a condition of obtaining the extension. The license extension will be amortized over its 20-year service life starting in 2025.

The CWIP change on line 6 from December 2022 to December 2024 is an increase of $436.0 million. This change is primarily due to $4,356.3 million of capital expenditures offset by $3,830.1 million of projects transferred to plant-in-service and a reclass of $90.1 million related to the Monroe regulatory asset. The CWIP increase from December 2024 to December 2025 of $287.0 million reflects $2,207.8 million of capital expenditures, less transfers to plant-in-service of $1,920.8 million. As can be seen on Exhibit A-12, Schedule B5, projected capital expenditures are over $2.5 billion annually. The largest capital expenditures are related to distribution and production assets. Witness Guillaumin supports the steam production investments including plant reliability and safety, coal ash projects, decommissioning work, and battery projects. Witnesses Hill, Elliott

Andahazy, Hartwick, Deol, and Steudle support distribution investments including emergent replacements, customer connections, infrastructure hardening and redesign, and technology.

The decrease in acquisition adjustments on line 7 from December 2022 to December 2025 of $17.4 million results from amortization of the adjustment for the Renaissance Power plant.

The decrease in depreciation reserve on line 8 from December 2022 to December 2024 of $721.0 million is due to $ $1,416.3 million of Monroe regulatory asset reclass, $767.3 million of removal costs and $764.8 million of plant retirements, offset by 2,227.4 million of depreciation expense. The increase of $277.0 million from December 2024 to December 2025 represents depreciation expense of $1,114.5 million partially offset by $263.0 million of removal costs and $574.5 million of plant retirements.

The change in Nuclear Fuel Property on line 12 from December 2022 to December 2024 is an increase of $1.0 million from nuclear fuel purchases of $112.0 million less nuclear fuel expense of $111.0 million. The change in Nuclear Fuel Property from December 2024 to December 2025 is an increase of $74.0 million due to fuel purchases of $135.1 million less nuclear fuel expense of $61.1 million. Witness Davis supports the nuclear fuel purchase amounts.

Q140. Why is CWIP included in Net Utility Plant for ratemaking purposes?

Line
No.

A140. CWIP is included in this rate filing as required by the Commission's May 10, 1976 Order in Case No. U-4771. CWIP is forecasted (in part) based on the expected in-service date for large projects, when they are reclassified from CWIP to Plant in Service. These projects generally include AFUDC, which is credited on the income statement, reducing the revenue deficiency, and offsetting the impact of the assets in rate base. AFUDC is applied to projects greater than $50,000 and lasting more than six months, with an exception for environmental and other specifically ordered projects.

Per the Commission's March 14, 1980 Order in Case No. U-5281, a generic proceeding on the Commission's own motion to examine the accounting treatment of CWIP and AFUDC, the Commission required that pollution control related CWIP should not accrue AFUDC but instead be included in rate base. This position was affirmed in the Commission's August 16, 2011 Order in Case No. U-15244 (page 72).

CWIP also includes lower cost, short duration projects that are not eligible for AFUDC. Projects involving smaller dollar assets, or mass assets, are initially charged to CWIP but are soon transferred to Plant in Service. The type of work included in the short duration items is generally standard and ongoing throughout the year. Thus, as the prior balance for these types of assets is cleared to Plant in Service, another wave of construction is adding new amounts to the CWIP balance. For these types of recurring items, I forecasted CWIP based on a historical trend of balances in the account.

Line
No.

Other Property and Investments

Q141. What are you forecasting for Other Property and Investments?

A141. Lines 16 and 17 are held constant at the historical 13-month average. As previously discussed, the Nuclear Decommissioning Trust Fund balance on line 18 was eliminated from the historical period because it does not impact base rates.

Current Assets

Q142. What is included in Current Assets on lines 21 through 32 of Exhibit A-12, Schedule B4.2?

A142. Current assets include cash, notes and accounts receivable, uncollectible reserve, unbilled revenues, fuel inventories, materials and supplies inventories, prepayments, and other current assets.

Q143. How did you forecast the balance for the various Current Assets?

A143. Individual line items that fluctuate throughout the year, and for which a specific forecast is not developed, were based on a 13-month historical average. These items include cash, other accounts receivable, other accounts receivable-assoc. companies, uncollectible reserve, unbilled revenues, and materials and supplies inventory. Notes receivable and other current assets were adjusted to zero at December historical and no changes were assumed in the projected period. Customer accounts receivable was also based on a 13-month average historical with additional forecast adjustments. Fuel inventory and prepayments were specifically forecasted.

Line No.

Q144. How did you forecast the balance for Customer Accounts Receivable on line 24?

A144. Customer Accounts Receivable was based on a 13-month weather normalized historical average, adjusted for rate relief approved in Case No. U-21297.

Q145. How did you forecast the balance for Fuel Inventory on line 29?

A145. The increase in Fuel Inventory from the historical period reflects additional fuel inventory at Monroe to support operations.

Q146. How did you forecast the balance for Prepayments on line 31?

A146. Prepayments primarily represents property taxes. The change is based on forecasted accruals and payments.

Deferred Debits

Q147. What is included in Deferred Debits on lines 35 through 68 of Exhibit A-12, Schedule B4.2?

A147. This section contains various regulatory assets and deferred tax items. Unamortized Debt Expense on line 35 is increased by projected issuance expense of $24.9 million assumed at 1% of new debt issues offset by annual straight-line amortization of approximately $4.7 million. Unamortized Loss on Reacquired Debt on line 36 is reduced by annual straight-line amortization of approximately $2.7 million. These balances are tied to specific debt issues and are amortized over the life of the issues.

Q148. What is the prepaid pension asset on line 38?

A148. Pension costs recognized by the Company are reflected in a pension liability account. However, when contributions to the pension trust are made, they reduce the liability. To date, the Company has funded more than it has recorded as a pension liability, resulting in a net debit balance, referred to as the prepaid pension asset. The prepaid pension asset represents the cumulative difference between the pension cost recognized by the Company and the Company's contribution to its pension trust. Specifically, when the Company's annual contributions exceed annual pension cost, the prepaid pension asset increases; and when the Company's annual contributions are less than the annual pension costs, the prepaid pension asset decreases. The pension plans and related pension costs are explained by Witness Cooper.

Q149. Does the prepaid pension asset reflect any funding during the projected period?

A149. No. However, it does include a transfer of pension assets of $50 million from the DTE Gas non-union plan in 2023.

Q150. Why did DTE Gas transfer $50 million to the DTE Electric pension plan?

A150. As of December 31, 2022, the DTE Gas Non-Union pension plan had assets in excess of its projected benefit obligation (PBO) of about $137 million, whereas the DTE Electric pension plan had assets that were about $387 million less than its PBO. Since the DTE Gas Non-Union pension plan is a component of the overall DTE Energy Retirement plan, as is the DTE Electric pension plan, the Company can transfer the excess assets in the DTE Gas Non-Union plan to DTE Electric without any income tax or ERISA consequences. Funding the pension plan

Line
No.

increases the return generated from plan assets, which will reduce pension costs over time. This transfer was accomplished through a payment by DTE Electric of $50 million in 2023 to DTE Gas in consideration for the transfer of DTE Gas trust assets of $50 million in 2023 within the DTE Energy Retirement plan trusts.

Q151. What is the Reg Asset – Pension Deferral on line 40 of Exhibit A-12, Schedule B4.2?

A151. The regulatory asset was established pursuant to the Commission's order in Case No. U-20836 that approved a pension expense deferral mechanism. Effective with the Order, actual pension expense is deferred as a regulatory asset if positive or a regulatory liability if negative. The regulatory asset balance reflects the deferral of the Company's projected pension expense as further described by Witness Cooper.

Q152. Why is there an item called "Monroe Regulatory Asset" on line 41 of Exhibit A-12, Schedule B4.2?

A152. As previously discussed, the July 26, 2023 Order in the Company's IRP in Case No. U-21193 requires (among other things) the Company to securitize approximately $845 million after the retirement of the Monroe Power Plant, expected in 2032. The portion of the plant to be securitized will remain classified within plant in service until it is retired. The balance of the plant not being securitized is to be recovered as a regulatory asset over fifteen years.

Q153. Why does the Monroe Regulatory Asset have a zero balance on line 41?

A153. The Order in Case No. U-21193 requires the overall return on the regulatory asset to reflect a return on equity of 9%. To accomplish this, I have excluded the regulatory asset from the balances underlying the base rate revenue deficiency calculations. A separate rate of return for the Monroe regulatory asset is supported by Witness Vangilder on Exhibit A11, Schedule A1.2.

Q154. How was the Monroe Regulatory Asset balance calculated?

A154. Refer to Exhibit A-12, Schedule B4.5. The total Monroe plant balance forecasted for December 31, 2024 is $3.2 billion as shown in column (a), line 9. To determine how much of this should be reclassified to the regulatory asset, I had to subtract the 2024 amount that will remain in plant and eventually be securitized after the plant is retired in 2032. Lines 13 through 16 calculate the 2024 amount that will result in the agreed upon securitization value of $845 million in 2032. That amount is $1.1 billion as shown on line 16. The $1.1 billion will remain in plant and be depreciated at 2.82% based on authorized depreciation rates. This results in a net plant balance of $845 million on December 31, 2032, as proven out in columns (c) through (k). Subtracting the $1.1 billion to be securitized from the $3.2 billion total plant balance, results in the $2.1 billion net plant amount to be reclassified to the regulatory asset, as shown in column (b). This amount is carried to Exhibit A-12, Schedule B4.4, line 3.

Q155. How is the Monroe regulatory asset calculated on Exhibit A-12, Schedule B4.4?

A155. The beginning balance on line 3 is carried from Exhibit A-12, Schedule B4.5. In column (d), capital additions and amortization for 2025 are shown on lines 5 and 6. Per the Case No. U-21193 July 26, 2023 IRP Order, capital additions approved in rate cases will be added to the regulatory asset. Witness Guillaumin supports the capital expenditures which are shown on Exhibit A-12, Schedule B5.1, page 2. The amortization is calculated based on a fifteen-year period per the Case No. U-21193 July 26, 2023 IRP Order. After reflecting the additions and amortization, the projected ending balance for 2025 is shown on column (d), line 7. The simple and thirteen-month averages are shown in column (f). The thirteen-month average from column (f) line 8 is used by Witness Vangilder on his Exhibit A-11, Schedule A1.2 to calculate the return.

Q156. What is the Ludington Regulatory Asset on line 42?

A156. On May 18, 2023 the Commission approved a joint application by DTE Electric and Consumers Energy in Case No. U-21310 to defer certain costs at the Ludington Pumped Storage Plant resulting from defective work by a third party. The balance represents costs deferred during 2023 after receipt of the Order.

Q157. How was the Customer 360 Regulatory Asset on line 44 developed?

A157. The Company implemented a new Customer Relationship and Billing system in April 2017 called Customer 360. Pursuant to the September 26, 2016 Order in Case No. U-17666, the Company deferred $47 million for certain project expenses in Account 182.3, Other Regulatory Assets. The Company also incurred $16.6 million of post implementation costs during 2017. The Commission approved recovery of the 2017 amount in Case No. U-20162. The deferred costs are being amortized over a 15-year period, and the balance reflects annual amortization of about $4.2 million.

Q158. What is the Residential Income Assistance regulatory asset on line 46?

A158. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential Income Assistance (RIA) and Low-Income Energy Assistance credits above a base amount. The balance reflects that in 2022, the Company issued more RIA credits to customers than were reflected in the base. In Case No. U-20836, the Commission ordered any unspent RIA and LIA be recorded as a regulatory liability. Effective with the Order in U-20836, any underspent amounts will be netted against any regulatory assets recorded for overspent amounts. The projected balances were based on a 13-month historical average.

Q159. What is the Program Evaluation & Review Committee (PERC) regulatory asset on line 47?

A159. This balance represents deferred costs for certain nuclear O&M projects. As further explained by Witness Davis, the Company executes PERC operations and maintenance projects. The change in balance is projected based on the addition of deferred costs less the amortization of deferred amounts over five years, as shown on my Exhibit A-13, Schedule C5.17. As previously discussed, the Order in Case No. U-18014 provided deferral treatment for any expenses over or under a $4.9 million base amount, and the base was increased to $15 million in Case No. U-20561.

Q160. What is the Advanced Distribution Management System (ADMS) regulatory asset on line 48?

A160. As previously discussed, the Company is installing an ADMS. The Commission approved deferral of certain O&M costs as a regulatory asset with amortization over fifteen years in Case No. U-20162. As shown on Exhibit A-12, Schedule B5.4, page 1 of 26, line 25, these expenses were deferred in the amount of $4.7 million in the 2022 historical year and are projected to be $3.6 million in the bridge period. The regulatory asset balance is reduced by annual amortization of approximately $1.2 million in 2024 and 2025.

Q161. What is the Charging Forward Regulatory Asset on line 49?

A161. As previously discussed, in Case Nos. U-20162 and U-20935 the Commission approved a program called Charging Forward to incentivize third parties to build charging stations for electric vehicles by providing rebates. Per the Order, the regulatory asset will be expensed over five years, concurrent with its inclusion in base rates. Additionally, the Company requested, and received approval for, an expansion of the Charging Forward program in Case Nos. U-20836 and U-21297. The Orders provide for the same regulatory asset treatment for rebates paid to schools, municipalities, gas stations, and similar customers. The projected balance of $47.1 million at December 2025 reflects deferred expense through the projected period, supported by Witness Bennett, less cumulative amortization.

Q162. What is the Advanced Customer Pricing Pilot Regulatory Asset on line 51?

A162. Regulatory Asset treatment for certain implementation costs for the ACPP was approved in the Commission's November 14, 2019 Order in Case No. U-20602. The Commission approved deferral of up to $7.3 million of costs. Actual costs deferred totaling $6.6 million are supported by Witnesses Bennett and Hatsios on Exhibit A-13, Schedule C5.9.2, less cumulative amortization.

Q163. What is the Time of Day (TOD) Regulatory Asset on line 52?

Line
No.

A163. Regulatory Asset treatment for certain implementation costs for the Company's Time of Day rate offering was approved in the Commission's November 18, 2022 Order in Case No. U-20836. The Company proposed a full implementation of TOD rates, and the project incurred both capital and O&M expenses. The balance as of December 2025 on line 52 of $4.9 million reflects $8.5 million of one-time implementation costs offset by $3.5 million of cumulative amortization expense through the projected period. Witnesses Bennett and Hatsios support one-time implementation costs on Exhibit A-13, Schedule C5.9.2.

My Exhibit A-13, Schedule C5.9.3 supports the calculation of annual amortization expense of $3.0 million for both the ACPP and TOD regulatory assets, which is included in Customer Service O&M expense supported by Witness Hatsios.

Q164. What is the Pension Capitalized on line 54?

A164. As previously described regarding pension expense, this balance represents the capitalized non-service cost components of pension expense. Because the non-service costs became negative, the deferred balance is projected to become a regulatory liability during 2023 and is shown on line 110.

Q165. What is the Demand Response Regulatory Asset on line 55?

A165. Witness Farrell describes the Company's Demand Response programs and the reconciliation process. The Commission's February 18, 2021 Order in Case No. U-20793 approved a $3.0 million regulatory asset for under recovered 2019 Demand Response costs, and recovery via inclusion of amortization expense in base rates. The Commission also issued an Order on February 10, 2022 approving a settlement in the DR 2020 Reconciliation, Case No. U-21044, reflecting an under recovery of $1.4 million and $202,000 of incentives. The balance also reflects a settlement in the DR 2021 Reconciliation, Case No. U-21242, of $4.3 million, approved by Order on January 19, 2023. The $1.8 million balance on December 31, 2025 reflects $8.9 million of deferrals in 2021 through 2023 offset by accumulated amortization of $7.1 million.

Q166. What is the Incentive Compensation Regulatory Asset on line 56?

A166. In Case No. U-20836, the Commission approved recovery of $12.7 million for incentive compensation related to operating metrics. The approved base amount assumed the Company achieved 60% of its targeted metrics. The Commission's Order also provided for deferral treatment above or below the base amount, up to a maximum 100% target level, to be refunded or recovered in DTE Electric's next rate case. In Case No. U-21297, the Commission reduced the approved base amount to $10.1 million assuming the Company achieves approximately 52% of its targeted metrics. The projected balance assumes that DTE Electric will not achieve 100% of its target levels in 2023 based on projected performance. The amount below base will be deferred to a regulatory liability. However, the Company expects to achieve 100% of its target levels in 2024 and will defer the difference between the actual results and the annual base amount of $10.1 million. Please refer to Exhibit A-13, Schedule C5.10.1. Line 4 shows the amounts to be deferred by calendar year. The calculation assumes the full amount of incentive expense will be approved for recovery starting with the projected test period (January 1, 2025 to December 31, 2025) with no deferral required.

Line
No.

Q167. Do you recommend that the incentive compensation deferral mechanism be continued?

A167. If the Commission approves the Company's forecasted incentive compensation costs for the projected test period, the mechanism is unnecessary. However, if a lesser amount is approved, I request the deferral be continued, but with some modifications.

Q168. What modifications to the incentive compensation mechanism are you proposing?

A168. I propose three modifications. First, the base amount should be reset equal to the amount of incentive compensation approved for recovery in base rates in this case. Second, the mechanism should apply to the totality of the Company's incentive compensation program including the portion related to financial metrics. Witness Cooper supports the reasonableness and prudency of the Company's compensation practices, including incentives tied to financial metrics. Third, the deferral should cover the total actual payout, including amounts above 100% of the target. As described in more detail by Witness Cooper, the incentive program allows for a range of payouts from zero to 200% of target. The incentive plan is designed to motivate employees to achieve results beyond the target, further improving organizational performance and benefitting customers. Since the Company must provide a refund to customers if results fall below the baseline, it is reasonable to include the cost of achieving exceptional results.

Q169. What is the Low-Income Assistance Tracker on line 57?

Line No.

A169. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential Income Assistance (RIA) and Low-Income Energy Assistance credits above a base amount. The balance reflects that in 2022, the Company issued more LIA credits to customers than were reflected in the base. In Case No. U-20836, the Commission ordered any unspent RIA and LIA be recorded as a regulatory liability. Effective with the Order in U-20836, any underspent amounts will be netted against any regulatory assets recorded for overspent amounts. The projected balances were based on a 13-month historical average.

Q170. What is the Low-Income Payment Stability Plan regulatory asset on line 58?

A170. In Case No. U-20929, the Commission authorized DTE Electric to defer costs associated with its low-income customer assistance pilot (the Payment Stability Plan or "PSP"). The PSP pilot creates a fixed maximum bill for participating customers based on their income, rather than providing a fixed credit amount on a variable bill like those provided by the residential income assistance or low-income assistance programs. The balance consists of supplemental payments, arrears forgiveness, benefit awards, and certain O&M implementation costs associated with the pilot.

Q171. What is causing the increase in Prepaid OPEB on line 62?

A171. The Prepaid Post-Retirement Benefit asset increases from $129.1 million on December 2022 to $194.3 million by December 2025. The year-to-year changes are primarily the result of negative OPEB expense as explained by Witness Cooper.

Q172. Can you explain the tax items on lines 59, 65 and 66 of Exhibit A-12, Schedule B4.2?

A172. Witness Wisniewski supports these tax-related assets. Line 59 represents the excess deferred taxes that were remeasured related to reduction of the federal corporate income tax rate change resulting from the 2017 Tax Cuts and Jobs Act (TCJA). Line 65, Miscellaneous Tax Related, represents regulatory assets resulting from changes in tax law such as Medicare Part D and the Michigan Corporate Income Tax, reduced each year by amortization of approximately $22.2 million. Line 66, Recoverable Income Taxes, reflects a regulatory asset recorded in conjunction with an offsetting ADFIT liability when ASC 740 (formerly FAS 109) was adopted in 1993. It has scheduled reductions of $2.4 million per year supported by Witness Wisniewski. The ASC 740 balance sheet accounts do not affect the revenue requirement. This accounting and rate treatment were approved by the Commission in Case No. U-10083.

Q173. How was Other Deferred Debits on line 68 of Exhibit A-12, Schedule B4.2 developed?

A173. The Other Deferred Debits balance consists of pre-paid software, refundable spent nuclear fuel storage costs, and short-term credit facility costs which were held constant at the 13-month historical period. It also includes a pre-paid long-term maintenance service agreement (LTSA) for the Blue Water Energy Center. Changes in the LTSA balance reflect payments to the service provider, reduced by transfers to capital and O&M as the services are rendered.

Q174. What components make up the Liabilities and Other Credits reflected in Exhibit A-12, Schedule B4.2, page 2 of 2?

A174. Exhibit A-12, Schedule B4.2, page 2 of 2 has four major components:

1) Capitalization
2) Non-Current Liabilities
3) Current Liabilities
4) Deferred Credits

<u>Capitalization</u>

Q175. How were the projected capitalization amounts determined in this case?

A175. Capitalization (lines 73 through 83) reflects DTE Electric's permanent capital in the form of long–term debt and common equity. Key long-term debt drivers include new capital requirements, scheduled debt retirements, refinancing, level of equity, and the amount of short-term debt. As previously discussed, the regulatory liability related to the REP is a source of short-term debt. Schedule B4.2, line 76, shows that long-term debt balances will increase during the forecast periods to support DTE Electric's increasing asset base, as supported by Company Witness Lepczyk.

Common equity balances on line 82 will also increase to finance the growing asset base and to meet targeted capitalization percentages. Since projected earnings are insufficient to meet the targeted equity capital percentages, common equity will need to be funded from additional equity infusions as discussed and supported by Witness Lepczyk. Projected common equity also reflects dividends required to sustain and attract equity investors.

Line
No.

Q176. What is the projected change in Capitalization?

A176. Exhibit A-12, Schedule B4.2, line 76, reflects a long-term debt increase from January 2023 to December 2024 of $1,014.2 million primarily due to $1,875.0 million of new debt issues, less redemptions of $861.0 million. The $144.3 million long-term debt increase from January 2025 to December 2025 is primarily due to new debt of $1,300.0 million, less $1,156.9 million of debt redemptions. Line 79 reflects Common Stock increases of approximately $2.2 billion through December 2025 due to planned equity infusions as addressed by Witness Lepczyk, offset by the removal of $806.9 million of equity supporting the Monroe regulatory asset. A portion of the Common Stock increases may be reduced from additional equity based on the Commission Order in this case granting the rate relief requested. Retained Earnings (line 80) decreases by $62.6 million from January 2023 to December 2024, resulting from net income of $1,416.8 million, less common dividend payments of $1,479.4 million. Retained Earnings decreases from January 2025 to December 2025 by $157.5 million resulting from twelve months ending December 2025 net income of $690.0 million less common dividend payments of $847.5 million. The changes in common equity are reconciled on Exhibit A-12, Schedule B4.3.

<u>Non-Current Liabilities</u>

Q177. What is included in Non-Current Liabilities on lines 85 through 91 of Exhibit A-12, Schedule B4.2?

A177. This section includes the liability for capital leases and injuries and damages. Capital leases on line 85 is being held constant and represents the long-term portion of the liability to offset the Net Capital Lease Property on line 10. The accumulated

Line
No.

provision for injuries and damages on line 87 is being held constant to the 13-month historical average during the forecast period as new claims and settlements cannot be predicted.

Current Liabilities

Q178. What is included in Current Liabilities on lines 94 through 103 of Exhibit A-12, Schedule B4.2?

A178. This section includes short-term debt and payables. DTE Electric's short-term debt balances on line 94 include the balances available from the REP regulatory liability. The REP regulatory liability represents the temporary over-collection of DTE Electric's REP surcharge. This liability is used by DTE Electric as an additional source of financing in base rates. Interest on this liability is paid to our customers via a credit in the Renewables Plan, lowering the revenue requirement for that program.

Q179. How did you forecast the balance for Accounts Payable on lines 96 and 97?

A179. Accounts payable was forecasted based on a 13-month historical average as of December 31, 2022.

Q180. How did you forecast the remaining current liabilities?

A180. Taxes Payable on line 98 reflects the timing of accruals and payments, as supported by Witness Wisniewski. The changes in Interest Payable on line 99 also reflect the timing of accruals and payments. Capital Leases Current on line 100 reflects the current portion of the liability to offset the Net Capital Lease Property on line 10. The fluctuations in line 102, Fermi 2 Outage accrual, result from forecasted accruals and expenditures for the Fermi 2 planned outages supported by Witness Davis on line 102. Other Current Liabilities on line 103 include vacation and payroll accruals, customer deposits, and refundable contributions in aid of construction, and are held constant at the historical 13-month average balance.

Deferred Credits

Q181. What is included in Deferred Credits on lines 106 through 116 of Exhibit A-12, Schedule B4.2?

A181. The December 2022 balance related to line 106 Regulatory Liability - Renewable Energy Program, was re-classified to short-term debt on my historical Exhibit A-2, Schedule B6.2. Other Deferred Credits on line 116 includes refundable customer advances, environmental reserves, and other accrued liabilities held constant at 13-month average historic levels.

Q182. What is the Regulatory Liability – OPEB on line 108?

A182. The OPEB liability was established pursuant to the Commission's Order in Case No. U-17767. Consistent with the treatment of pension expense, negative OPEB expense, less amounts capitalized and transferred, are offset by a regulatory liability. In Case No. U-21297, the Commission ordered that the Company must amortize the OPEB regulatory liability of $128.4 million as of the historical test year (December 2022) over a seven-year period. The projected balance includes additional deferrals due to projected negative OPEB expense offset by annual amortization of $18.3 million.

Q183. What is the OPEB Capitalized on line 109?

A183. As previously described regarding OPEB expense, this balance represents the capitalized non-service cost components of OPEB expense.

Q184. What is the Pension Capitalized on line 110?

A184. As previously described regarding the pension capitalized asset, the non-service costs became negative, and the balance is projected to become a regulatory liability during 2023.

Q185. What are the tax items on lines 113 through 115?

A185. Witness Wisniewski supports lines 113 through 115. Accumulated Deferred Income Taxes represents timing differences in the recognition of tax expenses for the financial statements compared to the tax return. Both the federal and state deferred tax balances reflect the netting of Deferred Tax Assets (Account 190) against Deferred Tax Liabilities (Accounts 281, 282, and 283), consistent with the presentation in the cost of capital calculation.

Deferred taxes on line 113 includes the outstanding tax liability balance to account for tax benefits previously flowed through to ratepayers stemming from the 1993 enactment of ASC 740 as previously discussed. It is offset by the Regulatory Asset (Recoverable Income Taxes) shown on Schedule B4.2, line 66. This accounting and rate treatment were approved by the Commission in Case No. U-10083.

Accumulated Deferred Investment Tax Credits on line 114, supported by Witness Wisniewski, are deferred tax credits generated and utilized by the Company with the tax benefits flowing back to customers on the same basis as customers pay for the assets that generated these tax credits.

The Tax Reform Regulatory Liability on line 115 results from the Tax Cuts and Jobs Act of 2017, which among other things, lowered the corporate Federal tax rate from 35% to 21%. The reduction in the tax rate required that all existing deferred tax balances be re-measured using the 21% rate. The reduction in deferred taxes was recorded to a regulatory liability to be refunded, generally, over the life of the items causing the deferred tax, primarily plant. However, it also reflects accelerated amortization of the liability per the Commission's April 8, 2021 Order in Case No. U-20835. Witness Wisniewski explains the calculation of the regulatory liability and the Company's refund schedule.

MERC Closure Impacts

Q186. What impact does the anticipated closure of MERC have on the projections in this case?

A186. None. As described by Witness Milo, MERC will continue to operate until generation using coal is discontinued at the Belle River Power Plant in mid-2026, beyond the projected test period. Witness Milo supports the O&M and capital expenditures required to safely operate MERC until it ceases operations.

Q187. How does the Company plan to address the recovery of the plant assets remaining after MERC ceases operations?

A187. The Company proposes to include the remaining net book value of MERC's assets in the securitization transaction for the Belle River coal assets. Securitization of the coal handling assets for Belle River was approved in the Company's IRP Case No. U-21193 by Commission Order issued on July 26, 2023. The Company estimates that the net book value will be in the range of $20 million.

<u>IRM Impacts</u>

Q188. How does the Infrastructure Recovery Mechanism impact the projected financials?

A188. An overview of the mechanism is provided by Company Witness Foley. The Commission Order in Case No. U-21297 approved an IRM for December 2023 through December 2025. 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. This exclusion ensures that the revenue requirement for the IRM is separate and distinct from the revenue requirement for base rates. Company Witness Foley describes and supports the Company's proposal to extend the IRM through 2027.

Q189. Will the IRM expenditures be permanently excluded from base?

A189. No. IRM investments will be transferred into the Company's overall rate base after the investments have been made and put into service. The Company will reflect this in the first general rate case after the investments have been reviewed through an IRM reconciliation proceeding consistent with the Commission's Order in Case No. U-21297. Until transferred to the Company's overall rate base rates, IRM investments will be recovered through the IRM surcharge. Once the Commission approves the transfer of assets from the IRM mechanism to the Company's overall rate base, these assets be removed from the IRM surcharge.

Q190. Is the Company proposing to reduce its future recovery by the amount of plant that is being retired in this IRM program?

A190. 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-investment portion of the revenue requirement calculation. As depreciation rates are periodically adjusted in subsequent depreciation cases, the impact of any abnormal retirements will be incorporated.

Q191. What is the impact to customers if the IRM is approved but the Company does not spend the full amount of projected capital expenditures?

A191. As explained by Witness Foley, the Company will record a regulatory liability for any over-recovery related to the IRM. The recording of any Regulatory Liability will be reviewed through an IRM reconciliation proceeding, consistent with the Commission's Order in Case No. U-21297. The Company will use account 254, Other Regulatory Liabilities, for that purpose.

Other Accounting Requests

Q192. What accounting treatment are you proposing for customer bill credits?

A192. As discussed in detail by Witness Crozier, the Company is proposing that bill credits related to outages beyond the Company's control be deferred for future recovery. Consistent with the proposal in Case No. U-20836, the Company will use account 182.3, Other Regulatory Assets, for that purpose. The Company proposes to amortize the deferred amounts concurrent with their recovery in base rates.

Q193. What accounting treatment are you proposing for storm costs?

A193. As described by Witness Foley, the Company is requesting a storm restoration cost sharing mechanism. I am requesting the use of account 182.3, Other Regulatory Assets, and 254, Other Regulatory Liabilities, to record the refundable or recoverable portion of any difference between actual storm costs and the base amount approved in this case.

Summary

Q194. Can you summarize what Commission approvals the Company is requesting?

A194. In addition to the forecasted costs and revenues included herein, the Company is requesting a continuation of the previously approved deferral treatment for Pension expense, OPEB expense, LIA/RIA credits, TOD implementation costs, PERC projects, and certain Charging Forward programs. I am also requesting approval to use accounts 182.3 and 254 to record any under/over recovery from the storm cost sharing mechanism.

Q195. Does this complete your direct testimony?

Line
No.

A195. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KIRK M. VANGILDER

Line
No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Kirk M. Vangilder (he/him/his). 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 the Regulatory Affairs organization as a Principal Financial Analyst for Revenue Requirements.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Arts Degree in Accounting from Michigan State University's Eli Broad College of Business in 2004 and a Master of Science Degree in Accounting from Michigan State University's Eli Broad Graduate School of Management in 2006.

Q4. Have you completed any seminars or other training courses?

A4. Yes, I have. I completed a utility finance and ratemaking course taught by Excidian, LLC. Additionally, I attended trainings hosted by Electric Utility Consultants, Inc, (EUCI) on utility cost of service and ratemaking. I also completed the ratemaking program conducted by the Institute of Public Utilities at Michigan State University.

Q5. What is your work experience?

A5. From 2006 to 2011, I practiced public accounting with the international accounting firm Grant Thornton LLP where I had positions of increasing responsibility.

Line
No.

During this time, I received my Certified Public Accountant license. In October 2011, I joined DTE Energy as a Financial Auditor in the Audit Services department. In March 2013 I was promoted to Senior Financial Auditor, where I performed substantive testing and controls testing to support DTE Energy's financial statement audits and regulatory filings process. In August 2014, I accepted a position within DTE Energy's Controllers organization as a Senior Business Financial Analyst with responsibility for various accounting, budgeting, and reporting activities for DTE Gas, including financial and revenue requirement modeling. In 2018, I transferred to Regulatory Affairs as a Senior Rate Analyst in their Revenue Requirements group, and in 2019 I was promoted to my current position as Principal Financial Analyst.

Q6. Do you hold any certifications or are you a member of any professional organizations?

A6. I received my Certified Public Accountant license in 2008 and am currently a registered accountant within the State of Michigan.

Q7. What are your current duties and responsibilities?

A7. As a Principal Financial Analyst for Revenue Requirements within DTE Energy's Regulatory Affairs organization, I am responsible for revenue requirement studies for regulatory filings, regulatory analysis and research, and for supporting certain MPSC filings, such as general rate cases.

Q8. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

Line
No.

A8. Yes, I have. I have sponsored testimony in the following cases:

U-20373	DTE Electric 2020-2021 EWR Plan
U-20373-A	DTE Electric 2020-2021 Amended EWR Plan
U-20429	DTE Gas 2020-2021 EWR Plan
U-20642	DTE Gas 2019 Main Rate Case
U-20703	DTE Electric 2019 EWR Reconciliation
U-20708	DTE Gas 2019 EWR Reconciliation
U-20711	DTE Electric 2019 PLD/TRM Reconciliation
U-20836	DTE Electric 2022 General Rate Case
U-20876	DTE Electric 2022-2023 EWR Plan
U-20881	DTE Gas 2022-2023 EWR Plan
U-20940	DTE Gas 2021 General Rate Case
U-20987	DTE Electric 2020 PLD/TRM Reconciliation
U-21206	DTE Electric & DTE Gas 2021 EWR Reconciliation
U-21242	DTE Electric 2021 Demand Response Reconciliation
U-21291	DTE Gas 2024 General Rate Case
U-21297	DTE Electric 2023 General Rate Case
U-21307	DTE Electric 2021 & 2022 PLD/TRM Reconciliations
U-21313	DTE Electric & DTE Gas 2022 EWR Reconciliation
U-21403	DTE Electric 2022 Demand Response Reconciliation

Purpose of Testimony

Q9. What is the purpose of your testimony in this proceeding?

A9. I am providing testimony related to the historical and the projected sections of this rate case filing. In Section A – Historical Test Period, I am supporting DTE Electric's historical revenue sufficiency for the twelve months ended December 31, 2022. In preparing my rate case exhibits, I relied on financial information supplied by Company Witnesses Uzenski and Lepczyk. I am sponsoring the derivation of the historical overall rate of return, Net Operating Income (NOI) adjustments for interest synchronization and income tax savings, and the revenue conversion factor.

In Section B – Projected Test Period, I am sponsoring DTE Electric's projected revenue deficiency for the twelve months ending December 31, 2025, as well as the derivation of the projected overall rate of return, the NOI adjustments for interest synchronization and income tax savings, and the projected revenue conversion factor. I also calculate the incremental revenue requirement for DTE Electric's Tree Trim Regulatory Asset and the return on DTE Electric's Monroe Regulatory Asset. In addition, I am supporting the calculation of the incremental revenue requirements for DTE Electric's Infrastructure Recovery Mechanism (IRM), and the Company's proposed reconciliation process should a different amount of IRM capital be placed in service than what has been approved. Lastly, I am supporting the calculation of the incremental revenue requirements for DTE Electric's alternative IRM proposal along with an alternate projected revenue deficiency should the alternative IRM be approved.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes. I am supporting the following historical and projected exhibits:

Section A – Historical Test Period Ended December 31, 2022

Exhibit	Schedule	Description
A-1	A1	Historical Revenue Deficiency (Sufficiency)
A-2	B1	Historical Rate Base
A-3	C2	Historical Revenue Conversion Factor
A-3	C12	Historical Tax Effect of Interest Allowed in Ratemaking Formula
A-3	C13	Historical Tax Effect of Interest Synchronization Adjustment
A-4	D1	Historical Rate of Return Summary

Section B – Projected Test Period Ending December 31, 2025

Exhibit	Schedule	Description
A-11	A1	Projected Revenue Deficiency (Sufficiency)
A-11	A1.1	Tree Trim Regulatory Asset – Return On
A-11	A1.2	Monroe Regulatory Asset – Return On
A-12	B1	Projected Rate Base
A-13	C2	Projected Revenue Conversion Factor
A-13	C14	Projected Tax Effect of Interest Allowed in Ratemaking Formula - 12 Months Ended 12/31/2022 and 12/31/2025
A-13	C15	Projected Tax Effect of Interest - Synchronization Adjustment - 12 Months Ended 12/31/2022 and 12/31/2025

A-14	D1	Projected Rate of Return Summary

Investment Recovery Mechanism

Exhibit	Schedule	Description
A-33	X4	Infrastructure Recovery Mechanism – Incremental Revenue Requirement – Distribution Operations
A-33	X5	Infrastructure Recovery Mechanism – Incremental Revenue Requirement – Distribution Operations Example of $1.0 MM Under Investment

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.

<u>Section A – Historical Test Period (Twelve Months Ended December 31, 2022)</u>

Q12. What information is displayed on Exhibit A-1, Schedule A1?

A12. Exhibit A-1, Schedule A1 titled "Historical Revenue Deficiency (Sufficiency)" shows the calculation of the Company's revenue sufficiency for the historical test period based on historical rate base, overall rate of return, adjusted NOI, and a revenue conversion factor. Line 8, of Schedule A1 shows that the Company experienced a revenue sufficiency of $80.5 million for the historical test period. The revenue sufficiency is based on a rate base of $20.1 billion, adjusted NOI of $1,132.0 million, and a required rate of return of 5.33%. The rate base balance is carried forward from Exhibit A-2, Schedule B1. The adjusted NOI is carried forward from Exhibit A-3, Schedule C1, which is supported by Witness Uzenski.

The defined historical required rate of return is set forth in Exhibit A-4, Schedule D1.

Q13. What is the Historical Rate Base?

A13. As shown on Exhibit A-2, Schedule B1, Historical Rate Base (line 15) is the end of period balances for net plant amounts for the historical test period and 13-month average balances for the allowance for working capital for the period ended December 31, 2022.

Q14. What is the purpose of the Revenue Conversion Factor?

A14. 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 the historical test period, each dollar of revenue the Company received was subject to Michigan Corporate Income Tax, Municipal Income Tax, and Federal Income Tax. Line 9 of Exhibit A-3, Schedule C2, shows DTE Electric's historical test period Revenue Conversion Factor of 1.3496, which means DTE Electric was required to collect $1.3496 in revenue to produce $1.00 of after-tax income.

Q15. How did you calculate the Income Tax Savings of Interest reflected in Exhibit A-3, Schedule C12?

A15. Exhibit A-3, Schedule C12, calculates the difference in the tax deduction amount for interest expense based on interest expense allowable in the rate case versus DTE Electric's actual interest expense for the historical test period as supplied to me by Witness Uzenski. Allowable interest expense starts with the Historical Rate Base (line 1) multiplied by the weighted cost of debt (line 2). The weighted cost of debt is the summation of the weighted costs associated with long-term debt (LTD) and short-term debt (STD) from Exhibit A-4, Schedule D1. Line 3 calculates the allowable ratemaking debt interest expense deduction while DTE Electric's actual interest expense deduction (line 4) is what was included in DTE Electric's computation of federal income tax per Company books. Allowable ratemaking interest expense is less than actual interest expense, which results in reducing the tax deduction by the net of these two amounts. This lower tax deduction increased federal income tax, state income tax and municipal tax expense and creates a corresponding decrease in NOI, as shown on line 11 of Schedule C12.

Q16. What is the Synchronization Adjustment calculated on Exhibit A-3, Schedule C13?

A16. 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. 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 state and municipal income tax expense (line 7) and federal income tax expense (line 10) due to the interest deduction associated with the debt component portion of JDITC. This Synchronization Adjustment reduces income tax expense and, as shown on line 11, results in a corresponding increase in NOI.

Q17. What is DTE Electric's historical rate of return?

Line
No.

A17. Exhibit A-4, Schedule D1, titled "Historical Rate of Return Summary" shows DTE Electric's historical test period overall rate of return on line 10, column (g). The capital structure is carried forward from the balance sheet on line 119, columns (e) through (i) of Exhibit A-2, Schedule B5 sponsored by Witness Uzenski, and equals the rate base amount on line 15, column (c) of Exhibit A-2, Schedule B1. The capital structure excludes any funds on deposit with trustees, and the financing related to regulatory assets and other items eliminated from the historical balance sheet by Witness Uzenski.

On Exhibit A-4, Schedule D1, the long-term debt, shown on line 1 includes reductions for the net amount of unamortized premium / discount and unamortized debt expense. DTE Electric's total long-term debt outstanding on December 31, 2022 is detailed on Exhibit A-4, Schedule D2, sponsored by Witness Lepczyk. The weighted long-term debt cost for the historical period was calculated by Witness Lepczyk on Schedule D2 using the net proceeds method for each issue outstanding on December 31, 2022.

Line 2 of Schedule D1 reflects that the Company had no preferred stock outstanding.

Line 3 of Schedule D1 shows common shareholders' equity, which includes common stock outstanding, less expense, plus premium, other paid-in capital, retained earnings and Other Comprehensive Income (OCI) adjustments. The cost of common shareholders' equity utilized for this exhibit for the historical test period is the 9.90% that was authorized by the Commission in Case No. U-20836 as indicated on Exhibit A-4, Schedule D5, sponsored by Witness Lepczyk.

The cost of short-term debt, on line 5, is the actual average short-term borrowing cost of the Company in the historical test period. The cost of short-term debt is detailed on Exhibit A-4, Schedule D3, sponsored by Witness Lepczyk.

The Job Development – ITC amounts on lines 6 (JDITC – Debt) and 7 (JDITC – Equity) of Schedule D1 reflect the corresponding permanent capital percentages for long-term debt and common equity. The associated returns for JDITC – Debt and JDITC – Equity reflect the corresponding permanent capital cost rates for long-term debt and common shareholders' equity, respectively. This calculation complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to assign a rate of return to JDITC at the weighted average cost of permanent capital.

Net deferred income taxes (line 9) are at zero cost.

<u>Section B – Projected Test Period (Twelve Months Ending December 31, 2025)</u>

Q18. What is the Revenue Deficiency for the projected test period?

A18. Line 11 of Exhibit A-11, Schedule A1, shows absent rate relief, DTE Electric will experience a Total Revenue Deficiency of $456.4 million for the projected test period, including the return on the Tree Trim Regulatory Asset (line 9) calculated on Exhibit A-11, Schedule A1.1 and the return on the Monroe Regulatory Asset (line 10) calculated on Exhibit A-11, Schedule A1.2. This deficiency is based on the Company's projected financial outlook for the twelve months ending December

31, 2025. The revenue deficiency on line 8 is based on the following: a projected rate base of $22.1 billion, adjusted NOI of $1,087.1 million, and a projected required rate of return of 5.92%. The total revenue deficiency for the projected test period is presented on line 11 and is calculated by adding the revenue deficiency on line 8 to the return on the Company's Tree Trim Regulatory Asset (line 9) and return on the Company's Monroe Regulatory Asset (line 10).

The calculation of rate base is detailed in Exhibit A-12, Schedule B1. The NOI for the projected test period is developed on Exhibit A-13, Schedule C1 sponsored by Witness Uzenski. The projected test period required rate of return is set forth in Exhibit A-14, Schedule D1. The components of rate base, NOI, capitalization, required rate of return, and regulatory assets are detailed within my exhibits and schedules, as well as those of Witnesses Uzenski and Lepczyk.

Q19. What information is displayed on Exhibit A-12, Schedule B1, entitled "Projected Rate Base"?

A19. Exhibit A-12, Schedule B1 shows the detailed composition of the Projected Rate Base (column (d)) for the projected test period on a simple average basis. Line 16, column (d), shows the total projected rate base which consists of net plant and the allowance for working capital. These amounts are carried forward to Exhibit A-11, Schedule A1. This exhibit also provides a comparison of rate base as of December 31, 2022 to the average rate base balances for the projected test period.

Q20. What is the Projected Revenue Conversion Factor?

Line
No.

A20. Projected Revenue Conversion Factor is 1.3496 and is used to convert after tax income into pre-tax revenue for the projected test period. Exhibit A-13, Schedule C2 calculates the Revenue Conversion Factor for the projected test period. The derivation of the revenue conversion factor is the same mathematical format as my Exhibit A-3, Schedule C2 from Section A.

Q21. What adjustments on Exhibit A-13, Schedule C1.1, "Adjustments to Projected Net Operating Income" for the Projected Twelve Months Ending December 31, 2025 are you supporting?

A21. On this exhibit, which is sponsored by Witness Uzenski, I am supporting the adjustments for:

1) Income Tax Effect of Interest (line 14) supported by Exhibit A-13, Schedule C14.

2) Interest Synchronization Tax Adjustment (line 15) supported by Exhibit A-13, Schedule C15.

Q22. What is the adjustment for "Income Tax Effect of Interest" on Exhibit A-13, Schedule C1.1, line 14?

A22. This NOI adjustment on line 14 of Exhibit A-13, Schedule C1.1, is the difference between the forecasted ratemaking amount of interest tax deductions allowed based on the rate case rate of return and the forecasted interest tax deductions included in the projected test period NOI supported by Witness Uzenski. This change in income tax expense is calculated on Exhibit A-13, Schedule C14. The sum of line 7 and line 10 of Schedule C14, column (c) reflects an adjustment to decrease income tax expenses resulting in a corresponding increase in NOI as shown on line 11 column (c).

Q23. What is the "Synchronization Adjustment" on Exhibit A-13, Schedule C1.1, line 15?

A23. This NOI adjustment on line 15 of Exhibit A-13, Schedule C1.1 is the rate case Interest Synchronization Adjustment for the projected test period. As I have discussed previously in Section A of my testimony, tax law requires, and prior Commission Orders have allowed, a return on JDITC at the rate of return for permanent capital. This change in the income tax expenses is set forth on Exhibit A-13, Schedule C15. The sum of line 7 and line 10 of Schedule C15, column (c) reflects an adjustment to decrease income tax expenses resulting in a corresponding increase in NOI as shown on line 11 column (c).

Q24. What information is reflected on Exhibit A-14, Schedule D1, page 1 of 2, entitled "Projected Rate of Return Summary"?

A24. Exhibit A-14, Schedule D1, develops DTE Electric's projected overall rate of return for the projected test period. The projected December 31, 2025 average balance sheet capital structure amounts, in column (b), are carried over from Exhibit A-12, Schedule B4.1, line 121, columns (e) through (i) and equals the rate base amount on line 16, column (d) of Exhibit A-12, Schedule B1. Schedule D1 calculates DTE Electric's weighted after-tax projected rate of return on line 10, column (g). This weighted after-tax projected rate of return is carried forward to Exhibit A-11, Schedule A1, line 4 and is used in the determination of the projected revenue deficiency, excluding the return on the Tree Trim Regulatory Asset and the Monroe

Line
No.

Regulatory Asset. Schedule D1 also calculates DTE Electric's weighted pre-tax projected rate of return at line 10, column (i). The capital structure excludes any funds on deposit with trustees, and the financing related to regulatory assets and other items eliminated from the historical balance sheet by Witness Uzenski.

Long-term debt, shown on line 1 of Schedule D1, includes reductions for the net amount of unamortized premium / discount and unamortized debt expense. This balance of long-term debt represents 50.0% of DTE Electric's permanent capital. DTE Electric's projected total long-term debt outstanding as of December 31, 2025 is detailed on Exhibit A-14, Schedule D2, sponsored by Witness Lepczyk. The weighted long-term debt cost was calculated by Witness Lepczyk on Schedule D2 using the net proceeds method for each issue outstanding as of December 31, 2025 including the financing cost of new debt issues.

Line 2 of Schedule D1 reflects that the Company has no preferred stock outstanding.

Line 3 of Schedule D1 shows common shareholders' equity, which includes common stock outstanding, less expense, plus premium, paid-in capital, retained earnings and other comprehensive income (OCI) adjustments. This level of common equity represents 50.0% of DTE Electric's permanent capital in the projected test period. The cost of common shareholders' equity utilized for this exhibit is 10.50%, which is supported by DTE Electric Witness Dr. Villadsen in her testimony.

Line
No.

The cost of short-term debt, on line 5, is the forecasted average short-term borrowing cost of the Company for the projected test period supported by Witness Lepczyk on Exhibit A-14, Schedule D3.

The Job Development – ITC amounts on line 6 (JDITC – Debt) and line 7 (JDITC – Equity) of Schedule D1 reflect the corresponding permanent capital percentages for long-term debt and common equity. The associated returns for JDITC–Debt and JDITC–Equity reflect the corresponding permanent capital cost rates for long-term debt and common shareholders' equity, respectively. This calculation complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to assign a rate of return to JDITC at the weighted average cost of permanent capital.

Average projected deferred income taxes (line 9) are at zero cost of capital.

Q25. What information is reflected on Exhibit A-14, Schedule D1, page 2 of 2, entitled "Projected Rate of Return - Base Rate Request and Monroe Regulatory Asset"?

A25. The Commission approved a settlement agreement in the Company's Integrated Resource Plan (IRP) in Case No. U-21193 on July 26, 2023. The settlement stipulates that "[t]he parties further agree that the remaining [net book value] of Monroe as of December 31, 2024, will be recovered through a regulatory asset with a return on equity (ROE) that will be set at 9.0% amortized over 15 years beginning upon the issuance of an order in the company's next rate case." Exhibit A-14, Schedule D1, page 2 of 2, performs the calculation of the rate of return to be applied to the Monroe regulatory asset.

Lines 1 through 7 are a restatement of Exhibit A-14, Schedule D1, page 1 of 2, summarizing the percent of capitalization, cost rate, pre-tax and after-tax rates of return. Lines 8 through 14 recalculate the pre-tax and after-tax rates of return utilizing a 9.0% return on equity for Common Shareholders' Equity and the equity component of the Job Development – ITC. The pre-tax rate of return calculated on line 14, column (f), is utilized on Exhibit A-11, Schedule A1.2 to determine the return on the Monroe Regulatory Asset.

Return On DTE Electric's Tree Trim Surge Proposal

Q26. What information is provided on Exhibit A-11, Schedule A1.1 entitled "Tree Trim Regulatory Asset – Return On"?

A26. Exhibit A-11, Schedule A1.1, identifies the return on the Tree Trim Regulatory Asset for the projected test period relating to the Tree Trim Surge proposal as discussed by Company Witness Steudle. Line 2 is the average balance for the Tree Trim Regulatory Asset as calculated on lines 8 through 16, based on the expenditures supported by Witness Steudle on Exhibit A-13, Schedule C5.6.1 and a reduction to the asset balance of $156.9 million for amounts approved to be securitized in Case No. U-21015 (page 91 of Order dated June 23, 2021). The Return on Tree Trim, shown on line 6 is based on the Average Net Rate Base on line 4 multiplied by the pre-tax Authorized Rate of Return on Permanent Capital on line 5. The pre-tax Authorized Rate of Return on Permanent Capital is calculated on Exhibit-14, Schedule D1 and was utilized as instructed by Company Witness Lepczyk.

Line
No.

Return On DTE Electric's Monroe Regulatory Asset

Q27. What information is provided on Exhibit A-11, Schedule A1.2 entitled "Monroe Regulatory Asset – Return On"?

A27. Exhibit A-11, Schedule A1.2, identifies the return on the Monroe Regulatory Asset for the projected test period relating to the balance of Monroe Power Plant that is not being securitized and is to be recovered as a regulatory asset over fifteen years as discussed by Company Witness Uzenski. Line 2 is the average balance for the Monroe Regulatory Asset as calculated on Exhibit A-12, Schedule B4.4 and supported by Witness Uzenski. The Return on Monroe Regulatory Asset, shown on line 4 is based on the average balance from line 2 multiplied by the Pre-tax Weighted Average Cost of Capital on line 3 as calculated on Exhibit A-14, Schedule D1, page 2.

Revenue Requirement for DTE Electric's Infrastructure Recovery Mechanism

Q28. What information is provided on Exhibit A-33, Schedule X4 entitled "Infrastructure Recovery Mechanism – Incremental Revenue Requirement – Distribution Operations"?

A28. Exhibit A-33, Schedule X4, page 1, identifies the annual incremental Revenue Requirements for DTE Electric's IRM program years 2024[1], 2025, 2026 and 2027 related to the Distribution Operations plant in service discussed by Company Witness Foley. The Revenue Requirement components consist of Return on Net Rate Base, Depreciation, and Property Taxes. Lines 19 through 22, on page 1 of Exhibit A-33, Schedule X4 show the underlying Revenue Requirement amounts for years 2024[1] through 2027 that are used by Company Witness Maroun to derive

---

[1] The 13 months ended December 31, 2024

the IRM Cost of Service by Voltage Class for the respective years. The revenue requirement calculation for years 2024[1] and 2025 within this exhibit utilize the same plant in service amounts, rate of return, depreciation rates, and property tax millage rates as those approved for the IRM by the Commission for DTE Electric Rate Case No. U-21297. As such, the calculated revenue requirements for 2024[1] and 2025 are identical to what was ordered within DTE Electric Rate Case No. U-21297.

Lines 3 through 8 represent the Distribution Operations plant in service amounts summarized by Witness Foley on Exhibit A-33, Schedule X1. Lines 12 through 16, 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 19, is based on the Average Net Rate Base multiplied by the pre-tax rate of return. Since rate base for the IRM is shown net of deferred taxes, the weighted cost of permanent capital is used. Depreciation, line 20, is based on the half year convention. The line 21 Property Taxes are derived on page 2 of this exhibit.

Q29. What is the basis for the pre-tax rate of return utilized?

A29. The pre-tax rate of return is DTE Electric's permanent capital projected weighted cost rates from Exhibit A-14, Schedule D-1, grossed up by the appropriate pre-tax multiplier discussed previously in my testimony.

Q30. What is the basis for the depreciation rate utilized on Exhibit A-33, Schedule X4?

A30. The depreciation rate reflects the composite depreciation rate for distribution plant, as supported by Witness Uzenski on Exhibit A-13, Schedule C6, page 2, line 9, column (h). The depreciation rate is applied to the projected plant in service for the three years shown on Exhibit A-33, Schedule X4.

Q31. What is the purpose of page 2 of Exhibit A-33, Schedule X4?

A31. Page 2 of Exhibit A-33, Schedule X4 shows the calculations of the accumulated deferred tax expense used in the derivation of Net Rate Base and the property taxes included in the revenue requirement, shown on page 1 of Exhibit A-33, Schedule X4.

Q32. How are property taxes calculated on page 2 of Exhibit A-33, Schedule X4?

A32. Property tax expense for the proposed IRM assets is applicable to both in-service and CWIP assets. Lines 19 through 30 calculate the applicable taxable value and property tax expense for plant in service assets. The property tax expense for plant in service assets is calculated by multiplying the taxable value by the millage rate, which is supported by Witness Wisniewski. In addition, lines 32 through 47 calculate the applicable taxable value and property tax expense for CWIP assets. The property tax expenses for CWIP assets are also calculated by multiplying the taxable value by the millage rate, which is supported by Witness Wisniewski.

Q33. How is the Company proposing to reconcile actual investment to the investment proposed for IRM treatment in the instant case?

A33. The Company's proposed reconciliation is more fully described by Witness Foley. At a high level, the Company is proposing that after the conclusion of each calendar year, the Company would calculate a revenue requirement based on actual investment and plant in service for the previous year. This actual revenue requirement would be compared to the revenue requirement ordered by the Commission and calculated in a manner consistent with Exhibit A-33, Schedule X4. If the actual revenue requirement is less than the ordered revenue requirement, it would represent an over-recovery to be returned to customers. Importantly, the amount of capital that can be placed into service for each program under the IRM construct is capped at the amounts proposed by Company Witness Foley and captured in my Exhibit A-33, Schedule X4 (page 1, lines 3-8). If the Company elects to invest and place into service capital above the amounts proposed in the instant case, it can request recovery of that additional capital in a future rate case.

Q34. Have you prepared an example to illustrate this?

A34. Yes. Exhibit A-33, Schedule X5 entitled "Infrastructure Recovery Mechanism – Incremental Revenue Requirement – Distribution Operations – Example of $1.0 MM Under Investment" utilizes the Company's filed IRM revenue requirement methodology and inputs to calculate the revenue requirement of a $1 million of lower plant in service recorded in the program in the first year of the IRM mechanism.

As can be seen on of Exhibit A-33, Schedule X5 (page 1, line 16), in this example $1 million less of in-service capital would result in an actual revenue requirement $65 thousand less than the revenue requirement calculated in Exhibit A-33, Schedule X4 (page 1, line 22). As proposed by Company Witness Foley, in this example the Company would record a $65 thousand Regulatory Liability to be returned to customers in a future rate case with interest.

Q35. What is the purpose of page 2 of Exhibit A-33, Schedule X5?

A35. Page 2 of Exhibit A-33, Schedule X5 shows the calculations of the accumulated deferred tax expense used in the derivation of Net Rate Base shown on page 1 of Exhibit A-33, Schedule X5.

<u>Summary</u>

Q36. What are you proposing based on your testimony in this proceeding?

A36. I am proposing that the Commission issue findings consistent with the matters presented in my testimony. Specifically, as shown in Section B, on Exhibit A-11, Schedule A1, that DTE Electric's revenue deficiency for the projected test period is $456.4.

Q37. Does this complete your direct testimony?

A37. Yes, it does.

BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION

DTE ELECTRIC COMPANY	**)**	
	)	
	)	**Case No. U-21534**
	)	
	)	

DIRECT TESTIMONY

OF

DR. BENTE VILLADSEN

LIST OF TOPICS ADDRESSED:

COST OF COMMON EQUITY CAPITAL

TABLE OF CONTENTS

I. Introduction and Purpose 2
II. Summary of Conclusions 5
III. Cost of Capital Principles and Approach 7
A. Risk and the Cost of Capital 7
B. Financial Risk and the Cost of Equity 10
C. Approach To Estimating the Cost of Equity 13
IV. Capital Market Conditions 14
A. Interest Rates 17
B. Yield Spreads 20
C. Risk Premiums 21
D. Inflation Expectations and Impact 23
V. Estimating the Cost of Equity 26
A. Approach to Cost of Equity Estimation 26
B. Proxy Group Selection 26
C. Financial Risk Adjustment 31
D. CAPM/ ECAPM Approach and Cost of equity Estimates 32
1. CAPM Approach 32
2. ECAPM Approach 32
3. CAPM/ ECAPM Cost of Equity Estimates 33
E. DCF Approach and Cost of Equity Estimates 35
1. Single-Stage DCF Approach 36
2. Multi-Stage DCF Approach 37
3. DCF Cost of Equity Estimates 37
F. Risk Premium Approach and Cost of Equity Estimate 38
G. Summary Results 40
VI. DTE Electric Specific Circumstances and ROE REcommendation 41
A. Regulatory Environment 41
VII. Cost of Capital Recommendation 45

BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION

DTE ELECTRIC COMPANY	)	
	)	
	)	**Case No. U-21534**
	)	
	)	

DIRECT TESTIMONY OF DR. BENTE VILLADSEN

I. INTRODUCTION AND PURPOSE

Q1. Please state your name, occupation, and business address for the record.

A1. My name is Bente Villadsen (she her hers). I am a Principal of The Brattle Group, whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts, 02108.

Q2. Briefly describe your present responsibilities at The Brattle Group.

A2. As a Principal, it is my responsibility to research and direct research into the utility industry as it pertains to cost of capital and related issues. It is also my responsibility to consult on utility industry issues and testify on utility industry matters. Among my other duties is the supervision and training of staff and ensuring that work products are of high quality and accurate.

Q3. Briefly describe your education and professional qualifications.

A3. I have 24 years of experience working with regulated utilities on cost of capital and related matters. My practice focuses on cost of capital, regulatory finance, and accounting issues. I am the co-author of the text, "Risk and Return for Regulated Industries"[1] and a frequent speaker on regulated finance at conferences and webinars.

---

1 Bente Villadsen, Michael J. Vilbert, Dan Harris, A. Lawrence Kolbe, "*Risk and Return for Regulated Industries*," Academic Press, 2017.

I have testified or filed expert reports on cost of capital in Alaska, Arizona, California, Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Ohio, Oregon, Virginia and Washington, as well as before the Bonneville Power Administration, Federal Energy Regulatory Commission, the Surface Transportation Board, the Alberta Utilities Commission, the Ontario Energy Board, Quebec's Régie de l'Énergie and Barbados' Fair Trading Commission. I have provided white papers on cost of capital to the British Columbia Utilities Commission, the Canadian Transportation Agency as well as to European and Australian regulators on cost of capital. I have testified or filed testimony on regulatory accounting issues before the Federal Energy Regulatory Commission ("FERC"), the Regulatory Commission of Alaska, the Michigan Public Service Commission, the Texas Public Utility Commission as well as in international and U.S. arbitrations and regularly provide advice to utilities on regulatory matters as well as risk management.

I hold a Ph.D. from Yale University and as BS/MS from University of Aarhus, Denmark. Appendix A contains more information on my professional qualifications as well as a list of my prior testimonies and publications.

Q4. What is the purpose of your testimony in this proceeding?

A4. DTE Electric Company ("DTE Electric", the "Company", or "DTEE") has asked me to estimate the cost of equity that the Michigan Public Service Commission (the "Commission") should allow DTE Electric an opportunity to earn on the equity-financed portion of its regulated utility rate base. My recommendation also considers the business and financial risk of the Company relative to the proxy companies to arrive at my recommendation for the allowed Return on Equity ("ROE").

Q5. Are you sponsoring any exhibits?

A5. Yes. I am sponsoring Exhibit A-14, Schedule D5.1 through Schedule D5.19, which contains the details of my analysis and supporting tables. Specifically, I sponsor the following exhibits:

Exhibit	Schedule	Description
A-14	D5	Cost of Common 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 Sample
A-14	D5.4	Capital Structure Summary of the Electric Sample
A-14	D5.5	Estimated Growth Rates of the Electric Sample
A-14	D5.6	DCF Cost of Equity of the Electric Sample
A-14	D5.7	Overall After-Tax DCF Cost of Capital of the Electric Sample
A-14	D5.8	DCF Cost of Equity at DTE Electric's Proposed Capital Structure
A-14	D5.9	Risk-Free Rates
A-14	D5.10	Risk Positioning Cost of Equity of the Electric Sample
A-14	D5.11	Overall After-Tax Risk Positioning Cost of Capital of the Electric Sample

A-14	D5.12	Risk Positioning Cost of Equity at DTE Electric's Proposed Capital Structure
A-14	D5.13	Hamada Adjustment to Obtain Unlevered Asset Beta
A-14	D5.14	Electric Sample Average Asset Beta Relevered at DTE Electric'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	FERC Market Risk Premium
A-14	D5.18	DTE Electric and Electric Sample's Generation and Capital Expenditures
A-14	D5.19	Available Regulatory Mechanisms

Q6. Were these Exhibits and the accompanying schedules prepared by you or under your supervision?

A6. Yes, they were.

II. SUMMARY OF CONCLUSIONS

Q7. Can you summarize your primary conclusions and opinions on the appropriate allowed ROE and business risk characteristics for DTE Electric?

A7. Based on my estimation of the cost of equity for a sample of integrated electric utilities and my analysis of DTE Electric's business and financial risk relative to the electric peer group, I find that that a comparable group of integrated electric utilities have a cost of equity in the range of 10.25 percent to 11.0 percent using data as of December 31, 2023. Given DTE Electric's higher than average business risk, allowing DTE Electric an opportunity to earn a ROE of 10.5 percent is conservative on its requested equity percentage of 50 percent. My recommendation is based on the following key observations:

- The estimated range determined by each of the implemented models is as follows:

Figure 1: Summary of Electric Estimates at 50% Equity

	Electric Sample	
	Low	High
CAPM / ECAPM	10.8%	11.7%
DCF	9.4%	11.2%
Risk Premium	10.5%	10.5%

Based on these results, I find that the estimated cost of equity indicates a CAPM based ROE in the range 10.75 to 11.75 percent, a DCF-based ROE of 9.5 to 11.0 percent,[2] and a risk premium ROE of 10.5 percent.[3] Taking the average of the low and high results indicates a range of 10.2 percent to 11.1 percent and a midpoint of 10.65 percent.

Based on my analysis, I conclude as follows:

- DTE Electric has higher business risk than the comparable electric utilities because of (1) the lack of a revenue decoupling mechanism (2) the generation mix, which is relatively heavy into coal and nuclear, and (3) the higher than

[2] Looking to the single-stage DCF before any consideration of financial risk, I find an average of 10.5 percent and an average of 10.2 percent if the highest and lowest two observations are ignored.

[3] I do not believe that the lowest DCF estimate is reasonable due to the plausible need for substantial growth in the electricity sector to move towards a low carbon environment. However, the range derived from the average of the DCF, CAPM/ECAPM and risk premium models is, in my opinion, reasonable.

average need for infrastructure investments.[4] Hence the recommended ROE is conservative and a modest move towards today's indicated cost of equity.

- Treasury bond yields have increased since DTE Electric's last rate case in U-21297, so it is no surprise that the cost of equity is higher today than at the time of the U-21297 filing (February 10, 2023).[5]

Q8. How is the remainder of your testimony organized?

A8. Section III formally defines the cost of capital and explains the techniques for estimating it in the context of utility rate regulation. Section III.A discusses conditions and trends in capital markets and their impact on the cost of capital. Specifically, I focus on the development in interest rates and inflation as well as the Federal Reserve's response to inflation pressures. Section V explains my analyses and presents the results. Section VI discusses DTE Electric's business risk characteristics, unique risks facing Michigan-based electric utilities, and other company-specific circumstances relevant to my recommended allowed ROE. Finally, Section VII concludes with a summary of my recommendations.

III. COST OF CAPITAL PRINCIPLES AND APPROACH

A. RISK AND THE COST OF CAPITAL

Q9. How is the "cost of capital" defined?

A9. The cost of capital is defined as the expected rate of return in capital markets on investments of equivalent risk. Cost of capital theory illustrates the direct relationship between risk and the expected rate of return – the higher the risk, the higher the cost of capital required. This relationship is represented in the "security market risk-return line" (or "Security Market Line" for short), which is depicted in Figure 2 below.

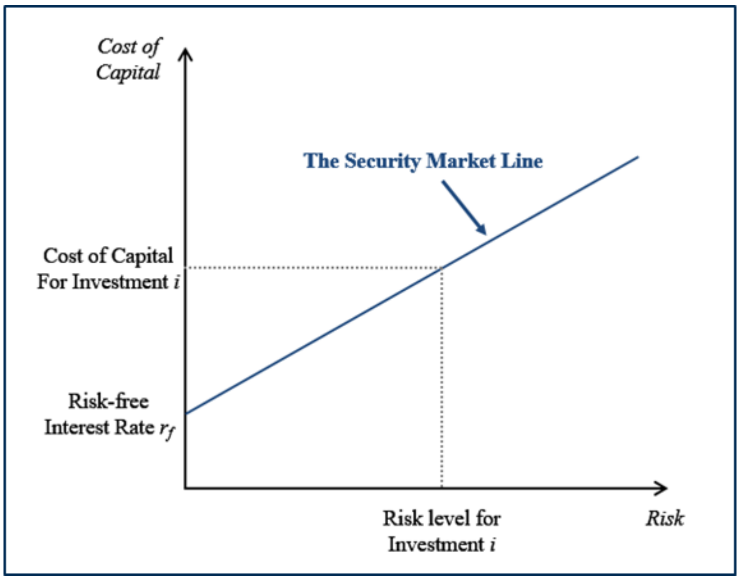
---

4 DTE Energy, "EEI Business Update," December 8, 2023, p. 18.

5 Data relied upon in the direct testimony in U-21297 would have been obtained somewhat earlier than February 10, 2023.

The cost of capital is comprised of the cost of debt and equity. Specifically, when estimating the cost of equity for a given asset or business, two categories of risk are important: (1) business risk and (2) financial risk. Business risk reflects the degree to which the cash flows generated by a business (and its assets) vary in response to moves in the broader market. Financial risk reflects the risk from the level of debt within a business.

Figure 2: The Security Market Line



Q10. What factors contribute to systematic risk for an equity investment?

A10. When estimating the cost of equity for a given asset or business venture, two categories of risk are important. The first is business risk, which is the degree to which the cash flows generated by the business (and its assets) vary in response to moves in the broader market. In context of the CAPM, business risk can be quantified in terms of an "assets beta" or "unlevered beta". For a company with an assets beta of 1, the value of its enterprise will increase (decrease) by 1% for a 1% increase (decline) in the market index.

The second category of risk relevant for an equity investment depends on how the business enterprise is financed and is called financial risk. Section III below explains how financial risk affects the systematic risk of equity.

Q11. What are the guiding standards that define a just and reasonable allowed rate of return on rate-regulated utility investments?

A11. The seminal guidance on this topic was provided by the U.S. Supreme Court in the *Hope* and *Bluefield* cases,[6] which found that:

- The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;[7]
- The return should be reasonably sufficient to assure confidence in the financial soundness of the utility; and
- The return should be adequate, under efficient and economical management for the utility to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[8]

Q12. How does the standard for just and reasonable rate of return relate to the cost of capital?

A12. The first component of the *Hope* and *Bluefield* standard, as articulated above, is directly aligned with the financial concept of the opportunity cost of capital.[9] The cost of capital is the rate of return investors can expect to earn in capital markets on alternative investments of equivalent risk.[10]

---

[6] Bluefield Water Works & Improvement Co. v. Public Service Com'n of West Virginia, 262 U.S. 679 (1923) ("Bluefield"), and Federal Power Com'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope").

[7] Hope, 320 U.S. at 603.

[8] Bluefield, 262 U.S. at 680.

[9] A formal link between the opportunity cost of capital as defined by financial economics and the proper expected rate of return for utilities was developed by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases*," Bell Journal of Economics & Management Science* 3:58-97 (1972).

[10] The opportunity cost of capital is also referred to as simply the "cost of capital," and can be equivalently described in terms of the "required return" needed to attract investment in a particular security or other

By investing in a regulated utility asset, investors are tying up some capital in that investment, thereby foregoing alternative investment opportunities. Hence, the investors are incurring an "opportunity cost" equal to the returns available on those alternative investments. The allowed return on equity needs to be at least as high as the expected return offered by alternative investments of equivalent risk or investors will choose these alternatives instead. If it is not, the utility's ability to raise capital and fund its operations will be negatively impacted. This is a fundamental concept in cost of capital proceedings for regulated utilities such as DTE Electric.

Q13. Please summarize how you considered risk when estimating the cost of capital.

A13. To evaluate comparable business risk, I looked to a proxy group of regulated electric and natural gas utilities.[11] The electric utilities I considered have a high proportion of regulated assets and revenue, with the majority of the electric utilities having more than 80% of assets subject to regulation (predominantly by state commissions). Additionally, all utilities I consider have a network of assets that are used to serve end customers and they are capital intensive (meaning that each dollar in revenue requires substantial investment in fixed assets).

B. FINANCIAL RISK AND THE COST OF EQUITY

Q14. How does financial risk affect the estimation of a fair return on equity?

A14. Regardless of the method used to calculate the cost of equity (versions of the CAPM, DCF and risk premium), an issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated company.[12] It may be tempting to simply estimate the cost of equity capital for each of the proxy companies (using one of the above approaches) and

asset (i.e., the level of expected return at which investors will find that asset at least as attractive as an alternative investment).

11 In past testimony on behalf of DTE Electric, I have included a gas LDC or water utility sample. Because of the substantial objection to the samples and because the samples have become smaller due to acquisitions or lack of data, I do not include such samples in this proceeding.

12 This is also a common valuation problem in general business contexts.

average them. After all, the companies were chosen to be comparable in their business risk characteristics, so why would an investor necessarily prefer equity in one to the other (on average)?

The problem with this argument is that it ignores the fact that underlying asset risk (*i.e.*, the risk inherent in the lines of business in which the firm invests its assets) for each company is typically divided between debt and equity holders. The firm's debt and equity are therefore financial derivatives of the underlying asset return, each offering a differently structured claim on the cash flows generated by those assets. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders.

The relative structures of debt and equity claims are such that higher degrees of debt financing increase the variability of returns on equity, *even when the variability of asset returns remains constant*. Consequently, otherwise identical firms with different capital structures will impose different levels of risk on their equity holders. Stated differently, increased leverage adds financial risk to a company's equity.[13]

If the companies in a proxy group are truly comparable in terms of the systematic risks of the underlying assets, then the **overall cost of capital of each company** should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. This is because a firm's asset value (and return) is allocated between equity and debt holders. The expected return to the underlying asset is therefore equal to the value weighted average of the expected returns to equity and debt holders – which is the overall cost of capital or the expected return on the assets of the firm as a whole.[14]

---

13 I refer to this effect in terms of financial risk because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context financial risk is distinct from and independent of the business risk associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

14 As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility.

Q15. What is the theoretical basis supporting the notion that the overall cost of capital for each company should be about the same, regardless of capital structure?

A15. The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.[15] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (*i.e.*, the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,[16] showed that while taxes and costs to financial distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,[17] the latter can still be shown to be constant across a broad range of capital structures.[18]

---

15 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.

16 Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

17 When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

18 This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

This reasoning suggests that one could compute the overall cost of capital for each of the proxy companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can then re-arrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis.[19]

Q16. What other methods do you use to account for financial risk when determining the cost of equity?

A16. An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta in the CAPM. The so-called Hamada method allows a financial analyst to adjust for differences in financial risk by first translating the equity beta obtained from market data into an asset beta (or a zero-debt beta) using the comparable companies leverage and second relever (or translating) the asset beta for the comparable companies into an equity beta for the target company using the regulated entity's capital structure. [20]

While there are several versions of the Hamada adjustment procedures as discussed in Appendix B, the need to consider leverage is ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

C. APPROACH TO ESTIMATING THE COST OF EQUITY

Q17. How do you approach your estimation of the cost of equity for DTE Electric?

A17. To analyze the cost of equity for DTE Electric, I evaluate companies of comparable business risk by choosing a proxy group of publicly traded regulated electric utilities. I use three models to analyze the cost of equity for DTE Electric: (1) the Capital Asset Pricing Model (CAPM) as well as an Empirical version thereof, the ECAPM, (2) the

---

19 Market value capital structures are used in estimating the overall cost of capital for the proxy companies.

20 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.

Discounted Cash Flow (DCF) models (single-stage and multi-stage), and (3) the Risk Premium. Due to the continual changes in financial markets, I consider two implementations of the CAPM / ECAPM – based on a historical and a forward-looking MRP to determine a fair and reasonable ROE for DTE Electric. Section V further explains my analyses and results.

Q18. How does your approach and the models you employ compare to what the Commission has considered in prior DTE Electric proceedings?

A18. The Commission has in past decisions considered the DCF, CAPM, and Risk Premium models, as do I. Additionally, the Commission has recognized that "atypical market conditions" deserve consideration when setting the ROE.[21] The Commission also stated that it will "continue to monitor a variety of market factors in future applications, including market reactions to recent events and measures of volatility and uncertainty, as well as measures of investor confidence, and the utility's risk profile."[22] It is also evident that the Commission, like I, consider "the company's unique circumstances and characteristics …" as well as "regional economic and company-specific risks."[23] Lastly, the Commission's recent decision in U-21297 acknowledged that "the cost of equity in the utility sector has generally increased over the last year …"[24] Consequently, I discuss the development in current capital market condition and the impacts they have on determining DTE Electric's cost of equity capital in Sections IV and V below.

IV. CAPITAL MARKET CONDITIONS

Q19. What do you cover in this section?

---

21 Michigan Public Service Commission Order for Case No. U-18255, April 18, 2018, p. 33.

22 Michigan Public Service Commission Order for Case No. U-20561, May 8, 2020, pp. 177.

23 *Ibid*., p. 176.

24 Michigan Public Service Commission, "Order in Case U-21297," issued December 1, 2023 ("Order in U-21297"), p. 186.

A19. In this section, I address recent changes in capital market conditions and how these factors affect the cost of equity and its estimation. Specifically, I address (i) interest rate developments; (ii) investors perception of the market risk premium; (iii) inflation expectations; (iv) volatility in the market as exemplified by the S&P 500; and (v) developments in utility stock prices.[25]

Q20. Why do you discuss capital market conditions in a testimony aimed at determining the DTE Electric's ROE?

A20. Capital market conditions are important to cost of equity estimation methodologies and can affect the inputs to the cost of equity models. Inputs to the DCF models are affected by the economy in general as economic growth will affect growth rates and utility stock prices. Consequently, the capital market developments affect the growth rates, the dividend yield, and the assessment of estimates' reasonableness.

Similarly, the risk-free rate is an input to the risk premium model and CAPM, so that recent and expected future developments in government bond yields are important to assess the validity of any measure of the risk-free rate. The MRP is also an input to the CAPM, so factors that affect the MRP (e.g., volatility and changes in investors' risk perceptions) are vital for accurate determination of the ROE. Lastly, inflation has recently been substantially above what the U.S. experienced over a very long period and the inflation is expected to be above the Federal Reserve's two percent target for a least the next two years.[26] Uncertainty about inflation expectations creates uncertainty about the cost of capital as well as other aspects of utilities' costs.[27]

Q21. Can you provide a summary of recent events that have impacted capital market conditions?

---

25 In past testimony, I have discussed utility credit spreads. Utility credit spreads are currently only modestly elevated, so I do not attempt to account for this. However, inflation expectations remain a source of substantial concern and therefore merit consideration.

26 *Blue Chip Economic Indicators*, January 2024 expects 2024 inflation to be 2.6%, so while the inflation rate has modified, it remains- above the Federal Reserve's target rate of 2%.

27 Because the cost of capital is measured in nominal terms, inflation will influence the cost of capital.

A21. Since DTE Electric's last rate case was filed in February 2023 (Order dated December 1, 2023)[28] key measures of debt cost such as Treasury yields have increased and utility bond yields and investors' perception of the risk premium they require to hold equity rather than debt has remained relatively constant. At the same time, inflation remains higher than in the recent past and inflation is expected to remain above the targeted 2 percent through at least 2025. In response, the Federal Reserve has increased the Federal Funds rate 11 times since the beginning of 2022, 3 times since February 2023, while holding the rate constant in recent months. The details are shown in Figure 3 below. Since the filing of DTE Electric's last rate case in February 2023, the Federal Funds rate has increased by 75 basis points, while the yield on BBB rated utility bonds increased during 2023 but as of now is comparable to that in late January / early February 2023.[29] The Federal Reserve's monetary policy responses are intended to achieve the Federal Reserve's goal of keeping "inflation at the rate of 2% over the longer run."[30] The January 31, 2024 meeting confirmed the Federal Reserve's position and kept the Federal Funds rate at 5.25 percent to 5.50 percent stating that "[t]he Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainable toward 2 percent."[31] Most recently, the Bureau of Labor Statistics on February 13, 2024 announced that the 12-month inflation was 3.1 percent as of January 2024,[32] above the Federal Reserve's target rate of 2.0 percent.

---

28 Order in U-21297.

29 Comparing the yield on BBB rated utility bonds as of January 31, 2024 (5.68%) to the yield in January and February 2023; 5.31% and 5.78%, respectively. Source: Bloomberg data as of February 13, 2024.

30 See, for example, Federal Reserve, Press Release, July 26, 2023, https://www.federalreserve.gov/monetarypolicy/files/monetary20230726a1.pdf

31 Federal Reserve, Press Release January 31, 2024.

32 Bureau of Labor Statistics, News Release, "CPI for all items rose 0.3% in January; shelter up," February 13, 2024.

Figure 3: Developments in the Federal Funds Rate Since 2022

FOMC Meeting	Change (bps)	Federal Funds Rate
March 17, 2022	+25	0.25% - 0.50%
May 5, 2022	+50	0.75% - 1.00%
June 16, 2022	+75	1.50% - 1.75%
July 28, 2022	+75	2.25% - 2.50%
September 22, 2022	+75	3.00% - 3.25%
November 2, 2022	+75	3.75% - 4.00%
December 14, 2022	+50	4.25% - 4.50%
February 1, 2023	+25	4.50% - 4.75%
March 22, 2023	+25	4.75% - 5.00%
May 3, 2023	+25	5.00% - 5.25%
June 14, 2023	+0	5.00% - 5.25%
July 26, 2023	+25	5.25% - 5.50%
September 20, 2023	+0	5.25% - 5.50%
November 1, 2023	+0	5.25% - 5.50%
December 13, 2023	+0	5.25% - 5.50%
January 31, 2024	+0	5.25% - 5.50%

Lastly, the risk of the electric utility industry as measured by, for example, the systematic risk (beta) has remained constant.[33] Thus, capital markets' data as well as utility specific risk characteristics indicate that the cost of equity is higher today than in the recent past.

A. Interest Rates

Q22. How do interest rates affect the cost of equity?

A22. The current interest rate environment affects the cost of equity estimation in several ways. Most directly, the CAPM takes as one of its inputs a measure of the risk-free rate (see Figure 2). All else equal, the estimated cost of equity using the CAPM increases (decreases) by one percentage point when the risk-free rate increases (decreases) by

33 In U-21297, I found an average beta of 0.88 for my electric sample (Villadsen Direct in U-21297, Figure 7, p. 33). I now find a slightly higher beta, 0.93 (Figure 7 below).

one percentage point. Therefore, to the extent that prevailing government yields are affected by monetary policy, and rising geopolitical tensions, using current yields as the risk-free rate would affect the CAPM estimate in a manner that may not reflect the forward-looking cost of equity. Therefore, the allowed fair return on equity for DTE Electric should reflect the future interest rate environment, specifically the environment at the time the rates being set in this proceeding will be in effect.

Q23. What are the relevant developments regarding interest rates?

A23. Yields on 20-year U.S. Treasury Bonds were 3.95% at the time DTEE's filed its last rate case in February 2023.[34] Since then the yield on 20-year Treasury bonds has increased to approximately 4.32% at the end of 2023 for an increase of about 40 basis point.[35] Looking forward, professional forecasters as well as government agencies expect Treasury bond yields to remain relatively constant in the near-term and then decrease slightly over the next couple of years. However, they expect the yields to remain well above the low levels of the recent past. Blue Chip Economic Indicators (BCEI) as of January 2024 forecast the yield on 10-year Treasury bonds at 3.9% for 2024 and 3.7% 2025 for an average of 3.8% over the next two years.[36] The 2024 forecast increased to 4.0% in February 2024.[37] The 2024 and 2025 BCEI forecasts are 40 to 60 basis points below the current 10-year Treasury bond yield (4.3%) indicating interest rate forecasts are currently lagging actual interest rates. Similarly, Congressional Budget Office's December 2023 economic forecasts expects the 2024

---

34 Exhibit D5.9.

35 Ibid.

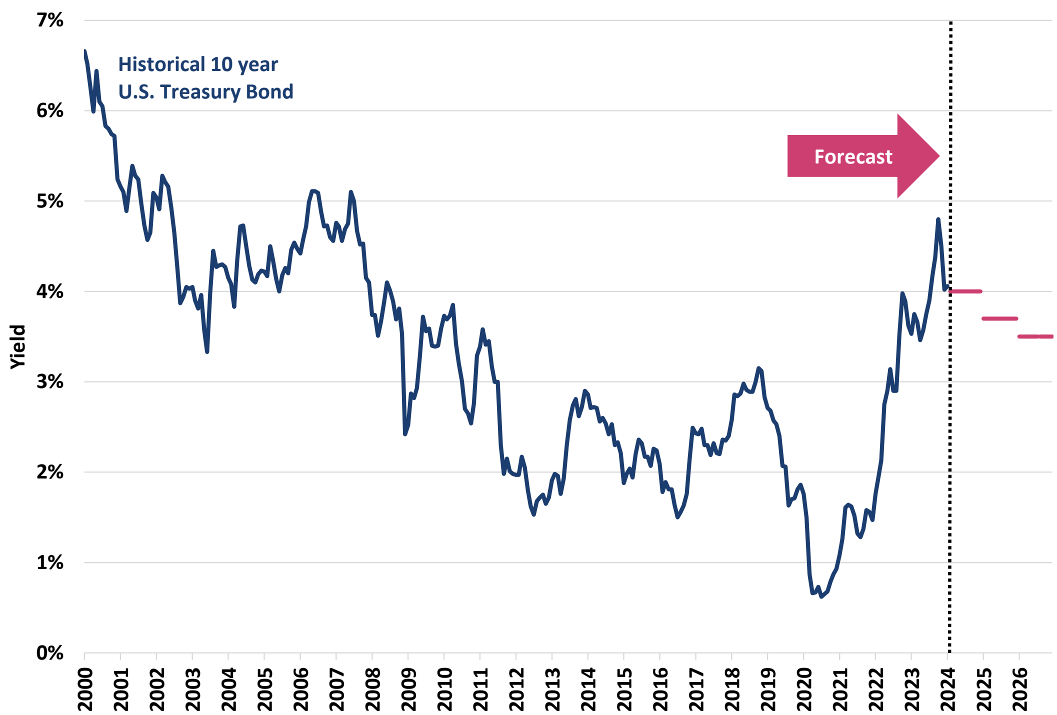
36 *Wolters Kluwer, Blue Chip Economic Indicators*, Vol. 49, No. 1, January 10, 2024, pp. 2-3.

37 *Wolters Kluwer, Blue Chip Economic Indicators*, Vol. 49, No. 2, February 9, 2024, pp. 2-3

10-year yield to be 4.8 percent.[38] Further, the materials released after the December 2023 FOMC meeting indicate that the Federal Funds rate will be 4.6% in 2024.[39]

Figure 4 below shows the development in the 10-year Treasury bond yield as well as the forecast for the 10-year yield. Notably, the current yield as well as the forecasted yield is higher than in the recent past.

Figure 4: Historical and Projected 10-year Treasury Bond Yields[40]



Lastly, I note that while the yield on Baa rated corporate bonds is expected to remain above 6.0 percent during 2024. This yield averaged 5.6 percent in February 2023,

38 The Congressional Budget Office expects the 10-year Treasury yield at 4.8 percent in Q4, 2024 (51135-2023-12-Economic-Projections.xlsx (live.com)). Other forecasts indicates a 20-year Treasury bond yield of 4.55 percent for June 2024 by World Government Bonds (United States 20 Years Bond - Forecast (worldgovernmentbonds.com);

39 Federal Reserve, "Summary of Economic Projections," December 13, 2023, p. 2, Summary of Economic Projections, December 13, 2023 (federalreserve.gov)

40 Bloomberg as of January 16, 2024 and *Blue Chip Economic Indicators*, January 10, 2024.

increased through most of 2023 and then declined to 5.6% again in December 2024.[41] Thus, indications are that the corporate bond yield will remain high through 2024.

B. Yield Spreads

Q24. Why are bond yield spreads relevant to a cost of equity analysis?

A24. Bond yield spreads (also called credit spreads) reflect the premium that investors demand to hold debt securities (specifically corporate or utility bonds) that are not risk free. Analogously, the MRP—which is a key input to the CAPM—represents the risk premium that investors require to hold a market portfolio of equities rather than risk-free government bonds.

If bond yields are influenced by some of the same underlying market forces that drive the systematic risk premium for equities, shifts in directly observable credit spreads can assist with inference about changes in the MRP, which itself must be estimated.[42] More specifically, if both credit spreads and equity premiums are determined in part of the general premium required by investors for bearing systematic risk, then an increase in credit spreads may indicate an increase in the forward-looking MRP.

Q25. How does the current spread between utility and U.S. Government bond yields compare to historic spreads?

A25. At present (January 2024), the spread between 20-year BBB-rated utility bond yields and 20-year U.S. government bond yields is 1.29%.[43] This compares to a long-term historic average spread of 1.23% prior to the financial crisis and 1.54% for the period

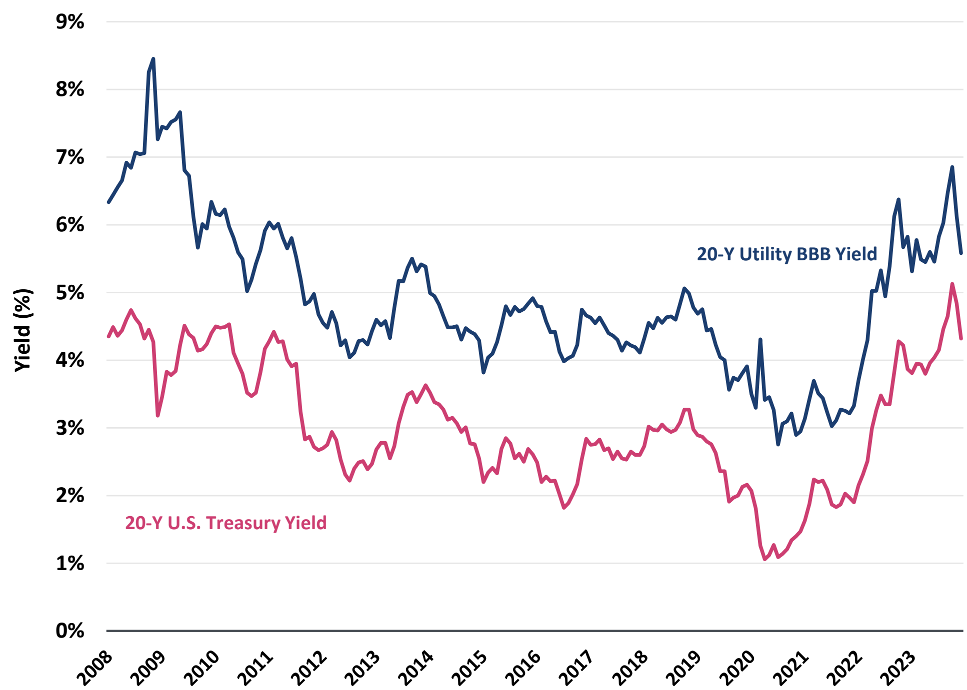
41 Sources: Federal Reserve, FRED, Moody's Seasoned Baa Corporate Bond Yield, Percent, Monthly, Not Seasonally Adjusted and Blue Chip Financial Forecasts, December 28, 2023. I refer to the corporate yield as I do not know of sources that forecast the utility bond yield.

42 This is the same issue as in cost of capital estimation more generally: the cost of debt can often be directly observed in the form of market bond yields, whereas the cost of equity must be estimated based on financial models.

43 Bloomberg as of February 13, 2024. The data for December 2023 are similar.

1990 through 2023,[44] so currently the spread is comparable the long-run average. Importantly, the current (December 2023) yield on utility bonds remains higher than at any time since 2013.

Figure 5: Yield on BBB-rated Utility Bonds and 20-Year Treasury Bonds[45]



\

C. Risk Premiums

Q26. How do risk premiums affect the cost of equity?

A26. Risk premiums provide an indication of the compensation investors expect to hold securities that are not risk-free. If an investor demands a larger risk premium, then the cost of equity will be larger. There are several indicators of risk premiums in addition to the yield spreads discussed above. For example, indicators such as stock market volatility (e.g., VIX) provide insights into the risk premium required by investors in the

---

44 *Ibid.,* Average for prior to the financial crisis is for the period April 1991 to 2007.

45 Bloomberg as of January 16, 2024.

coming 30 days. SKEW provides a useful indicator of volatility over the next 12 months. Whereas the MRP measures the compensation required to hold a security over a long investment horizon, such as the period when rates set in this proceeding will be in effect. For this reason, the forecast MRP needs to be taken into consideration when determining the cost of equity in this proceeding.

Q27. What is the current evidence regarding market volatility and investors' risk perception?

A27. Measures of market volatility are slightly below long-term averages. For example, VIX is currently around 15 but was higher at about 22 at the end of October 2023 – these figures are a bit below the long-run average of about 19.5.[46] However, the SKEW index, which measures the market's willingness to pay for protection against negative "black swan" stock market events (i.e., sudden substantial downturns),[47] shows that investors remain cautious. A SKEW value of 100 indicates outlier returns are unlikely, but as the SKEW increases, the probability of outlier returns becomes more significant. The SKEW index is currently 148.[48] While the VIX shows close to historical volatility going forward, the SKEW indicates investors are cautious.

During the last several month, investors have seen several bank failures,[49] the on-going wars in Ukraine and Israel, and the unprecedented mix of monetary tightening (e.g., the raises to interest rates described above) and fiscal stimulus (e.g., the Inflation Reduction Act of 2022[50]). Consequently, the evidence regarding investors' risk perception is mixed.

Q28. What is the Market Risk Premium?

46 Cboe, VIX, accessed January 17, 2024, https://www.cboe.com/tradable_products/vix/

47 Cboe, SKEW, accessed January 17, 2024, https://www.cboe.com/us/indices/dashboard/skew/

48 *Ibid*.

49 First Public Bank, Silicon Valley Bank, and Signature Bank collapsed in 2023.

50 Inflation Reduction Act, H.R. 5376, https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf

A28. In general, a risk premium is the amount of "excess" return—above the risk-free rate of return—that investors require to compensate them for taking on risk. As illustrated in Figure 2 above, the riskier the investment, the larger the risk premium investors will require.

The market risk premium ("MRP") is the risk premium associated with investing in the market as a whole. Since the so-called "market portfolio" embodies the maximum possible degree of diversification for investors,[51] the MRP is a highly relevant benchmark indicating the level of risk compensation demanded by capital market participants. It is also a direct input necessary to estimating the cost of equity using the CAPM and other risk-positioning models.

Q29. Please explain the current evidence on the MRP.

A29. As of 2023, the historic MRP has declined slightly relative to the last few years due primarily to higher returns on government bonds. Specifically, for the period 1926 through 2022, the average historic MRP was 7.17%.[52] At the same time, the forecast MRP from Bloomberg was 6.37%, relative to a 20-year Treasury bond, as of December 29, 2023.[53] Using the FERC methodology, the forecasted MRP was 7.69% over the 20-year Treasury bond yield using IBES growth rates and 7.71% using Value Line growth rates.[54]

D. Inflation Expectations and Impact

Q30. Why is inflation relevant to estimating the cost of equity for DTE Electric?

---

51 In finance theory, the "market portfolio" describes a value-weighted combination of all risky investment assets (e.g., stocks, bonds, real estate) that can be purchased in markets. In practice, academics and financial analysts nearly always use a broad-based stock market index, such as the S&P 500, to represent the overall market.

52 Kroll, U.S. Cost of Capital Navigator, January 2024.

53 Bloomberg data as of January 16, 2024.

54 Exhibit D5.17, estimated as of December 31, 2023.

A30. The return on equity that is being determined is expected to be in effect for a period time going forward and the ROE is measured in nominal terms—meaning that it includes the expected inflation. The Federal Reserve forecasts that inflation will be elevated through at least 2025,[55] while the BCEI expect inflation to be elevated through at least 2024.[56] Thus, for at least the next year inflation is expected to be above the Federal Reserve's target level of 2% on average.

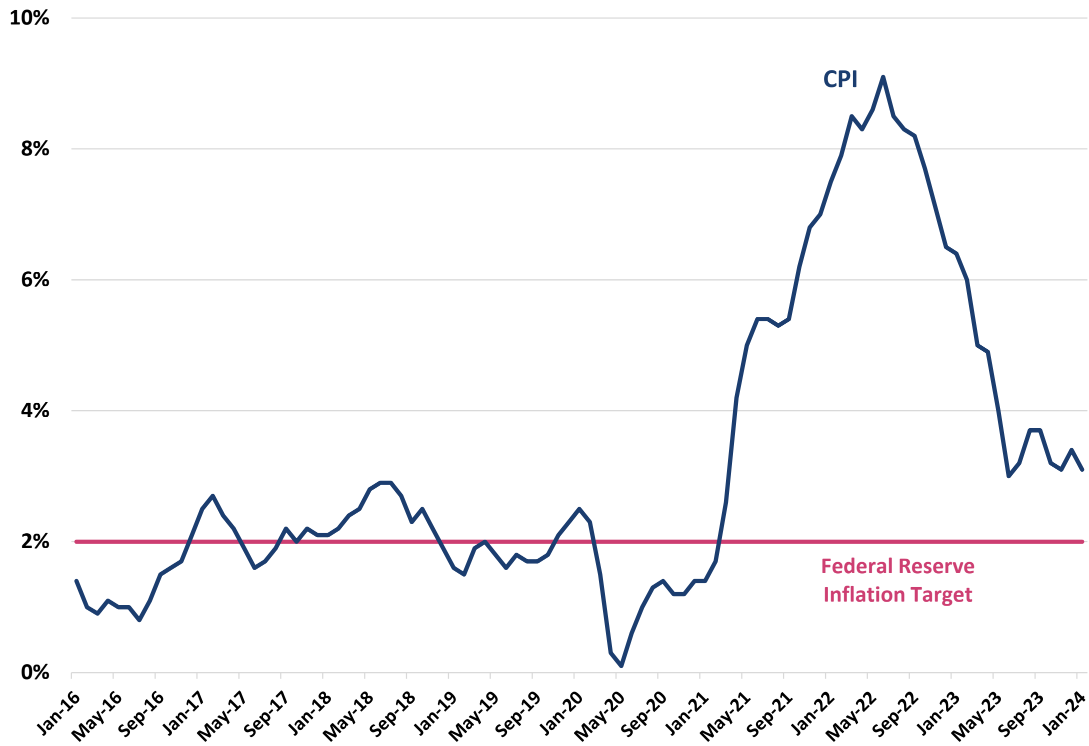
Q31. What are the recent indicators of inflation for the U.S. economy?

A31. Inflation, as measured by CPI, reached a recent high of 9.1% in June 2022. Since then, inflation has decreased to between 3.1% and 6.4% in 2023 with the most recent data for December 2023 and January 2024 being 3.4% and 3.1%, respectively (see Figure 6 below). Thus, while the inflation rate has come down it remains well above the Federal Reserve's target of 2.0% on average.

55 Federal Reserve, "Summary of Economic Projections," September 20, 2023, p. 2. This view was affirmed in the FOMC's December 2023 Summary of Economic Projections.

56 *Blue Chip Economic Indicators*, February 9, 2024, pp. 2-3. The January 2024 issue had the same inflation expectations.

Figure 6: Inflation as Measured by the Consumer Price Index[57]



Looking forward, recent surveys by economists, such as the *BCEI* survey, indicate that U.S. inflation will be 2.6% in 2024 and 2.2% in 2025.[58]

Q32. Are there other factors that may impact the financial conditions for utilities such as DTE Electric?

A32. Yes. The evolving situation in the Middle East has the potential to substantially impact economic policy, world markets and especially energy markets.[59] The unrest may cause investors to change their risk tolerance and hence the return they require to invest in

57 Bureau of Labor Statistics.

58 *Blue Chip Economic Indicators,* February 2024 pp. 2-3.

59 I acknowledge there are many non-economic aspects to this conflict but discuss only the factors that may impact the cost of equity for utilities in the US.

assets that are not risk-free. Because the Middle East is a large supplier of energy, it could impact inflation and financial markets more broadly.

Q33. Please summarize how economic developments discussed above have affected the return on equity and debt that investors require.

A33. Utilities rely on investors in capital markets to provide funding to support their capital expenditure programs and efficient business operations. Investors consider the risk-return tradeoff in choosing how to allocate their capital among different investment opportunities. It is therefore important to consider how investors view the current economic conditions, including the plausible development in the risk-free rate, inflation, and other key indicators.

These investors have been affected by the development in interest rate and inflation that remains above the Federal Reserve's target, so there are reasons to believe that their return expectations reflect the increase in interest rates and higher than usual inflation.

V. ESTIMATING THE COST OF EQUITY

A. Approach to Cost of Equity Estimation

Q34. Can you explain your approach to estimating the cost of equity for DTE Electric?

A34. As discussed in Section IV, the financial and economic conditions are impacted by a variety of factors; including rising interest rates and high inflation.

In the remainder of Section V, I present the inputs, assumptions, and results from my cost of equity estimation methods.

B. Proxy Group Selection

Q35. How do you identify sample companies of comparable business risk to DTE Electric?

A35. DTE Electric is a regulated electric utility. The business risk associated with these business activities depend on several factors, including the specific characteristics of the service territory and regulatory environment in which the utility operates. Consequently, it is not possible to identify publicly traded companies that replicate every aspect of DTE Electric's business risk profile. However, an appropriate starting pointing to create proxy groups of comparable business risk to DTE Electric is to select other companies whose primary business operations are concentrated in regulated industries or companies that have similar lines of business and/or business environments. As a second step, I must evaluate DTE Electric or Michigan-specific risks to ensure that the Company's ROE is appropriately placed relative to the proxy samples.

To that end, I have selected a proxy group composed of regulated utility companies that focus on (i) the provision of electricity to end-users ("Electric Utility Proxy Group").[60] This proxy group is similar to DTE Electric in that they are rate regulated by state utility commissions, serve customers through a network of assets, and rely on substantial capital to provide service—that is, they are capital intensive like DTE Electric.

It is important that the proxy groups used to assess the cost of equity for DTE Electric (absent any unique Michigan or Company specific characteristics) are comprised of regulated entities, because regulation tends to place substantial requirements and protections on the companies. I also believe the physical characteristics of the industry—*e.g.*, network, capital intensive, serving many different customers—are characteristics of DTE Electric and of other highly regulated utilities. The network characteristic implies that assets cannot readily be employed in a different capacity; the capital intensive characteristic affects the operating risks through the split between fixed and variable costs; and the customer composition affects the demand risk.

---

60 To reduce the number of disagreements with Staff, I have eliminated the natural gas distribution utilities.

Q36. How do you identify suitable utilities for inclusion in your proxy groups?

A36. First, I start with the universe of publicly traded electric utilities reported by Value Line Investment Analyzer ("Value Line"). It is necessary to focus on publicly traded companies because non-traded entities do not have the necessary stock price data to utilize the financial models relied upon to estimate the cost of equity. Second, I narrow down this universe of electric, utilities identified by Value Line using the following screening criteria:

- Must be an investment grade utility,
- Must have a market capitalization greater than $300 million (to avoid micro caps),
- Must pay dividends with no dividend cuts for three years,
- Cannot have engaged in substantial merger, acquisition, or divesture activity for three years,

and

- Must have sufficient data for estimation.

Third, I review business descriptions and financial reports of these companies and eliminate those that have less than 50% of their assets dedicated to regulated utility activities. Within this group of companies, I apply further screening criteria to eliminate companies with recent significant events (*i.e.*, litigation) that could affect the market data necessary to perform cost of capital estimation.

To the degree that a subset or subsets of these utilities have risk characteristics that match those of DTE Electric to a larger degree, subset(s) will be created and analyzed.

Q37. What are the results of your sample selection process?

A37. The selection process produced a proxy group of 25 integrated, regulated electric utilities of which one (Exelon) lacks a beta from Value Line.[61]

Q38. What are the characteristics of your Electric Utility Proxy Group?

61 Relative to my direct testimony in U-21297, I eliminate Dominion Energy due to its large divesture.

A38. The Electric Utility Proxy group is comprised of electric utilities, whose primary source of revenues and the majority of its assets are subject to regulation. The final proxy group consists of 25 electric utilities listed in Figure 7 below.[62] These companies own regulated electric utility subsidiaries and are classified by EEI as either "regulated" (having at least 80% of their assets dedicated to regulated utility operations) or "mostly regulated" having less than 80% regulated assets.[63] (These EEI categories are designated with an "R" or "M" in the Figure below). Therefore, the Electric Utility Proxy Group is broadly representative of the regulated electric industry from a business risk perspective.

The market capitalization, betas, and growth estimates for both cost of equity estimation dates are presented side-by-side. The annual revenue as well as the market capitalization was obtained from Bloomberg. The credit rating is reported by Bloomberg. The growth rate estimate is a weighted average between estimates from Thomas Reuters and *Value Line*. The betas were obtained from *Value Line* as of December 31, 2023. The categorization was based on the companies' most recent 10-K.

62 Relative to my testimony for DTE Electric in U-21297, I have eliminated Dominion Energy as Dominion sold substantial gas distribution assets to Enbridge Inc. in September 2023.

63 Edison Electric Institute (EEI), Financial Report, 2022. As of February 13, 2024, the 2023 data were not available. Note: I eliminate any companies with less than 50% of regulated assets. See Appendix B for further detail.

Figure 7: Electric Utility Sample

Company	Annual Revenue (Q4 2023) ($MM) [1]	Regulated Assets [2]	Market Cap. (Q4 2023) ($MM) [3]	Value Line Beta [4]	S&P Credit Rating [5]	Long-Term Growth Estimate [6]
ALLETE	$1,856	MR	$3,509	0.95	BBB	5.8%
Alliant Energy	$4,143	R	$13,077	0.90	A-	6.9%
Amer. Elec. Power	$19,747	R	$42,680	0.80	A-	5.2%
Ameren Corp.	$7,942	R	$19,455	0.90	BBB+	5.6%
Avista Corp.	$1,614	R	$2,744	0.95	BBB	5.9%
Black Hills	$2,147	R	$3,700	1.00	BBB+	4.7%
CMS Energy Corp.	$7,185	R	$16,914	0.85	BBB+	6.9%
CenterPoint Energy	$8,374	R	$18,194	1.15	BBB+	5.0%
Duke Energy	$29,842	R	$74,426	0.90	BBB+	6.4%
Edison Int'l	$17,334	R	$26,793	1.00	BBB	5.1%
Entergy Corp.	$13,018	R	$21,439	0.95	BBB+	0.9%
Evergy Inc.	$5,990	R	$11,915	0.95	BBB+	5.1%
Exelon Corp.	$22,341	R	$36,500	n/a	BBB+	9.0%
IDACORP Inc.	$1,865	R	$4,978	0.85	BBB	4.3%
MGE Energy	$686	R	$2,620	0.75	AA-	4.5%
NextEra Energy	$28,409	MR	$124,492	1.00	A-	8.2%
NorthWestern Corp.	$1,387	R	$3,151	0.95	BBB	4.2%
OGE Energy	$3,053	R	$7,074	1.05	BBB+	11.3%
Otter Tail Corp.	$1,393	R	$3,428	0.95	BBB	-13.1%
Pinnacle West Capital	$5,342	R	$8,270	0.95	BBB+	6.6%
Public Serv. Enterprise	$11,088	R	$30,750	0.95	BBB+	5.4%
Sempra Energy	$16,563	R	$23,414	1.00	BBB+	7.5%
Southern Co.	$26,188	R	$77,031	0.95	BBB+	7.9%
WEC Energy Group	$8,633	R	$26,358	0.85	A-	5.8%
Xcel Energy Inc.	$14,426	R	$34,132	0.85	A-	6.2%
Electric Sample	**$10,423**	**R**	**$25,482**	**0.93**	**BBB+**	**5.3%**

Q39. How does the proxy group compare to DTE Electric in terms of financial metrics?

A39. DTE Electric's regulated electric operations generated an annual revenue of 6,397 MM in 2022,[64] which is lower than the average annual revenues for the Electric Utility proxy groups. DTE Electric's S&P senior unsecured credit rating is BBB, which is similar to the Electric Utility proxy group average. DTE Electric is a regulated entity as are all of my proxy companies. The proxy groups, like DTE Electric, operate a capital-intensive network of assets, which are subject to state regulation. I discuss below further the similarities and differences between DTE and the proxy group focusing on the

64 DTE 2022 10-K, p. 32.

composition of generation, capital needs, and the availability of regulatory mechanisms.

C. Financial Risk Adjustment

Q40. Can you explain the difference between the data relied upon to estimate the cost of equity and the regulatory rate base to which the cost of equity is applied?

A40. Both the CAPM and the DCF models rely on market data to estimate the cost of equity for the sample companies, so the results reflect the value of the capital that investors hold during the estimation period (market values). The allowed return on equity is applied to rate base, which is determined using historical cost and hence reflect the (net) book values of assets.

Q41. Why is this difference important to the estimation of the cost of equity?

A41. Taking the level of financial risk or leverage into account is necessary to reflect the fact that different capital structure ratios have different levels of financial risk. Specifically, all else equal, higher levels of debt financing increases the risk faced by equity investors. Therefore, investors require higher ROEs from companies with more debt than from comparable business risk companies with less debt. To reflect the effect of capital structure on the cost of equity, I adjust the cost of equity estimates I obtain from applying the models to the market data of the proxy companies. I do so using two different approaches: (1) the overall cost of capital approach and (2) the Hamada approach. I provide further details of these two approaches in Appendix B.[65]

65 In recognition of the Commission's past decision to not rely on the overall cost of capital approach, my CAPM / ECAPM recommended range is based on the Hamada approach. This approach cannot be applied to the DCF model.

D. CAPM/ ECAPM Approach and Cost of equity Estimates

1. CAPM Approach

Q42. Can you briefly explain the CAPM?

A42. The CAPM is a "risk-positioning model" that models the direct relationship between risk and return illustrated in the Security Market Line (see Figure 2 above). More precisely, the CAPM states that the cost of capital for an investment, S (*e.g.*, a particular common stock), is determined by the risk-free rate plus the stock's systematic risk multiplied by the market risk premium (MRP). Mathematically, the relationship is shown by the following formula:

Formula 1

$$\boldsymbol{r_s = r_f + \beta_s \times MRP}$$

where $\boldsymbol{r_S}$ is the cost of capital for investment S;

$\boldsymbol{r_f}$ is the risk-free interest rate;
$\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and
$\boldsymbol{MRP}$ is the market equity risk premium.

2. ECAPM Approach

Q43. Can you briefly explain the ECAPM?

A43. Another risk-positioning model is the Empirical CAPM (ECAPM), which builds upon the CAPM. Empirical research has found 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. The ECAPM corrects for this by adjusting the CAPM using the formula below:

Formula 2

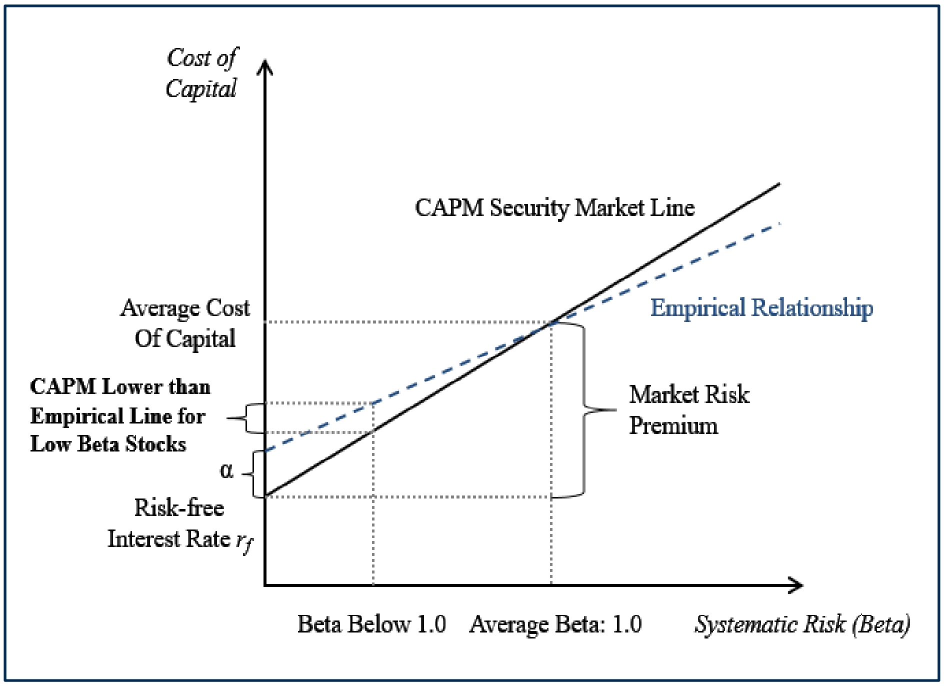
$$\boldsymbol{r_S = r_f + \alpha + \beta_S \times (MRP - \alpha)}$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant; and

$\boldsymbol{r_S}$, $\boldsymbol{r_f}$, $\boldsymbol{\beta_S}$, and $\boldsymbol{MRP}$ are defined in Formula 1 above.

The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 8, which results in a Security Market Line that more closely matches the results of empirical tests. The impact on the Security Market Line is illustrated in Figure 8 below. In the ECAPM implementation, I use an alpha of 1.5 based on academic research documenting the magnitude of alpha.[66]

Figure 8
The Empirical Security Market Line



3. CAPM/ ECAPM Cost of Equity Estimates

Q44. Can you summarize the parameters of the scenarios you considered when conducting your CAPM and ECAPM analyses?

66 See Black, Fisher. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18; Black, Fisher, Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests. *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, pp. 79-121. New York: Praeger; Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): pp. 607-636; Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): pp. 427-465; Fama, Eugene F. and Kenneth R. French. 2004. The Capital Asset Pricing Model: Theory and Evidence. *Journal of Economic Perspectives* 18 (3): pp. 25-46.

A44. I performed each CAPM/ ECAPM analysis using two scenarios to obtain a range of cost of equity estimates. Specifically, I rely on a forecasted risk-free rate and (i) a historical MRP or (ii) a forecasted MRP.

In Scenario I, I use the average forecasted risk-free rate for 2024-2025, which I determined as the 10-year forecast by Blue Chip Economic Indicators plus 50 basis points, which is the average maturity premium of a 20-year government bond yield over the 10-year government bond yield.[67] This gives me a risk-free rate of 4.30 percent, which is comparable to the December 2023 yield of approximately 4.32 percent.[68] In Scenario I, I combine this risk-free rate with the historical average MRP as provided by Duff & Phelps.[69] In Scenario II, I use Bloomberg's forecasted MRP (over the 20-year Treasury bond yield) for a MRP of 6.37 percent.[70]

Figure 9
Scenarios in CAPM/ ECAPM Analysis

	Scenario 1	Scenario 2
Risk-Free Interest Rate	4.30%	4.30%
Market Risk Premium	7.17%	6.37%

I note that relative to the time of DTEE's filing in U-21297, the forecasted risk-free rate and the actual risk-free rate have increased as has the forecasted MRP, while the historical MRP has declined very modestly.

67 *Blue Chip Economic Indicators*, January 10, 2024. I use the 20-year government bond yield because the historical MRP is calculated over an approximately 20-year government bond yield. The February 2024 issue of Blue Chip Economic Indicators show a slightly higher forecast for the 2024 risk-free rate at 4.0 percent as compared to the 3.9 percent in January 2024.

68 Bloomberg as of December 31, 2023.

69 The MRP of 7.17% is sourced from Duff & Phelps, Cost of Capital Navigator.

70 Bloomberg as of December 31, 2023. Bloomberg calculates the MRP over the 10-year government bond yield as 6.87%. I subtract 50 basis points as that is my estimate of the average maturity premium of the 20-year government bond over the 10-year government bond.

Q45. Can you summarize the results from your CAPM and ECAPM analyses?

A45. The results from the CAPM and ECAPM models are presented in Figure 10 below.

Figure 10: CAPM/ ECAPM Cost of Equity Estimates
Electric Sample

Estimated Return on Equity	**Scenario 1** [1]	**Scenario 2** [2]
Electric Sample		
Hamada Adjustment Without Taxes		
CAPM	11.7%	10.9%
ECAPM (α = 1.5%)	11.7%	10.8%
Hamada Adjustment With Taxes		
CAPM	11.7%	10.9%
ECAPM (α = 1.5%)	11.7%	10.9%

Q46. How do you interpret the result of your CAPM and ECAPM analyses?

A46. First, there is very little difference between the CAPM and ECAPM results at this point in time. Second, the Electric Utility Sample's results are consistent with a cost of equity in the range of 10.75 percent to 11.75 percent (rounding to the nearest ¼ percent).[71] Relative to the results reported in the U-21297 matter, the range is narrower and the lower bound has increased.[72]

E. DCF Approach and Cost of Equity Estimates

Q47. Can you describe the discounted cash flow approach to estimating the cost of equity?

71 I note that I do not report the results from the financial risk adjustment method for the CAPM method and ignore them in my recommendation as the Commission in the past has been critical of the approach.

72 I note that prior to applying the Hamada method, the average ROE from the CAPM model is 11.0 percent using the historical average MRP and 10.2 percent using the forecasted MRP for an average of 10.6 percent.

A47. The DCF model estimates the cost of capital for a given company directly, rather than based on its risk relative to the market as the CAPM does. There are two variations of the DCF model, the single-stage DCF and multi-stage DCF, as explained below.

1. Single-Stage DCF Approach

Q48. Can you please briefly describe the single-stage DCF and the inputs used to determine the cost of equity?

A48. Yes. The single-stage DCF model assumes that the current market price of a stock is equal to the present value of the dividends that its owners expect to receive. The expected stream of future dividends is discounted at a risk-appropriate rate to arrive at the present value of the dividends, represented by the current stock price. In this application of the DCF, the risk-appropriate rate is the cost of equity. Mathematically, the DCF model is shown in the formula below:

Formula 3

$$\boldsymbol{P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T}}$$

where $\boldsymbol{P_0}$ is the current market price of the stock;

$\boldsymbol{D_t}$ is the dividend expected at the end of period $\boldsymbol{t}$;

$\boldsymbol{T}$ is the last period in which a dividend is to be received; and

$\boldsymbol{r}$ is the cost of equity capital.

Formula 3 implies that if one knows the current market price of a stock and its expected stream of future dividends, then it is possible to solve for the cost of equity r. The single-stage DCF model assumes that the stream of future dividends will grow at a constant rate into perpetuity. This assumption allows Formula 3 to be algebraically rearranged into the formula below to directly estimate the cost of equity:

Formula 4

$$\boldsymbol{r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1+g) + g}$$

where $\boldsymbol{D_0}$ is the current dividend; and

g is the constant growth rate of the current dividend.

Another variation of the DCF model relaxes the restrictive constant growth rate assumption and instead, allows the dividend to grow at different rates at different points in time. This variation is known as the multi-stage DCF model and is further explained below.

2. Multi-Stage DCF Approach

Q49. Can you briefly describe the multi-stage DCF and the inputs used to determine the cost of equity?

A49. The multi-stage DCF accommodates different dividend growth rates at different points in time. Specifically, in the implementation of the multi-stage DCF, I assume three different growth rate phases. In the first phase, companies grow their dividend for five years at the forecasted company-specific rate of earnings growth. In the second phase, the company-specific growth rate incrementally steps down (or steps up) to the overall growth rate of the economy, represented by the long-term GDP growth rate. Finally, in the third phase, companies grow their dividend at the long-term GDP growth rate into perpetuity.

I calculate both the single- and multi-stage DCF using growth rates from *Value Line* and *IBES* as well as GDP forecasts from Blue Chip Economic Indicators in the case of the multi-stage DCF. The growth rates utilized in the DCF implementations are shown in Figure 7 above.

3. DCF Cost of Equity Estimates

Q50. What are the results from your DCF based cost of equity estimates for your samples?

A50. The financial risk adjusted single- and multi-stage DCF cost of equity estimates are presented in Figure 11 below.

Figure 11: DCF Cost of Equity Estimate

	Simple	Multi-stage
Electric Sample	11.2%	9.4%

In addition to the results above, I note that the average of the simple DCF calculations before any financial risk considerations is 10.5 percent.[73]

Q51. How do you interpret the results from your DCF analyses?

A51. The range of estimates obtained from the DCF methods range from 9.4 percent to 11.2 percent (9.5% to 11.25% rounding to the nearest ¼ percent). Relative to the results I obtained in my direct testimony for U-21297 both the lower and upper bound has increased by 0.50 percent. I view the multi-stage results as unrepresentative because they (1) are out of line with other results (2) may fail to capture the substantial growth needed in the electric sector to accomplish the transition to low-carbon economy, which may require a higher growth for a prolonged period of time. I also consider the very high end unrepresentative. Consequently, I consider the narrower range of 10.0 to 11.0 percent for the Electric Sample and note the results from the simple DCF without adjustments fall at the middle of that range.

F. Risk Premium Approach and Cost of Equity Estimate

Q52. Can you briefly describe the Risk Premium approach to estimating the cost of equity?

A52. The Risk Premium approach adds a "risk premium" to the current risk-free rate to estimate the current cost of equity, as shown in Formula 5 below.

73 Schedule D5.6, Panel A. The calculation ignores results below the yield on BBB rated debt.

Formula 5

$$Cost\ of\ Equity = r_f + Risk\ Premium$$

The risk premium component of Formula 5 is estimated using the allowed ROEs and prevailing risk-free rates from past utility rate cases. In our implementation, I calculate the risk premium as the difference between allowed ROEs and the prevailing quarterly 20-year Treasury bond yield over the period 1990-Q4, 2023.[74] This difference represents the compensation for risk allowed by regulators. I use the statistical technique of ordinary least squares (OLS) regression to estimate the parameters of the linear equation:

Formula 6

$$Risk\ Premium = A_0 + A_1 \times (r_f)$$

where A_0 and A_1 are parameters to be estimated by the regression technique; and

r_f is the risk-free rate as measured by the 20-year Treasury bond yield.

Q53. How are the parameters to the Risk Premium approach estimated?

A53. The parameters estimated by regression analysis (*i.e.*, OLS) are shown in Figure 12 below. Additionally, the regression analysis finds that the risk-free rate has a high degree of statistical explanatory power in capturing changes in the risk premium. The negative coefficient A_1 reflects the empirical fact that regulators grant lower risk premiums–and by extension, lower allowed ROEs–when the risk-free rate is higher. This is consistent with the observation that investors require a higher risk premium to hold equities over government bonds as bond yields decline. I then use the parameters from the regression analysis, A_0 and A_1, to estimate the cost of equity using the risk-free rate of 4.30 percent. As the prevailing risk-free rate of 4.32 percent is virtually similar, I do not report results from using that figure.

74 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.

Q54. Can you describe the results from your Risk Premium model?

A54. Applying the calculated risk premium and a risk-free rate of 4.30% to Formula 5 above results in an estimated cost of equity of 10.5% for electric utilities. These results are depicted in Figure 12 below.

Figure 12: Implied Risk Premium Model Estimate: Electric Utilities

	R Squared [1]	Estimate of Intercept (A0) [2]	Estimate of Slope (A1) [3]	Implied Cost of Equity Range [4]
Electric Utility	85.6%	8.6%	-56.3%	10.5%

Q55. How do you interpret the results from your Risk Premium model?

A55. Based on the Risk Premium model using the forecasted interest rate indications, an average ROE for the average electric utility is 10.5 percent. This range is consistent with the estimates obtained from the CAPM and the DCF model for the Electric Utility Sample. I note that the R-squared is 85.6%, so that the regression has a high degree of explanatory power.

G. Summary Results

Q56. Can you briefly summarize the results from the various models you employed to estimate the cost of equity for DTE Electric.

A56. Based on the discussions above, I obtain the following estimates for my proxy groups.

Figure 13: ROE Estimates

	Electric Sample		Reasonable Range	
	Low	High	Low	High
CAPM / ECAPM	10.8%	11.7%	10.75%	11.75%
DCF	9.4%	11.2%	9.50%	11.00%
Risk Premium	10.5%	10.5%	10.50%	10.50%
Average	10.2%	11.1%	10.25%	11.08%
Midpoint	10.70%		10.67%	

The average of the low and high is 10.2 percent and 11.1 percent, respectively with the reasonable range being close at approximately 10.25 to 11.0 percent for the electric sample.

I note that DTE Electric's requested ROE of 10.5 percent is below the midpoint of my estimates by within the range of my reasonable estimates. Consequently, I view the requested ROE as conservative and especially so given DTEE's risk profile, which indicates the company has higher business risk than the comparable companies.

VI. DTE ELECTRIC SPECIFIC CIRCUMSTANCES AND ROE RECOMMENDATION

A. Regulatory Environment

Q57. Are there any differences in the regulatory environment in which the comparable companies and DTE Electric operates?

A57. Like many of the sample companies, DTE Electric benefits from certain regulatory policies that reduce regulatory lag, including a forward test year for rate cases, and an annual Power Supply Cost Recovery ("PSCR") clause for expenses such as fuel, capacity, energy, transmission, and purchased power.[75] Subject to Commission review,

75 S&P Global Market Intelligence, Commission Details for the Michigan Public Service Commission, accessed November 8, 2022, https://platform.mi.spglobal.com/interactivex/CommissionDetails.aspx?Printable=1&id=4081574&Type=1&State=MI.

the Company is permitted to include construction work in progress ("CWIP") for pollution control measures and significant new infrastructure projects in rate base.[76] Cost-tracking mechanisms such as these are also in effect in states affecting several of the sample companies.[77] However, unlike some of the sample companies, DTE Electric does not currently have a revenue decoupling mechanism (since a 2012 Court of Appeals ruling reversed Michigan Public Service Commission approval for such a program that DTE Electric had implemented) or lost revenue adjustment mechanism ("LRAM") in place, as some sample companies do.[78]

A more complete listing of regulatory mechanisms available to DTE and the companies in the electric proxy group is included in Exhibit D5.19. I discuss the findings from this comparison below.

Q58. Are there any differences to the sample?

A58. Yes. First, as noted above, Michigan does not have a decoupling or decoupling-like mechanism for electric utilities. Combined with the partial electric choice in Michigan, this could create a downward risk for DTE Electric. Second, DTE Electric relies to a larger degree than many of the comparators on nuclear generation (about 19 percent). Nuclear generation is associated with certain risks. Third, a relatively large proportion of DTE Electric's generation is coal based (approximately 45 percent in 2023)[79] meaning that if Michigan's Healthy Climate Plan's goal of 50 percent renewable by

---

76 *Id*.

77 Lillian Federico, "Alternative ratemaking plans in the U.S.," S&P Global Market Intelligence, Regulatory Research Associates. April 16, 2020, accessed April 21, 2020, https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#news/article?id=58062563&KeyProductLinkType=6. Checked for updates July 31, 2021.

78 *Edison Electric Institute*, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," January 2013. Many of the companies in my comparable sample have a decoupling mechanism in place. This means that these companies benefit from regulatory provisions allowing them to recover their fixed costs independent of volumetric charges: if the utilities' customers use less electricity than was forecast, the decoupling mechanism ensures that the utilities can recover their cost despite the decrease in variable revenues.

79 DTE, "DTE Business Update," December 8, 2023.

2030 is to be reached,[80] then DTEE will need to replace substantial parts of its generation fleet – leading to the need for large investments, which create execution risks as well as increases the proportion of fixed expenses, which all else equal, increases risk. Additionally, DTE Electric has a higher than average for the proxy companies reliance on nuclear power (19% versus the sample average of 9%).[81]

Looking to the regulatory mechanisms that are available to companies in the sample and DTE Electric, I note (in addition to DTEE's lack of a decoupling mechanism) that DTEE similar to most other electric utilities' operating entities has an electric fuel purchase power adjustment clause. Similar to nearly half of the regulated operating entities, DTEE has access to a renewable/non-traditional generation rider, but unlike about 40 percent of the operating entities owned by the sample companies, DTEE does not have access to delivery infrastructure or environmental compliance riders.[82] Overall, I do not see any major differences in access to regulatory mechanisms other than the lack of an electric decoupling mechanism in Michigan.

Q59. Please elaborate on the impact of Fermi 2 ownership on the Company's risk profile.

A59. Although empirical tests of the effects of the ownership of nuclear generating plants on the cost of capital are inconclusive, the cost of capital is affected by business risk which is the risk remaining after diversifiable risk is removed from total risk.

The additional risk of the Fermi 2 Nuclear Generation Plant is likely to be largely diversifiable, but it is also asymmetric. Asymmetric risk refers to a downside risk for which there is no corresponding upside to balance the risk.

---

80 *Forbes,* "Michigan 2050 Carbon Neutrality Goal Could Be An Economic Engine – If It Avoids A Rush to Gas," February 9, 2022.

81 Source: Schedule D5.18.

82 Source: Schedule D5.19.

Q60. If the risk of Fermi 2 does not affect the cost of capital, what do you recommend that the Commission do?

A60. First, the Commission should recognize that the risk of nuclear power plants is asymmetric. The Commission should remove the asymmetric risk if there is an event at the plant because the Company has not been previously compensated through its cost of capital for potential loss. Second, the empirical tests of the effect of nuclear power plants on the cost of capital are likely too "weak" in the sense that is extremely difficult to develop a test likely to detect the effects of nuclear generating assets on the cost of capital for a company. That is because there are so many other factors that affect the cost of capital. For example, nuclear plants are generally owned by holding companies with many other types of assets and are affected by varying regulatory policies. It may well be that nuclear generating plants increase the cost of capital even though empirical tests have not been able to detect it. I regard ownership of Fermi 2 as one more factor indicating that the Company is riskier than the sample on average.

Q61. Did you consider DTE Electric's capital expenditures relative to those of the sample?

A61. Yes. As shown in Schedule D5.18, DTE Electric's capital expenditures are higher than of the average company in the Electric Sample. Specifically, the average capital expenditure to net plant is above the average or median of the sample. A higher capital expenditure introduces relatively higher fixed costs, which cannot readily be eliminated should circumstances change. Thus, all else equal, higher capital expenditures increases business risk.

Q62. Can you summarize your assessment of DTE Electric's business risk relative to the sample companies?

A62. In consideration of the factors mentioned above, I believe DTE Electric is of higher than average business risk relative to the sample companies.

VII. COST OF CAPITAL RECOMMENDATION

Q63. What do you recommend for DTE Electric's cost of equity in this proceeding?

A63. The cost of equity estimates from my analyses were summarized in Figure 13 above and repeated below in Figure 14.

Figure 14: Summary ROE Results

	Electric Sample	
	Low	High
CAPM / ECAPM	10.8%	11.7%
DCF	9.4%	11.2%
Risk Premium	10.5%	10.5%
Average	10.2%	11.1%

* The single-stage DCF average is 10.5% ignoring financial risk.

Based on the figures above, it is evident that the current cost of equity is higher than in DTE Electric's last rate case, when a ROE of 9.9 percent was allowed. The average of the low and high estimates results in a range of 10.2 to 11.1 percent, so that the average of the lowest estimates are above the most recently allowed ROE. The midpoint of the range is 10.65 percent. The increase in the cost of equity is predominantly caused by a higher risk-free rate and an increase in the forecasted MRP, while other parameters have remained relatively stable.

Based on the data above I recommend that DTE Electric be allowed a ROE of 10.5 percent on the 50 percent equity financed rate base. The recommendation is conservative based on my finding that the midpoint of the range I estimate for the comparable sample is above 10.5 percent and DTE Electric has higher business risk than the electric sample group.

Q64. Does this conclude your testimony?

A64. Yes.

APPENDIX A: RESUME OF DR. BENTE VILLADSEN

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is assisting entities in the acquisition of regulated utilities regarding issues such the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, Dr. Villadsen was a faculty member at Washington University in St. Louis, University of Michigan, and University of Iowa.

She has taught financial and managerial accounting as well as econometrics, quantitative methods, and economics of information to undergraduate or graduate students. Dr. Villadsen served as the president of the Society of Utility Regulatory Financial Analysts for 2016-2018.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Forensics
  - Credit Issues in the Utility Industry

- Damages and Valuation (incl. international arbitration)
  - Utility valuation
  - Lost Profit for construction, oil&gas, utilities
  - Valuation of construction contract
  - Damages from the choice of inaccurate accounting methdology

EXPERIENCE

Regulatory Finance

- Dr. Villadsen has testified on cost of capital and capital structure for many regulated entities including electric and gas utilities, pipelines, railroads, water utilities and barges in many jurisdictions including at the FERC, the Surface Transportation Board, the states of Alaska, Arizona, California, Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Ohio, Oregon, Virginia and Washington as well as in the provinces of Alberta, Ontario, and Quebec.
- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.
- On behalf of two taxpayers, Dr. Villadsen has testified on the methodology used to estimate the discount rate for the income approach to property valuation in Utah district court.
- For several electric, gas and transmission utilities as well as pipelines in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- On behalf of gas distribution and storage utilities in Quebec, Dr. Villadsen provided expert testimony on the appropriate cost of equity and capital structure for of Énergir, Gazifère, and Intragaz before Régie de l'énergie du Québec.
- For Barbados Light & Power, she provided testimony on the appropriate weighted average cost of capital including the cost of equity, the cost of debt, and capital structure. The matter was heard by the Barbados Fair Trading Commission.
- For potential acquirers of electric, natural gas, and water utilities, Dr. Villadsen has conducted regulatory due diligence in the form of an assessment of the regulatory environment in the jurisdictions at issue including the ability to earn the allowed return and recover costs associated with operations or capital expenditures. Her evaluations also involved an assessment of needed capital expenditures and the recovery of such expenditure through rates or specific

adjustment clauses. Her prior work includes more than 15 US states, the FERC, and several Canadian provinces.

- She has worked on formula rates for transmission companies at FERC; including matters where specific issues such as the determination of the rate base, the treatment of leases, and the recovery of transaction costs have been litigated.
- Dr. Villadsen has estimated the cost of capital and recommended an appropriate capital structure for natural gas and liquids pipelines in Canada, Mexico, and the US. using the jurisdictions' preferred estimation technique as well as other standard techniques. This work has been used in negotiations with shippers as well as before regulators.
- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.
- Dr. Villadsen has advised many acquirers and potential acquirers of regulated utilities regarding the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Her work has pertained to many jurisdiction in the U.S. and Canada including more than 20 states and three provinces as well as the Federal Energy Regulatory Commission. She has worked on electric, natural gas, pipeline, transmission, and water utility acquisitions.
- She has estimated the cost of equity on behalf of entities such as Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, NW Natural, Nicor, Consolidated Edison, Southern California Edison, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the FERC on behalf of electric transmission and natural gas pipelines as well as Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted

a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.

- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.
- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- For a FERC-regulated entity, Dr. Villadsen undertook an assessment of the company's classification of specific long-term commitments, leases, regulatory assets, asset retirement obligations, and contributions / distributions to owners in the company's FERC Form 1.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities,

transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.

- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.

- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.

- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.

- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.

- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.

- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.
- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.

- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 14 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.
- For an electric utility, Dr. Villadsen provided guidance regarding the regulatory accounts needed as the utility was separated into separate generation, transmission, and distribution entities with each their accounting records.

Accounting and Corporate Finance

- For an electric utility subject to international arbitration, Dr. Villadsen submitted expert testimony on the application of IFRS as it pertains to receivables, the classification of liabilities and contingencies.
- In international arbitration, she submitted an expert report on IFRS' requirements regarding carve out financials, impairment, the allocation of costs to segments, and disclosure issues.
- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- On behalf of a taxpayer, Dr. Villaden has provided an expert report on the nature of the cost of equity used in regulatory proceedings as well as the interest rate regine in 2014.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs

and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.

- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.

- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.

- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.

- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.

- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.

- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.

- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.

- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

BOOKS

"*Risk and Return for Regulated Industries*," (with Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe) Elsevier, May 2017.

PUBLICATIONS AND REPORTS

"International Rate of Return Methods – Recent Developments," (with Toby Brown and Andrew W. Thompson), prepared for Energy Networks Australia and submitted to the *Australian Energy Regulator*, September 2022.

"A Review of International Approaches to Regulated Rates of Return," (with J. Anthony, T. Brown, L. Figurelli, D. Harris, and N. Nguyen) published by the *Australian Energy Regulator*, September 2020.

"Global Impacts and Implications of COVID-19 on Utility Finance," (with R. Mudge, F. Graves, J. Figueroa, T. Counts, L. Mwalenga, and S. Pant), *The Brattle Group*, July 2020.

"Impact of New Tax Law on Utilities' Deferred Taxes," (with Mike Tolleth and Elliott Metzler), *CRRI 37'th Annual Eastern Conference*, June, 2018.

"Implications of the New Tax Law for Regulated Utilities," The Brattle Group, January 2018.

"Using Electric and Gas Forwards to Manage Market Risks: When a power purchase agreement with a utility is not possible, standard forward contracts can act as viable hedging instruments*," North American Windpower*, May 2017, pp. 34-37.

"*Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies*," (with Onur Aydin and Frank Graves), Brattle Whitepaper, January 2017.

"Aurizon Network 2016 Access Undertaking: Aspects of the WACC," (with Mike Tolleth), filed with the *Queensland Competition Authority*, Australia, November 2016.

"Report on Gas LDC multiples," with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

"Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC," prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

"Brattle Review of AE Planning Methods and Austin Task Force Report." (with Frank C. Graves) September 24, 2014.

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

"Calculating the Equity Risk Premium and the Risk Free Rate," (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

"Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World," (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

"Public Sector Discount Rates" (with rank Graves, Bin Zhou), *Brattle* white paper, September 2011

"FASB Accounting Rules and Implications for Natural Gas Purchase Agreements," (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

"IFRS and You: How the New Standards Affect Utility Balance Sheets," (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

"Corporate Pension Plans: New Developments and Litigation," (with George Oldfield and Urvashi Malhotra), Finance Newsletter, Issue 01, *The Brattle Group*, November 2010.

"Review of Regulatory Cost of Capital Methodologies," (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

"Understanding Debt Imputation Issues," (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," *Public Utilities Fortnightly*, August 2005 (with A. Lawrence Kolbe and Michael J. Vilbert).

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," (with A. Lawrence Kolbe and Michael J. Vilbert, and with "*The Brattle Group*" listed as author), *Edison Electric Institute,* April 2005.

"Communication and Delegation in Collusive Agencies," *Journal of Accounting and Economics*, Vol. 19, 1995.

"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

SELECTED PRESENTATIONS

"Financing Infrastructure Investments in an Era of Deep Uncertainty: In Need of Updating the Regulatory Toolbox – an International Perspective," webinar sponsored by *Utilitalia*, September 26, 2023.

"Current Issues in Cost of Capital" presented to *EEI Members*, July, 2018-19, 2021-23, Madison, WI.

"The Future of Gas: Options and Regulatory Strategies in a Carbon-Constrained Future," (with Ahmad Faruqui, Josh Figueroa, Long Lam), Presented to Executive Team at Gas Utility, June 2021.

"FERC's new ROE methodology for pipelines and electric transmission," (with Michael J. Vilbert) *UBS Fireside Chat*, June 24, 2020.

"Managing Price Risk for Merchant Renewable Investments," (with Onur Aydin) *EIA Electricity Pricing Workgroup* (webinar), April 30, 2019.

"Decoupling and its Impact on Cost of Capital" presented to *SURFA Members and Friends*, February 27, 2019.

"Introduction to Capital Structure & Liability Management", *the American Gas Association/Edison Electric Institute "Introduction and Advanced Public Utility Accounting Courses",* August 2018-2019, August 2022-2023.

"Issues Cost of Capital," *the American Gas Association/Edison Electric Institute* "*Advanced Public Utility Accounting Courses Advanced Public Utility Accounting Course,"* August 2023.

"Lessons from the U.S. and Australia" presented at *Seminar on the Cost of Capital in Regulated Industries: Time for a Fresh Perspective?* Brussels, October 2017.

"Should Regulated Utilities Hedge Fuel Cost and if so, How?" presented at *SURFA's 49 Financial Forum*, April 20-21, 2017.

"Transmission: The Interplay Between FERC Rate Setting at the Wholesale Level and Allocation to Retail Customers," (with Mariko Geronimo Aydin) presented at *Law Seminars International: Electric Utility Rate Cases*, March 16-17, 2017.

"Capital Structure and Liability Management," *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2015-2017.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2013-2017.

"Alternative Regulation and Rate Making Approaches for Water Companies," *Society of Depreciation Professionals Annual Conference*, September 2014.

"Capital Investments and Alternative Regulation," *National Association of Water Companies Annual Policy Forum*, December 2013.

"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"GAAP / IFRS Convergence," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

"Deferred Income Taxes and IRS's NOPR: Who should benefit?" *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

"Discussion of 'Are Performance Measures Other Than Price Important to CEO Incentives?'" *Annual Meeting of the American Accounting Association*, 2000.

"Contracting and Income Smoothing in an Infinite Agency Model: A Computational Approach," (with R.T. Boylan) *Business and Management Assurance Services Conference*, Austin 2000.

TESTIMONY

Affidavit on the Cost of Capital Mechanism on behalf of Pacific Gas & Electric Company, San Diego Gas & Electric, Southern California Gas, and Southern California Edison before the *California Public Utilities Commission*, Application 22-04-008 and related matters, January 2024.

Direct testimony on the cost of equity on behalf of DTE Gas before the *Michigan Public Service Commission*, Case No. U-21291, January 2024.

Direct testimony on the cost of equity on behalf of Orange & Rockland Utilities before the *New York Public Service Commission* (with Josh Figueroa), Case No. 24-E-0060, January 2024.

Direct testimony on the cost of equity on behalf of Northern Border Pipeline Company before the *Federal Energy Regulatory Commission*, Docket No. RP-24-287, December 2023.

Direct testimony on the cost of equity and capital structure on behalf of Anchorage Water Utility and Anchorage Wastewater Utility before the *Regulatory Commission of Alaska*, TA178-122 and TA180-126, December 2023.

Direct and Supplemental Direct testimony on the cost of equity on behalf of Interstate Power and Light before the *Iowa Utilities Board*, Docket No. RPU-2023-0003, October 2023, January 2024.

Direct prepared testimony on the cost of equity on behalf of GTN before the *Federal Energy Regulatory Commission*, Docket No. RP23-1099, September 2023.

Rehearing testimony, Rebuttal Rehearing testimony and hearing appearance on fixed ROE for advanced ratemaking on behalf of Interstate Power and Light before the *Iowa Utilities Board*, Docket No. RPU-2021-0003, July 2023, August 2023.

Expert report on IFRS accounting and forensics in the matter of an *arbitration in London, UK*, under the Arbitration Act 1996, at the instruction Allen & Overy (with Richard Caldwell), June 2023.

Rebuttal Testimony on decoupling in general rate case on behalf of California-American Water Company before the *California Public Utilities Commission*, A.22-07-001, May 2023.

Reply Evidence and Hearing Appearance on cost of equity, capital structure and formula approach behalf of ATCO Utilities, FortisAlberta, and Apex on Cost of Capital before the *Alberta Utilities Commission,* Proceeding 27084, February 2023, April 2023, May 2023.

Direct, Rebuttal and Surrebuttal Testimony on behalf of Portland General Electric on Cost of Capital before the *Public Utility Commission of Oregon*, UE-416, February, July, September 2023.

Direct and Rebuttal Testimony on behalf of DTE Electric on Cost of Capital before the *Michigan Public Service Commission*, Docket No. U-21297, February 2023, July 2023.

Direct Testimony, Rebuttal Testimony and Surrebuttal Testimony on behalf of Northern Illinois Gas Company (Nicor) on Cost of Capital before the *Illinois Commerce Commission*, Docket No. 23-0066, January 2023, May 2023, July 2023.

Direct and Rebuttal Testimony on behalf of Consolidated Edison's Steam Utility on Cost of Capital before the *New York Public Service Commission*, Docket No. 22-S-0659, November 2022, April 2023.

Direct and Rebuttal Testimony on Cost of Capital on behalf of Virginia Natural Gas before the *Virginia State Corporation Commission*, Docket No. 2022-00052, August 2022, May 2023.

Direct and Rebuttal Testimony on 2023 Cost of Capital on behalf of Southern California Edison before the *California Public Utilities Commission*, Application A.22-04-009 (U-338), April 2022, August 2022.

Written Evidence on Cost of Equity on behalf of ATCO, APEX, and Fortis Alberta before the *Alberta Utilities Commission*, Proceeding No. 27084, February 2022.

Prepared Direct Testimony on Cost of Equity on behalf of ANR Pipeline before the *Federal Energy Regulatory Commission*, Docket No. RP22-501-000, January 2022.

Direct Testimony and Rebuttal Testimony on Cost of Capital and Capital Structure on behalf of Consolidated Edison Company of New York before *New York Public Service Commission*, Case No. 22-E-0064 and 22-G-0065, January, June 2022.

Opening and Rebuttal Testimony, Hearing appearance on the Cost of Capital Mechanism on behalf of Southern California Edison before the *Public Utilities Commission of California*, Application A.21-08-013, January, February 2022.

Direct Testimony and Rebuttal Testimony on Cost of Equity on behalf of DTE Electric Company before *the Michigan Public Service Commission*, Case No. U-20836, January, June 2022.

Direct and Rebuttal Testimony on the Cost of Equity and Capital Structure on behalf of Anchorage Water and Wastewater Utility before the *Regulatory Commission of Alaska*, TA-172-122 and TA-172-126, December 2021, October 2022.

Direct Testimony on the Cost of Equity on behalf of Northwest Natural before the *Public Utility Commission of Oregon* (with Josh Figueroa), Docket No. UG-435, December 2021

Direct Testimony and Hearing Appearance on Cost of Equity and Capital Structure on behalf of Énergir, Gazifère, and Intragaz before *Régie de l'énergie du Québec*, R-4156-2021, November 2021, June 2022.

Direct Testimony, Rebuttal Testimony, and Hearing appearance on Cost of Equity for Advanced Ratemaking on behalf of Interstate Power and Light Company, *Iowa Utilities Board*, RPU-2021-0003, November 2021, June and August 2022.

Expert Report and Hearing appearance on Cost of Equity and the Weighted Average Cost of Capital on behalf of Barbados Light and Power Company, *Barbados Fair Trading Commission*, September 2021, October 2022.

Direct Testimony on California's Cost of Capital Mechanism and Cost of Equity on behalf of Southern California Edison, *California Public Utilities Commission*, Application A.21-08-013, August 2021.

Expert Report on Contingent Liabilities and Materiality under IFRS on behalf of of Norilsk Nickel Mauritius, *LCIA Arbitration* No. 163506, August 2021.

Deposition Testimony re. rate of return and bypass rates on behalf on Southwest Gas Corporation, *Superior Court for the state of Arizona, County of Maricopa*, CV2012-050939, August 2021.

Report on Cost of Capital for Hawaii American Water submitted to the *Public Utilities Commission of the State of Hawaii*, Docket No. 2021-0063, August 2021.

Direct Testimony on Cost of Equity on behalf of Portand General Electric, *Oregon Public Utility Commission*, UE-324, July 2021.

Direct Testimony, Rebuttal Testimony, and Hearing Testimony on Cost of Capital on behalf of California-American Water Company, *California Public Utilities Commission*, Application No. A.21-05-001 et al, May 2021, March 2022, May 2022.

Prefiled Direct Testimony on cost of equity on behalf of Southern Star Central Gas Pipeline, *Federal Energy Regulatory Commission*, Docket RP21-778-000, April 2021.

Direct Testimony re. the prospective excessive earnings test on behalf of Cleveland Electric Illuminating Company and the Toledo Edison Company, *Public Utilities Commission of Ohio*, Case Nos. 20-1034-EL UNC and 20-1476-EL-UNC, March 2021.

Rebuttal Testimony re. the discount rate for property valuation in tax assessment on behalf of Union Pacific Railroad, *Utah District Court*, Case No. 2:18-cv-00630-DAK_DBP (Union Pacific Railroad v. Utah State Tax Commission et al), February 2021.

Direct Testimony and Rebuttal Testimony on cost of equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, U-20940, February and June 2020.

Direct Testimony on the cost of equity on behalf of Orange & Rockland Utilities submitted to the *New York Department of Public Service*, Case No. 21-E-0074, January 2021.

Direct Testimony, Rebuttal Testimony, and Surrebuttal Testimony on the cost of equity on behalf of Nicor Gas submitted to the *Illinois Commerce Commission*, Docket No. 21-0098, January 2021, June 2021, July 2021.

Direct Testimony and Hearing Testimony on the cost of equity and capital structure on behalf of Anchorage Water and Wastewater Utility submitted to the *Regulatory Commission of Alaska*, Matters TA168-122 and 168-126, December 2020, January 2022.

Direct Testimony on the cost of equity on behalf of NW Natural submitted to the *Washington Transportation and Utilities Commission*, Docket No. UG-200994, December 2020.

Written Evidence in Review and Variance of Decision 22570-D01-2018 Stage 2 (AltaGas' capital structure) (joint with Paul R. Carpenter) on behalf of AltaGas Utilities Inc. Filed with the *Alberta Utilities Commission*, Proceeding 25031, January 2020.

Written Evidence on Cost of Equity and Capital Structure on behalf of ATCO, AltaGas and FortisAlberta in 2021-2022 Generic Cost of Capital Proceeding. Filed with the *Alberta Utilities Commission*, Proceeding No. 24110, January 2020.

Report on the Return Margin for the Alberta Bottle Depots on behalf of the Alberta Beverage Container Recycling Corporation, February 2020.

Verified Statement and Reply Verified Statement regarding Revisions to the Board's Methodology for Determining the Railroad Industry's Cost of Capital on behalf of the American Association of Railroads before the *Surface Transportation Board*, Docket No. EP 664 (Sub-No. 4), January, February 2020.

Affidavit regarding the creation of a regulatory asset for earthquake related costs on behalf of Anchorage Water and Wastewater submitted to the *Regulatory Commission of Alaska*, December 2019.

Expert Report and Hearing Appearance on Going Concern and Impairment, *American Arbitration Association*: International Engineering & Construction S.A., Greenville Oil & Gas Co. Ltd and GE Oil & Gas, Inc., November, December 2019.

Direct Testimony and Rebuttal Testimony on the cost of equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, Docket No. U-20642, November 2019.

Expert Report, Reply Report and Hearing Testimony on IFRS Issues and Forensics. *SIAC Arbitration* No. 44 of 2018, October 2019, September 2021, September 2022.

Expert Report, Reply Report and Hearing Appearance on IFRS issues. *ICC Arbitration* No. 23896/GSS, September 2019, September and November 2020.

Direct Testimony on the cost of debt and equity capital as well as capital structure on behalf of Young Brothers, LLC. submitted to the *Public Utilities Commission of the State of Hawaii*, Docket No. 2019-0117, September 2019.

Direct Testimony on Cost of Equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, Docket No. U-20940, February 2021.

Expert Report on discount rates in property tax matter for Union Pacific Company in *Union Pacific Railroad Co. v. Utah State Tax Comm'n, et. al.*, Case No. 2:18-cv-00630-DAK-DBP, Utah August 2019.

Answering Testimony on the Cost of Equity on behalf of Northern Natural Gas Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-59-000, August 2019.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on Cost of Equity on behalf of DTE Electric Company submitted to the *Michigan Public Service Commission*, Docket No. U-20561, July, November, December 2019.

Prepared Direct Testimony on Cost of Capital for Northern Natural Gas Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-1353-000, July 2019.

Prepared Direct Testimony on Cost of Capital and Term Differentiated Rates for Paiute Pipeline Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-1291-000, May 2019.

Expert report, deposition, and oral trial testimony on behalf of PacifiCorp in the Matter of *PacifiCorp, Inc. v. Utah State Tax Comm'n*, Case No. 180903986 TX, *Utah District Court* April, May, September 2019.

Direct Testimony, Rebuttal Testimony, and hearing appearance on the cost of capital for Southern California Edison submitted to the *California Public Utilities Commission*, Docket No. A.19-04-014, April 2019, August 2019.

Prepared Direct Testimony on the cost of equity for Southern California Edison's transmission assets submitted to the *Federal Energy Regulatory Commission*, Docket No. ER19-1553, April 2019.

Direct and Rebuttal Testimony on cost of equity for Consolidated Edison of New York submitted to the *New York Public Service Commission*, Matter No. 19-00317, January, June 2019.

Direct Testimony on cost of capital and capital structure for Northwest Natural Gas Company submitted to the *Washington Utilities and Transportation Commission*, Docket No. 181053, December 2018.

Pre-filed Direct Testimony and Reply Testimony on cost of capital and capital structure for Anchorage Water Utility and Anchorage Wastewater Utility submitted to the *Regulatory Commission of Alaska*, TA163-122 and TA164-126, December 2018, October 2019.

Expert Report on the Cost of Capital for Sur De Texas-Tuxpan Pipeline provided to *Comisión Reguladora de Energía*, Mexico (with Paul Carpenter and Augustin J. Ros), May 2018.

Expert Report on the Cost of Capital for Tuxpan-Villa de Reyes Pipeline provided to *Comisión Reguladora de Energía*, Mexico (with Paul Carpenter and Augustin J. Ros), May 2018.

Direct Testimony on cost of capital for Portland General Electric Company submitted to the *Oregon Public Utility Commission* on behalf of Portland General Electric Company (with Hager and Liddle), UE 335, February 2018.

Direct Testimony and Rebuttal Testimony on cost of capital for NW Natural submitted to the *Oregon Public Utility Commission* on behalf of NW Natural, UG 344, December 2017, May 2018.

Direct Pre-filed Testimony and Reply Pre-filed Testimony on cost of equity and capital structure for Anchorage Water and Wastewater Utilities before the *Regulatory Commission of Alaska*, TA161-122 and TA162-126, November 2017, September 2018.

Direct Testimony, Rebuttal Testimony, deposition, and hearing appearance on wholesale water rates for Petitioner Cities, *Texas Public Utility Commission*, PUC Docket 46662, SOAH Docket 473-17-4964.WS, November 2017, January, June, July, October 2018.

Affidavit on Lifting the Dividend Restriction for Anchorage Water Utility for AWWU, *Regulatory Commission of Alaska*, U-17-095, November 2017.

Written Evidence, Rebuttal Evidence and Hearing appearance on the Cost of Capital and Capital Structure for the ATCO Utilities and AUI, 2018-2020 Generic Cost of Capital Proceeding, *Alberta Utilities Commission*, October 2017, February – March 2018.

Written Evidence, Rebuttal Evidence, and Hearing Appearance on Regulatory Tax Treatment for the ATCO Utilities and AUI, 201802020 Generic Cost of Capital Proceeding, *Alberta Utilities Commission*, October 2017, February – March 2018.

Affidavit on the Creation of a Regulatory Assets for PRV Rebates for Anchorage Water Utility, submitted to the *Regulatory Commission of Alaska*, U-17-083, August 2017.

Direct and Rebuttal Testimony, Hearing Appearance on Cost of Capital for California-American Water Company for California-American Water submitted to the *California Public Utilities Commission*, Application 17-04-003, April, August, September 2017.

Direct, Rebuttal, Surrebuttal, Supplemental, Supplemental Rebuttal Testimony and Hearing Appearance on the Cost of Capital for Northern Illinois Gas Company submitted to the *Illinois Commerce Commission*, GRM #17-055, March, July, August, September, and November 2017.

Direct and Rebuttal Testimony on Cost of Capital for Portland General Electric Company submitted to the *Oregon Public Utility Commission* on behalf of Portland General Electric Company, Docket No. UE 319, February, July 2017.

Pre-filed Direct and Reply Testimony and Hearing Appearance on Cost of Equity and Capital Structure for Anchorage Municipal Light and Power, *Regulatory Commission of Alaska*, Docket No. TA357-121, December 2016, August and December 2017.

Expert report and Hearing Appearance regarding the Common Equity Ratio for OPG's Regulated Generation for OEB Staff, *Ontario Energy Board*, EB-2016-0152, November 2016, April 2017.

Pre-filed Direct Testimony on Cost of Equity and Capital Structure for Anchorage Municipal Wastewater Utility, *Regulatory Commission of Alaska*, Docket No. 158-126, November 2016.

Expert Report, Reply Expert Report and Hearing on damages (quantum) in exit arbitration (with Dan Harris), *International Center for the Settlement of Investment Disputes*, October 2016, October 2018, July 2019.

Direct Testimony on capital structure, embedded cost of debt, and income taxes for Detroit Thermal, Michigan Public Service Commission, Docket No. UE-18131, July 2016.

Direct Testimony on return on equity for Arizona Public Service Company, Arizona Corporation Commission, Docket E-01345A-16-0036, June 2016.

Written evidence, rebuttal evidence and hearing appearance regarding the cost of equity and capital structure for Alberta-based utilities, the *Alberta Utilities Commission*, Proceeding No. 20622 on behalf of AltaGas Utilities Inc., ENMAX Power Corporation, FortisAlberta Inc., and The ATCO Utilities, February, May and June 2016.

Verified Statement, Verified Reply Statement, and Hearing Appearance regarding the cost of capital methodology to be applied to freight railroads, the *Surface Transportation Board* on behalf of the Association of American Railroads, Docket No. EP 664 (Sub-No. 2), July 2015, September and November 2015.

Direct Testimony on cost of capital submitted to the Oregon Public Utility Commission on behalf of Portland General Electric, Docket No. UE 294, February 2015.

Supplemental Direct Testimony and Reply Testimony on cost of capital submitted to the *Regulatory Commission of Alaska* on behalf of Anchorage Water and Wastewater utilities, Docket U-13-202, September 2014, March 2015.

Expert Report and hearing appearance on specific accrual and cash flow items in a Sales and Purchase Agreement in international arbitration before the *International Chamber of Commerce*. Case No. 19651/TO, July and November 2014. (*Confidential*)

Rebuttal Testimony regarding Cost of Capital before the *Oregon Public Utility Commission* on behalf of Portland General Electric, Docket No. UE 283, July 2014.

Direct Testimony on the rate impact of the pension re-allocation and other items for Upper Peninsula Power Company in connection with the acquisition by BBIP before the *Michigan Public Service Commission* in Docket No. U-17564, March 2014.

Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013. (with A. Lawrence Kolbe, Michael J. Vilbert, *Confidential*)

Direct Testimony on the treatment of goodwill before the *Federal Energy Regulatory Commission* on behalf of ITC Holdings Corp and ITC Midwest, LLC in Docket No. PA10-13-000, February 2012.

Direct and Rebuttal Testimony on cost of capital before the *Public Utilities Commission of the State of California* on behalf of California-American Water in Application No. 11-05, May 2011.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Case No. 11-00196-UT, May 2011, November 2011, and December 2011.

Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, EL11-13-000, December 2010.

Expert Report and deposition in Civil Action No. 02-618 (GK/JMF) in the *United States District Court for the District of Columbia*, November 2010, January 2011. (*Confidential*)

Direct Testimony, Rebuttal Testimony, and Rejoinder Testimony on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-10-0448, November 2010, July 2011, and August 2011.

Direct Testimony on the cost of capital before *the New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 09-00156-UT, August 2009.

Direct and Rebuttal Testimony and Hearing Appearance on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-09-0343, July 2009, March 2010 and April 2010.

Rebuttal Expert Report, Deposition and Oral Testimony re. the impact of alternative discount rate assumptions in tax litigation. *United States Court of Federal Claims*, Case No. 06-628 T, January, February, April 2009. (*Confidential*)

Direct Testimony, Rebuttal Testimony and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 08-00134-UT, June 2008 and January 2009.

Direct Testimony on cost of capital and carrying charge on damages, U.S. Department of Energy, *Bonneville Power Administration*, BPA Docket No. WP-07, March 2008.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-08-0227, April 2008, February 2009, March 2009.

Expert Report, Supplemental Expert Report, and Hearing Appearance on the allocation of corporate overhead and damages from lost profit. *The International Centre for the Settlement of Investment Disputes*, Case No. ARB/03/29, February, April, and June 2008 (*Confidential*).

Expert Report on accounting information needed to assess income. *United States District Court* for the District of Maryland (Baltimore Division), Civil No. 1:06cv02046-JFM, June 2007 (*Confidential*)

Expert Report, Rebuttal Expert Report, and Hearing Appearance regarding investing activities, impairment of assets, leases, shareholder' equity under U.S. GAAP and valuation. *International Chamber* *of Commerce* (ICC), Case No. 14144/CCO, May 2007, August 2007, September 2007. (Joint with Carlos Lapuerta, *Confidential*)

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0491, July 2006, July 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, Supplemental Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0403, June 2006, April 2007, May 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, and Hearing Appearance on cost of capital before *the Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0014, January 2006, October 2006, November 2006.

Expert report, rebuttal expert report, and deposition on behalf of a major oil company regarding the equity method of accounting and classification of debt and equity, *American Arbitration Association*, August 2004 and November 2004. (*Confidential*).

APPENDIX B; Technical Appendix to the Direct Testimony of Bente Villadsen

This technical appendix contains methodological details related to my implementations of the DCF and CAPM / ECAPM models. It also contains a discussion of both the basic finance principles and the specific standard formulations of the financial leverage adjustments employed to determine the cost of equity for a company with the level of financial risk inherent in DTE Electric's requested regulatory capital structure.

Table of Contents

APPENDIX B; Technical Appendix to the Direct Testimony of Bente Villadsen i

I. DCF Models 1
- A. DCF Estimation of Cost of Equity 1
- B. Details of the DCF Model 1
  1. Dividends, Cash Flows, and Share Repurchases 2
- C. DCF Model Inputs 3
  1. Dividends and Prices 3
  2. Company Specific Growth Rates 3

II. CAPM and ECAPM 4
- A. The Capital Asset Pricing Model (CAPM) 4
- B. Inputs to the CAPM 6
  1. The Risk-free Interest Rate 6
  2. The Market Equity Risk Premium 7
- C. The Empirical CAPM 8
  1. Description of the ECAPM 8
  2. Academic Evidence on the Alpha Term in the ECAPM 9

III. Financial Risk and the Cost of Equity 10
- A. The Effect of Financial Leverage on the Cost of Equity 10
- B. Methods to Account for Financial Risk 11
  1. Cost of Equity Implied by the Overall Cost of Capital 11
  2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment) 13

I. DCF Models

A. DCF Estimation of Cost of Equity

The DCF method for estimating the cost of equity capital 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:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \qquad (1)$$

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; r is the cost of equity capital; and T is the last period in which a dividend cash flow is to be received. 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. Since the current market price is known, it is possible to infer the cost of equity that corresponds to that price and a forecasted pattern of expected future dividends. In terms of Equation (1), if P_0 is known and $D_1, D_2, \dots D_T$ are estimated, an analyst can "solve for" the cost of equity capital r.

B. Details of the DCF Model

Perhaps the most widely known and used application of the DCF method assumes that the expected rate of dividend growth remains constant forever. In the so-called Gordon Growth Model, the relationship expressed in Equation (1) is such that the present value equation can be rearranged algebraically into a formula for estimating the cost of equity. 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

$$P_0 = \frac{D_1}{r-g} \qquad (2)$$

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 market price and the cost of capital, as before. Equation (2) is a simplified version of Equation (1) that can be solved algebraically to yield the well-known "DCF formula" for the cost of equity capital,

$$r = \frac{D_1}{P_0} + g = \frac{D_0 \times (1+g)}{P_0} + g \tag{3}$$

There are other versions of the DCF model that relax this restrictive assumption and posit a more complex or nuanced pattern of expected future dividend payments. For example, if there is reason to believe that investors do *not* expect a company's dividends to grow at a steady rate forever, but rather have different growth rate expectations in the near term (e.g., over the next five or ten years), compared to the distant future (e.g., a period *starting* ten years from the present moment), a "multi-stage" growth pattern can be modeled in the present value formula (Equation (1)).

1. Dividends, Cash Flows, and Share Repurchases

In addition to the DCF model described above, there are many alternative formulations. Notable among these are versions of the model that use cash flows rather than dividends in the present value formula (Equation (1)).[1]

Because investors are interested in cash flow, it is technically important to capture *all* cash flows that are distributed to shareholders when estimating the cost of equity using the DCF method. In some circumstances, investors may expect to receive cash in forms other than dividends. An important example concerns the fact that many companies distribute cash to shareholders through share buybacks in addition to dividends. To the extent such repurchases are expected by investors, but not captured in the forecasted pattern of future dividends; a dividend-based implementation of the DCF model will <u>underestimate</u> the cost of equity.

Similarly, if investors have reason to suspect that a company's dividend payments will not reflect a full distribution of its available cash free cash flows in the period they were generated, it may be appropriate replace the forecasted dividends with estimated free cash flows to equity in the present value formula (Equation (1)). Focusing on *available* cash rather than that actually distributed in the form of dividends can help account for instances when near-term investing and financing activities (e.g., capital expenditures or asset sales, debt issuances or retirements, or share repurchases) may cause dividend growth patterns to diverge from growth in earnings.

---

[1] For an example in a regulatory context, the U.S. Surface Transportation Board uses a cash flow based model with three stages to estimate the cost of equity for the railroads. See Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009. Confirmed in EP-664 (Sub-No. 2), October 31, 2016 and EP 664 (Sub-No. 4), June 23, 2020.

Many utility companies such as those included in my proxy group have long histories of paying a dividend. In fact, as mentioned in Section I of this Appendix, one of my standard requirements for inclusion in my proxy group is that a company pays dividends for 5-years without a gap or a dividend cut (on per share basis) in the last six months. Additionally, although some utility companies have engaged in share repurchase programs, the companies in my proxy group do not distribute substantial cash flows by means other than dividends.

C. DCF MODEL INPUTS

1. Dividends and Prices

As described above, DCF models are forward-looking, comparing the *current* price of a stock to its expected *future* dividends to estimate the required expected return demanded by the market for that stock (i.e., the cost of equity). Therefore, the models demand the current market price and currently prevailing forecasts of future dividends as inputs.

The stock price input I employ for each proxy group company is the average of the closing stock prices for the 15 trading days ending on the date of my analysis. This guards against biases that may arise on a single trading day, yet is consistent with using current stock prices.

2. Company Specific Growth Rates

a. Analysts' Forecasted Growth Rates

Finding the right growth rate(s) is usually the "hard part" of applying the DCF model, which is sometimes criticized due to what has been called "optimism bias" in the earnings growth rate forecasts of security analysts. Optimism bias is defined as tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. Any optimism bias might be related to incentives faced by analysts that provide rewards not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts the cost of capital estimates from the DCF model would be too high.

While academic researchers during the 1990s as well as in early 2000s found evidence of analysts' optimism bias, there is some evidence that regulatory reforms have eliminated the issue. A more recent paper by Hovakimina and Saenyasiri (2010) found that recent efforts to curb analysts' incentive to provide optimistic forecasts have worked, so that "the median forecast bias essentially disappeared."[2] Thus, some recent research indicates that the analyst bias may be a problem of the past.

The findings of several academic studies[3] show that analyst earnings forecasts turn out to be too optimistic for stocks that are more difficult to value, for instance, stocks of smaller firms, firms with high volatility or turnover, younger firms, or firms whose prospects are uncertain. Coincidentally, stocks with greater analyst disagreement have higher analyst optimism bias—all of these describe companies that are more volatile and/or less transparent—none of which is applicable to the majority of utility companies with wide analyst coverage and information transparency. Consequently, optimism bias is not expected to be an issue for utilities.

b. Sources for Forecasted Growth Rates

For the reasons described above, I rely on analyst forecasts of earnings growth for the company-specific growth rate inputs to my implementations of the single- and multi-stage DCF models. Most companies in my proxy group have coverage from equity analysts reporting to Thomson Reuters IBES, so I use the consensus 3-5 year EPS growth rate provided by that service. I supplement these consensus values with growth rates based on EPS estimates from *Value Line*.[4]

II. CAPM and ECAPM

A. The Capital Asset Pricing Model (CAPM)

The Capital Asset Pricing Model (CAPM) is a theoretical model stating that the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 2 in my Direct Testimony), in which

---

2 A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts Journal*, vol. 66, 2010.

3 These studies include the following: (i) Hribar, P, McInnis, J. "Investor Sentiment and Analysts' Earnings Forecast Errors," *Management Science* Vol. 58, No. 2 (February 2012): pp. 293-307; (ii) Scherbina, A. (2004), "Analyst Disagreement, Forecast Bias and Stock Returns," downloaded from Harvard Business School Working Knowledge: http://hbswk.hbs.edu/item/5418.html; and (iii) Michel, J-S., Pandes J.A. (2012), "Are Analysts Really Too Optimistic?" downloaded from http://www.efmaefm.org.

4 Specifically, I compute the growth rate implied by *Value Line*'s current year EPS estimate and its projected 3-5 year EPS estimate. I then average this in with the IBES consensus estimate as an additional independent estimate, giving it a weight of 1 and weighting the IBES consensus according to the number of analysts who contributed estimates.

the required expected return on an asset is proportional to that asset's risk relative to the market as measured by its "beta". More precisely, the CAPM states that the cost of capital for an investment S (e.g., a particular common stock), is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \tag{4}$$

where $\boldsymbol{r_S}$ is the required return on investment S;
$\boldsymbol{r_f}$ is the risk-free interest rate;
$\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and
$\boldsymbol{MRP}$ is the market equity risk premium.

The CAPM is based on portfolio theory, and recognizes two fundamental principles of finance: (1) investors seek to minimize the possible variance of their returns for a given level of expected returns (or alternatively, they demand higher *expected* returns when there is greater uncertainty about those returns), and (2) investors can reduce the variability of their returns by diversifying—constructing portfolios of many assets that do not all go up or down at the same time or to the same degree. Under the assumptions of the CAPM, the market participants will construct portfolios of risky investments that minimize risk for a given return so that the aggregate holdings of all investors represent the "market portfolio." The risk-return trade-off faced by investors then concerns their exposure to the risk inherent in the market portfolio, as they weight their investment capital between the portfolio of risky assets and the risk-free asset.

Because of the effects of diversification, the relevant measure of risk for an individual security is its *contribution* to the risk of the market portfolio. Therefore, beta (β) is defined to capture the sensitivity of the security's returns to the market's returns. Formally,

$$\boldsymbol{\beta_s} = \frac{covariance(\boldsymbol{r_s}, \boldsymbol{R_m})}{variance(\boldsymbol{R_m})} \tag{5}$$

where $\boldsymbol{R_m}$ is the return on the market portfolio.

Beta is usually calculated by statistically comparing (using regression analysis) the excess (positive or negative) of the return on the individual security over the government bond rate with the excess of the return on a market index such as the S&P 500 over a government bond rate.

The basic idea behind beta is the risk that cannot be diversified away in large portfolios is what matters to investors. Beta is a measure of the risks that *cannot* be eliminated by diversification. It is this non-diversifiable risk, or "systematic risk", for which investors require compensation in the form of higher expected returns. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk; its returns vary to the same degree as those on the market as a whole. According to the CAPM, the required return demanded by investors (i.e., the cost of equity) for investing in that stock will match the expected return on the market as a whole. Similarly, stocks with betas above 1.0 have more than average risk, and so have a cost of equity greater than the expected market return; those with betas below 1.0 have less than average risk, and are expected to earn lower than market levels of return.

B. INPUTS TO THE CAPM

1. The Risk-free Interest Rate

The precise meaning of a "risk-free" asset according to the finance theory underlying the CAPM is an investment whose return is guaranteed, with no possibility that it will vary around its expected value in response to the movements of the broader market. (Equivalently, the CAPM beta of a risk-free asset is zero). In developed economies like the U.S., government debt is generally considered to have no default risk. In this sense they are "risk-free"; however, unless they are held to maturity, the rate of return on government bonds may in fact vary around their stated or expected yields.[5]

The theoretical CAPM is a single period model, meaning that it posits a relationship between risk and return over a single "holding period" of an investment. Because investors can rebalance their portfolios over short horizons, many academic studies and practical applications of the CAPM use the short-term government bond as the measure of the risk-free rate of return. However, regulators frequently use a version based on a measure of the long-term risk-free rate; e.g., a long-term government bond. I rely on the 20-year Treasury bond as a measure of the risk-free asset in this proceeding.[6] I use the term "risk-free rate" as describing the yield on the 20-year Treasury bond.

However, I do not believe the *current* yield on long-term Treasury bonds is a good estimate for the risk-free rate that will prevail over the time period relevant to this proceeding. Instead, I believe it is more important to use the yield that is expected to prevail during the rate period.[7] For this reason I average Blue Chip's forecast of 3.9% and 3.7% for the yield on a 10-year Treasury bond for 2024 and 2025, respectively.[8] I adjust this average (3.80%) upward by 50 basis points, which

---

5 This is due to interest rate fluctuations that can change the market value of previously issued debt in relation to the yield on new issuances

6 The use of a 20-year government bond is consistent with the measurement of the Ibbotson MRP and permits us to use a series that has been in consistent circulation since the 1990's (the 30-year government bond was not issued from 2002 to 2006).

7 At the end of the technical appendix, I provide a version of the CAPM results which use current bond yields.

8 Wolters Kluwer, Blue Chip Economic Indicators, vol. 49, January 10, 2024, pp. 2-3.

is my estimate of the maturity premium for the 20-year over the 10-year Treasury bond. This provides me with an estimate of the risk free rate of 4.30%.

2. The Market Equity Risk Premium

a. Historical Average Market Risk Premium

Like the cost of capital itself, the market risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable, and must be inferred or forecasted based on known market information.

One commonly use method for estimating the MRP is to measure the historical average premium of market returns over the income returns on risk-free government bonds over some long historical period. When such a calculation is performed using the traditional industry standard Ibbotson data, the result is an arithmetic average of the annual observed premiums of U.S. stock market returns over income returns on long-term (approximate average maturity of 20-years) U.S. Treasury bonds from 1926 to the present is 7.17%.[9]

b. Forward Looking Market Equity Risk Premium

An alternative approach to estimating the MRP eschews historical averages in favor of using current market information and forecasts to infer the expected return on the market as a whole, which can then be compared to prevailing government bond yields to estimate the equity risk premium. Bloomberg performs such estimates of country-specific MRPs by implementing the DCF model on the market as a whole—using forecast market-wide dividend yields and current level on market indexes; for the U.S. Bloomberg performs a multi-stage DCF using dividend-paying stocks in the S&P 500 to infer the expected market return.

When calculated relative to 20-year Treasury bond yields, Bloomberg's estimate of the forward-looking market-implied MRP over the month leading up to my analysis was 6.37% over the 20-year Treasury bond yield.[10] I note that this is a conservative estimate as the FERC-relied upon methodology to determine the MRP as of December 31, 2023 results in an MRP 7.87% and 7.90% as shown in Schedule D5.17. I therefore consider the historical estimate of 7.17 percent to be more reasonable.

---

9 Kroll Cost of Capital Navigator, U.S. Cost of Capital Module, accessed January 5, 2024, value as of December 31, 2022.

10 Bloomberg, as of December 31, 2024.

C. The Empirical CAPM

1. Description of the ECAPM

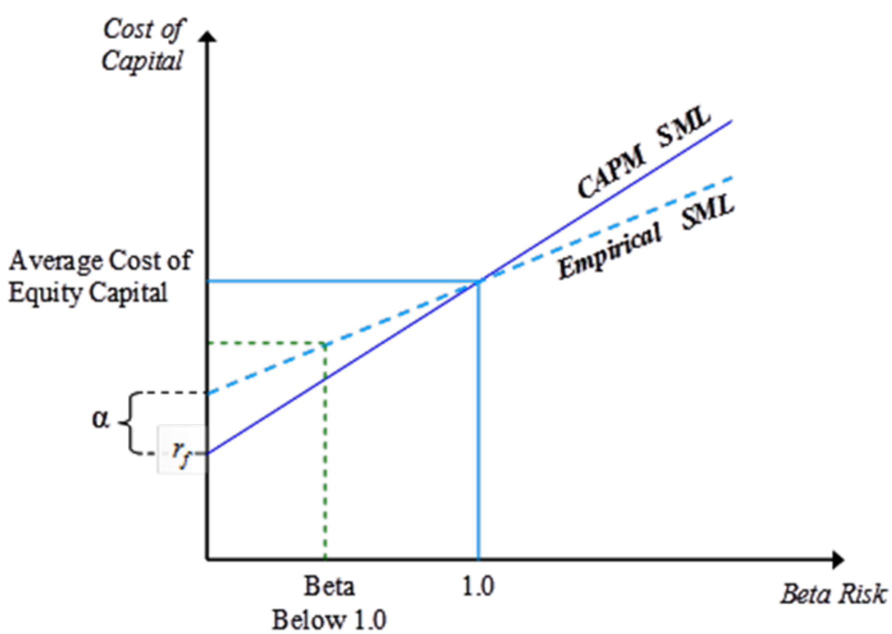
Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original 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.

The Empirical CAPM (ECAPM) makes use of these empirical findings. It estimates the cost of capital with the equation,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S \times (MRP - \alpha)} \qquad (6)$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (4)). The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line, 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.

Figure B-2
The Empirical Security Market Line



2. Academic Evidence on the Alpha Term in the ECAPM

Figure B-3 below summarizes the empirical results of tests of the CAPM, including their estimates of the "alpha" parameter necessary to improve the accuracy of the CAPM's predictions of realized returns.

Figure B-3

EMPIRICAL EVIDENCE ON THE ALPHA FACTOR IN ECAPM*

AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993)[1]	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972)[2]	4.31%	1931-1965
Fama and McBeth (1972)	5.76%	1935-1968
Fama and French (1992)[3]	7.32%	1941-1990
Fama and French (2004)[4]	N/A	
Litzenberger and Ramaswamy (1979)[5]	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995)[6]	4.6%	1936-1990

*The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

[1]Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.
[2]Estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.
[3]Calculated using Ibbotson's data for the 30-day treasury yield.
[4]The article does not provide a specific estimate of alpha; however, it supports the general finding that the CAPM underestimates returns for low-beta stocks and overestimates returns for high-beta stocks.
[5]Relies on Lizenberger and Ramaswamy's before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.
[6]Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

Sources:
Black, Fischer. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.
Black, F., Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests, from Studies in the theory of Capital Markets. In *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, 79-121. New York: Praeger.
Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): 607-636.
Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): 427-465.
Fama, Eugene F. and Kenneth R. French. 2004. The Capital Asset Pricing Model: Theory and Evidence. *Journal of Economic Perspectives* 18 (3): 25-46.
Litzenberger, Robert H. and Krishna Ramaswamy. 1979. The Effect of Personal Taxes and Dividends on Capital Asset Prices, Theory and Empirical Evidence. *Journal of Financial Economics* XX (June): 163-195.
Litzenberger, Robert H. and Krishna Ramaswamy and Howard Sosin. 1980. On the CAPM Approach to Estimation of a Public Utility's Cost of Equity Capital. *The Journal of Finance* 35 (2): 369-387.

III. Financial Risk and the Cost of Equity

A common issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated company.[11] It may be tempting to simply estimate the cost of equity capital for each of the proxy companies (using one of the above approaches) and average them. After-all, the companies were chosen to be comparable in their business risk characteristics, so why would an investor necessarily prefer equity in one to the other (on average)?

The problem with this argument is that it ignores the fact that underlying asset risk (i.e., the risk inherent in the lines of business in which the firm invests its assets) for each company is typically divided between debt and equity holders. The firm's debt and equity are therefore financial derivatives of the underlying asset return, each offering a differently structured claim on the cash flows generated by those assets. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders. The relative structures of debt and equity claims are such that higher degrees of debt financing increase the variability of returns on equity, *even when the variability of asset returns remains constant*. As a consequence, otherwise identical firms with different capital structures will impose different levels of risk on their equity holders. Stated differently, increased leverage adds financial risk to a company's equity.[12]

A. The Effect of Financial Leverage on the Cost of Equity

To develop an intuition for the manner in which financial leverage affects the risk of equity, it is helpful to consider a concrete example. Figure B-4 and Figure B-5 below demonstrate the impact of leverage on the risk and return for equity by comparing equity's risk when a company uses no debt to finance its assets, and when it uses a 50-50 capital structure (i.e., it finances 50 percent of its assets with equity, 50 percent with debt). For illustrative purposes, the figures assume that the cash flows will be either \$5 or \$15 and that these two possibilities have the same chance of occurring (e.g., the chance that either occurs is ½).

[11] This is also a common valuation problem in general business contexts.

[12] I refer to this effect in terms of *financial risk* because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context financial risk is distinct from and independent of the *business risk* associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

Figure B-4: All Equity Capital Structure

		Asset Cash Flow	Debt Service	Equity Dividend	ROE	
$100	½	$15	$0	$15	15/100 =	15%
	½	$5	$0	$5	5/100 =	5%
					E(ROE)=	*10%*
					σ(ROE)=	*5%*

Figure B-5: 50/50 Capital Structure

		Asset cash flow	Debt Service	Equity Dividend	ROE	
$100	½	$15	$2.50	$12.50	12.50/50 =	25%
	½	$5	$2.50	$2.50	2.50/50 =	5%
					E(ROE)=	*15%*
					σ(ROE)=	*10%*

In the figures, E(ROE) indicates the mean return and σ(ROE) represents the standard deviation. This simple example illustrates that the introduction of debt increases both the mean (expected) return to equity holders and the variance of that return, even though the firm's expected cash flows—which are a property of the line of business in which its assets are invested—are unaffected by the firm's financing choices. The "magic" of financial leverage is not magic at all—leveraged equity investors can only earn a higher return because they take on greater risk.

B. Methods to Account for Financial Risk

1. Cost of Equity Implied by the Overall Cost of Capital

If the companies in a proxy group are truly comparable in terms of the systematic risks of the underlying assets, then the overall cost of capital of each company should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. The intuition here is as follows. A firm's asset value (and return) is allocated between equity and debt holders.[13] The expected return to the underlying asset is therefore equal to the value weighted

[13] Other claimants can be added to the weighted average if they exist. For example, when a firm's capital structure contains preferred equity, the term $\frac{P}{V} \times r_p$ is added to the expression for the overall cost of capital shown in Equation (7), where P refers to the market value of preferred equity, r_P is the cost of preferred equity and $V = E + D + P$. In my analysis, I attribute the same implied yield to the cost of preferred equity as to the cost of debt.

average of the expected returns to equity and debt holders – which is the overall cost of capital ($\boldsymbol{r}^*$), or the expected return on the assets of the firm as a whole.[14]

$$\boldsymbol{r}^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D(1 - \tau_c) \qquad (7)$$

where r_D is the market cost of debt,
r_E is the market cost of equity,
τ_c is the corporate income tax rate,
D is the market value of the firm's debt,
E is the market value of the firm's equity, and
$V = E + D$ is the total market value of the firm.

Since the overall cost of capital is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the overall cost of capital of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.[15]

The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.[16] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (i.e., the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at all by the

---

14 As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility. Note that the precise formulation of the weighted average formula representing the required return on the firm's *assets* independent of financing (sometimes called the *unlevered* cost of capital) depends on specific assumptions made regarding the value of tax shields from tax-deductible corporate debt, the role of personal income tax, and the cost of financial distress. See Taggart, Robert A., "Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management*, 1991; 20(3) for a detailed discussion of these assumptions and formulations. Equation (7) represents the overall weighted average cost of capital to the firm, which can be assumed to be constant across a relatively broad range of capital structures.

15 Empirically, companies within the same industry tend to have similar capital structures, while typical capital structures may vary between industries, so whether a leverage ratio is "unusual" depends upon the company's line of business.

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.

debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,[17] showed that while taxes and costs to financial distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,[18] the latter can still be shown to be constant across a broad range of capital structures.[19]

This reasoning suggests that one could compute the overall cost of capital for each of the proxy companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can then re-arrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis.[20]

2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)

An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta. Notice that this means working within the CAPM framework as the methodology cannot be applied directly to the DCF models.

---

17 Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

18 When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

19 This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

20 Market value capital structures are used in estimating the overall cost of capital for the proxy companies.

Recognizing that under general conditions, the value of a firm can be decomposed into its value with and without a tax shield, I obtain:[21]

$$V = V_U + PV(ITS) \tag{8}$$

where $V = E + D$ is the total value of the firm as in Equation (7),

V_U is the "unlevered" value of the firm—its value if financed entirely by equity

$PV(ITS)$ represents the present value of the interest tax shields associated with debt

For a company with a fixed book-value capital structure and no additional costs to leverage, it can be shown that the formula above implies:

$$r_E = r_U + \frac{D}{E}(1 - \tau_c)(r_U - r_D) \tag{9}$$

where r_U is the "unlevered cost of capital"—the required return on assets if the firm's assets were financed with 100% equity and zero debt—and the other parameters are defined as in Equation (7).

Replacing each of these returns by their CAPM representation and simplifying them gives the following relationship between the "levered" equity beta β_L for a firm (i.e., the one observed in market data as a consequence of the firm's actual market value capital structure) and the "unlevered" beta β_U that would be measured for the same firm if it had no debt in its capital structure:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \tag{10}$$

where β_D is the beta on the firm's debt. The unlevered beta is assumed to be constant with respect to capital structure, reflecting as it does the systematic risk of the firm's assets. Since the beta on

---

21 This follows development in Fernandez (2003). Other standard papers in this area include Hamada (1972), Miles and Ezzell (1985), Harris and Pringle (1985), Fernandez (2006). (See Fernandez, P., "Levered and Unlevered Beta," IESE Business School Working Paper WP-488, University of Navarra, Jan 2003 (rev. May 2006); Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock," *Journal of Finance*, 27, May 1972, pp. 435-452; Miles, J.A. and J.R. Ezzell, "Reformulating Tax Shield Valuation: A Note," *Journal of Finance*, XL5, Dec 1985, pp. 1485-1492; Harris, R.S. and J.J. Pringle, "Risk-Adjusted Discount Rates Extensions form the Average-Risk Case," *Journal of Financial Research*, Fall 1985, pp. 237-244; Fernandez, P., "The Value of Tax Shields Depends Only on the Net Increases of Debt," IESE Business School Working Paper WP-613, University of Navarra, 2006.) Additional discussion can be found in Brealey, Myers, and Allen (2014).

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 that holds when the market value capital structures (rather than book value) are assumed to be held constant:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \tag{11}$$

Unlike Equation (10), Equation (11) 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. And both equations allow an analyst to adjust for differences in financial risk by translating back and forth between β_L and β_U. In principal, Equation (10) 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 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 (10), or Equation (11). Rather than estimating debt betas, I rely on the standard financial textbook of Professors Berk & DeMarzo, who report a debt beta of 0.05 for A-rated debt and a beta of 0.10 for BBB rated debt.[22]

Once a decision on debt betas is made, the levered equity beta of each proxy 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 proxy companies are comparable on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the proxy 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 CAPM reapplied with this levered beta, which reflects both the business and financial risk of the target company.

---

[22] Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada who contributed to their development[23]—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

[23] 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.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

AARON WILLIS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF AARON WILLIS

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Aaron Willis (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company as Manager, Regulatory Economics.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Arts in Political Science from the University of Michigan, a Master's in Environmental Management from the Yale School of Forestry and Environmental Studies, and a Master's in Business Administration from the University of Maryland.

Q4. What is your work experience?

A4. In 2009, I was employed by the US Army Corps of Engineers, Institute for Water Resources as Social Scientist. In this role I supported enforcement of the Clean Water Act and engagement with domestic and international partners on a variety of water resources issues. In 2015, I was employed by Booz Allen Hamilton in their energy practice, providing support to commercial and federal clients on a variety of energy matters including market strategies, project development, and new energy technologies. In 2017, I began my employment with DTE Energy as an Associate in Corporate Strategy. In this role I supported key operational and strategic work across the Company. I was promoted to Senior Associate in 2019 and transitioned to Corporate Development, where I supported the Company's financial strategy. In

2020, I accepted a position in Regulatory Affairs supporting the Company's state regulatory strategy and engagement with the Michigan Public Service Commission (MPSC or Commission), MPSC Staff, and Michigan energy stakeholders. In 2021, I was promoted to my current position of Manager, Regulatory Economics.

Q5. What are your current duties and responsibilities?

A5. My responsibilities include the management of regulatory activities relative to DTE Electric's rate strategy, pricing, and load research.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission?

A6. Yes. I have sponsored testimony in the following cases:

- U-21163 XL High Load Factor Rate
- U-20836 DTE Electric 2022 General Rate Case
- U-21193 DTE Electric 2022 Integrated Resource Plan
- U-21306 Rider No. 16 Transition
- U-21338 DTE Electric 2023 Securitization
- U-21297 DTE Electric 2023 General Rate Case
- U-18091 DTE Electric 2024 PURPA Case

Line
No.

Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to address five topics as outlined below: Forecast Allocation Schedules, Power Supply Costs, Rate Design, Investment Recovery Mechanism (IRM) Surcharge Design, and Other Tariff Changes.

- **Forecast Allocation Schedules:** Support the allocation schedules and methodology utilized by the Company for the 12-month period ending December 31, 2025; support allocation schedules for the EV rate design cost of service and rate design.
- **Power Supply Costs and Nuclear Surcharge:** Support total power supply costs for the 12-month period ending December 31, 2025, and the Nuclear Surcharge.
    - Power supply costs include the projected base transmission expense, and base fuel and purchased power expense necessary for the sales forecast. While maintaining the current Power Supply Cost Recovery (PSCR) base of 31.26 mills per kilowatt hour at the generation level, I am proposing to update the loss factor to 7.69%, which will result in a PSCR base of 33.66 mills per kilowatt hour at the sales level to facilitate recovery of the projected costs. The method is consistent with prior Commission Orders, including in the Company's most recent general rate case, Case No. U-21297.
    - Nuclear surcharge is designed to collect the Proposed Nuclear Surcharge Revenue
- **Rate Design:** Support the proposed rate design and language modifications for the Company's rate schedules:

Line
No.

- *Residential:* (1) The development of capacity and non-capacity charges for each residential rate schedule based on the cost of service supported by Company Witness Maroun; (2) design of variable distribution rates for all residential secondary rate schedules; (3) proposed transition of customers on Rate Schedule D1.6 to Rate Schedule D1.11, the applicability of Low Income Assistance credits to all residential whole home, base rates, and the closure of Rate Schedule D1.6
- *Commercial secondary:* (1) The development of capacity and non-capacity charges for each commercial secondary rate schedule based on the cost of service supported by Company Witness Maroun; (2) design of distribution rates for all commercial secondary rate schedules; (3) proposed design for an optional, commercial secondary time of use rate pursuant to the Commission's December 1, 2023, Order in Case No. U-21297
- *Primary:* (1) The development of capacity and non-capacity charges for each primary rate schedule based on the cost of service supported by Company Witness Maroun; (2) design of distribution rates for all primary rate schedules; (3) development of power supply rates for Rate Schedule D13 (4) proposed design for an optional, primary time of use rate pursuant to the Commission's December 1, 2023, Order in Case No. U-21297
- *Other:* (1) Proposed Rider 18 outflow credits; (2) Proposed determinants and rates for a DC Fast Charging rate schedule pursuant to the Commission's December 1, 2023, Order in Case No. U-21297

- **IRM Surcharge Design:** Support pricing of the 2026 and 2027 IRM surcharge allocated by Company Witness Maroun.

Line
No.

- **Other Tariff Changes:** Propose changes to (1) CIAC waivers for Charging Forward in C6.1(16), (2) update line extension costs in Section C6 pursuant to the final Order in Case No. U-21297

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-5	E2	Cost of Service Allocation Methodology Diagram
A-5	E3	Allocation Schedule Description
A-13	C4	Calculation of Power Supply Expenses
A-13	C4.1	Five Year Average Loss Factor
A-16	F2	Summary Present and Proposed Revenues by Rate Schedule – 12 months ending December 31, 2025
A-16	F3	Present and Proposed Revenues by Rate Schedule – 12 months ending December 31, 2025
A-16	F4	Comparison of Present and Proposed Monthly Bills – 12 months ending December 31, 2025
A-16	F5	Calculation of Voltage Level Distribution Charges
A-16	F6	Calculation of Nuclear Surcharge
A-16	F7	Calculation of Rider 18 Outflow Credits
A-16	F8	Proposed Tariff Sheets
A-16	F9	DCFC Rate Design
A-17	G1.1	Forecast Energy Allocation Schedules – 12 months ending December 31, 2025

Line
No.

A-17	G1.2	Demand and Energy Allocation Percentages by Rate Class
A-17	G1.3	Forecast Energy Allocation Schedules – 12 months ending December 31, 2025 – DCFC Study
A-17	G1.4	Demand and Energy Allocation Percentages by Rate Class – DCFC Study
A-33	X7	IRM Surcharge Design

With respect to Exhibit A-16, Schedule F3, I am sponsoring pages 1-46, and Company Witness Bellini is sponsoring the remaining sheets contained in the exhibit.

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

<u>Allocation Schedules</u>

Q10. Are there any technical terms used in your allocations testimony that may require explanation?

A10. Yes. To aid in understanding and to avoid confusion, I am defining the following terms that I use throughout my testimony:

- Customer Class or Class of Service: A set of customers with similar characteristics who have been grouped for the purpose of setting an applicable rate for electric service.

- Total System Analysis (TSA): The study of all customer classes that identifies the hourly demand values for all hours of the year. This is the foundation of allocation schedules.
- Energy: The total kilowatt-hours (kWh) or megawatt-hours (MWh) supplied to or used by an individual customer or customer class.
- Demand: The rate at which electric energy is used at a given instant or averaged over a designated time interval. Typically, demand is expressed in kilowatts (kW) or megawatts (MW).
- Service Area System Peak Demand: The highest hourly demand for all customers (full service and choice) served on the DTE Electric distribution system within a specific period (day, month, year, etc.). Service Area System Peak Demand is commonly referred to as the 'system peak.'
- Bundled Peak Demand: The highest hourly demand for all full service customers served by DTE Electric's production system within a specific period (day, month, year, etc.). Bundled Peak Demand is commonly referred to as 'bundled peak.'
- Coincident Peak Demand (CP): The demand of any customer class within a specific period (day, month, year, etc.) that occurs at the same time as the system peak or the bundled peak demand for the same period.
- 12CP: The demand value derived by averaging the actual demand values registered on the monthly system or bundled peak hours for January through December for each customer class.
- 4CP: The demand value derived by averaging the actual demand values registered on the monthly bundled peak hours for June through September for each customer class.

Line
No.

- Non-Coincident Peak Demand: The maximum demand of any customer class within a specific period but not necessarily occurring at the time of the system peak demand for that period.
- Losses: A term used to define the difference between the electrical energy delivered to a customer (or a given point on the electrical distribution system) and the amount of electrical energy that must be generated at the power plant to serve that customer. In other words, losses refer to the difference in the amount of power generated from the power plant and the point of delivery.
- Load Factor: The ratio, in percent, of the total energy over a designated period of time to the maximum hourly demand (bundled or system) occurring in that period. Load factor is calculated by the formula:
  LF (%) = (Total Energy / (Peak Demand * No. of Hours)) * 100
- Customer-Owned: Industrial customers that use customer owned substations.
- DTE-Owned: Industrial customers that use DTE Electric single customer or joint-use general distribution substations.
- Transmission Voltage Level: Served directly from the transmission system at 120 kV or above, or from the transmission system through a DTE-owned substation dedicated or primarily providing service to the customer and located on or immediately adjacent to the customer's premises.
- Sub-transmission Voltage Level: Served directly from the sub-transmission system at voltages from 24 kV to 41.6 kV or from the sub-transmission system through a DTE-owned substation dedicated or primarily providing

service to the customer and located on or immediately adjacent to the customer's premises.

- Primary Voltage Level: Served directly from the primary distribution system at a nominal voltage between 4.8 kV and 13.2 kV who does not qualify as either a transmission voltage customer or a sub-transmission voltage customer.
- Secondary Service: Served directly from the secondary distribution system at a nominal voltage less than or equal to 4.8 kV and who does not qualify as either a transmission voltage customer, sub-transmission voltage customer or a primary voltage customer.

Q11. What are the data sources for the allocation schedules?

A11. The forecasted test year allocation schedules are based on 2022 customer class sales data obtained from the 2022 Total System Analysis (TSA). The forecast allocation schedules are based on the energy sales forecast for the residential, commercial, and industrial classes supported by Company Witness Leuker, the street lighting and traffic signals sales forecast supported by Company Witness Bellini, and the forecast billing determinants supported in my exhibits. These sales levels are shown with losses on Exhibit A-17, Schedule G1.1.

Q12. What is the purpose of the allocation schedules you have developed?

A12. Allocation schedules are developed using customer class sales, data from Advanced Metering Infrastructure (AMI), and quantitative methods to determine the extent (expressed as a percentage) that each customer class uses the various portions of the electrical system. In this case, the customer class usage percentages determined in the allocation schedules are one of the inputs used by Company Witness Maroun to determine customer class cost responsibility. Because all customer classes do not utilize the full distribution system to take delivery of electrical service, the allocation schedules are developed to assign only the portions of the system used by each customer class. Exhibit A-5, Schedule E2, is a diagram which reflects the applicability of allocation schedules to customer class.

Q13. How did you develop the allocation schedules?

A13. There are 13 forecast allocation schedules that I developed for use in cost-of-service studies (see Exhibit A-5, Schedule E3 for a description of each schedule). Each schedule was developed to allocate to each customer class's utilization of a particular part of the electrical system, which is the industry standard practice for developing allocation schedules. Schedule 100, shown in Exhibit A-17, Schedule G1.2, is based on the class's forecasted energy consumption. and the remaining 12 allocation schedules described in Exhibit A-5, Schedule E3, are based on the forecasted demand that a customer class places on the various portions of the electrical system. The allocation schedule numbers and the associated portion of the electrical system they represent are shown schematically on Exhibit A-5, Schedule E2.

Q14. Why does the measurement basis differ for each allocation schedule?

A14. The measurement basis for each allocation schedule is based on the design and service requirements for each portion of the electrical system. Specifically, forecasted energy is used for Power Plant Energy Production (Schedule 100)

Line
No.

required to serve customers. As customers use energy, they create a demand (rate at which energy is used and/or delivered) on the system.

The output capacity of power plant production is designed considering the peak demand requirements of the production system, measured as the bundled peak demand. Production Schedule 200A is measured on forecasted bundled 12 CP and Schedule 200B is measured based on the forecasted bundled 4CP. Schedule 201 – Input to Transmission Substation is based on the forecasted 12CP of the of the Service Area.

Schedules 202A, 202B, 202C, 203A, 203B, 203C, 204, and 205 refer to substations, high voltage lines and transformers, which are designed to carry the maximum load required by the customer classes they serve regardless of whether the class maximum demand occurs at the same time or a different time as the system peak. The forecasted non-coincident peak and individual customer maximum peak demand is the measurement basis for these allocation schedules.

Low voltage secondary lines are designed to serve the absolute maximum demand level of the customers they feed. Therefore, Schedule 300 is based upon the forecasted sum of the individual customer maximum demands.

Q15. How was the 2022 TSA used to develop the demand values determined for the forecast allocation schedules?

A15. The basis for the forecast allocation schedules developed for this instant case are the forecasted net sales values presented in Witness Leuker's Exhibit A-15, Schedule E1. However, because Witness Leuker's system peak demand forecast does not contain the associated customer class level demand values necessary for allocation schedule development, it was necessary to develop these corresponding demand values by customer class. This was done by applying historical load factors to the forecast energy values using industry standard load research principles to derive demand values using energy and load factor. Therefore, forecast demands were calculated by dividing the net forecast energy values without losses, by the product of the historic load factor and annual hours.

Q16. How were the appropriate historic load factors determined?

A16. A 5-year average load factor was derived from years 2018-2022 and used for each cost-of-service class.

Q17. Why is using the 5-year average historical load factor a better representation of the class's performance than the actual 2022 historic load factor?

A17. Using the 5-year average load factor accounts for any abnormalities in any single year and smooths out any variability due to weather, or other anomalies such as economic conditions.

Q18. Why is using average historical load factors a reasonable method of determining forecast demand values?

A18. There is a mathematical relationship between energy, load factor, and demand. Forecasting demand is necessarily a function of forecasted sales and forecasted load factors. Utilizing load factors to forecast demand values maintains the relationship between energy and demand.

Line No.

Q19. How did you develop the forecast allocation schedules?

A19. I applied the 5-year average load factors to the forecasted energy sales received from Witness Leuker to produce the January 2025 to December 2025 forecast schedules shown in Exhibit A-17, Schedule G1.1.

Q20. How are line losses used in forecast allocation schedules?

A20. Line loss factors are used as a multiplier in allocation schedules to increase the energy or demand value for a given schedule to reflect the amount of production needed to serve the customer class. Line losses were measured by voltage level, allowing allocation schedules to accurately reflect demands on the system caused by different classes of customers.

Q21. Are the allocation schedules defined in your testimony developed using established principles and methods?

A21. Yes. I used the industry recognized and accepted load research principles. The methods I used are consistent with the methods used by the Company in all its electric general rate cases filed since 2014.

Q22. How did you develop the Direct Current Fast Charging (DCFC) allocation schedules?

A22. The EV allocations process replicated the original allocation with the addition of an EV class for power supply and distribution, utilizing billing determinants as described later in my testimony.

Power Supply Costs and Nuclear Surcharge

Q23. Is DTE Electric proposing to reset the base power supply cost in this proceeding?

A23. No. The base power supply cost reflected in Exhibit A-13, Schedule C4 consists of two components: 1) base cost at generation, and 2) a loss factor. The Company is proposing to update the loss factor in this case consistent with the method approved in Case No. U-21297 and prior cases – it is not proposing any change to the base power supply cost at generation originally established by the Commission in its Order in Case No. U-15244. Since it was established, the amount of 31.26 mills per kilowatt hour has been maintained in each of the Company's subsequent general rate cases (Case Nos. U-15768, U-17767, U-18014, U-18255, U-20162, U-20561, U-20836, and U-21297). I have applied a loss factor of 7.69% to this amount, which results in a total PSCR base at the sales level of 33.66 mills per kilowatt hour as reflected in Exhibit A-13, Schedule C4. If approved, this amount will become the basis for recovery of the power supply costs with the same effective date as other rate changes approved in this proceeding. This amount will be reflected in the annual PSCR reconciliation, where the actual monthly PSCR revenue is a function of the approved base and the PSCR sales.

Q24. How did you determine the loss factor of 7.69%?

A24. The loss factor of 7.69% is the average difference between the annual system output and sales over the last five years ending with the historic test year, 2018 through 2022, as shown in Exhibit A-13, Schedule C4.1. This is the method approved by the Commission in the Company's last rate case (Case No. U-21297).

Line No.

Q25. Have you projected any under or over recovery of power supply costs in this proceeding?

A25. No. For the purpose of the instant case, the power supply costs equal the associated power supply revenues so there is no projected under or over recovery. Any actual under or over recovery of power supply costs are reconciled annually in the PSCR reconciliation filings. For purposes of this filing, Company Witness Bellini and I have calculated present revenues using the existing base rates approved by the Commission on December 1, 2023, in Case No. U-21297. We have used a zero PSCR factor to calculate revenues for the projected test period.

Q26. What does Exhibit A-13, Schedule C4 show?

A26. This schedule calculates the power supply expense for the projected test period. As stated earlier, the power supply costs and revenues are equivalent in the instant case, so the projected costs are a function of the proposed PSCR base shown on line 3 and the projected power supply sales volumes on line 5. The transmission expense on line 7 is the amount included in the current base, as originally approved in Case No. U-15244. The power supply costs attributable to specific Rider 10, Rider 3 (sales shown together on line 16) and D13 sales (sales shown on line 17), are not subject to the PSCR. Line 18 reflects total retail sales less Rider 10, Rider 3, and D13. The corresponding costs are shown on Lines 21 and 22 for Rider 10 and Rider 3, and line 23 for D13. The total expense for the test period including transmission expense is $1,354 million, as shown on line 31. Lines 35 through line 40 show the split of the total power supply expense between capacity and non-capacity, based on the PA295 and PURPA related generation costs, capacity purchases and the net energy market sales supported by Company Witness Burgdorf.

Q27. What does Exhibit A-16, Schedule F6 show?

A27. The Company's proposed nuclear surcharge is designed to collect the Proposed Nuclear Surcharge Revenue. Exhibit A-16, Schedule F6 shows the calculation of the Nuclear Surcharge, which recovers costs associated with nuclear site security & radiation protection, and the funding for nuclear decommissioning and low-level radioactive waste disposal. The proposed nuclear surcharge increase is due to increases in site security and radiation protection costs as supported by Company Witness Davis and lower forecasted jurisdictional sales.

<u>Rate Design</u>

Q28. What does Exhibit A-16, Schedule F2 show?

A28. This exhibit summarizes present and proposed revenues by rate schedule for the 12-month period ending December 31, 2025. Present revenues are based on rates approved on December 1, 2023, in the Company's last general rate case, Case No. U-21297. The exhibit provides a comparison of total present and proposed revenues on page 2, present and proposed power supply revenues on page 3, and present and proposed distribution revenues on page 4. The proposed power supply revenues on page 3 provides a separate breakout of capacity and non-capacity related power supply revenues.

Q29. What does Exhibit A-16, Schedule F3 show?

A29. This exhibit shows the present and proposed rate design and corresponding revenue by rate schedule based on the billing determinants for the 12-month period ending December 31, 2025. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The billing determinants were developed based on historical data and relationships, as well as known and measurable changes, and are consistent with Company Witness Leuker's sales forecast. The existing rates, as approved by the MPSC's Order in Case No. U-21297 on December 1, 2023, are in column (c), and are used to calculate the present revenues in column (d). The rates proposed in this proceeding are in column (e), with the resulting revenues in column (f).

The only exceptions to the layout described above are for pages 10, 22, 37, and 38 of Exhibit A-16, Schedule F3. Page 10 contains the rate design for a residential rate schedule the Commission first approved in the Company's last general rate case, Rate Schedule D1.13 Overnight Savers TOD. This rate schedule is designed to be revenue neutral to the Company's proposed Rate Schedule D1.11 in this case. For this page of Exhibit A-16 Schedule F3, column (d) is the proposed Rate Schedule D1.11 revenue. Column (e) contains the rates being proposed for Rate Schedule D1.13, with the resulting revenues in column (f). A comparison of the totals in columns (d) and (f) on this page shows the rate schedule is designed to be revenue neutral to the proposed D1.11 Rate Schedule. A similar structure is used on page 22, which contains new Rate Schedule D3.11 being proposed for the first time in this case, being designed revenue neutral to Rate Schedule D3. A similar structure is again used on pages 37-38, which contains new Rate Schedule D14 being proposed for the first time in this case, being designed revenue neutral to Rate Schedule D11. The proposed rate schedules D3.11 and D14 are described further below in my testimony.

Line No.

Residential Rate Design

Q30. What residential rate schedules does the Company currently offer?

A30. The Company offers several rate schedules for residential customers:

- Rate Schedule D1 is the Company's former standard residential service rate, which is now titled the Non-Transmitting Meter rate.
- Rate Schedule D1.11 is a product with rates that vary depending on season and time of day and is the Company's standard residential service rate.
- Rate Schedule D1.13 is a product with rates that vary depending on season and time of day and was approved in Case No. U-21297; it will be available to customers no later than November 30, 2024.
- Rate Schedule D1.1 is a separately metered interruptible space conditioning service rate.
- Rate Schedule D1.2 is a product with rates that vary depending on season and time of day.
- Rate Schedule D1.6 is a product available to qualifying low-income customers and supplies them with a $40 monthly credit. The volumetric rate design is consistent with Rate Schedule D1.
- Rate Schedule D1.7 is a separately metered rate available for supplemental geothermal electric service with rates dependent on season and time of day.
- Rate Schedule D1.8 is a dynamic peak pricing product that has three pricing periods based on time of day and that is periodically subject to critical peak pricing.
- Rate Schedule D1.9 is a separately metered product for supplemental service to charge electric vehicles.

- Rate Schedule D2 was available to customers for all electric service if all space heating was total electric and installed on a permanent basis. It is now available only to dwellings being served on the rate prior to December 17, 2015.
- Rate Schedule D5 is a separately metered interruptible electric water heating product.

Q31. What is the basis for the Company's proposed residential rate levels in this proceeding?

A31. The basis for the proposed rate levels are the functionalized power supply and distribution deficiency/sufficiency amounts supported by Company Witness Maroun as shown in his Exhibit A-16, Schedule F1.1, page 2 (for power supply) and his Exhibit A-16, Schedule F1.2, page 1 (for distribution). The proposed residential power supply and distribution charges were designed to meet the power supply and distribution deficiencies shown in these exhibits. The proposed residential power supply capacity and non-capacity rates were designed to recover the revenues pursuant to Company Witness Maroun's Exhibit A-16, Schedule F1.5, which shows how much of the power supply revenue requirement for each rate class is capacity and non-capacity related.

Within the power supply cost of service, Company Witness Maroun identifies three separate residential cost classes: "D1.11/Other", "D1.2", and "D2". All current residential rate schedules except D1.2 and D2 are included in D1.11/Other. For the D1.11/Other rate schedules, the power supply deficiency was allocated based on each rate schedule's percentage contribution to the present D1.11/Other power supply revenue. For those rate schedules with their own cost of service class (D1.2 and D2), the deficiency was directly allocated to the corresponding class. This is the same method used to develop the approved residential power supply rates in the Company's last rate case, Case No. U-21297.

Q32. Are you proposing any changes to power supply rate design on residential rate schedules?

A32. Yes. The Company is proposing to design Rate Schedule D1.7 non-capacity charges on a time-of-use basis such that the D1.7 non-capacity rate structure would be the same as the D1.7 capacity rate structure – pricing differentials are consistent with the ordered D1.7 power supply design in Case No. U-20836. This approach is similar to currently approved Rate Schedules D1.11, D1.2, and D1.8. This change will further align rate design methodologies across the residential rate schedules.

Q33. What is the Company's proposed residential distribution rate design?

A33. In the Company's rate case filed in 2014, Case No. U-17767, MPSC Staff recommended, and the Commission approved, variable distribution rates designed such that all customers in the Residential class would have the same rate, with the caveat that a cap was applied to limit the increase of any specific variable distribution rate. This method was again proposed and approved in each of the Company's subsequent rate cases. The Company designed the variable distribution rates for each residential rate schedule in this case using this same premise. The Residential class rate schedules now all have the same distribution rate, and thus no cap on any individual Residential Secondary rate schedule's distribution rate is

Line No.

applied in this case. The one exception is Rate Schedule D1.13, which has variable distribution rates designed consistent with the Order in Case No. U-21297.

Q34. What does Exhibit A-16, Schedule F4 show?

A34. This exhibit shows a comparison of typical monthly bills by rate schedule based on present and proposed rates. For each rate schedule, the exhibit calculates the amount of a bill under existing rates and proposed rates across a broad range of energy consumption levels. The difference is representative of the impact of the proposed rate changes.

Q35. What did the Commission Order with respect to Rate Schedule D1.6 in Case No. U-21297?

A35. The Company, in Case No. U-21297, proposed to transition Rate Schedule D1.6 customers to Rate Schedule D1.11, make the Low-Income Assistance credit available on additional residential base rates (compared to only D1.6 at present), and close Rate Schedule D1.6. The Commission declined to approve the Company's proposal and instead said "DTE Electric Company shall conduct an impact study before retiring Rate Schedule D1.6 and transitioning customers to Rate Schedule D1.11.[1]"

Q36. What is the Company's proposal in this case for Rate Schedule D1.6 and the associated Low Income Assistance credit?

A36. The Company proposes three specific actions[2]:

[1] December 1, 2023, Order in Case No. U-21297, Pg 372

[2] Separate and apart from these three specific actions, Company Witness Sparks proposed to increase the LIA credit from $40 to $50

Line No.

- Open availability of the low-income assistance (LIA) credit, which currently requires the customer to switch from their existing rate schedule to D1.6, to all residential base rates. This would eliminate the requirement that customers seeking the LIA credit must take service on D1.6. All other requirements for the LIA would remain as they are presently.
- Transition current D1.6 customers to D1.11, the Company's default residential rate schedule, while allowing customers receiving the credit to modify their service to any other residential base rate for which they are otherwise eligible. Any D1.6 customer with a non-transmitting meter will be transitioned to Rate Schedule D1 Non-Transmitting Meter rate in the alternative.
- Retire Rate Schedule D1.6 as the final piece of the Company's transition to time of use rates for residential customers[3], a process which formally commenced with the Commission's April 18, 2018, Order in Case No. U-18255 and was completed in Spring 2023.

Q37. Why does the Company believe customers receiving, or desiring to receive, the low-income assistance credit should have choice in which rate schedule they are on?

A37. Customers should have optionality in their base rates and the opportunity to choose the option that is best for their energy usage circumstances. Today, LIA-recipient customers have one rate schedule available to them. The Company proposes to extend this to all residential base rate schedules, which for most customers includes D1.11, D1.2, D1.8, and D1.13, consistent with the options available to all other

[3] Notwithstanding the small number of customers remaining on Rate Schedule D1 Non-Transmitting Meter Rate

Line No.

residential customers. There is no basis to limit options for this specific group of customers.

Q38. Did the Company conduct an impact study of a transition from Rate Schedule D1.6 to Rate Schedule D1.11?

A38. Yes. The Company calculated a distribution of customer impacts on D1.6 and D1.11 using 2022 actual sales for customers who in 2022 were served on D1.6[4] and rates effective following the implementation of Case No. U-20836. The analysis ultimately included 26,126 such customers. The purpose of this analysis was to determine if there is structurally adverse impact of transitioning customers from D1.6 to D1.11; it does not reflect customer behavior change nor does it reflect a forecast of actual outcomes related to this case. Actual bills vary based on a variety of factors including weather, rate schedule, and the timing/volume of usage.

Q39. Did the impact study identify a structurally adverse impact of transitioning D1.6 customers to D1.11?

A39. No. The average impact of a customer transitioning from D1.6 to D1.11 is a decrease of their bill of 0.17%. Given the average impact is near zero, this confirms there is no structurally adverse impact. Rate Schedule D1.6 maintains the legacy structure previously utilized by most DTE residential customers, which is known as an "inverted block rate". This type of rate charges customers more per kilowatt hour at a specified level of usage – in the case of D1.6 that level is +/- 17 kilowatt hours per day. Before the implementation of advanced meters, it was an effective way to design a rate which incentivized the efficient use of energy. However, with

[4] With a minimum of 300 billing days

Line No.

the wide implementation of advanced meters, time-of-use rates are a more precise way to design rates than an inverted block approach. They charge higher rates when the cost to provide electricity is higher instead of simply when more is consumed. Necessarily, customers will have somewhat different bill outcomes on different rate designs based on how and when they use energy.

In general, customers with higher average usage tend to benefit on D1.11 and customers with lower average usage tend to benefit on the inverted block rate. For context, in the instant case, the Company is forecasting average monthly sales per customer of ~631 kWh on Rate Schedule D1.6 and ~582 kWh on Rate Schedule D1.11[5]. This dynamic is further described in Table 1 below.

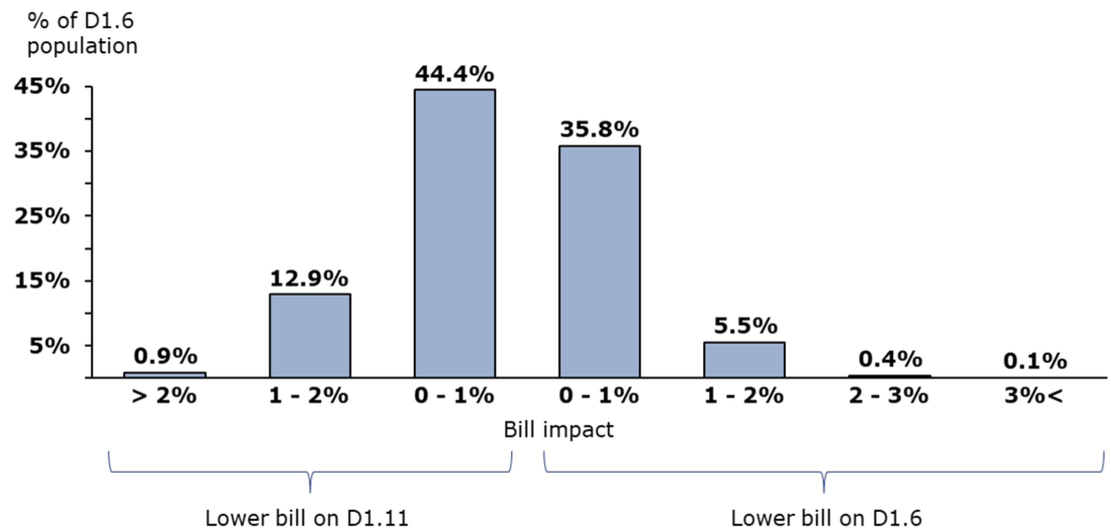
Table 1 Customer usage and impact statistics

	Lower bill on D1.11	Lower bill on D1.6
Customers in analysis	15,220	10,906
Average usage per month	785 kWh	486 kWh
Average usage >17kWh/mo.	32%	13%
Average % difference in bill	(0.66%)	0.52%
Average $ difference in bill	($1.29)	$0.51

And as the chart below (Figure 1.) describes, there is a narrow distribution of bill changes when comparing D1.6 and D1.11 and the average change is a very slightly lower bill on D1.11 – 58% of customers in the analysis would see a lower bill on D1.11, all else equal.

[5] See Exhibit A-14, Schedule F3

Figure 1 . Difference in bill on D1.11 compared to D1.6



Q40. Given the results of the study and your demonstration that there is no structurally adverse impact of the proposal, what is your recommendation to the Commission?

A40. I recommend the Commission approve the Company's proposal to:

- Open LIA credit availability to all residential base rates
- Transition D1.6 customers to D1.11
- Retire D1.6

Upon approval the Company would complete rate transition and retirement by the end of the projected test year.

<u>Rider 18 Outflow Credits</u>

Q41. What does Exhibit A-16, Schedule F7, pages 1 through 2 show?

A41. In Case No. U-20836, the Commission approved the Staff's method to calculate the outflow credit for customers taking service under Rider 18 (Distributed Generation). That same calculation method was utilized by the Company and once again approved in its last general rate case, Case No. U-21297. The outflow credit is based on power supply rates. Pages 1 and 2 of this exhibit show the calculation of the proposed outflow rates for each rate schedule by adding the non-capacity rate (column b) and capacity rate (column c). The outflow credits are calculated using the same methodology proposed by Staff and approved by the Commission in Case Nos. U-20836 and U-21297.

Q42. Do the power supply outflow credits calculated on Exhibit A-16, Schedule F7 and shown on Exhibit A-16, Schedule F8 (Sheet Nos. D-115.00 and 116.00), include the current PSCR factor?

A42. No. Given the more frequent changes in the PSCR factor, for administrative convenience, the PSCR factor is not included. However, as stated in the currently approved Rate Book on Sheet No. D-114.00, when calculating the actual outflow credit applied to customer bills, the Company will add or subtract the current PSCR factor (which is shown on Sheet No. C-62.00) to the rates shown on Sheet Nos. D-115.00 and D-116.00. Rate Schedule D13 outflow credits would not be adjusted by PSCR as those customers are not subject to PSCR.

Commercial Secondary Rate Design

Q43. Can you please provide a brief description for each of the Company's commercial secondary rate schedules?

A43. Yes, the following descriptions are in the order shown in Exhibit A-16, Schedule F3.

- Rate Schedule D1.1 is a separately metered interruptible space conditioning service rate.
- Rate Schedule D1.7 is a separately metered rate available for supplemental geothermal electric service with rates dependent on season and time of day.
- Rate Schedule D1.8 is a dynamic peak pricing product with three time of day pricing periods that is periodically subject to critical peak pricing.
- Rate Schedule D1.9 is a separately metered product for service to charge electric vehicles.
- Rate Schedule D3 is our general service rate for non-residential customers.
- Rate Schedule D3.1 is an unmetered general service rate available to customers for loads which are impractical to meter.
- Rate Schedule D3.2 is a secondary educational rate available for school, college, or university customer locations.
- Rate Schedule D3.3 is available to customers desiring interruptible service.
- Rate Schedule D3.5 is a Company owned charging service and includes on/off peak non-capacity energy charges and a session fee.
- Rate Schedule D4 is the Company’s large general service rate and includes a demand charge.
- Rate Schedule D5 is an interruptible electric water heating rate available to commercial customers based on certain size criteria.
- Rate Schedule E1.1 is for any metered energy provided to municipality-owned streetlights.
- Rate Schedule Rider 7 is available to customers with high intensity lighting requirements, such as greenhouses.

- Finally, Rate Schedule Rider 8 is available to customers with total electric commercial space conditioning needs.

Q44. What is the basis for the Company's proposed commercial secondary rates in this proceeding?

A44. The proposed commercial secondary power supply and distribution charges were designed to meet the respective deficiencies shown in Company Witness Maroun's Exhibit A-16, Schedule F1.1, page 2 (for power supply) and Exhibit A-16, Schedule F1.2, page 1 (for distribution). The proposed power supply capacity and non-capacity rates were designed to recover the revenues pursuant to Company Witness Maroun's Exhibit A-16, Schedule F1.5, which shows how much of the power supply revenue requirement for each rate class is capacity and non-capacity related.

Q45. How are the power supply revenue targets allocated in your rate design?

A45. I followed the same methodology utilized in Case No. U-21297 to allocate both the capacity and non-capacity power supply revenue requirements to the individual tariffs within the secondary class. In his cost-of-service analysis, Company Witness Maroun identifies three separate cost classes: one specific to Rate Schedule D3.2, one specific to Rate Schedule D4, and one to capture Rate Schedule D3 and all remaining rate schedules. The revenue requirements for D3.2 and D4 are assigned directly to the respective class. The revenue requirement for the D3 and other subgroup is further allocated based on each tariff's percentage contribution to the total present power supply revenue for that same subgroup.

Q46. How were the commercial secondary energy rates determined?

A46. With the exception of rate schedules D3.5 and D4, all commercial secondary power supply rates are energy based. After allocating the revenue targets to each individual rate schedule as discussed earlier, I divided the capacity and non-capacity targets for each rate schedule by the associated power supply sales to determine the capacity and non-capacity energy rates, respectively. The rate structure for Rate Schedule D3.5 has a non-capacity energy charge based on time of use and a session fee which includes power supply capacity and is based on the demand rating of the charging station, consistent with the approved rate design in Case No. U-21297. The rate structure for Rate Schedule D4 has a capacity power supply demand charge which is set at a level to recover the full capacity revenue requirement, consistent with the methodology approved in Case Nos. U-18248, U-18255, U-20105, U-20162, U-20561, U-20836, and U-21297. The non-capacity revenue for D4 is currently collected through a non-capacity demand charge, and two separate energy charges, dependent on the total hours use of demand.

Q47. Did you make any changes from previous rate design?

A47. Yes. For Rate Schedule D1.7 (Secondary), I designed the proposed non-capacity power supply rates to vary across summer and winter and by time of use period. The previous design utilized a flat non-capacity energy charge. This change ensures consistency with the existing rate design on D1.7 as well as mimics the proposed design structure for residential D1.7.

Q48. How does Company Witness Maroun's revenue deficiency/sufficiency for distribution presented in this instant case impact your rate design?

Line No.

A48. My rate design in this instant case is consistent with the rate design methodology used by the MPSC Staff to calculate rates which were approved by the Commission in Case Nos. U-18014, U-18255, U-20105, U-20162, U-20561, U-20836 and most recently, U-21297. The Company and MPSC Staff maintained the position in each of these cases that if the customers are alike enough to be classified together, their distribution rates should also be alike to the extent possible.

Q49. How did you design Rate Schedule D3.5?

A49. Rate Schedule D3.5 is the Company's Charging Hub Rate. It has zero forecast determinants in this case and, as such, I increase the energy charges by the same percentage as Rate Schedule D3 power supply charges.

Q50. Are you proposing changes to the secondary service charges in this case?

A50. No.

Q51. Are you proposing any new commercial secondary rate schedules?

A51. Yes. In compliance with the December 1, 2023, Order in Case No. U-21297, pg. 372, which said "[f]or its next general rate case, DTE Electric Company shall develop and present optional time-of-use rates for its commercial secondary and primary customers", the Company is proposing an optional time of use rate for commercial secondary customers. Proposed Rate Schedule D3.11 is further described below and reflected in my Exhibit A-16, Schedules F3 and F8. The proposed rate is fully optional, and the Company is not proposing to transition any customer to the rate without a customer-initiated request.

Line No.

Q52. Are you including any additional commercial secondary rate schedules?

A52. Yes. I am also including rates designed for electric vehicle fast charging pursuant to the Order in Case No. U-21297, pg. 373, which said "DTE Electric Company shall conduct a separate cost of service study to allocate appropriate costs to fast charging and design and propose rates for this specific class of customer". As described by Company Witness Maroun, the cost of service and rate design is for discussion and not proposed for implementation in the instant case. As such, the Company has not included it in Exhibit A-16 Schedule F2, F3, or F8. The rate design is provided in Exhibit A-16, Schedule F9.

<u>Commercial Secondary Time of Use</u>

Q53. How is proposed Rate Schedule D3.11 designed?

A53. The rate schedule is designed to be revenue neutral to Rate Schedule D3 until there is sufficient historical usage to determine the utility of, and potentially implement, a separate revenue line in the D3/Other cost of service class, or a separate cost of service class. This approach also reduces the near-term risk of forecasting customer adoption on the new rate and any associated usage changes on existing rates. Thus, the rate utilizes the same overall billing determinants, cost allocations, and underlying revenue requirements as D3 in this case, similar to the initial D1.11 proposal in Case No. U-20836. The proposed tariff included in Exhibit A-16, Schedule F8 requires any customer electing D3.11 to remain on that rate for at least 12-months before switching to another rate.

In addition, the proposed tariff caps enrollment on the rate at 1,000 customers to account for potential unanticipated usage patterns on the rate – this is consistent

Line No.

with the Commission approval of Rate Schedule D1.13, a residential, voluntary time of use rate, in Case No. U-21297. The Commission approved a cap of 10,000 customers, or ~0.5% of the Company's approximately 2 million residential customers in that case. Considering the same 0.5% percentage and the ~200k commercial secondary customers forecasted in this case suggests 1,000 customers as an appropriate starting point.

Q54. What are the proposed power supply time of use pricing periods?

A54. The Company proposes that Rate Schedule D3.11 power supply vary based on season and time of day, consistent with the Company's default residential rate schedule. The on-peak hours remain constant across the year to support customer understanding and to maintain simplicity in the Company's rates.

- Season
  - Summer pricing in effect June – September
  - Non-summer pricing in effect from October - May
- Time of day
  - On-peak from 1:00pm – 5:00pm, Monday – Friday
  - Off-peak in all other hours

Q55. What is the basis for the 1:00 – 5:00pm on-peak period?

A55. This period aligns with both the system coincident peaks during the summer months[6] as well as the secondary class peaks in the summer months. Considering the period 2018 – 2022, 18 of 20 summer system coincident peaks occur within the proposed on-peak hours, and all 20 of the summer secondary class peaks occur

[6] June, July, August, September

Line No.

within the proposed on-peak period[7]. This alignment ensures the on-peak period reflects those periods of highest use on the system and the highest system use of this customer group, encouraging system-efficient usage.

Q56. How did you develop the determinants and the power supply pricing differential between the peak periods and the seasons?

A56. I allocated determinants to each pricing period based on (1) historic D3 actuals and (2) an assumed on-peak to off-peak shift of 8.2% for the summer months and 3.3% for the non-summer months. These shifts reflect the expected change in behavior for customers electing service on this rate. The Company's Advanced Customer Pricing Pilot included a rate with the same pricing differential approach (relative LMP and TOU structure for both capacity and non-capacity power supply) and opt-in enrollment, which mimics the method by which customers would enroll on D3.11. Therefore, this is the best available proxy for expected shifts in usage.

For power supply pricing differentials, I utilized the relative difference in LMP for the years 2020-2022 between the periods and seasons. This is consistent with the method approved by the Commission for rate schedule D.11, which varies power supply costs using the relative difference in LMP.

Q57. How are the distribution rate and service charge design?

A57. Both the distribution rate and monthly service charge are designed consistent with Rate Schedule D3. The distribution rate is a flat, non-time variant rate.

[7] Data as reflected in Part III Attachment 5 (29)

Line No.

Q58. What are the proposed prices considering both the periods and methodology and what is the resulting differential?

A58. The table below describes the total volumetric prices for each period[8], and "all in" differential. Off peak does not vary by season.

	Rate (¢/kWh)	Differential to Off Peak
Summer On Peak	19.49	1.38x
Non-Summer On Peak	14.67	1.04x
Off Peak	14.11	1.00x

Q59. When would this rate schedule be effective if approved by the Commission?

A59. Upon approval from the Commission, the rate would need to be developed, tested, and implemented in the Company's billing system. As such, and as reflected in my Exhibit A-16, Schedule F8, the Company intend to have the rate available for customers no later than the end of the projected test year in the instant case (December 31, 2025).

EV Fast Charger Rate Design

Q60. Please summarize the Company's EV Fast Charger Rate Design.

A60. The Company's proposed EV fast charger rate is designed as a secondary voltage rate with time of use power supply pricing which varies by time period and season. Power supply capacity and non-capacity rates are designed to recover the respective revenue requirements allocated by Company Witness Maroun. Both capacity and

[8] Consisting of power supply capacity, power supply non-capacity, and distribution only.

Line No.

non-capacity include an on-peak period of 1:00 – 5:00pm, Monday-Friday, and a seasonal component with summer rates effective June, July, August, and September, and non-summer rates effective in all other months. The pricing differential between the four pricing periods is based on the relative differences in LMP, consistent with the proposed Rate Schedule D3.11 and the currently effective Rate Schedule D1.11. Delivery rates are designed to recover the revenue requirements allocated by Company Witness Maroun, including a service charge consistent with Rate Schedule D3. The distribution rate is designed as a flat volumetric rate. All surcharges are consistent with a similarly situated D3 customer.

Q61. How did the Company develop the determinants and load shape for the rate?

A61. The Company utilized usage from current, known EV fast chargers to develop the determinants for the rate. Company Witness Bennett provided me a list of 68 known EV fast chargers customers taking service from the Company. In order to isolate EV fast chargers from other load and appropriately design this rate, I used information from those chargers on separate meters as the basis for the load shapes. I also excluded chargers with fewer than 300 read days, which typically indicates a charger installed sometime during the analysis period. Ultimately, the determinants and rate design leverage historical data from a total of 21 chargers.

Q62. Do you have any concerns about the data sample size or quality?

A62. Yes. As noted above, there are approximately 68 known EV fast charger customers served by the Company, of which 21 were usable for this analysis. While this data supports a reasonable first step of analysis for discussion purposes, it is apparent that the ability to identify all EV fast charger load and to isolate it from other co-located load has limitations. Thus, this data has two notable constraints:

1) The sample size is small because the overall density of EV fast chargers is still small relative to customer counts in other cost of service classes. Very small cost of service classes such as this one can lead to volatile determinants, COS, and rate design from case to case and individual customers may have an outsized impact on the overall class.
2) The sample size, while reasonably defined, does not include all EV fast chargers served by the Company given the co-location of charging load with other general service loads.

Q63. What do you recommend the Commission order with respect to the EV Fast Charger Rate?

A63. The Company acknowledges the merit in continuing this discussion. The data constraints and generally small customer set indicate that this proposal should be used as a starting point for discussion only and not as a rate to be implemented at the conclusion of this case.

<u>Primary Rate Design</u>

Q64. Can you please provide a brief description for each of the Company's primary customer rate schedules?

A64. Yes, the Company offers several primary rates.

- Rate Schedule D11 is the Company's main primary rate schedule and is available to customers served at primary, sub-transmission, or transmission voltage.

- Rate Schedule D6.2 is available to educational institution customer locations (schools, colleges, or universities) desiring service at primary, sub-transmission, or transmission voltage.
- Rate Schedule D8 is the Company's primary voltage interruptible rate which is limited to 300 megawatts.
- Rate Schedule D10 is the Company's all-electric school building rate (including electric space and water heating).
- Rate Schedule D12 is the Company's Experimental Large Customer Low Peak Demand Supply rate.
- Rate Schedule D13 is the Company's XL Large Industrial Rate.
- Riders 1.1 and 1.2 are specific interruptible rates for customers operating electric furnaces for metal melting (Rider 1.1) or using electric heat as an integral part of manufacturing (Rider 1.2).
- The Company's Rider 3 rate provides standby service for various customers with generation facilities operating in parallel with the Company's system.
- Rider 10 is an interruptible supply rate available to customers with larger interruptible loads.

Q65. How were the capacity and non-capacity charges determined for the primary rate schedules?

A65. My proposed primary rate designs result in power supply rates which are set equal to cost-to-serve. Company Witness Maroun determined the capacity and non-capacity revenue requirement for each cost-of-service class, which are shown in his Exhibit A-16, Schedule F1.5. For primary rates with billing demand components, capacity rates were designed to collect the total capacity revenue requirement through the billing demand charges. For primary rates that do not have billing demand components, capacity rates were designed to collect capacity revenue requirement through energy charges. Generally, non-capacity rates were designed to recover non-capacity revenue requirement through energy and/or demand charges.

Q66. Did you make any changes from previous rate design?

A66. No.

Q67. How were the Distribution charges determined for the primary rate schedules?

A67. The Company's proposed primary delivery rates are cost based by voltage level, utilizing the distribution base revenue deficiency/sufficiency levels by voltage class shown in Exhibit A-16, Schedule F1.2 and sponsored by Company Witness Maroun. Exhibit A-16, Schedule F5 shows the development of the voltage level Distribution Demand Charges for the primary tariffs. The present (U-21297 Base Rates) base delivery revenue by voltage level for each rate schedule is shown in column (a). The base delivery revenue includes all revenues from service charges, distribution energy and demand charges, and substation credits. The cost-based deficiency/sufficiency for each service voltage level, from Exhibit A-16, Schedule F1.2, sponsored by Company Witness Maroun, are shown in column (b). Column (c) shows the total proposed base delivery revenue to be collected from each voltage level, which is the sum of columns (a) and (b). Columns (d) and (e) show the proposed service charge revenue and substation credits. Columns (d) and (e) are subtracted from column (c) to determine the amount of base delivery revenue to be collected in distribution demand charges, shown in column (f). The distribution demand revenue in column (f) was divided by the distribution demands in column (g) to determine the distribution demand charges by voltage level shown in column (h).

Q68. Will all primary customers pay the same $/kW distribution charges (i.e., an equivalent amount as shown in column (h))?

A68. All primary rates will have the same $/kW charges shown in column (h) with the exception of rate D10 and riders R1.1 and R1.2 which have energy-based delivery charges. For rate D10 and riders R1.1 and R1.2, I have calculated energy charges equivalent to the proposed voltage level distribution charges. Rate Schedule D13 is also a primary rate schedule with energy-based delivery charges and is discussed below.

Q69. How is Rate Schedule D12 designed?

A69. Rate Schedule D12 is designed to have increases consistent with D11. There are no present or forecasted sales on D12 and, as such, this method is appropriate. Power supply rates are increased at the same percentage increase as D11, and distribution rates are consistent with the voltage level rates for all primary service customers.

Q70. How is Rate Schedule D13 designed?

A70. The proposed design is consistent with the approved design in Case No. U-21297 and utilizes Blue Water Energy Center (BWEC) as a proxy indication of marginal cost to serve. Proposed capacity rates maintain the levelized cost of BWEC capacity approved by the Commission in successive case, including Case No. U-21297, and are unchanged. Proposed non-capacity rates utilize BWEC proxy costs using a fixed heat rate assumption which is unchanged from Case No. U-21297, forecasted natural gas costs as described in the Company's direct testimony and exhibits in Case No. U-21425[9], and a non-fuel O&M assumption. Proposed transmission rates reflect the incremental cost of transmission to the Company resulting from projected D13 load. The proposed administrative charge reflects the incremental cost to administer the Rate Schedule and is unchanged. Distribution rates are consistent with the voltage level distribution rates for primary, sub transmission, and transmission voltage. Distribution rates are designed as volumetric assuming a 75% load factor. The customer charge is consistent with those proposed for all primary customers.

Q71. Are you proposing changes to the primary rate service charges?

A71. No.

Q72. Are you proposing any new primary rate schedules?

A72. Yes. Consistent with the December 1, 2023, Order in Case No. U-21297, pg. 372, which said "[f]or its next general rate case, DTE Electric Company shall develop and present optional time-of-use rates for its commercial secondary and primary customers", the Company is proposing an optional time of use rate for primary customers. Proposed Rate Schedule D14 is further described below and reflected in my Exhibit A-16, Schedules F3 and F8. The proposed rate is fully optional, and the Company is not proposing to transition any customer to the rate without a customer-initiated request.

[9] Exhibit A-14, CY 2025

Line No.

Q73. How is proposed Rate Schedule D14 designed?

A73. The rate schedule is design to be revenue neutral to rate schedule D11 until there is sufficient historical usage to determine the utility of, and potentially implement, a separate cost of service class or a separate revenue line within D11/Other. This approach also reduces the complexity of forecasting customer adoption on the new rate and any associated usage changes on existing rates. Thus, the rate utilizes the same overall billing determinants, cost allocations, and underlying revenue requirements as D11 in this case. The time of use structure applies to power supply charges, while distribution charges remain demand charges based on voltage level and consistent with other primary rate schedules.

Q74. What are the proposed time of use pricing periods?

A74. The Company proposes that Rate Schedule D14 vary based on season and time of day. The on-peak hours remain constant across the year to support customer understanding and to maintain simplicity in the Company's rates.

- Season
    - Summer pricing in effect June – September
    - Non-summer pricing in effect from October - May
- Time of day
    - On-peak from 11:00a – 7:00p, Monday – Friday, excluding holidays as defined in Section C11 of the Company's rate book. This is consistent with the existing on-peak hours for rate schedule D11, the Company's standard primary voltage rate
    - Off-peak in all other hours

Q75. How did you determine the pricing differential between the peak periods and the seasons?

A75. I utilized the relative difference in LMP for the years 2020-2022 to define the pricing differentials between the periods and seasons. This is consistent with the design approved by the Commission for Rate Schedule D1.11 and proposed for Rate Schedule D3.11, which varies power supply costs using the relative difference in LMP.

Q76. What are the proposed prices, considering both the periods and methodology, and the resulting differentials?

A76. The table below describes the pricing differentials for energy-only power supply. Distribution rates continue to be demand-based, are determined separately, and are not reflected in the table. Off peak does not vary by season.

	Rate (¢/kWh)	Differential to Off Peak
Summer On Peak	10.67	1.68x
Non-Summer On Peak	7.38	1.16x
Off Peak	6.35	1.00x

Q77. What are the risks of customers shifting from D11 to the proposed D14?

A77. D11 is a demand-based rate which, all else being equal, encourages more efficient usage of the system. More efficient usage results in a lower average cost. Customers who use more energy per increment of demand (i.e., they have a higher load factor) have a lower average volumetric rate compared to a customer with the same demand but lower total energy usage. The average load factor implied in the Company's proposed D11 power supply billing determinants is 73%[10]. A D11 customer with a load factor higher than 73% would expect to see a relatively lower than average volumetric rate on D11, and a customer with a lower load factor would see a relatively higher than average rate on D11. This difference in average rates is, simply, a reflection of the relatively different cost to serve each customer based on the efficiency of their energy usage.

The proposed Rate Schedule D14 eliminates this dynamic for power supply charges and substantially reduces the incentive for customers to operate efficiently and manage their relative demand on the system. Until such time that D14 is supported by its own cost of service class, this may lead to an under-recovery of cost, which would ultimately be allocated to other customers in a subsequent case. As such, the Company proposes to limit total load on this rate to 50 MW of contract capacity. The Company proposes a minimum contract term of 36-months, which will support stability in cost of service and pricing and limit opportunities to arbitrage between D14 and D11.

Q78. When would this rate schedule be effective if approved by the Commission?

A78. Upon approval from the Commission, the rate would need to be developed, tested, and implemented in the Company's billing system. As such, and as reflected in my Exhibit A-16, Schedule F8, the Company intends to have the rate available for

[10] In total, without respect to voltage level, and only for power supply determinants. The figure is used here for illustration of a conceptual discussion about load factor and not for the purposes of ratemaking. See Exhibit A-16, Schedule F3

Line No.

customers no later than the end of the projected test year in the instant case (December 31, 2025).

Investment Recovery Mechanism (IRM) Surcharge

Q79. What is the basis for your proposed surcharge design?

A79. The proposed IRM includes exclusively distribution investments, and therefore it is most appropriate to design the surcharge consistent with distribution rate design generally. Company Witness Maroun provided IRM revenue requirements allocated among the existing distribution cost of service classes, which include Residential Secondary, Commercial Secondary, Primary, and Subtransmission, and four classes related to lighting. Consistent with the IRM surcharge rate design approved in Case No. U-21297 and the testimony of Company Witnesses Vangilder and Maroun, I designed surcharges for each distribution cost of service class and rate schedule (as applicable), as reflected in Exhibit A-33, Schedule X-7. The rates are unchanged from what was approved in Case No. U-21297 for the 2025 IRM Year and therefore not included in the exhibit. Plan Years 2026 and 2027 reflect the updated IRM proposal and associated revenue requirement as described by Company Witness Foley.

Other Tariff Changes

Q80. What does Exhibit A-16, Schedule F8 show?

A80. This exhibit contains the proposed residential rate and tariff sheet changes which result from the pricing changes and other proposals described above and additional proposals described below.

Line No.

Q81. Are you sponsoring any new tariff sheets?

A81. Yes. As described in the preceding testimony, I am sponsoring new tariff sheets for proposed Rate Schedules D3.11 and D14.

Q82. Are you proposing any changes to residential tariff credit language?

A82. Yes, as described previously in my testimony, I am proposing the following changes to the residential tariffs:

- Expansion of the low-income assistance (LIA) credit to all residential base rates
- Increase of the LIA credit from $40 to $50 as supported by Company Witness Sparks

Q83. Are you proposing any updates to the Contribution in Aid of Construction (CIAC) standard allowance table?

A83. Yes. I am proposing updates to the CIAC standard allowance table for customers with new or expanded load greater than 1000 kW consistent with the method approved in Case No. U-20836 and consistent with the Commission's Order in Case No. U-21297, which required the Company to propose updated per foot construction costs in this case. Those changes are included in Exhibit A-16, Schedule F8, Section C6 and supported by Company Witness Hill. The standard allowance table can be found in Exhibit A-16, Schedule F8, Section C6.2.

Q84. Are you proposing any other changes to the Company's rate book?

A84. Yes.

- I am proposing to eliminate Section C6.1(16) of the Company's rate book, which is the waiver of CIAC for certain customers participating in the

Line No.

Company's Charging Forward program. This change is supported by Company Witness Bennett.

- I am proposing updates to Rate Schedules D1.1, D1.8, D3.3, and D5 as supported by Company Witness Burgdorf.
- I am proposing to eliminate the tariff sheets for Rate Schedules D1-A and D1-B. Both rates previously supported the Advanced Customer Pricing Pilot and with the full transition to time of use now complete, these two rates are obsolete.
- I am proposing to update the service territory map on page A-18.00 to better reflect the Company's locations

Q85. Does this conclude your testimony?

A85. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHERRI L. WISNIEWSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHERRI L. WISNIEWSKI

Line
No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Sherri L. Wisniewski (she/her/hers). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. 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.

Q4. What is your work experience?

A4. I have been with DTE Energy in the Tax Department since 1996 and became Director of Tax Operations in July 2016 and am currently responsible for tax accounting, tax forecasting, and regulatory tax.

Q5. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A5. I have sponsored testimony in the following cases:

U-18232	DTE Electric REP Amended Plan
U-18232	DTE Electric 2020 Amended REP Plan - March 2020
U-18255	DTE Electric Rate Case
U-18999	DTE Gas Rate Case

U-20029	DTE Electric EWR 2017 Reconciliation
U-20051	DTE Electric 2017 TRM Reconciliation
U-20105	DTE Electric Credit A Rate Case
U-20106	DTE Gas Credit A Rate Case
U-20162	DTE Electric Rate Case
U-20172	DTE Electric REP 2017 Reconciliation
U-20298	DTE Gas Calculation C
U-20484	DTE Electric REP 2018 Reconciliation
U-20561	DTE Electric Rate Case
U-20642	DTE Gas Rate Case
U-20723	DTE Electric REP 2019 Reconciliation
U-20835	DTE Electric Company for Accounting Approval to Accelerate Amortization of the Tax Cuts and Job Act Regulatory Liability for Non-Plant Related Accumulated Deferred Income Taxes
U-20851	DTE Electric 2020 Amended REP Plan
U-20940	DTE Gas Rate Case
U-21010	DTE Electric 2020 REP Reconciliation
U-20836	DTE Electric Rate Case
U-21285	DTE Electric 2022 Amended REP Plan
U-21198	DTE Electric 2021 REP Reconciliation
U-21291	DTE Gas Rate Case
U-21297	DTE Electric Rate Case
U-21353	DTE Electric REP 2022 Reconciliation
U-21361	DTE Electric 2023 Amended REP Plan

Line
No.

Purpose of Testimony

Q6. What is the purpose of your testimony in this proceeding?

A6. The purpose of my testimony is to discuss and support the reasonableness of DTE Electric's Federal Income Tax (FIT), Michigan Corporate Income Tax (MCIT), municipal (city) income tax, property tax and other general taxes for the 2022 calendar year historical period and the twelve months ending December 31, 2025, projected test period.

Q7. Are you sponsoring any exhibits in this proceeding?

A7. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-3	C7	Historical General Taxes
A-3	C8	Historical Federal Income Taxes
A-3	C9	Historical State and Local Income Taxes
A-3	C10	Historical Other Taxes
A-13	C7	Projected General Taxes – Other
A-13	C7.1	Projected General Taxes – Property
A-13	C8	Projected Federal Income Tax
A-13	C8.1	Projected TCJA Regulatory Liability
A-13	C9	Projected State Income Tax
A-13	C10	Projected Local Income Tax

Q8. Were these exhibits prepared by you or under your direction?

A8. Yes, they were.

Line
No.

Q9. What income tax rates are you assuming in this instant case?

A9. For all periods in this case, I am assuming a FIT rate of 21% and a MCIT rate of 5.88% (6% statutory rate at 98% apportionment) and municipal income tax of 0.33%. The municipal income tax rate represents a composite rate including all cities in which DTE Electric has a municipal income tax obligation.

<u>HISTORIC PERIOD</u>

Q10. How was the 2022 historical period property tax expense derived for the rate case?

A10. The 2022 historical period property tax expense in Exhibit A-3, Schedule C7, line 1, column (c) and Exhibit A-13, Schedule C7, line 1, column (b) of $286.6 million represents property tax expense on all DTE Electric property. Exhibit A-13, Schedule C7, line 1, shows the walk from the $286.6 million in column (b) to $265.9 million adjusted historical property tax expense in column (e). Adjusted historical property tax expense of $265.9 million was applicable to property reflected in DTE Electric's general rate case filings (referred to hereafter as general rate case property), which includes $1.0 million for Midwest Energy Resources Company (MERC) and excludes $21.6 million applicable to Renewable Energy Plan (REP) property. Property tax *expense* refers to the amount of property taxes deducted for book purposes. Property tax *liability* refers to the amount of property taxes payable to local governments. Because the Company expenses its property tax liability over a two-year period,[1] one will see a difference annually between liability and expense.

[1] The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years and is based, generally, on the fiscal years of the various taxing jurisdictions to which property taxes are paid.

Q11. How was the 2022 historical period payroll tax expense derived?

A11. The 2022 historical period payroll tax expense in Exhibit A-3, Schedule C7, line 2, column (c) of $36.7 million consists of Social Security and Medicare taxes referred to collectively as "FICA" as well as federal and Michigan state unemployment taxes. These payroll taxes for the historic period are before rate case and normalization adjustments and are derived from the Company's payroll system based on individual employees' wages up to a maximum taxable limit times a prescribed rate.

Q12. What are the Other General Taxes reflected on Exhibit A-3, Schedule C7?

A12. In addition to payroll taxes of $36.7 million, Public Utility Assessment fees of $12.9 million and Use Tax and Other tax totaling $0.2 million are included in the Total Other General Taxes. Total Other General Taxes of $49.8 million as shown on Exhibit A-3, Schedule C7 are for DTE Electric as a whole. Total 2022 historical other general tax expense after rate case and normalization adjustments is $49.2 million as shown on Exhibit A-3, Schedule C1.1, which is supported by Company Witness Uzenski.

Q13. Is there anything unique or unusual regarding 2022 historical period income tax expense?

A13. The 2022 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-21297. Income tax expense includes both current income taxes (taxes payable currently) and deferred taxes (taxes payable in the future). Historical income tax expense amounts are shown on Exhibit A-3, Schedules C8 and C9.

The 2022 historical period FIT expense includes additional amortization of the Tax Cuts and Jobs Act (TCJA) regulatory liability consistent with the order received in U-20835, which allowed the November 30, 2021, balance of the non-plant component of the TCJA regulatory liability of $103 million to be fully amortized from December 2021 thru November 2022.

The income tax expense amounts shown on Exhibit A-3, Schedules C8 and C9 reflect income tax expense for DTE Electric as a whole. These income tax expense amounts are adjusted for rate case, normalization, and other adjustments in Exhibit A-3, Schedule C1.1, which is supported by Company Witness Uzenski. Total 2022 historical year income tax expense after the adjustments is $94.1 million.

Q14. What does the balance sheet reclass for Accumulated Deferred Income Taxes and Accumulated Deferred Investment Tax Credit on Witness Uzenski's Exhibit A-2, Schedule B6.1, column (e) represent?

A14. There are two adjustments that are reflected in Witness Uzenski's exhibit that are reclassified to Accumulated Deferred Income Tax Liability.

The first adjustment is to reclassify the Accumulated Deferred Income Tax Asset on Exhibit A-2, Schedule B6.1, pages 1 of 2, line 67 to Accumulated Deferred Income Tax Liabilities, line 113, for proper balance sheet presentation. This is consistent with prior rate case filings.

The second adjustment is to reclassify a portion of the regulatory liability on line 114 to accumulated deferred income taxes on line 113. This represents Investment Tax Credits (ITCs) DTE Electric generated but had not yet utilized as of 12/31/2022. Because these ITCs will be utilized in a future year, a deferred tax asset was recorded and is included in line 113. Because DTE Electric has not recognized the cash benefit of the ITCs, the regulatory liability for these credits must be reclassified to eliminate any impact it would have on the cost of capital. This is consistent with prior rate case filings.

FORECAST PERIOD

Q15. What subjects will your testimony and exhibits cover related to the twelve months ending December 31, 2025, projected test period?

A15. I am supporting the FIT, MCIT, Municipal Income Tax, Property Tax and Other general taxes shown on Exhibit A-13, Schedules C7 through C10. These schedules, which are primarily based on forecasted amounts sponsored by other Company witnesses, are used to derive the various tax expense amounts for the projected test period.

Q16. How are Michigan property taxes assessed?

A16. 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 2022 liability is based on the taxable value of property on December 31, 2021.

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.

Q17. In the calculation of the property tax liability, what is 'true cash value' and how is it calculated?

A17. True cash value is meant to represent fair market value and is determined by local assessors who apply guidelines set forth by the State Tax Commission (STC), which supervises the valuation and assessment of property. To determine true cash value, assessors will utilize multiplier tables established by the STC. 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. An STC multiplier enables an assessor to determine true cash value by multiplying the appropriate

STC multiplier by the historical cost of the property instead of performing a comprehensive market value analysis every year.

Q18. When does the Company know its property tax liability for any given year?

A18. 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 updated as the Company receives assessments from local assessors in March and April and bills in June and December.

Q19. How are the 2022 and 2023 property tax liabilities reflected in your exhibits?

A19. Exhibit A-13, Schedule C7.1 shows the 2022 and 2023 property tax liabilities in column (c) on lines 3 and 4, respectively.

The 2022 tax liability[2] of $265.4 million (line 3, column (c)) represents the actual property taxes assessed and paid on all general rate case property on hand as of December 31, 2021.

The 2023 tax liability of $281.4 million (line 4, column (c)) represents the estimated property taxes that will be assessed and paid on all general rate case property on

[2] Property tax *liability* refers to the amount of property taxes payable to local governments, whereas property tax *expense* refers to the amount of property taxes deducted for book purposes. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. The 2022 Property tax expense as stated in the historical section of my testimony was $286.6. million.

Line
No.

hand as of December 31, 2022, based primarily on assessments received from local assessors.

Q20. What is the projected 2024 Property tax liability?

A20. Exhibit A-13, Schedule C7.1, shows the projected 2024 property tax liability of $313.8 million on line 54, column (c).

Q21. How was the projected 2024 Property Tax liability on Exhibit A-13, Schedule C7.1, line 54 calculated?

A21. This represents the projected property taxes that will be assessed and paid on all general rate case property projected to be on hand as of December 31, 2023. This is based on the 2023 estimated tax liability of $281.4 million (line 52, column (c)) plus the increase in liability projected for 2024 of $32.4 million (line 53, column (c)). The increase in liability projected for 2024 is calculated in column (c) on lines 25 through 50. The taxable value of 2023 net additions is estimated to be $618.7 million (line 35, column (c)), driven primarily by 2023 capital additions less retirements and reductions and nontaxable expenditures. It also takes into consideration the change in CWIP and applies first year STC multipliers to both the net additions and the change in CWIP. Annual inflation of real property on hand as of December 31, 2022, is estimated to be an increase in taxable value of $33.5 million (line 41, column (c)). Annual obsolescence of personal property on hand as of December 31, 2022, is estimated to be a reduction in taxable value of $73.6 million (line 47, column (c)). The estimated composite millage rate of 56.0 is then applied to the net increase in taxable value of $578.5 million (line 48, column (c)).

Capital additions and retirements for all periods presented are supported by Company Witnesses sponsoring Schedules B5 through B5.10 of Exhibit A-12.

Q22. What is the projected 2025 Property tax liability?

A22. Exhibit A-13, Schedule C7.1, shows the projected 2025 property tax liability of $349.7 million on line 56, column (e).

Q23. How was the projected 2025 Property Tax liability on Exhibit A-13, Schedule C7.1, line 56 calculated?

A23. This represents the projected property taxes that will be assessed and paid on all general rate case property projected to be on hand at December 31, 2024. This is based on the 2024 projected tax liability of $313.8 million (line 54, column (e)) plus the increase in liability projected for 2025 of $35.9 million (line 55, column (e)). The increase in liability projected for 2025 is calculated in column (e) on lines 25 through 50. The taxable value of 2024 net additions is estimated to be $679.7 million (line 35, column (e)), driven primarily by 2024 capital additions less retirements and reductions and nontaxable expenditures. It also takes into consideration the change in CWIP and applies first year STC multipliers to both the net additions and the change in CWIP. Annual inflation of real property on hand as of December 31, 2023, is estimated to be an increase in taxable value of $35.2 million (line 41, column (e)). Annual obsolescence of personal property on hand as of December 31, 2023, is estimated to be a reduction in taxable value of $72.5 million (line 47, column (e)). The estimated composite millage rate of 56.0

Line
No.

is then applied to the net increase in taxable value of $642.4 million (line 48, column (e)).

Q24. What is the amount of property tax expense the Company is seeking recovery of, and how is it calculated?

A24. The Company is seeking recovery of property tax expense of $328.8 million for the projected test period (January 1, 2025, through December 31, 2025), which is included in Exhibit A-13, Schedule C1, line 6, column (e) supported by Witness Uzenski. Property tax *expense* refers to the amount of property taxes deducted for book purposes. Property tax *liability* refers to the amount of property taxes payable to local governments. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years and is based, generally, on the fiscal years of the various taxing jurisdictions to which property taxes are paid.

The 2024 calendar year property tax expense of $294.9 million (Exhibit A-13, Schedule C7.1, line 13, column (e)) represents 61% of the 2023 property tax liability and 39% of the 2024 property tax liability. Due to the two-year expensing methodology, the increase of $22.3 million over the 2023 property tax expense of $272.6 million was driven by the changes in both the 2023 estimated tax liability and the 2024 projected tax liability.

The 2025 calendar year property tax expense of $328.8 million represents 61% of the 2024 projected property tax liability and 39% of the 2025 projected property tax liability. Due to the two-year expensing methodology, the increase of $33.9 million over the 2024 property tax expense of $294.9 million is driven by the increases in both the 2024 and the 2025 projected tax liabilities.

Projected test period property tax expense is equal to the 2025 calendar year property tax expense of $328.8 million.

Q25. What is the Other Tax Expense portion of DTE Electric's operating expense?

A25. DTE Electric is seeking recovery of Other Tax expense for the projected test period of $53.2 million. Other Tax expense consists of payroll taxes ($39.3 million), Public Utility Assessment fees ($13.6 million), and miscellaneous other taxes ($0.2 million, primarily use taxes) as shown on Exhibit A-13, Schedule C7 on lines 2 through 5 in column (j).

Q26. How did you forecast the Other Tax Expense?

A26. DTE Electric's O&M forecast is driven primarily by inflation increases. Because payroll taxes generally follow O&M expense, it has been forecasted by incrementing the historic period actual amounts by DTE Electric's assumed annual wage inflation rate. Exhibit A-13, Schedule C5.15, which is supported by Witness Uzenski, lists inflation rates for the interim forecast and projected test periods. DTE Electric's forecast for Public Utility Assessment fees was adjusted to account for an increase in contributions to the Utility Customer Representation Fund expected for DTE Electric as a result of Public Act 231 of 2023. Other miscellaneous other taxes were held to their 2022 historical amounts.

Line No.

Q27. How much total income tax expense is the Company seeking recovery of?

A27. DTE Electric is seeking recovery of total income tax expense of $169.2 million. This is comprised of FIT expense of $107.8 million and MCIT and municipal income tax expense of $61.4 million.

Q28. How was the FIT Expense portion of DTE Electric's operating expense developed?

A28. Exhibit A-13, Schedule C8, line 53 shows DTE Electric's FIT expense for the projected test period is $107.8 million. Exhibit A-13, Schedule C8, illustrates that FIT expense is comprised of current FIT expense (line 5) and deferred FIT expense (line 6). Current FIT expense is $12.5 million, which is calculated based on taxable income as shown on line 8 through 44. Deferred FIT expense is shown on lines 45 thru 52 and is based on book versus tax temporary differences and the net operating loss (NOL) carryforward (line 45), annual amortization of several Deferred Debits and Credits (Medicare Part D Subsidy, FAS 109, Investment Tax Credit (ITC), and the Tax Cuts and Jobs Act (TCJA) Regulatory Liability (lines 46 - 49), R&D Tax Credit carryforward (line 50) and utilization of tax credits generated in prior years (line 51).

Q29. Is the overall methodology for amortizing the TCJA regulatory liability, as reflected in Exhibit A-13, Schedule C8.1, consistent with the order received in U-21297?

A29. Yes. Amortization for the projected test period January 1. 2025 through December 31, 2025, reduces tax expense by $50.2 million as reflected in Exhibit A-13, Schedule C8, line 49.

Line No.

Q30. How was the MCIT expense portion of DTE Electric's operating expense developed?

A30. Line 14 of Exhibit A-13, Schedule C9, shows DTE Electric's MCIT expense for the projected test period is $58.4 million. Exhibit A-13, Schedule C9, illustrates that MCIT expense is comprised of current MCIT and deferred MCIT. Current MCIT is zero due to a MCIT NOL carryforward being utilized in the projected test period, as reflected on Exhibit A-13, Schedule C9, line 7. Deferred MCIT is based on book versus tax temporary differences, NOL carryforward, and the annual amortization of the MCIT Deferred Debit. The amortization of the MCIT Deferred Debit includes the impacts of the Michigan tax law changes of 2008 and 2012 and the re-measurement of MCIT deferred tax balances at December 31, 2018.

Q31. How was the Municipal Income Tax Expense portion of DTE Electric's operating expense developed?

A31. Line 11 of Exhibit A-13, Schedule C10, shows DTE Electric's municipal income tax for the projected test period is $3.0 million. Exhibit A-13, Schedule C10, illustrates that municipal income tax expense is comprised of current and deferred municipal income tax expenses. Current municipal income tax is $0.3 million due to a municipal NOL being utilized in the projected test period, as reflected on Exhibit A-13, Schedule C10, line 4. Deferred municipal income tax is based on book versus tax temporary differences, NOL carryforward, and the annual amortization of the City of Detroit Deferred Debit that arose from the City of Detroit tax law change of 2012.

Line
No.

Q32. Does this complete your direct testimony?

A32. Yes, it does.