DTE Gas Company
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DTE

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December 17, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter of the Application of **DTE Gas Company** for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2023
MPSC Case No: U-21064

Dear Ms. Felice:

Attached for electronic filing in the above referenced matter is DTE Gas Company's Application for Gas Cost Recovery Plan and Monthly GCR Factor and Evaluation of Its Five-Year Forecast, Direct Testimony and Exhibits of Witnesses, George H. Chapel, Eric P. Schiffer, Lucian Bratu, Timothy J. Krysinski, Andrea R. Hardy, and Kenneth A. Sosnick. Also attached is the Proof of Service.

Very truly yours,

Carlton D. Watson
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Date: 2021.12.17 19:47:27 -05'00'

Carlton D. Watson

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cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE GAS COMPANY** for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2023	)))))	Case No. U-21064

APPLICATION FOR APPROVAL OF DTE GAS COMPANY'S GAS COST RECOVERY PLAN AND MONTHLY GCR FACTOR, AND EVALUATION OF ITS FIVE-YEAR FORECAST

DTE Gas Company ("DTE Gas") pursuant to 1939 PA 3, as amended, MCLA 460.6h *et seq*., requests approval of its Gas Cost Recovery ("GCR") Plan and monthly GCR factor for a 12-month period from April 1, 2022 through March 31, 2023 ("GCR Plan Year"), and evaluation of its five-year Forecast as set forth in this Application. In support of this request, DTE Gas states the following:

1. DTE Gas is a subsidiary of DTE Energy Company, a Michigan corporation with its principal offices located at One Energy Plaza, Detroit, MI 48226. DTE Gas is a public utility subject to the jurisdiction of the Michigan Public Service Commission ("Commission" or "MPSC") and is engaged in the acquisition, storage, transportation, distribution, and sale of natural gas and other related services to approximately 1.3 million residential, commercial and industrial customers within the State of Michigan.

2. For the GCR Plan Year, DTE Gas proposes to implement a maximum base GCR factor of $3.29 per thousand cubic feet ("Mcf") that can be increased by a contingency factor matrix based on increases in New York Mercantile Exchange ("NYMEX") gas commodity prices resulting in a new maximum GCR factor. The proposed maximum GCR factor, as adjusted, when necessary, by the NYMEX based contingency factor matrix includes costs to be paid to DTE Gas's

gas and pipeline suppliers. In addition, DTE Gas further proposes to implement for the GCR Plan Year a Supplier of Last Resort ("SOLR") Reservation Charge in the amount of $0.40 per Mcf that will be billed to GCR customers while the Reservation Charge billed to Gas Customer Choice ("GCC") customers will be $0.27 per Mcf, which reflects the 30% discount from the average rate as mandated by the Commission in Case No. U-17691.

3. The testimony and exhibits of Eric P. Schiffer, George H. Chapel, Timothy J. Krysinski, Lucian Bratu, Kenneth A. Sosnick and Andrea R. Hardy are attached to this Application and made a part hereof. The attached testimony and exhibits support the proposed 12-month GCR factor and constitute DTE Gas's Gas Cost Recovery Plan for the requested 12-month GCR factor along with its 5-Year Forecast of Gas Requirements in accordance with Sections 6h (3) and (4) of 1939 PA 3, as amended.

4. This Application, including testimony and exhibits, will be promptly furnished to all intervenors in DTE Gas's 2022-2023 GCR Plan, Case No. U-21064 ("Case No. U-21064"). It will also be promptly made available to any other persons seeking to intervene in this proceeding pursuant to Rule 410 of the Commission's Rules of Practice and Procedure.

5. This Application, including testimony and exhibits, continues to support fundamental proposals including, but not limited to, DTE Gas's fixed price purchase program and DTE Gas's Reservation Charge.

6. Jurisdiction in this matter is pursuant to 1939 PA 3, as amended, MCL 460.6h *et seq*.; as well as 1909 PA 300, as amended; MCL 460.2 *et seq*.; 1919 PA 419, as amended; 1969 PA 306, as amended; MCL 24.200 *et seq*.; and the Commission's Rules of Practice and Procedure, 1979 Michigan Administrative Code, R 460.17101 *et seq*.

WHEREFORE, DTE Gas respectfully prays that the Commission immediately commence a gas supply and cost review pursuant to Sections 6h (5), (6) and (7) of 1939 PA 3, as amended, establish dates for a hearing on DTE Gas's Application, supporting testimony, and exhibits as soon as scheduling permits in order to facilitate the issuance of a final Commission order that:

i. Approves a maximum base gas cost recovery factor of $3.29 per Mcf that can be adjusted to a new maximum GCR rate by the monthly NYMEX-based contingency factor matrix, to be reflected in DTE Gas's monthly gas customer billings beginning April 1, 2022, and continuing through March 31, 2023, and further approves a SOLR Reservation Charge of an additional $0.40 per Mcf that is billed to GCR customers while the Reservation Charge billed to GCC customers will be $0.27 per Mcf;

ii. Finds that DTE Gas's 5-Year (April 2022-March 2027) Forecast of Gas Requirements, Supplies and Costs, and Gas Supply Plan does not include any cost items that the Commission would be unlikely to permit DTE Gas to recover in the future;

iii. Grants such other and further relief as it may find appropriate.

Respectfully submitted,

DTE GAS COMPANY

By: Carlton D. Watson Digitally signed by Carlton D. Watson Date: 2021.12.17 19:48:46 -05'00'

Carlton D. Watson(P77857)
One Energy Plaza, 1635 WCB
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(313) 235-6648

Dated: December 17, 2021

Approved:

By: Robert D. Feldmann Digitally signed by Robert D. Feldmann Date: 2021.12.17 19:44:23 -05'00'

Robert D. Feldmann
Vice President -Gas Sales & Supply

Dated: December 17, 2021

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Gas Company** for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2023	))))))	Case No. U-21064

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

GEORGE H. CHAPEL

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

A1. My name is George H. Chapel. My business address is DTE Energy Gas ("DTE Gas" or "the Company"), One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Gas as Manager, Market Forecasting.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Gas Company.

Q3. What is your educational background?

A3. In December 1985, I earned a Bachelor of Science degree from Central Michigan University with a major in mathematics.

Q4. What work experience do you have?

A4. In April 1988, I was hired by Michigan Gas Company ("MiGas") as a Rates and Gas Supply Analyst where I performed various duties of increasing responsibility arising out of the regulation of MiGas as a public utility. In 1993, the assets of MiGas were rolled in with those of affiliate Southeastern Michigan Gas Company and Battle Creek Gas Company. These companies were combined to form what is known today as SEMCO Energy Gas Company ("SEMCO"). My duties with SEMCO included demand forecasting, supply planning, supply purchasing, nominating, and pipeline capacity management. I have attended numerous industry conferences focusing on natural gas demand forecasting, sharing knowledge and expertise with a nationwide range of industry peers.

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

Q5. What are your current duties and responsibilities?

A5. I am responsible for projecting DTE Gas' Gas Cost Recovery (GCR), Gas Customer Choice (GCC), and Aggregate rate schedule customer growth/decline, natural gas supply demand, and review and analysis of the natural gas market. These duties support DTE Gas' regulatory, finance, and accounting functions.

Q6. Have you been involved in any prior regulatory proceedings?

A6. Yes. I sponsored testimony on behalf of SEMCO and its subsidiaries in a variety of cases before the Commission. These cases include two general rate cases, two Michigan Residential Conservation Surcharge cases, and several GCR Plan and Reconciliation proceedings. I have also provided testimony in a large number of regulatory proceedings for DTE Gas, including GCR Plan and Reconciliation proceedings as well as DTE Gas' most recent general rate cases. My experience as a GCR witness began with SEMCO in 1990 and has continued to the present day with DTE Gas.

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Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to present and describe the Company's GCR market forecast for the five-year operational period 2022-2027. My testimony will address DTE Gas's natural gas demand forecast over the next five years, April 2022 through March 2027 ("the 5-Year Forecast Period"). My testimony will describe:

A) How the Company's GCR/GCC sales are projected to be 153 Bcf for the 2022-2023 GCR Plan year and will decrease slightly over the course of the five-year forecast period. It will also describe how the number of customers is expected to increase over the five-year period due primarily to steadily increasing new customer attachments anticipated over the five-year period.

B) The Company's rate schedule market forecast techniques. I will describe how the Company's customer count forecast is projected using a build-up approach that incorporates components that contribute to customer count increases and decreases and how customer volumetric demand is projected using the Company's three-step linear methodology.

C) The Company's GCC projection and why it is expected to remain unchanged over the five-year period.

D) The Company's 2023 peak day load requirements, which are expected to change from the volumes projected in last year's Plan case.

E) The Company's ongoing conservation assumptions with regard to its filed Energy Waste Reduction (EWR) plan.

For reasons more fully described in my testimony below, the conclusions and opinions I have reached regarding the above subjects support the reasonableness and prudence of the decisions underlying DTE Gas's proposed GCR plan for the 12-month period ending March 31, 2023.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-1	Market Outlook – Weather Normalized Sales & Customers
A-2	Market Forecast Analysis – Forecasted GCR Volumes
A-3	Market Forecast Analysis - Forecasted GCR Number of Customers
A-4	April 2022 – March 2027 Total Market Requirements
A-5	Mean Peak Day Temperatures by District Peak Day Load by Area
A-6	Historical Normalized Annual Sales (GCR & GCC)

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

A9. Yes, they were.

MARKET OUTLOOK

Q10. What is DTE Gas's rate schedule and GCR sales forecast for the 2022 through 2027 planning period?

A10. For the April 2022 - March 2023 operational plan year (OPY), I am forecasting GCR/GCC sales volumes of approximately 153 Bcf for DTE Gas's rate schedule sales customers (Exhibit A-1, page 1 of 2, line 13, column (a)). Rate schedule sales customers include both GCR customers and GCC customers. Over the course of the five-year forecast period, I am expecting annual volumes to generally decrease slightly, with sales decreasing to approximately 150 Bcf for April 2026 – March 2027.

Q11. Why are you projecting annual volumes to decrease slightly?

A11. Though the Company expects that customer count will grow over the five-year forecast period, I expect the ongoing efforts of the Company's EWR program to more than offset the higher volumes normally associated with customer count growth. The combination of higher customer count along with the Company's ongoing EWR efforts are expected to result in a slight reduction to overall GCR/GCC natural gas demand by the end of the five-year forecast period.

Q12. What is your projection for average number of rate schedule customers from 2022 through 2027?

A12. As reflected on Exhibit A-1, page 2 of 2, line 13, column (a), I am projecting approximately 1.32 million rate schedule customers (mean average) during the 2022-2023 OPY. This number is expected to increase to approximately 1.36 million customers through 2026-2027 as shown in columns (b) through (e), line 13.

Q13. Why is DTE Gas's customer count projected to increase over the course of the five-year forecast period?

A13. The Company's customer count continues to show growth. The Company continues to observe a higher rate of requests for service and a lower rate of customer-requested terminations of service, which could be reasonably interpreted as a sign that the Company is still experiencing a period of customer growth.

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WEATHER NORMAL PERIODS

Q14. What is weather normalization and how is it used?

A14. Weather normalization adjusts actual volumes from a past period to eliminate the impact of non-normal weather on the data during that time-period. Weather-normalized data is then used to make inferences about customer behavior trends. Normal weather is also a key component in compiling volumetric forecasts.

Q15. What weather-normalization technique does DTE Gas utilize to calculate normal weather?

A15. Consistent with the weather-normalization methodology included in prior Commission-approved GCR Plan Cases, the Company uses a rolling 15-Year Normal weather pattern to project its normal demand requirements in this GCR Plan.

Q16. What 15-year period is DTE Gas using in this plan?

A16. DTE Gas is calculating 15-year normal weather based upon actual weather from calendar year 2006 to calendar year 2020.

Q17. Why is DTE Gas proposing to utilize 15-year normal to project forecasted demand requirements in this case?

A17. Consistent with the Commission Order in Case No. U-15985 (general rate case), DTE Gas utilizes a rolling 15-year weather period for its normal weather in all of its regulatory filings.

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Q18. Why is the weather-normalization period important?

A18. Weather is one of the primary determinants of natural gas demand. If the Company can project Heating Degree Days (HDDs) more accurately, then it can more accurately project demand on its system. Accurate projections lead to optimal planning, which in turn reduces the gas costs DTE Gas will need to recover from its customers.

Q19. What is an HDD?

A19. An HDD is a measure of how temperature relates to natural gas usage for heating purposes; HDDs give an indication of a customer's likelihood of using their furnace to heat their home or facility. Basically, the greater the number of HDDs, the greater the heating demand. Mathematically, HDDs are defined as the greater of A) zero, or B) 65 – average daily temperature (in degrees Fahrenheit).

For instance, if the daily high temperature is 30 degrees and the daily low temperature is 20 degrees, then the daily average temperature is 25 degrees. The HDDs for that day then, are: 65 – 25 = 40 HDDs.

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

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RESIDENTIAL RATE SCHEDULE SALES MARKET

Q20. How did you develop the forecast for the residential rate schedule sales market including both GCR and GCC customers?

A20. The projected residential GCR sales markets are shown on Exhibit A-2, pages 1 through 5. There are two key elements used in projecting volumes in the residential sales market. The first element is the forecast of the number of customers, by month, in the seven different market areas that DTE Gas serves. These seven different service regions are: Detroit/Ann Arbor, Grand Rapids, Muskegon, Traverse City, Alpena, Sault Ste. Marie, and Iron Mountain.

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

The combination of the two elements (customer count and three-step linear heat load factor), along with normal HDDs by month for each respective market area yields the monthly residential sales market forecast.

Q21. How does the three-step linear methodology work?

A21. The three-step linear equation consists of three components: a base load component and two linear temperature-driven components. The base load component determines how much gas a customer is expected to use every single day, regardless of the weather. The remaining linear temperature-driven components determine how much gas a customer is expected to use depending on how many HDDs are present on any

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given day. The three-step linear equation is described mathematically with the following equation:

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

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

For the purposes of example, I have included a sample general graph that depicts this equation. It shows the daily consumption pattern of a typical Residential Space Heating customer. At relatively low HDDs (<10), on the left side of the graph, the slope of the graph is upward, but gradual. At higher levels of HDDs (>10), the slope of the graph gets steeper, indicating higher consumption per HDD the colder it gets.

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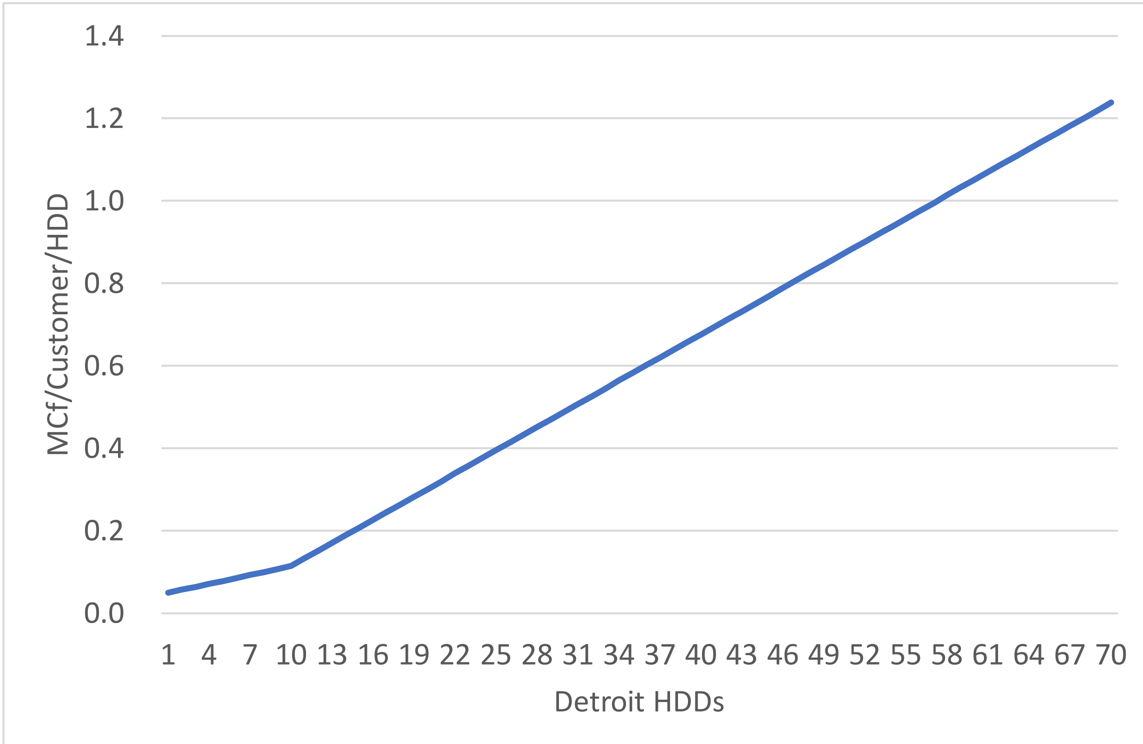

Please note that the above graph is representative of the Detroit residential space-heating gas customer class. Other rate classes will reflect similar demand curves.

Q22. How is the forecast of the number of customers, including both GCR and GCC, derived?

A22. A forecast of the number of customers by class, by month, is prepared using a recent three-year historical average growth/loss rate calculated for each of DTE Gas's seven demand regions. For this forecast, the historical three-year period was 36 months ended July 2021. The seven demand regions are: Detroit/Ann Arbor, Grand Rapids, Muskegon, Traverse City, Alpena, Sault Ste. Marie, and Iron Mountain.

Once this regional forecast is developed, incremental customer growth and losses are projected. Forecasted customer change is developed through a combination of projected attachments and the 12-month historical look-back of net non-attachment customer change to the growth/loss rate. Projected attachments are provided by the Company's Marketing Department and is their assessment of how many new customers the Company expects to attach through marketing efforts in expanding areas. The forecast also reflects marketing initiatives within the Company that are expected to add approximately 9,500-10,000 customers annually over the 5-Year Forecast Plan Period.

Q23. What is the "net non-attachment customer change?"

A23. The net non-attachment customer change is the monthly variance in customer total from one month to the next less new attachments for that month. For example, if the customer count for month M is 1,200,000, the customer count for succeeding month M+1 is 1,210,000, and customer attachments for that month is 8,000, then the net non-attachment customer change is calculated as:

1,210,000 – 1,200,000 – 8,000 = 2,000

The customer change in this group represents the net activity of an entire month's worth of customers moving out of and into existing properties connected to the Company's system. For instance, if Customer A moves out of 123 Main Street on the 12th of a month and Customer B moves into 123 Main Street on the 15th of that month, then the net change in customer count due to those activities is 0. On the other hand, if Customer A moves out of 123 Main Street on the 12th of a month and no one moves into 123 Main Street during that month, then the net change in customer count due to that activity is -1.

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Q24. Are you forecasting growth in the number of customers from 2022 to 2027?

A24. Yes. Company billing data over the past ten years has shown that customer count continues to grow. Further, the Company is continuing to project new attachments through its marketing efforts over the five-year forecast period. Going forward, DTE Gas will continue to monitor these factors and adjust its long-term forecast as necessary.

<u>COMMERCIAL & INDUSTRIAL MARKETS</u>

Q25. How did you develop the forecast for commercial and small industrial markets including both GCR and GCC customers?

A25. The methodology used for forecasting volumes in the commercial and small industrial GCR and GCC markets is essentially the same as that used for the residential market. The process involves forecasting the number of customers for each year and calculating the average base load and usage per HDD per customer. As reflected on Exhibit A-1, page 1 of 2, line 10, I am projecting a slight decrease in commercial and industrial GCR volumes from 27.6 Bcf to 26.7 Bcf for commercial and industrial GCR sales customers from OPY 2022-2023 to OPY 2026-2027, respectively.

Q26. For which of the commercial and industrial classes do you use the three-step linear forecast methodology?

A26. All rate classes are forecast using the three-step linear methodology.

Q27. Does the implementation of the three-step linear methodology impact the way in which DTE Gas calculates its Warmer-than-Normal and Colder-than-Normal weather scenarios?

A27. Yes. The three-step linear approach captures the sensitivities around Warmer-than-Normal, and Colder-than-Normal scenarios. During a period of very cold weather, the "b" coefficient (see pages 8-9), which is generally greater than the "a" coefficient, has greater weight in the equation, generating increasingly higher heat load factors because the weather data includes colder temperatures. During a period of very warm weather, the "b" coefficient has less weight, and the equation will generate decreasingly lower heat load factors as the weather gets warmer. The net result is that the three-step method will produce lower consumption per customer per HDD during warmer weather (i.e. spring and fall months) and higher consumption per customer per HDD during colder weather (i.e. the deep winter months). This phenomenon produces an asymmetry in the application of Colder-than-Normal and Warmer-than-Normal demands.

GAS CUSTOMER CHOICE

Q28. What impact does the GCC program have on forecasted DTE Gas' markets?

A28. The GCC program continues to have a significant impact on DTE Gas's GCR markets. For 2022-2023 OPY, I have assumed that approximately 124,000 customers, or about 9% of DTE Gas' total rate schedule customers, will be served by an alternate supplier through the GCC program (Exhibit A-1, page 2 of 2, line 12). Over the five-year forecast period, I am forecasting no change in the number of customers participating in the GCC program. Going forward, the Company will continue to monitor participation in the GCC program and adjust its sales projections accordingly.

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Q29. What are the forecasted GCC sales volumes?

A29. Exhibit A-1, page 1 of 2, sets forth DTE Gas' forecasted GCC sales volumes by OPY. The annual projected GCC sales volumes, identified on line 12, are: 21.9 Bcf for OPY 2022-2023, dropping to 21.0 Bcf by OPY 2026-2027.

FORECASTED GCR SALES VOLUMES

Q30. What are the forecasted GCR sales volumes and customers?

A30. Exhibit A-2, pages 1 through 5, sets forth DTE Gas's forecasted GCR sales volumes by month, and Exhibit A-3, pages 1 through 5, contains DTE Gas's forecasted number of GCR customers by month. The annual projected GCR sales volumes, identified on line 11 of each of the pages of Exhibit A-2 are laid out in Table 1 below:

Table 1

OPY	Bcf
2022-2023	131.1
2023-2024	131.5
2024-2025	130.3
2025-2026	129.8
2026-2027	129.3

The annual projected average GCR customer counts by OPY are laid out in Table 2 below:

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Table 2

OPY	GCR Customer Count
2022-2023	1,193,971
2023-2024	1,204,994
2024-2025	1,215,969
2025-2026	1,226,758
2026-2027	1,237,106

Q31. What is the basis for DTE Gas's total annual GCR requirements?

A31. The forecasted requirements are based on 15-year normal weather, which assumes a change in daily temperature in accordance with the 15-year daily volatility (i.e. "normal variable"); the distribution of daily HDDs assumes 15-year normal weather for the 2022-2023 plan year, as well as for years 2 through 5 of the five-year plan. Exhibit A-4, pages 1 through 3, identifies projected total requirements for OPYs 2022 – 2027, made up of Company use, lost gas, unbilled volume change and balance, and the forecasted GCR sales market volumes previously described.

<u>DESIGN DAY DEMAND</u>

Q32. What average temperatures does DTE Gas use to plan its design-day demand?

A32. DTE Gas uses the coldest mean-average temperature it can expect during critical periods in January, February and March. Exhibit A-5, page 1 of 2 identifies sixteen key locations across DTE Gas's service territory. The coldest mean-average temperature (in degrees Fahrenheit) that DTE Gas can expect at each location during three pivotal times during the winter is also identified on this exhibit. These pivotal

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times occur at the ends of January, February, and March and represent the mean-average temperatures that DTE Gas uses to plan its design-day demand.

Q33. What is the 2023 design day load requirement associated with each of the three critical-period mean-average temperatures?

A33. DTE Gas plans to serve its peak-day requirements around critical end-of-month demand. DTE Gas's design-day demand model examines the design weather at these sixteen different locations and condenses them down to five primary demand locations. Exhibit A-5, page 2 of 2 details the projected end-of-month peak demand in January, February, and March 2023 at five primary demand locations (calculated using statewide weather). These five locations are Detroit/Ann Arbor, Alpena, Grand Rapids, the Upper Peninsula, and Traverse City.

Q34. Have these design day load volumes changed as compared to DTE Gas's previous GCR filing?

A34. Yes. For the 2022 design-day projection, these loads have changed from prior years. January 2023 design-day requirements have decreased by 162 MDth/day versus January 2022. February 2023 design-day requirements have decreased versus February 2022 by 128 MDth/day while March 2023 design-day requirements have decreased by 132 MDth/day versus March 2022. The primary reason for these changes is the annual update of DTE Gas's database of historical billing data in its Load Program. There is also a slight decline in the expected system average heating value which will result in slightly higher volumetric values. The annual update reflects a combination of customer count and load changes in the Company's Detroit area reflecting changes in peaker load; usage data for large end-use customers (including peaker plants) was recently updated. Natural gas fired generators are modeled, by design day by month, using their most recent three years of activity.

Continued population growth in specific areas such as Kent County (major city: Grand Rapids), Washtenaw County (major city: Ann Arbor), and Grand Traverse County (major city: Traverse City) together with the population decrease in the Wayne County area (specifically in the city of Detroit) will continue to change the peak-day load. According to the US Census Bureau, from 2010 to 2020, the population of Kent County increased by 9.2% (approximately 55,000 persons), the population of Washtenaw County increased by 8.0% (approximately 27,000 persons), and the population of Grand Traverse County increased by 9.5% (approximately 8,300 persons). By contrast, the population in Wayne County decreased by 1.5% (approximately 27,000 persons). As I previously indicated, DTE Gas will continue to evaluate the population and customer changes so that it is positioned to respond to regional peak-day load demand changes.

DEMAND CHANGES

Q35. Has the Company experienced a change in normalized GCR and GCC sales in recent years?

A35. DTE Gas saw a relatively steep decline in normalized sales through 2009-2010. Into 2012, normalized usage characteristics amongst the Company's customer base appeared to stabilize, and then into 2016, normalized consumption appeared to be rebounding, until tapering off over the past couple of years. Please see the graph on Exhibit A-6. As shown on this exhibit, the steepest declines occurred in 2004-2005 and 2005-2006 (9-10 Bcf per year). Coincidentally, these two years saw increasingly

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higher natural gas prices. Though still high from a longer-term historical perspective, the 2006-2008 period generally saw a return to lower prices. The 2008-2009 period, shown in column (f), once again showed a marked reduction in normalized consumption, which was driven largely by the continued decline of the economy in the state of Michigan and higher natural gas prices in general. From September 2009 through August 2012, normalized consumption stabilized to approximately 152-153 Bcf per year (about 127 Dth per customer). In 2012-2013 and 2013-2014, normalized consumption rebounded up slightly to 155-156 Bcf each year. Beginning in 2017, GCR/GCC demand increased steadily for the next several years, reaching 160 Bcf annually (132 Dth per customer) by 2019.

The advent of the present CoVid-19 situation, however, has seen a marked dip in normalized customer demand, with a drop to 154 Bcf normalized annual demand for 2019-2020 (127 Dth/customer) and then a further drop to 152 Bcf for 12 months ended August 2021 (123 Dth/customer).

Q36. What is the cumulative effect of the load changes from 2004 through 2021?

A36. In general, DTE Gas has seen a long-term load reduction in GCR/GCC demand.

Q37. Is the long-term load reduction permanent?

A37. A portion of the long-term load reduction is permanent due to several factors.

Q38. What factors contribute to the permanency of a portion of the longer-term load reduction?

A38. First, there is a time-sensitive load reduction, which means that there continues to be ongoing replacement of old equipment with newer and more efficient equipment such as furnaces, water heaters, and appliances. Also, household energy efficiencies are gained by the demolition of older, less well-insulated houses in addition to the construction of new homes built with better building materials.

Q39. What are some differences between permanent and non-permanent load reduction strategies amongst DTE Gas's customers?

A39. Potentially less permanent are load reductions that are reflective of higher natural gas prices. The data suggests that customers will react to higher natural gas market prices by reducing their natural gas consumption in a variety of ways, from adding insulation and new windows to their existing homes (permanent), to dialing down their thermostats and delaying furnace use in the fall and hastening furnace turn-offs in the spring (not permanent). This phenomenon affects natural gas customers across the United States.

Q40. Did you make any adjustments to the demand forecast in response to the economic environment presented by the current CoVid-19 situation?

A40. I did not make any specific adjustments to any of the rate classes due to the current CoVid-19 situation. To develop the usage factors, I regressed customer demand over the 24-month ended July 2021 billing periods. This time frame already encompasses much of the demand changes that our customers have made in response to CoVid-19 and, as such, I did not make any further adjustments to expected customer behavior. The Company will continue to monitor customer behavior moving forward and will make necessary adjustments to notable changes in customer behavior.

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Q41. What has the Company assumed for system-wide heating value for forecast purposes in this case?

A41. The Company assumes that the system-wide heating value for the entire forecast period of this GCR Plan case is 1,052 Btu/cf.

Q42. Why has the Company assumed 1,052 Btu/cf for the system-wide heating value for this GCR Plan?

A42. The system weighted-average heating value has seemed to stabilize in recent years. The 12-month system average heating value from August 2020 to July 2021 is 1,052 Btu/cf; the Company has assumed this heating value of 1,052 Btu/cf for all forecast years in this case.

Q43. Did you make an adjustment to the usage factors pursuant to changes in heating value for this GCR Plan?

A43. Yes. The weighted average heating value for the 24-month regression period was 1,056.18 Btu/cf. The assumed heating value for the forecast period is 1,052 Btu/cf. I therefore made an adjustment to the usage factors of an increase of 0.397% (or a factor of 1.00397). I derived at this value by simply dividing 1,056.18 Btu/cf by 1,052 Btu/cf. (Note that a lower heating value is expected in the forecast period than was observed in the historical regression period. A lower heating value, or "cooler" gas, will result in higher volumetric consumption.)

Q44. What are DTE Gas' current assumptions concerning ongoing conservation efforts from its rate schedule customers?

Line
No.

A44. In this plan, DTE Gas has assumed that normalized customer consumptive behavior will closely resemble that shown in the 24-month period ended July 2021 with a further adjustment consistent with expected demand reductions from the EWR program that DTE Gas has put in place in compliance with 2008 PA 295. In discussions this summer with the Company's EWR team, the Company projected annual demand reductions due to EWR to be 1% for 2021, and then up to 1.05% for forecast years 2022 and beyond. These are the rates that the EWR team was expecting to implement at the time this forecast was put together. I have included these levels of projected savings in my demand forecast.

Q45. Does this complete your direct testimony?

A45. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE Gas Company for approval of a	)	
Gas Cost Recovery Plan, 5-year Forecast	)	Case No. U-21064
and Monthly GCR Factor for the 12 months	)	
ending March 31, 2023	)	
____	)	

EXHIBITS

OF

GEORGE H. CHAPEL

DTE Gas Company
Market Outlook
April 2022 through March 2027
Weather Normalized Sales by Rate Class

Volumes in MMcf

Line	Rate Schedule	Apr-Mar 2022-2023 Col (a)	Apr-Mar 2023-2024 Col (b)	Apr-Mar 2024-2025 Col (c)	Apr-Mar 2025-2026 Col (d)	Apr-Mar 2026-2027 Col (e)
1	**Residential - Rate A**	950	935	908	888	868
2	**Residential - Rate A Heat**	98,988	99,506	98,828	98,714	98,572
3	**Residential - Rate 2A (Meter I)**	274	277	277	278	280
4	**Residential - Rate 2A (Meter II)**	3,278	3,207	3,097	3,007	2,918
5	**Residential - Total**	**103,491**	**103,925**	**103,110**	**102,887**	**102,637**
6	**Rate GS-1**	2,240	2,217	2,167	2,132	2,097
7	**Rate GS-1 Heat**	23,734	23,745	23,358	23,163	22,960
8	**Rate GS-2 Heat**	484	465	451	439	415
9	**Rate S**	1,137	1,157	1,164	1,177	1,190
10	**Commercial/Industrial - Total**	**27,595**	**27,584**	**27,140**	**26,911**	**26,661**
11	**GCR Total**	**131,086**	**131,509**	**130,250**	**129,797**	**129,299**
12	**Gas Customer Choice**	**21,917**	**21,687**	**21,459**	**21,234**	**21,011**
13	**Total GCR and GCC Sales Market**	**153,003**	**153,195**	**151,709**	**151,031**	**150,309**

DTE Gas Company
Market Outlook
April 2022 through March 2027
Projected Average Number of Customers

Line	Rate Schedule	Apr-Mar 2022-2023 Col (a)	Apr-Mar 2023-2024 Col (b)	Apr-Mar 2024-2025 Col (c)	Apr-Mar 2025-2026 Col (d)	Apr-Mar 2026-2027 Col (e)
1	**Residential - Rate A**	16,481	16,287	16,093	15,899	15,702
2	**Residential - Rate A Heat**	1,098,440	1,109,566	1,120,652	1,131,569	1,142,101
3	**Residential - Rate 2A (Meter I)**	1,314	1,338	1,362	1,386	1,410
4	**Residential - Rate 2A (Meter II)**	3,845	3,787	3,727	3,668	3,607
5	**Residential - Total**	**1,120,080**	**1,130,978**	**1,141,834**	**1,152,522**	**1,162,820**
6	**Rate GS-1**	4,102	4,075	4,048	4,021	3,993
7	**Rate GS-1 Heat**	69,638	69,788	69,932	70,058	70,134
8	**Rate GS-2 Heat**	36	35	34	33	32
9	**Rate S**	115	118	121	124	127
10	**Commercial/Industrial - Total**	**73,891**	**74,016**	**74,135**	**74,236**	**74,286**
11	**GCR Total**	**1,193,971**	**1,204,994**	**1,215,969**	**1,226,758**	**1,237,106**
12	**Gas Customer Choice**	**124,088**	**124,088**	**124,088**	**124,088**	**124,088**
13	**Total GCR and GCC Sales Customers**	**1,318,059**	**1,329,082**	**1,340,057**	**1,350,846**	**1,361,194**

Case No.: U-21064
Witness: GH Chapel
Exhibit No.: A-2

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Volumes

Volumes in MMcf

Line No.	2022-23 GCR Demand FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	TOTAL Col (m)
1	**Residential - Rate A**	77	40	22	21	21	24	53	98	148	169	151	124	950
2	**Residential - Rate A Heat**	7,923	3,916	2,052	1,440	1,451	1,821	5,388	10,670	16,237	18,311	16,440	13,337	98,988
3	**Residential - Rate 2A (Meter I)**	24	16	12	9	9	9	15	24	33	46	41	35	274
4	**Residential - Rate 2A (Meter II)**	257	145	96	54	55	67	192	371	559	567	506	411	3,278
5	**Residential - Total**	**8,282**	**4,118**	**2,182**	**1,525**	**1,536**	**1,921**	**5,649**	**11,164**	**16,977**	**19,092**	**17,139**	**13,907**	**103,491**
6	**Rate GS-1**	158	80	62	84	84	89	149	205	264	411	374	279	2,240
7	**Rate GS-1 Heat**	1,582	501	307	413	402	340	1,163	2,472	3,914	4,967	4,431	3,243	23,734
8	**Rate GS-2 Heat**	38	20	16	27	27	26	32	40	51	78	71	58	484
9	**Rate S**	96	41	8	5	6	14	62	126	192	223	202	162	1,137
10	**Commercial/Industrial - Total**	**1,874**	**643**	**392**	**530**	**519**	**470**	**1,406**	**2,843**	**4,421**	**5,679**	**5,078**	**3,742**	**27,595**
11	**TOTAL**	**10,156**	**4,760**	**2,574**	**2,055**	**2,055**	**2,391**	**7,055**	**14,006**	**21,397**	**24,772**	**22,216**	**17,649**	**131,086**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Volumes

Volumes in MMcf

Line No.	2023-24 GCR Demand FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	TOTAL Col (m)
1	**Residential - Rate A**	76	39	22	21	21	24	52	96	144	165	153	121	935
2	**Residential - Rate A Heat**	7,918	3,915	2,051	1,440	1,451	1,821	5,384	10,661	16,223	18,297	17,018	13,327	99,506
3	**Residential - Rate 2A (Meter I)**	24	17	12	9	9	9	16	24	33	46	43	36	277
4	**Residential - Rate 2A (Meter II)**	250	141	94	53	53	65	187	362	544	549	509	398	3,207
5	**Residential - Total**	**8,269**	**4,112**	**2,179**	**1,523**	**1,534**	**1,919**	**5,639**	**11,142**	**16,944**	**19,057**	**17,724**	**13,882**	**103,925**
6	**Rate GS-1**	156	78	60	83	83	88	146	202	260	405	382	274	2,217
7	**Rate GS-1 Heat**	1,570	497	304	410	399	337	1,153	2,452	3,882	4,928	4,593	3,219	23,745
8	**Rate GS-2 Heat**	35	19	14	25	25	24	30	39	50	76	72	56	465
9	**Rate S**	97	42	7	6	6	14	63	127	194	225	211	164	1,157
10	**Commercial/Industrial - Total**	**1,858**	**636**	**385**	**523**	**513**	**464**	**1,393**	**2,820**	**4,386**	**5,635**	**5,259**	**3,713**	**27,584**
11	**TOTAL**	**10,127**	**4,748**	**2,564**	**2,046**	**2,047**	**2,383**	**7,032**	**13,962**	**21,330**	**24,691**	**22,983**	**17,596**	**131,509**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Volumes

Volumes in MMcf

Line No.	2024-25 GCR Demand FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	TOTAL Col (m)
1	**Residential - Rate A**	74	39	21	20	21	23	51	94	141	161	145	119	908
2	**Residential - Rate A Heat**	7,914	3,913	2,050	1,440	1,450	1,821	5,380	10,650	16,206	18,278	16,411	13,314	98,828
3	**Residential - Rate 2A (Meter I)**	25	17	12	9	9	10	16	24	33	46	41	36	277
4	**Residential - Rate 2A (Meter II)**	243	137	92	52	52	63	182	352	529	533	476	386	3,097
5	**Residential - Total**	**8,255**	**4,106**	**2,175**	**1,521**	**1,532**	**1,917**	**5,629**	**11,120**	**16,909**	**19,018**	**17,073**	**13,855**	**103,110**
6	**Rate GS-1**	153	77	59	82	81	87	144	198	255	399	363	270	2,167
7	**Rate GS-1 Heat**	1,558	493	301	407	396	335	1,144	2,432	3,849	4,889	4,361	3,194	23,358
8	**Rate GS-2 Heat**	34	18	13	24	24	24	29	38	49	74	68	55	451
9	**Rate S**	98	42	7	6	6	15	64	129	197	228	206	166	1,164
10	**Commercial/Industrial - Total**	**1,844**	**630**	**380**	**518**	**508**	**460**	**1,381**	**2,796**	**4,350**	**5,589**	**4,998**	**3,685**	**27,140**
11	**TOTAL**	**10,099**	**4,736**	**2,555**	**2,039**	**2,040**	**2,377**	**7,010**	**13,916**	**21,258**	**24,607**	**22,071**	**17,540**	**130,250**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Volumes

Volumes in MMcf

Line No.	2025-26 GCR Demand FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	TOTAL Col (m)
1	**Residential - Rate A**	72	38	21	20	20	22	50	92	138	158	141	116	888
2	**Residential - Rate A Heat**	7,908	3,911	2,048	1,439	1,450	1,821	5,375	10,637	16,184	18,254	16,390	13,298	98,714
3	**Residential - Rate 2A (Meter I)**	25	17	12	9	9	10	16	24	33	46	42	36	278
4	**Residential - Rate 2A (Meter II)**	235	134	91	50	51	61	178	342	514	516	461	374	3,007
5	**Residential - Total**	**8,240**	**4,099**	**2,171**	**1,518**	**1,529**	**1,914**	**5,618**	**11,094**	**16,869**	**18,974**	**17,034**	**13,824**	**102,887**
6	**Rate GS-1**	151	75	58	80	80	85	141	194	250	393	357	266	2,132
7	**Rate GS-1 Heat**	1,546	489	298	403	393	332	1,134	2,410	3,816	4,847	4,325	3,168	23,163
8	**Rate GS-2 Heat**	33	17	13	24	24	23	28	37	47	73	67	54	439
9	**Rate S**	99	43	7	6	6	15	65	130	199	230	208	168	1,177
10	**Commercial/Industrial - Total**	**1,830**	**624**	**375**	**513**	**503**	**455**	**1,369**	**2,772**	**4,313**	**5,543**	**4,957**	**3,655**	**26,911**
11	**TOTAL**	**10,070**	**4,724**	**2,546**	**2,032**	**2,032**	**2,370**	**6,987**	**13,866**	**21,182**	**24,517**	**21,992**	**17,479**	**129,797**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Volumes

Volumes in MMcf

Line No.	2026-27 GCR Demand FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	TOTAL Col (m)
1	**Residential - Rate A**	71	37	20	20	20	22	49	90	135	154	138	113	868
2	**Residential - Rate A Heat**	7,899	3,908	2,046	1,438	1,449	1,820	5,368	10,620	16,157	18,225	16,365	13,278	98,572
3	**Residential - Rate 2A (Meter I)**	25	17	12	9	9	10	16	24	34	46	42	36	280
4	**Residential - Rate 2A (Meter II)**	228	130	89	49	49	60	173	332	499	500	446	363	2,918
5	**Residential - Total**	**8,223**	**4,092**	**2,167**	**1,516**	**1,527**	**1,911**	**5,605**	**11,066**	**16,825**	**18,926**	**16,991**	**13,790**	**102,637**
6	**Rate GS-1**	149	74	56	79	79	84	139	191	246	387	352	262	2,097
7	**Rate GS-1 Heat**	1,534	485	295	400	390	329	1,124	2,389	3,781	4,805	4,287	3,141	22,960
8	**Rate GS-2 Heat**	32	17	12	23	23	22	26	34	44	68	63	50	415
9	**Rate S**	100	43	7	6	6	15	66	132	202	232	211	170	1,190
10	**Commercial/Industrial - Total**	**1,816**	**619**	**370**	**508**	**498**	**451**	**1,355**	**2,745**	**4,273**	**5,492**	**4,912**	**3,623**	**26,661**
11	**TOTAL**	**10,039**	**4,710**	**2,537**	**2,024**	**2,025**	**2,362**	**6,960**	**13,811**	**21,097**	**24,418**	**21,904**	**17,412**	**129,299**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Number of Customers

Line No.	2022-23 GCR Customers FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	AVERAGE Col (m)
1	**Residential - Rate A**	16,601	16,562	16,527	16,521	16,496	16,485	16,438	16,391	16,420	16,438	16,438	16,454	16,481
2	**Residential - Rate A Heat**	1,094,728	1,094,193	1,093,512	1,093,002	1,093,663	1,094,373	1,097,652	1,101,349	1,103,114	1,104,451	1,105,409	1,105,828	1,098,440
3	**Residential - Rate 2A (Meter I)**	1,306	1,302	1,302	1,304	1,304	1,310	1,311	1,315	1,326	1,327	1,332	1,329	1,314
4	**Residential - Rate 2A (Meter II)**	3,866	3,861	3,859	3,866	3,867	3,842	3,836	3,832	3,837	3,834	3,827	3,818	3,845
5	**Residential - Total**	**1,116,501**	**1,115,918**	**1,115,200**	**1,114,693**	**1,115,330**	**1,116,010**	**1,119,237**	**1,122,887**	**1,124,697**	**1,126,050**	**1,127,006**	**1,127,429**	**1,120,080**
6	**Rate GS-1**	4,124	4,117	4,114	4,099	4,091	4,074	4,083	4,106	4,106	4,105	4,106	4,102	4,102
7	**Rate GS-1 Heat**	69,895	69,604	69,291	69,091	68,959	68,912	69,374	69,809	70,035	70,204	70,264	70,220	69,638
8	**Rate GS-2 Heat**	38	37	37	37	37	37	35	35	35	35	36	36	36
9	**Rate S**	113	113	112	113	114	114	116	116	115	116	116	116	115
10	**Commercial/Industrial - Total**	**74,170**	**73,871**	**73,554**	**73,340**	**73,201**	**73,137**	**73,608**	**74,066**	**74,291**	**74,460**	**74,522**	**74,474**	**73,891**
11	**TOTAL**	**1,190,671**	**1,189,789**	**1,188,754**	**1,188,033**	**1,188,531**	**1,189,147**	**1,192,845**	**1,196,953**	**1,198,988**	**1,200,510**	**1,201,528**	**1,201,903**	**1,193,971**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Number of Customers

Line No.	2023-24 GCR Customers FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	AVERAGE Col (m)
1	**Residential - Rate A**	16,407	16,368	16,333	16,327	16,302	16,291	16,244	16,197	16,226	16,244	16,244	16,260	16,287
2	**Residential - Rate A Heat**	1,105,811	1,105,284	1,104,611	1,104,109	1,104,779	1,105,500	1,108,789	1,112,502	1,114,273	1,115,604	1,116,556	1,116,970	1,109,566
3	**Residential - Rate 2A (Meter I)**	1,330	1,326	1,326	1,328	1,328	1,334	1,335	1,339	1,350	1,351	1,356	1,353	1,338
4	**Residential - Rate 2A (Meter II)**	3,808	3,803	3,801	3,808	3,809	3,784	3,778	3,774	3,779	3,774	3,767	3,758	3,787
5	**Residential - Total**	**1,127,356**	**1,126,781**	**1,126,071**	**1,125,572**	**1,126,218**	**1,126,909**	**1,130,146**	**1,133,812**	**1,135,628**	**1,136,973**	**1,137,923**	**1,138,341**	**1,130,978**
6	**Rate GS-1**	4,097	4,090	4,087	4,072	4,064	4,047	4,056	4,079	4,079	4,078	4,079	4,075	4,075
7	**Rate GS-1 Heat**	70,039	69,750	69,437	69,239	69,107	69,062	69,525	69,962	70,188	70,357	70,416	70,371	69,788
8	**Rate GS-2 Heat**	36	35	35	35	35	35	33	34	34	34	35	35	35
9	**Rate S**	116	116	115	116	117	117	119	119	118	119	119	119	118
10	**Commercial/Industrial - Total**	**74,288**	**73,991**	**73,674**	**73,462**	**73,323**	**73,261**	**73,733**	**74,194**	**74,419**	**74,588**	**74,649**	**74,600**	**74,016**
11	**TOTAL**	**1,201,644**	**1,200,772**	**1,199,745**	**1,199,034**	**1,199,541**	**1,200,170**	**1,203,879**	**1,208,006**	**1,210,047**	**1,211,561**	**1,212,572**	**1,212,941**	**1,204,994**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Number of Customers

Line No.	2024-25 GCR Customers FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	AVERAGE Col (m)
1	**Residential - Rate A**	16,213	16,174	16,139	16,133	16,108	16,097	16,050	16,003	16,032	16,050	16,050	16,066	16,093
2	**Residential - Rate A Heat**	1,116,948	1,116,415	1,115,735	1,115,226	1,115,887	1,116,599	1,119,874	1,123,574	1,125,336	1,126,649	1,127,589	1,127,991	1,120,652
3	**Residential - Rate 2A (Meter I)**	1,354	1,350	1,350	1,352	1,352	1,358	1,359	1,363	1,374	1,375	1,380	1,377	1,362
4	**Residential - Rate 2A (Meter II)**	3,748	3,743	3,741	3,748	3,749	3,724	3,718	3,714	3,719	3,715	3,708	3,699	3,727
5	**Residential - Total**	**1,138,263**	**1,137,682**	**1,136,965**	**1,136,459**	**1,137,096**	**1,137,778**	**1,141,001**	**1,144,654**	**1,146,461**	**1,147,789**	**1,148,727**	**1,149,133**	**1,141,834**
6	**Rate GS-1**	4,070	4,063	4,060	4,045	4,037	4,020	4,029	4,052	4,052	4,051	4,052	4,048	4,048
7	**Rate GS-1 Heat**	70,189	69,899	69,586	69,387	69,255	69,208	69,669	70,105	70,329	70,497	70,554	70,508	69,932
8	**Rate GS-2 Heat**	35	34	34	34	34	34	32	33	33	33	34	34	34
9	**Rate S**	119	119	118	119	120	120	122	122	121	122	122	122	121
10	**Commercial/Industrial - Total**	**74,413**	**74,115**	**73,798**	**73,585**	**73,446**	**73,382**	**73,852**	**74,312**	**74,535**	**74,703**	**74,762**	**74,712**	**74,135**
11	**TOTAL**	**1,212,676**	**1,211,797**	**1,210,763**	**1,210,044**	**1,210,542**	**1,211,160**	**1,214,853**	**1,218,966**	**1,220,996**	**1,222,492**	**1,223,489**	**1,223,845**	**1,215,969**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Number of Customers

Line No.	2025-26 GCR Customers FORECAST	April Col (a)	May Col (b)	June Col (c)	July Col (d)	August Col (e)	September Col (f)	October Col (g)	November Col (h)	December Col (i)	January Col (j)	February Col (k)	March Col (l)	AVERAGE Col (m)
1	**Residential - Rate A**	16,019	15,980	15,945	15,939	15,914	15,903	15,856	15,809	15,838	15,856	15,856	15,872	15,899
2	**Residential - Rate A Heat**	1,127,957	1,127,410	1,126,720	1,126,198	1,126,844	1,127,538	1,130,782	1,134,456	1,136,196	1,137,493	1,138,419	1,138,809	1,131,569
3	**Residential - Rate 2A (Meter I)**	1,378	1,374	1,374	1,376	1,376	1,382	1,383	1,387	1,398	1,399	1,404	1,401	1,386
4	**Residential - Rate 2A (Meter II)**	3,689	3,684	3,682	3,689	3,690	3,665	3,659	3,655	3,660	3,656	3,649	3,640	3,668
5	**Residential - Total**	**1,149,043**	**1,148,448**	**1,147,721**	**1,147,202**	**1,147,824**	**1,148,488**	**1,151,680**	**1,155,307**	**1,157,092**	**1,158,404**	**1,159,328**	**1,159,722**	**1,152,522**
6	**Rate GS-1**	4,043	4,036	4,033	4,018	4,010	3,993	4,002	4,025	4,025	4,024	4,025	4,021	4,021
7	**Rate GS-1 Heat**	70,325	70,034	69,719	69,519	69,385	69,335	69,793	70,226	70,448	70,614	70,670	70,622	70,058
8	**Rate GS-2 Heat**	34	33	33	33	33	33	31	32	32	32	33	33	33
9	**Rate S**	122	122	121	122	123	123	125	125	124	125	125	125	124
10	**Commercial/Industrial - Total**	**74,524**	**74,225**	**73,906**	**73,692**	**73,551**	**73,484**	**73,951**	**74,408**	**74,629**	**74,795**	**74,853**	**74,801**	**74,236**
11	**TOTAL**	**1,223,567**	**1,222,673**	**1,221,627**	**1,220,894**	**1,221,375**	**1,221,972**	**1,225,631**	**1,229,715**	**1,231,721**	**1,233,199**	**1,234,181**	**1,234,523**	**1,226,758**

DTE Gas Company
Market Forecast Analysis
Forecasted GCR Number of Customers

Line No.	2026-27 GCR Customers FORECAST	April	May	June	July	August	September	October	November	December	January	February	March	AVERAGE
		Col (a)	Col (b)	Col (c)	Col (d)	Col (e)	Col (f)	Col (g)	Col (h)	Col (i)	Col (j)	Col (k)	Col (l)	Col (m)
1	**Residential - Rate A**	15,825	15,786	15,751	15,745	15,720	15,709	15,662	15,615	15,644	15,652	15,652	15,668	15,702
2	**Residential - Rate A Heat**	1,138,763	1,138,203	1,137,500	1,136,964	1,137,594	1,138,267	1,141,481	1,145,130	1,146,846	1,147,417	1,148,331	1,148,710	1,142,101
3	**Residential - Rate 2A (Meter I)**	1,402	1,398	1,398	1,400	1,400	1,406	1,407	1,411	1,422	1,422	1,427	1,424	1,410
4	**Residential - Rate 2A (Meter II)**	3,630	3,625	3,623	3,630	3,631	3,606	3,600	3,596	3,601	3,589	3,582	3,573	3,607
5	**Residential - Total**	**1,159,620**	**1,159,012**	**1,158,272**	**1,157,739**	**1,158,345**	**1,158,988**	**1,162,150**	**1,165,752**	**1,167,513**	**1,168,080**	**1,168,992**	**1,169,375**	**1,162,820**
6	**Rate GS-1**	4,016	4,009	4,006	3,991	3,983	3,966	3,975	3,998	3,998	3,992	3,993	3,989	3,993
7	**Rate GS-1 Heat**	70,438	70,145	69,829	69,627	69,491	69,440	69,894	70,324	70,544	70,603	70,658	70,609	70,134
8	**Rate GS-2 Heat**	33	32	32	32	32	32	30	31	31	31	32	32	32
9	**Rate S**	125	125	124	125	126	126	128	128	127	128	128	128	127
10	**Commercial/Industrial - Total**	**74,612**	**74,311**	**73,991**	**73,775**	**73,632**	**73,564**	**74,027**	**74,481**	**74,700**	**74,754**	**74,811**	**74,758**	**74,286**
11	**TOTAL**	**1,234,232**	**1,233,323**	**1,232,263**	**1,231,514**	**1,231,977**	**1,232,552**	**1,236,177**	**1,240,233**	**1,242,213**	**1,242,834**	**1,243,803**	**1,244,133**	**1,237,106**

DTE Gas Company
April 2022 - March 2027
Total Market Requirements
Volumes in MMcf

Case No.: U-21064
Witness: GH Chapel
Exhibit No.: A-4

				GCR				Other			Total GCR	Gas Customer Choice				Total GCR+GCC
				Billed	Unbilled			Company				Billed	Unbilled			
Line	Year	Month	Days	Sales	Change	Balance	Total	Use	Losses	Total		Sales	Change	Balance	Total	
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)	(Col. 15)	(Col. 16)
1		Beginning Balance				**9,225**								**1,458**		
2	2022	April	30	13,726	(3,570)	5,655	10,156	421	150	571	10,727	2,091	(622)	836	1,469	12,196
3		May	31	7,804	(3,044)	2,611	4,760	406	90	496	5,256	1,199	(422)	414	777	6,034
4		June	30	3,667	(1,093)	1,518	2,574	360	100	460	3,034	599	(124)	289	474	3,508
5		July	31	2,271	(216)	1,301	2,055	337	200	537	2,592	452	(46)	244	406	2,998
6		August	31	2,113	(58)	1,243	2,055	378	150	528	2,583	413	11	255	424	3,006
7		September	30	2,066	325	1,568	2,391	384	350	734	3,125	488	180	435	668	3,792
8		October	31	3,814	3,241	4,809	7,055	389	500	889	7,944	835	403	838	1,238	9,182
9		November	30	9,469	4,538	9,347	14,006	273	1,000	1,273	15,279	1,631	771	1,609	2,402	17,681
10		December	31	17,228	4,170	13,517	21,397	295	1,000	1,295	22,693	2,912	705	2,314	3,617	26,310
11	2023	January	31	24,393	378	13,895	24,772	280	750	1,030	25,801	4,048	8	2,322	4,056	29,857
12		February	28	22,784	(567)	13,328	22,216	361	500	861	23,077	3,745	(96)	2,226	3,648	26,726
13		March	31	21,784	(4,134)	9,193	17,649	316	200	516	18,165	3,520	(783)	1,443	2,737	20,901
14		Total Period	365	131,118	(32)		131,086	4,199	4,990	9,189	140,276	21,932	(15)		21,917	162,192

				GCR				Other			Total GCR	Gas Customer Choice				Total GCR+GCC
				Billed	Unbilled			Company				Billed	Unbilled			
Line	Year	Month	Days	Sales	Change	Balance	Total	Use	Losses	Total		Sales	Change	Balance	Total	
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)	(Col. 15)	(Col. 16)
15	2023	April	30	13,681	(3,555)	5,639	10,127	420	150	570	10,697	2,069	(616)	827	1,454	12,151
16		May	31	7,782	(3,035)	2,604	4,748	404	90	494	5,242	1,187	(418)	410	769	6,011
17		June	30	3,656	(1,092)	1,512	2,564	358	100	458	3,022	592	(123)	286	469	3,491
18		July	31	2,262	(216)	1,296	2,046	336	200	536	2,582	447	(45)	241	402	2,984
19		August	31	2,104	(58)	1,238	2,047	376	150	526	2,573	408	11	252	419	2,993
20		September	30	2,058	325	1,563	2,383	382	350	732	3,115	483	178	430	661	3,776
21		October	31	3,802	3,230	4,793	7,032	386	500	886	7,919	827	398	829	1,225	9,144
22		November	30	9,438	4,524	9,317	13,962	272	980	1,252	15,214	1,614	763	1,592	2,377	17,591
23		December	31	17,173	4,157	13,474	21,330	294	1,000	1,294	22,623	2,881	698	2,290	3,579	26,202
24	2024	January	31	24,315	376	13,850	24,691	277	750	1,027	25,718	4,005	8	2,298	4,013	29,731
25		February	29	23,046	(63)	13,788	22,983	358	500	858	23,841	3,705	(95)	2,203	3,610	27,451
26		March	31	22,218	(4,622)	9,166	17,596	315	200	515	18,111	3,483	(775)	1,428	2,708	20,818
27		Total Period	366	131,536	(28)		131,509	4,177	4,970	9,147	140,656	21,702	(15)		21,687	162,342

DTE Gas Company
April 2022 - March 2027
Total Market Requirements
Volumes in MMcf

Case No.: U-21064
Witness: GH Chapel
Exhibit No.: A-4

				GCR				Other			Total GCR	Gas Customer Choice				Total GCR+GCC
				Billed	Unbilled			Company				Billed	Unbilled			
Line	Year	Month	Days	Sales	Change	Balance	Total	Use	Losses	Total		Sales	Change	Balance	Total	
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)	(Col. 15)	(Col. 16)
1	2024	April	30	13,642	(3,542)	5,624	10,099	420	150	570	10,669	2,048	(609)	818	1,439	12,108
2		May	31	7,762	(3,026)	2,598	4,736	404	90	494	5,230	1,174	(413)	405	761	5,992
3		June	30	3,646	(1,091)	1,507	2,555	358	100	458	3,013	586	(122)	283	464	3,478
4		July	31	2,254	(215)	1,292	2,039	336	200	536	2,575	443	(45)	239	398	2,973
5		August	31	2,097	(57)	1,234	2,040	376	150	526	2,566	404	11	250	415	2,981
6		September	30	2,052	325	1,559	2,377	382	350	732	3,108	478	176	426	654	3,762
7		October	31	3,791	3,219	4,779	7,010	386	500	886	7,897	818	394	820	1,212	9,109
8		November	30	9,408	4,508	9,286	13,916	272	975	1,247	15,163	1,597	755	1,575	2,352	17,515
9		December	31	17,116	4,142	13,429	21,258	294	980	1,274	22,532	2,851	690	2,266	3,541	26,073
10	2025	January	31	24,233	374	13,803	24,607	277	750	1,027	25,634	3,963	8	2,274	3,971	29,605
11		February	28	22,634	(562)	13,241	22,071	358	500	858	22,929	3,666	(94)	2,180	3,572	26,501
12		March	31	21,644	(4,104)	9,136	17,540	315	200	515	18,054	3,446	(767)	1,413	2,679	20,734
13		Total Period	365	130,279	(29)		130,250	4,177	4,945	9,122	139,372	21,474	(15)		21,459	160,831

				GCR				Other			Total GCR	Gas Customer Choice				Total GCR+GCC
				Billed	Unbilled			Company				Billed	Unbilled			
Line	Year	Month	Days	Sales	Change	Balance	Total	Use	Losses	Total		Sales	Change	Balance	Total	
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)	(Col. 15)	(Col. 16)
14	2025	April	30	13,599	(3,529)	5,607	10,070	420	150	570	10,640	2,026	(603)	810	1,424	12,064
15		May	31	7,740	(3,016)	2,591	4,724	404	90	494	5,218	1,162	(409)	401	753	5,971
16		June	30	3,636	(1,089)	1,502	2,546	358	100	458	3,005	580	(121)	280	459	3,464
17		July	31	2,246	(215)	1,287	2,032	336	200	536	2,568	438	(44)	236	394	2,961
18		August	31	2,090	(57)	1,230	2,032	376	150	526	2,559	400	11	247	411	2,969
19		September	30	2,045	325	1,555	2,370	382	350	732	3,102	473	174	421	647	3,748
20		October	31	3,779	3,208	4,762	6,987	386	500	886	7,873	809	390	812	1,200	9,072
21		November	30	9,375	4,491	9,253	13,866	272	900	1,172	15,038	1,580	747	1,559	2,327	17,366
22		December	31	17,055	4,127	13,381	21,182	294	950	1,244	22,426	2,821	683	2,242	3,504	25,930
23	2026	January	31	24,145	372	13,753	24,517	277	750	1,027	25,544	3,922	8	2,250	3,930	29,473
24		February	28	22,551	(560)	13,193	21,992	358	500	858	22,849	3,628	(93)	2,157	3,535	26,384
25		March	31	21,567	(4,088)	9,105	17,479	315	200	515	17,994	3,410	(759)	1,398	2,651	20,645
26		Total Period	365	129,829	(32)		129,797	4,177	4,840	9,017	138,814	21,248	(15)		21,234	160,048

DTE Gas Company
April 2022 - March 2027
Total Market Requirements
Volumes in MMcf

				GCR				Other			Total GCR	Gas Customer Choice				Total GCR+GCC
				Billed	Unbilled			Company				Billed	Unbilled			
Line	Year	Month	Days	Sales	Change	Balance	Total	Use	Losses	Total		Sales	Change	Balance	Total	
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)	(Col. 15)	(Col. 16)
1	2026	April	30	13,554	(3,515)	5,590	10,039	420	150	570	10,608	2,005	(596)	801	1,409	12,017
2		May	31	7,716	(3,006)	2,583	4,710	404	90	494	5,204	1,150	(405)	397	745	5,950
3		June	30	3,625	(1,088)	1,496	2,537	358	100	458	2,995	574	(119)	278	455	3,450
4		July	31	2,238	(214)	1,282	2,024	336	200	536	2,560	433	(44)	234	389	2,949
5		August	31	2,081	(57)	1,225	2,025	376	150	526	2,551	395	11	244	406	2,957
6		September	30	2,038	325	1,550	2,362	382	350	732	3,094	468	173	417	640	3,734
7		October	31	3,765	3,195	4,744	6,960	386	500	886	7,846	801	386	803	1,187	9,033
8		November	30	9,339	4,472	9,217	13,811	272	800	1,072	14,883	1,563	740	1,543	2,303	17,186
9		December	31	16,987	4,111	13,327	21,097	294	900	1,194	22,291	2,791	676	2,219	3,467	25,758
10	2027	January	31	24,048	370	13,697	24,418	277	700	977	25,394	3,881	8	2,226	3,888	29,283
11		February	28	22,460	(557)	13,140	21,904	358	500	858	22,761	3,590	(92)	2,134	3,497	26,258
12		March	31	21,482	(4,070)	9,070	17,412	315	200	515	17,927	3,374	(751)	1,383	2,623	20,551
13		Total Period	365	129,333	(35)		129,299	4,177	4,640	8,817	138,116	21,025	(15)		21,011	159,126

DTE Gas Company

Mean Design Day Temperatures by District

(Temperatures in ^{o} F)

Line	District (Col. 1)	January End of Mo. (Col. 2)	February End of Mo. (Col. 3)	March End of Mo. (Col. 4)
1	Alpena	-10	-7	5
2	Ann Arbor	-10	-2	16
3	Big Rapids	-11	-6	6
4	Cadillac	-20	-10	-6
5	Detroit	-6	4	14
6	Escanaba	-16	-7	5
7	Grand Rapids	-7	1	7
8	Grayling	-21	-13	1
9	Iron Mountain	-22	-8	0
10	Ludington	-3	0	11
11	Mount Pleasant	-9	-4	6
12	Muskegon	-6	0	11
13	Petoskey	-12	-10	5
14	Sault Ste. Marie	-16	-9	2
15	Tawas	-8	-5	7
16	Traverse City	-11	-9	5

DTE Gas Company
2023 Design Day Load by Area
(Volumes in MMcf/d at 1,052 Btu/cf)

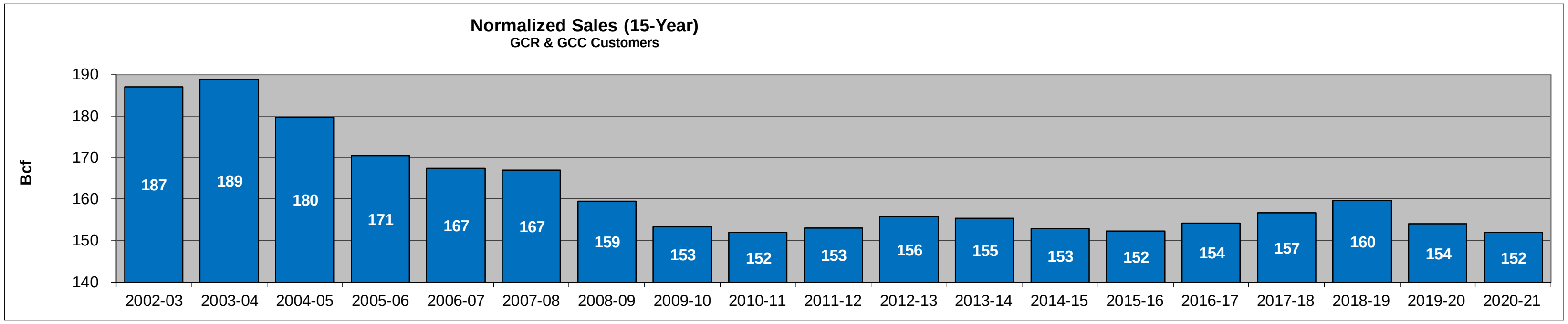
		End-of-Month Peak Day Load		
Line		January	February	March
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	**Detroit / Ann Arbor**	1,396	1,243	1,056
2	**Alpena**	123	119	103
3	**Grand Rapids**	667	618	567
4	**Upper Peninsula**	72	65	57
5	**Traverse City**	163	158	136
6	**Total**	**2,422**	**2,204**	**1,919**

Case No.: U-21064
Witness: GH Chapel
Exhibit No.: A-6

DTE Gas Company
Historical Normalized Annual Sales (GCR & GCC)
September 2002 through August 2021

Volumes in MMcf unless otherwise noted

Line	Rate Schedule	Sep-Aug 2002-03 Col (a)	Sep-Aug 2003-04 Col (b)	Sep-Aug 2004-05 Col (c)	Sep-Aug 2005-06 Col (d)	Sep-Aug 2006-07 Col (e)	Sep-Aug 2007-08 Col (f)	Sep-Aug 2008-09 Col (g)	Sep-Aug 2009-10 Col (h)	Sep-Aug 2010-11 Col (i)	Sep-Aug 2011-12 Col (j)	Sep-Aug 2012-13 Col (k)	Sep-Aug 2013-14 Col (l)	Sep-Aug 2014-15 Col (m)	Sep-Aug 2015-16 Col (n)	Sep-Aug 2016-17 Col (o)	Sep-Aug 2017-18 Col (p)	Sep-Aug 2018-19 Col (q)	Sep-Aug 2019-20 Col (r)	Sep-Aug 2020-21 Col (s)
1	Actual Billed Sales	204,960	190,672	184,039	162,205	168,102	169,253	169,230	148,239	161,560	132,683	156,391	178,617	167,276	137,706	139,273	159,850	165,761	150,758	148,082
2	Actual Base Load (August Billed Sales x 12)	45,615	50,532	43,193	42,476	43,865	40,861	38,857	35,069	35,483	35,322	37,687	32,041	33,604	33,608	37,747	34,680	33,405	31,704	32,755
3	Actual Heat Load Sales (Row 1 - Row 2)	159,345	140,140	140,845	119,729	124,237	128,392	130,372	113,171	126,078	97,361	118,705	146,575	133,671	104,098	101,527	125,170	132,356	119,053	115,327
4	Average Number of GCR & GCC Customers	1,248,757	1,247,174	1,256,099	1,262,307	1,253,489	1,244,788	1,229,535	1,216,844	1,212,623	1,213,521	1,219,246	1,224,856	1,230,358	1,240,008	1,249,623	1,260,882	1,271,509	1,285,272	1,300,927
5	Detroit Actual HDDs	6,650	5,985	6,089	5,521	5,939	6,010	6,385	5,652	6,387	4,884	5,937	7,016	6,615	5,183	5,149	6,057	6,190	5,745	5,710
6	Heat Load Mcf per Customer per HDD ((Row 3 x 1,000) / Row 4 / Row 5)	0.0192	0.0188	0.0184	0.0172	0.0167	0.0172	0.0166	0.0165	0.0163	0.0164	0.0164	0.0171	0.0164	0.0162	0.0158	0.0164	0.0168	0.0161	0.0155
7	Detroit 15-Year (06-20) Normal HDDs	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904	5,904
8	Normalized Heat Load (Row 4 x Row 6 / 1,000 x Row 7)	141,470	138,244	136,566	128,035	123,504	126,128	120,551	118,217	116,543	117,695	118,045	123,344	119,304	118,579	116,413	122,008	126,240	122,348	119,245
9	Normalized Sales (Row 2 + Row 8)	187,085	188,776	179,759	170,511	167,369	166,989	159,409	153,285	152,026	153,016	155,732	155,385	152,908	152,187	154,160	156,688	159,645	154,053	152,001
	Mcf per Customer	149.8	151.4	143.1	135.1	133.5	134.2	129.6	126.0	125.4	126.1	127.7	126.9	124.3	122.7	123.4	124.3	125.6	119.9	116.8
		187	189	180	171	167	167	159	153	152	153	156	155	153	152	154	157	160	154	152



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Gas Company** for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2023	))))))	Case No. U-21064

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ERIC P. SCHIFFER

DTE GAS COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ERIC P. SCHIFFER

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Q1. What is your name and business address?

A1. My name is Eric P. Schiffer. My business address is One Energy Plaza, Detroit, Michigan 48226.

Q2. By whom are you employed and in what capacity?

A2. I am employed by DTE Gas Company (DTE Gas or Company) as Principal Marketing Specialist.

Q3. What is your educational background?

A3. I earned both my Bachelor of Arts Degree in Professional Accounting and my Master of Business Administration degree from Michigan State University. I have attended conferences related to Risk Management, the natural gas industry, the LDC Gas Forum, revenue requirements calculation, and Value at Risk (VaR).

Q4. What is your business experience?

A4. I have been employed full time by DTE Gas (formerly Michigan Consolidated Gas Company), DTE Energy or MCN Energy Group (parent of MichCon, acquired by DTE in 2001) since 1993. From 1993 to 2001, I held various positions primarily in the non-regulatory accounting groups responsible for Oil and Gas production as well as pipeline and processing plant accounting. From 2001 to 2013, I held various positions of increasing responsibility in Enterprise Risk Management, including Risk Associate for DTE Energy Trading (gas), Sarbanes Oxley Control Center lead for Trading and Risk Analyst (Enterprise Risk and DTE Gas). In 2013, I was promoted to Principal Supervisor responsible for Gas Accounting – gross margin and then in 2014 I accepted a position in the LLC Controllers – Decision Support Consolidation. In 2018, I accepted my current position, Principal Marketing Specialist. I have participated on the Gas Buyers' Panel at the LDC Gas Forums since 2019.

Q5. What are your responsibilities as a Principal Marketing Specialist?

A5. As a Principal Marketing Specialist, I am responsible for the purchase of natural gas and interstate transportation capacity to deliver the supply to the DTE Gas system to serve GCR customers. I am also responsible for the analysis, planning and forecasting of DTE Gas natural gas supply and transportation volumes, prices and costs, and development and administration of the fixed price program and represent the Company on the Natural Gas Sustainability Collaborative (NGSC).

Q6. Have you previously testified or submitted testimony in any Michigan Public Service Commission (MPSC or Commission) proceeding?

A6. Yes, I testified in U-20210 GCR 2018-2019 Reconciliation case, U-20235 GCR 2019-2020 Plan case, U-20236 GCR 2019-2020 Reconciliation case, U-20543 GCR 2020-2021 Plan case, U-20544 GCR 2020-2021 Reconciliation case and U-20816 GCR 2021-2022 Plan Case. I also adopted testimony in MPSC Case No. U-20076.

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Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony in this proceeding is to present DTE Gas's natural gas supply plan ("Plan") for the Plan Period extending from April 1, 2022 through March 31, 2027 ("Plan Period"). My testimony will cover the following subjects and demonstrates that DTE Gas's proposed gas supply plan for the plan year and the five-year Plan Period is reasonable and prudent:

1) **Supply Pricing Mix -** DTE Gas's pricing strategy is a mixture of both fixed price supply where the price is known months in advance of delivery and index price supply where the price is uncertain until delivery begins. Specifically, my testimony will discuss how DTE Gas will mitigate price uncertainty utilizing the Volume Cost Averaging methodology (VCA or VCA Method) of purchasing fixed price supply, which was first approved by the MPSC in the Company's 2010-2011 GCR Plan, Case No. U-16146, and contained in every subsequent Commission-approved GCR Plan (Case Nos. U-16482, U-16921, U-17131, U-17332, U-17691, U-17941, U-18152, U-18412, U-20235) through the Company's 2020-2021 GCR Plan, Case No. U-20543.

2) **Price Forecast –** The price forecast is based on the average settled prices of the first five trading days of December 2021 because this is the most recent data available at the time this filing was prepared. This approach is consistent with past practice.

3) **Gas Supply Purchasing -** How the appropriate supply requirements are determined for the ensuing month in monthly gas supply meetings after considering the supply currently under contract and subsequently contracting for supply needs from different geographic production regions and market zones based on operational requirements first, followed by the lowest cost supply basin second, while

acknowledging such factors as weather, natural gas market fundamentals, national inventory levels, geographical pricing, and system requirements.

4) **Transportation Portfolio Changes –** Since its last GCR Plan Case filing, the Company renewed ANR Northern Zone Contract #122248 for 21 MDth/d, Viking Gas Transmission Contract # FT-A (AF0081) for 21 MDth/d, NEXUS Gas Transmission Contract # 860003/00002 for 75 MDth/d alternate receipt point at Clarington for 37,500 dth/d and did not exercise ROFR rights on ANR Pipeline Contract # 122247 for 15 MDth/d.

5) 400 MDth/d transportation – The rationale why it is prudent to have 400 MDth/d of firm transportation to provide safe, clean, reliable and reasonably priced gas supply to its customers.

6) **NEXUS Contract**. In response to the Commission's Orders in U-20210 and U-20243, the Company is providing additional supporting evidence for the NEXUS contract (including the TEAL amendment) including an updated independent analysis of the benefits of the capacity contract.

7) **Projected Total Gas Supply Costs -** How DTE Gas's total supply requirements for the 2022-23 GCR Plan Period are forecasted at approximately 134 Bcf at a total cost around $468 million, including approximately $60 million in total transportation costs and $250 thousand for the Gas Supply physical call option.

8) **Projected Supply Costs for Last in First Out (LIFO) Valuation of Gas in Storage -** The projected NYMEX, volumes and costs are associated with the January 2022 through March 2022 period for LIFO valuation of gas in storage, which is utilized by Company Witness Hardy.

9) **Gas Supply Strategy for April 2023 and Beyond –** How DTE Gas's gas supply strategy for April 2023 and beyond is essentially consistent with the strategy

used for the April 2022-March 2023 period including a projection of gas purchases and transportation costs.

10) **Impact of DTE Gas net zero commitment on Gas Supply Strategy** - How DTE Gas's commitment to reach a net zero carbon future impacts the gas supply strategy for April 2022 and beyond.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-7	Fixed Price Purchase Guidelines
A-8	Projected NYMEX, Basis, and Supply Basin Prices
A-9	Summary of Transport Contracts
A-10	Projected Purchase Volumes and Cost (Excluding Transportation Costs)
A-11	Projected Transportation Utilization, Reservation Costs, and Usage Costs
A-12	Projected Total Delivered Cost Including Transportation Cost
A-25	Historical Backcast of NYMEX Prices
A-27	Fixed Price Program Analysis -- Purchase Percentages
A-28	Affiliate Transactions with DTE Energy Trading
A-29	NYMEX Monthly Settlement History
A-30	Pipeline 2022 Expiring Capacity Summary
A-34	TEAL 1 Year Amendment Option

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

A9. Yes, they were.

Supply Pricing Mix

Q10. How is DTE Gas proposing to price its supply during the 2022-2023 GCR Plan Period?

A10. DTE Gas's supply will be priced utilizing a mixture of both fixed price supply where the price is known months in advance of delivery and index price supply where the price is uncertain until delivery begins.

Q11. What fixed price method is DTE Gas proposing to operate under during the 2022-23 GCR Plan Period?

A11. DTE Gas will continue to purchase fixed price supply under the Volume Cost Average (VCA) Method, which is the same fixed price method that was first approved expressly by the Commission on September 28, 2010 in the Company's 2010-2011 GCR Plan, Case No. U-16146, thereby replacing the quartile indices method (QIM). This very same VCA method has been contained in every subsequent Commission-approved GCR Plan (Case Nos. U-16482, U-16921, U-17131, U-17332, U-17691, U-17941, U-18152, U-18412, and U-20543), through the Company's pending 2021-22 GCR Plan Case No. U-20816. The specific guidelines of the VCA Method are detailed in Exhibit A-7.

Q12. What is the purpose of the VCA Method?

A12. The VCA Method is a methodology used to create price certainty for natural gas volumes that will be delivered at a future date. VCA provides upward price protection, downward price participation, a year-over-year smoothing effect on the

GCR factor, and most importantly, it is a simple and effective way to manage price fluctuations and dampen natural gas price uncertainty and volatility for GCR Customers under a variety of actual and potential market and operating conditions.

Q13. How does the VCA Method operate?

A13. In general, DTE Gas will fix the price of its future supply requirements over a two-year period prior to the start of delivery during the GCR Period. For the 2022-23 GCR year, DTE Gas bought 75% of the projected requirements ratably between January 2020 and December 2021 (approximately 3% each month). This program results in the price of 75% of DTE Gas's supply requirements being known prior to the start of the GCR Period.

Q14. Did DTE Gas conduct an annual review of the VCA Method?

A14. Yes. DTE Gas reviewed the fixed price program (FPP) objectives, the current 75% level of fixed price coverage, and updated the quantitative analysis based on current market conditions. These reviews and analyses were necessary to corroborate the Company's opinion that the VCA Method continues to form the foundation of a reasonable and prudent FPP. Specifically, DTE Gas updated the NYMEX back test through March 2021, which provides a 20-year historical view of how the VCA Method would have performed based on the current purchase pattern with historical prices. In addition, DTE Gas updated the Random Price Analysis, which is a forward-looking analysis of the VCA Method's performance in 5,000 different price scenarios. The Random Price Analysis update was necessary to determine that the original conclusions resulting from the analysis have not changed based on current market conditions. The NYMEX back test, Random Price Analysis updates, and related conclusions are described in greater detail below as are the FPP's objectives. This annual review and analyses support the continued use of the VCA Method. DTE Gas also performed two additional analyses, an analysis of the fixed price program consisting of the Future NYMEX Projection and a 95% Confidence Interval of possible future prices, and an analysis of the historical NYMEX natural gas price frequency distribution.

Q15. What are the objectives of a reasonable and prudent FPP?

A15. The objectives of a reasonable and prudent FPP include:

1) mitigating the impact of market price fluctuations and price uncertainty, also known as price volatility or price risk, to provide GCR factor stability;
2) allowing participation in downward price movements;
3) protecting customers against upward price movements;
4) utilizing a prescriptive methodology that limits speculation; and
5) ensuring simplicity by utilizing a methodology that is not overly complex.

Q16. Does the VCA Method still meet all the objectives of a reasonable and prudent FPP?

A16. Yes. The VCA Method continues to meet all the objectives for a reasonable and prudent program for purchasing fixed price gas. VCA allows continual market participation over an extended period, up to two years in advance of the GCR Period start date. The methodology is consistent with the philosophy that one should not try to beat or time the market, but instead regularly participate in the market over an extended period, which is a reasonable and prudent method for mitigating price fluctuations or volatility. VCA provides upward price protection, downward price participation, GCR factor stability, and most importantly it is a simple and effective way to manage price uncertainty and dampen price fluctuations.

Q17. How does VCA protect the customer against upward price movements and allow for downward price participation?

A17. In the event of a temporary price spike in any given month, only approximately 3% of supply would be exposed to that price spike. Fast forward in time and assume that the temporary price spike does not abate, but instead becomes a fundamental upward price level shift. Under such circumstances, the purchase made during the initial price increase under VCA will be favorable in the new, higher price environment. In the event prices abate in subsequent months, then the customer will participate in the downside price movements with the execution of fixed price purchases during that abatement period. VCA spreads risk evenly over time and volumes in contrast to alternative approaches that may be speculative in nature and subject customers to additional price risks that are inherent with speculative trading.

Q18. How would VCA provide benefits to the customers in the event prices do not abate but continue in a perpetual fundamental upward price shift?

A18. If the market is in a long-term upward price shift, then VCA would fix prices during the upward march of market prices, thereby contributing to a lower weighted average cost relative to the higher market prices at the time of the final delivery date.

Q19. How does VCA eliminate price speculation?

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A19. VCA eliminates price speculation because the volumetric amount of the purchases is fixed each month regardless of price. Therefore, the purchases are time dependent as opposed to price dependent. VCA also provides protection from price risk and uncertainty through equal volume purchases executed monthly over a defined period well in advance of the delivery month. The purchase price in any given month could be an outlier that is an extreme high or low relative to historical prices. However, any individual monthly price will have a limited impact on the volume weighted price of gas.

Q20. Does the VCA provide GCR factor stability?

A20. Yes. The VCA Method mitigates price uncertainty, price risk, price variability, and volatility, thereby creating greater GCR factor stability.

Q21. How will the VCA Method perform in a stable price environment?

A21. In a stable price environment, the VCA will yield gas costs that are similar to not purchasing forward at all. This is because VCA is a time-dependent technique and if VCA purchase prices fixed in advance of the delivery date remain relatively stable until the actual delivery date, then VCA will yield similar gas costs to purchasing at Index. Index purchasing is a passive strategy that does not involve any form of advanced purchasing that locks in price certainty for future deliveries, which exposes all purchase requirements to market price fluctuations until the time of delivery.

Q22. Would the Company continue to purchase forward transactions during a stable price environment in which the VCA will yield gas costs that are similar to not purchasing forward at all?

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A22. Yes, because a stable price environment is only visible in hindsight. It is not until the trading for a month has elapsed that one can know what the monthly settlement price will be. The Webster's New International Dictionary, Second Edition, defines "stable" as meaning "Firmly established; not easily moved, shaken or overthrown; solid; fixed; steadfast."[1] See Exhibit A-29, NYMEX Monthly Settlement History, for a history of NYMEX monthly settlement data. As shown in Exhibit A-29, the NYMEX settlement price has varied between a high of $6.202 in November 2021 and a low of $1.495 in July 2020. These settlements are 16 months apart, which is only nine months shorter than the 24-month term utilized by DTE Gas's Volume Cost Averaging (VCA) program. During this 16-month period, the highest settlement price is over four times or 415% greater than the lowest settlement price. This type of large price swing is not a characteristic of the above definition of a "stable" market.

Q23. Is there any way to predict that a "stable" market will occur in the future?

A23. No. One cannot know with any certainty how much the price of natural gas will change or fluctuate from month to month. It is only upon looking back over a period of time that one can ascertain that pricing did not change and can deem that period of time as "stable" in hindsight. Lacking the ability to foresee the future, the most reliable method to secure pricing stability is by acquiring gas supply under fixed prices. That is the function of the VCA program. It is to create a "stable" price environment for the GCR customers regardless of the actual vagaries of the marketplace.

[1] *Webster's New International Dictionary* 2449 (2d ed. 1934)

Q24. What is the Random Price Analysis?

A24. The Random Price Analysis, originally presented in DTE Gas's Commission-approved 2012-2013 GCR Plan Case No. U-16921, is a method for analyzing the range of possible random outcomes from a particular purchasing method. The Analysis is used to compare the VCA (at different fixed price percentages) with an all-index method. Utilizing the price curve as of the 1st five trading days in December and current volatility (11%), I ran 5,000 random scenarios to identify the range of gas costs an average consumer would experience under each method.

Q25. What updates did you make to the Random Price Analysis?

A25. The Random Price Analysis has been updated for this GCR Plan Case to reflect minor changes in DTE Gas's purchase profile, current market prices, and associated market price volatility.

Q26. Did your update change the results of the Random Price Analysis?

A26. No. The conclusions and findings of the analysis, that were originally presented in Case No. U-16921, have not changed. Specifically, the Random Price Analysis confirms that the level of price risk or uncertainty that is borne by customers is dependent upon the level of fixed price coverage. More specifically, decreasing the level of fixed price coverage produces an increasingly wider range of potential price outcomes, or higher level of price uncertainty, which is synonymous with increased price volatility or price risk. This can be seen on Table 1, at line 5, where 95% of the time, the Index Method produces price outcomes between $0.93 and $7.93. However, 95% of the time, the 75% VCA Method, represented on line 1, produces price outcomes in a smaller, more compact range between $1.40 and

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$6.53. Stated differently, 95% of the time, the Index Method produces residential gas costs that are 29% to 152% of the average cost. In contrast, the 75% VCA Method produces a more condensed and compact range of possible cost outcomes that are 44% to 207% of the average cost.

Table 1 – Random Price Analysis

								Rising Prices		Falling Prices	
		Low Price (25th percentile)		Average Price		High Price (97.5th percentile)		Annual Residential Gas Cost Compared to Index		Annual Residential Gas Cost Compared to Index	
Line	Fixed Price Method	$/Dth	Annual Residential Gas Cost [1]	$/Dth	Annual Residential Gas Cost [1]	$/Dth	Annual Residential Gas Cost [1]	Maximum Customer Savings [1]	Average Customer Savings [1]	Maximum Customer Cost [1]	Average Customer Cost [1]
	col. (a)	col. (b)	col. (c)	col. (d)	col. (e)	col. (f)	col. (g)	col. (h)	col. (i)	col. (j)	col. (k)
1	75% VCA	$ 1.40	$ 126	$ 3.16	$ 284	$ 6.53	$ 587	$ (641)	$ (53)	$ 167	$ 34
2	65% VCA	1.34	121	3.16	284	6.71	604	(555)	(46)	145	30
3	55% VCA	1.29	116	3.16	284	6.89	620	(470)	(39)	123	25
4	45% VCA	1.23	110	3.16	284	7.09	638	(384)	(32)	100	21
5	Index	0.93	84	3.15	284	7.93	714				

(1) Based on average residential consumption of 95 Dth per year for the forecast year of 2021

Q27. What is the NYMEX back test?

A27. The NYMEX back test was originally presented in DTE Gas's 2012-2013 GCR Plan Case No. U-16921. The NYMEX is an industry wide benchmark price of natural gas at the Henry Hub receipt point in Louisiana. The NYMEX back test assumes a purchase profile similar to DTE Gas's current purchase profile for all years to maintain consistency over the 18-year period. The intent of the analysis is to show the cost and benefit of the VCA Method as compared to settled NYMEX prices over an extended historical period. The analysis used NYMEX prices to represent gas costs because of the availability of historical data and because it is an industry recognized benchmark of natural gas prices that correlate to DTE Gas's purchase costs.

Q28. Did DTE Gas update the NYMEX back test for the most recent GCR Period ending March 2021?

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A28. Yes. DTE Gas updated the back test of historical NYMEX prices to include the most recent April 2020 through March 2021 GCR Period. This NYMEX back test update is designated as Exhibit A-25.

Q29. What were the results of the NYMEX back test update in terms of residential gas costs?

A29. As shown in Exhibit A-25, at line 21, over the 20-year historical period, a typical residential customer would have paid $432 annually on average under the VCA Method and $400 annually on average under the Index Method. In other words, over the 20-year period customers would have paid $32 more annually or approximately $2.62 more per month on average under the VCA Method than compared to the Index Method. However, gas price fluctuations, or price uncertainty, which is synonymous with price volatility, over the 20-year period was only 13% under the VCA Method, which was significantly less than the Index Method volatility of 29%, as described more fully below.

Q30. What does a reduction in volatility mean for the GCR customer?

A30. As shown in Exhibit A-25, at line 21, volatility under the VCA Method means that for any given year, 95% of the time the customers' gas costs would be within a range of 26% higher or 26% lower than the average cost based on the past 20 years. By contrast, volatility under the Index Method means that, for any given year, 95% of the time the customers' gas costs would be within a range of 58% higher or 58% lower than the average cost based on the past 20 years. Consequently, the VCA Method significantly reduces the risk of extreme price run ups and provides greater price certainty for the GCR customers, therefore providing greater assurance of price affordability.

Q31. What conclusions did you reach based on the NYMEX back test?

A31. The $32 annual cost difference between the VCA Method and the Index Method that occurred over the historical 20 years used in the back test is approximately 7% of the customers' gas cost (and an even lower percentage on a total bill basis), which is a reasonable cost to pay to lower the gas price volatility from 29% under the Index Method to 13% under the VCA Method as explained above.

Q32. In addition to these two analyses, did DTE Gas perform any additional review of the VCA Fixed Price Purchase Program?

A32. Yes. DTE Gas prepared the analysis presented in Graph 1, Fixed Price Program Analysis -- Future NYMEX Projection – 95% Confidence Interval and the Frequency Distribution of Historical NYMEX prices analysis. These analyses were created in response to the April 23, 2015 Commission Order U-17332, which states at page 5 that:

> The Commission reiterates that, going forward, the burden continues to be on DTE Gas to manage risk and to facilitate the affordability of the natural gas sold to GCR customers. The Commission is not looking for proof that a specific percentage of purchases were locked-in, but wants to ensure that, over time and under a variety of actual and potential market and operating conditions, the benefits of price stability to the GCR customers outweigh any additional cost associated with the procurement strategy. Accordingly, the Commission expects DTE Gas to address the risk mitigation costs and benefits under different conditions…

These analyses are intended to show that the benefits of price stability to the GCR customers outweigh any additional cost associated with the VCA procurement

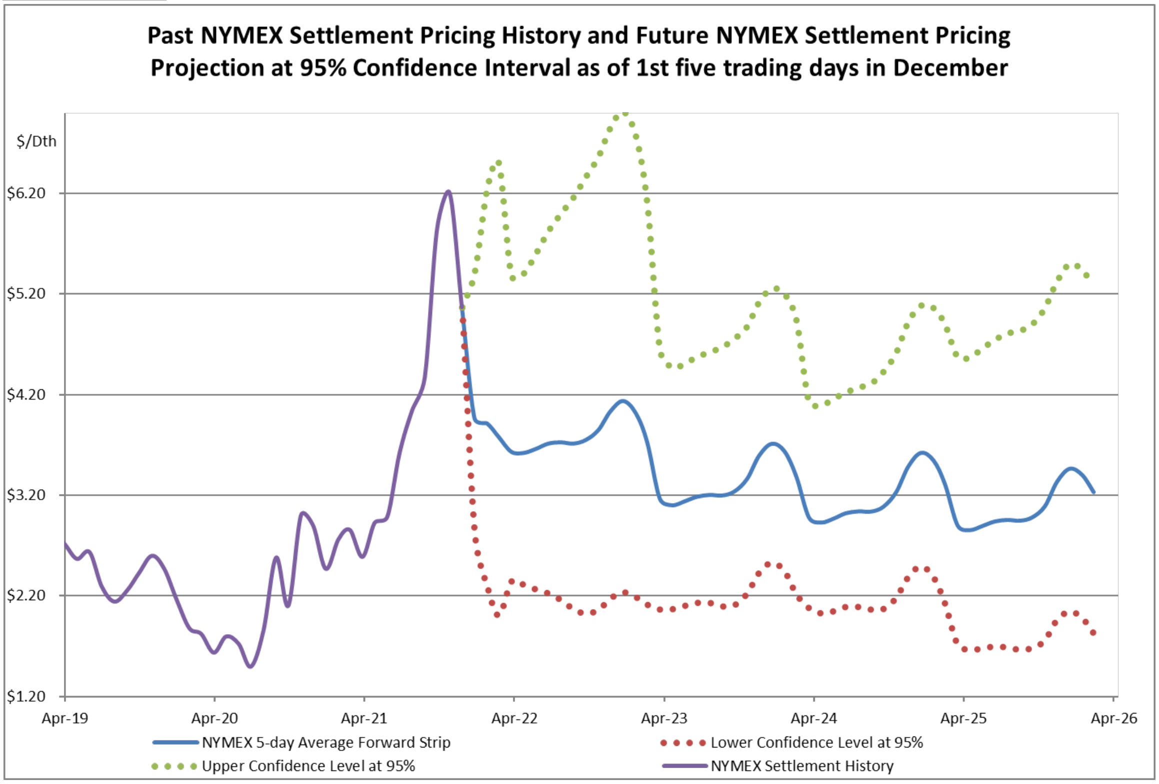
Line No.

strategy. These analyses represent this cost vs. benefit by comparing and quantifying the upside risk of higher prices against the downside opportunity of lower prices in future natural gas prices.

Q33. What data is contained in the price probability model?

A33. Graph 1 is based on the methodology from the "EIA Past Henry Hub Price and 95% NYMEX Confidence Interval" analyses performed by the United States Department of Energy's Energy Information Administration (EIA) in each monthly publication of its Short-Term Energy Outlook (STEO). The upper and lower dotted lines that create the cone-shaped projection are the Upper Confidence Level (UCL) and Lower Confidence Level (LCL) projected five years into the future for NYMEX natural gas futures prices. The 95% confidence level represents the 95% probability that the final market price for a particular futures contract will fall somewhere within the lower and upper range of prices. Note that the lower range of prices has the same probability of occurrence as the upper range.

Graph 1



Q34. What do the remaining lines on Graph 1 represent?

A34. The blue line in the middle of the Graph that displays a series of peaks and valleys as it goes into future months represents the NYMEX natural gas futures prices for the next five years derived from the forward curve as of the first five trading days in December 2021. The purple jagged line on the left side of the Graph is the actual monthly NYMEX settlement price from January 2019 through December 2021. This shows a range of recent prices that have been as high as \$6.20/Dth in November 2021 and as low as \$1.50/Dth in July 2020. By displaying the market projections in this manner, the observer can easily review purchases from the perspective of the data that was known at the time that the purchase decisions were made. This removes the coloring of hindsight from the equation and allows for an understanding of the rationale that shows that the benefits of the VCA outweigh any additional costs.

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Q35. How would you quantify the value of the upside risk and the downside opportunity in future natural gas pricing where the future prices are uncertain?

A35. Graph 1 is based upon the methodology used in the EIA STEO for quantifying price uncertainty. This graph covers the time range from December 2018 through March 2027. This graph shows projections at a 95% confidence interval at the Henry Hub for Natural Gas Prices going forward for the next six years as projected by the NYMEX prices as of first trading days in December 2021. The average of the Upper Confidence Level (UCL) of natural gas pricing is $1.88/Dth above the average NYMEX, and the average of the Lower Confidence Level (LCL) is $1.31/Dth below the average NYMEX. This tells us that there is an equal chance of the price rising by $1.88 as there is of the price declining by $1.31. Thus, although the probability is equal of prices going up or down, the 95% confidence interval range of a price increase is 32% greater than the range of a price decrease (44% = ($1.88-$0.1.31) / ($1.31)). This graphically displays (as summarized in Table 2 below) the fact that the potential cost (risk) exposure of a price increase is greater than the potential cost savings (opportunity) from a price decrease.

Price Outlook for Jan 2021 through Mar 2026:

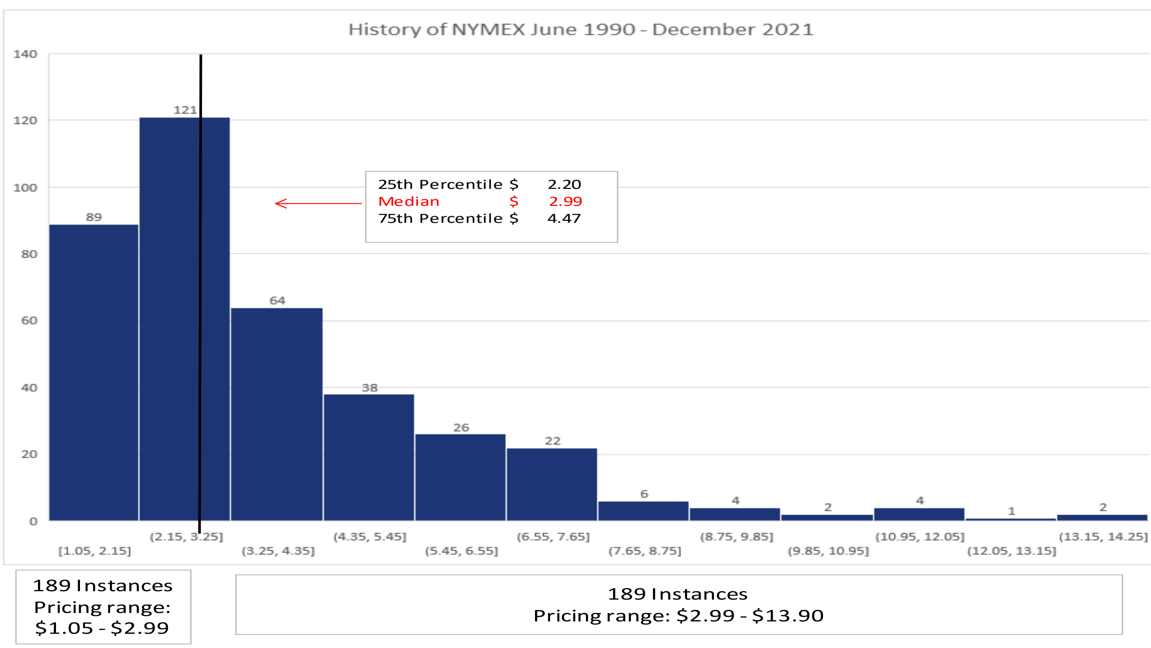
Table 2

NYMEX Price (Col 1)	UCL Avg Price (Col 2)	LCL Avg Price (Col 3)	UCL Range (Col 4)	LCL Range (Col 5)	Range Ratio UCL/LCL (Col 6)
$3.32	$5.20	$2.01	$1.88	$1.31	144%

Q36. Have you also observed this upside risk and the downside opportunity in historical natural gas pricing?

A36. Yes, I reviewed the historical NYMEX settled prices from June 1990 to December 2021 to prove the upward bias of pricing. Graph 2 is a frequency distribution graph of the historical NYMEX settlement prices from June 1990 to December 2021. The X axis on the graph shows the range of settlement prices from lowest to highest in $1.10 increments, or bins, during that time period, and the Y axis shows the number of occurrences that the NYMEX settled within the price range for each increment.

Graph 2



Q37. Is there a historical bias toward the upside risk versus downside opportunity?

A37. Yes, history has shown that 50% of the time prices ran up as much as $10.91 from the median price but only dropped from the median price by as much as $1.94. The average price above the median was $4.47 ($1.48 above median) and the average price below the median was $2.20 ($0.79 below median), which shows on average that price run ups were 1.9 times greater than price drops ($1.48/$0.79 = 1.88).

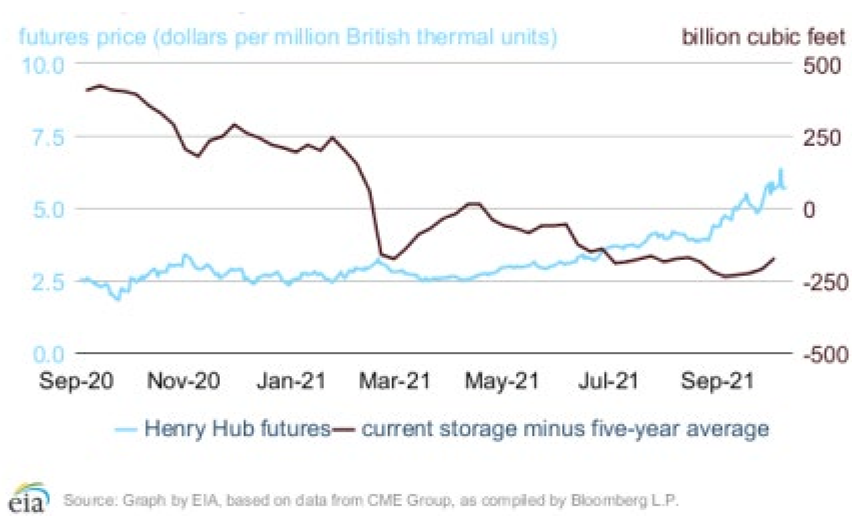
Thus, compared to the median price, higher prices occurred an equal amount of the time as lower prices, but the cost impact was 1.9 times greater for the higher prices than the lower prices. The fixed price program helps protect the customer from this upside risk of higher gas prices, which historically have 1.9 times greater cost impact than lower prices relative to the median.

Q38. How does Graph 2 and Table 2 demonstrate that the benefits of price stability to the GCR customers outweigh any additional cost associated with the fixed price procurement strategy?

A38. The benefits are twofold: one benefit is the price certainty obtained with a fixed price, and the other benefit is the protection from the potential of higher prices. By implementing the VCA, the Company has locked in 75% of the gas costs prior to the gas year. Assuming normal weather, approximately 2/3 of the costs will be similar from the prior year, thus there will not be huge swings in customer bills. As for the potential of higher prices, the cost of a fixed price program is the impact of higher prices to the customer while the benefit is the potential for lower prices when prices fall. When you look at the asymmetry of rising versus falling prices and where gas prices have been historically a monthly $2.625 cost clearly outweighs the benefits.

Q39. What are the "current and forecasted market conditions and fundamental economic and physical considerations that affect gas supply and prices" (see MPSC Order dated April 15, 2014 in Case No. U-17131)?

A39. As described in my testimony above, the forecasted market conditions contain risk and uncertainty. The STEO released by the EIA in October of 2021[2] shows, at page 2, that September Henry Hub spot prices averaged $5.16 up $1.09/MMBtu from August when it averaged $4.07/MMBtu and up almost $2.00 for the first half of 2021. The reason for the high prices is storage levels below the five-year average. In addition, inventory builds during the summer were below the five-year average and then in September there have been sharp increases in international prices. Below is a chart of the U.S. natural gas front-month futures prices and storage deviation from the five-year average.



Q40. Why is the VCA method reasonable and prudent for DTE Gas's customers?

A40. In general, natural gas is not a discretionary purchase that can be avoided based on price or some other factor. DTE Gas's customers need to purchase and consume natural gas throughout the year for such basic needs as warmth in their homes and businesses. The greatest unknown to the customer is not necessarily how much natural gas they will consume but more importantly at what price they will purchase

[2] https://www.eia.gov/outlooks/steo/archives/oct21.pdf

natural gas to supply their inherent need for natural gas. DTE Gas's customers should not be unduly subject to risk taking or speculating on what the price of natural gas will be in the future. The greater risk to DTE Gas's customers is rising prices because most customers, especially residential customers and small businesses, are generally believed to have a fixed amount of non-discretionary income to spend on a natural gas utility bill. These customers would ultimately be more financially burdened with higher bills (if gas prices rise over time) as opposed to steady or somewhat lower bills (if gas prices decline over time).

Q41. How does the VCA Program mitigate this rising price risk for the customers?

A41. Without some method of managing price uncertainty, DTE Gas's customers could be exposed to prices that could rise without constraint and be exposed to unlimited price risk. While the Random Price Analysis and the 95% Confidence Interval analyses contained in the Graphs and Tables above show the probability of a range of prices into the future, they only represent a snapshot in time reflected by the price volatility of the current market. However, the volatility of gas prices has and can swing widely, rapidly, and unpredictably without any prior notice or forewarning. Thus, to mitigate the potentially unlimited price risk and uncertainty, which could adversely impact customers' budgets, DTE Gas has implemented the VCA method wherein the price of natural gas is fixed for a portion of their supply many months prior to delivery, thereby creating price certainty or price protection.

Q42. Why is 75% a reasonable and prudent level of fixed price coverage?

A42. The optimal level of fixed price protection that DTE Gas can provide customers and still have operational flexibility to adjust for lower purchase requirements associated with GCC migration, warmer than normal weather, or conservation resulting from ongoing energy-efficiency initiatives is 75%. Stated differently, customers currently shoulder 25% of the price risk during the delivery period, which is an acceptable and reasonable level of price risk or uncertainty based on operational constraints and the customers' inherent risk-adverse nature. As the level of fixed-price coverage is reduced from the 75% level, there is an equal and offsetting increase in the level of price risk or uncertainty. Under the 75% VCA Method, if prices rise over time, customers are rewarded through protection from the rising prices. However, if prices fall over time, customers risk paying more than they would have under a fixed-price-coverage ratio less than 75%. The greater risk to DTE Gas's customers is the risk of rising prices because they typically have a fixed amount of non-discretionary income to spend on a natural gas utility bill, and customers would ultimately be more financially burdened with higher bills as opposed to steady or somewhat lower bills. Using the 75% ratio strikes the appropriate balance between protecting customers against rising prices and allowing them to participate in any price decrease. Using a lower ratio exposes customers to too much risk of price increases. Therefore, using the VCA method with a 75% fixed price coverage ratio is a reasonable and prudent approach to protecting customers from price risk.

Q43. How does the VCA Method perform relative to the Index Method in different price environments in terms of gas costs?

A43. In a rising price environment, in which prices consistently increase as time progresses, the VCA Method will produce lower gas costs than the Index method. In a falling price environment, in which prices consistently decrease as time

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progresses, the VCA Method will produce higher gas costs than the Index method. It is important to remember that no one can accurately predict the future natural gas price environment, and the greater risk to DTE Gas's customers comes from a drastically rising price environment as opposed to a drastically falling price environment. It is equally important to bear in mind that one of the goals of the VCA Method is to mitigate the risk of price spikes and to provide a stable price to DTE Gas's customers, and that the VCA Method was not designed or intended to compete with or "beat" the Index-based natural gas market. Although gas costs in a falling price environment may be lower with a fixed price coverage that is less than 75%, there is an equal and offsetting risk of higher gas costs in a rising price environment. The VCA Method protects against the financial burden of higher gas costs to the customer; which is of primary concern because the natural gas utility bill, insofar as it provides home heating during the frigid cold winters of the Michigan climate, is a non-discretionary expense, and many customers may not be able to afford the added cost without undue hardship.

Q44. How much gas has DTE Gas purchased under the VCA FPP for delivery in the April 2022 - March 2023 GCR Period?

A44. Currently, DTE Gas has purchased 75% of the April 2022 through March 2023 requirements and has therefore achieved the 75% fixed-price-coverage ratio by December 31, 2021, as specified in the Commission-approved FPP. Purchased volumes under the VCA are shown on Exhibit A-10, page 1, line 1.

Q45. Is DTE Gas proposing any changes to the VCA FPP that was originally approved by the Commission in Case No. U-16146 and subsequently approved

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as part of every GCR Plan in Case Nos. U-16482, U-16921, U-17131, U-17332, U-17691, U-17941, U-18152, U-18412, U-20235, and U-20543?

A45. No.

Q46. Why is the Company not proposing any changes to the VCA FPP?

A46. The Company's analysis of the VCA Method contained in this filing supports the continuation of the FPP and the benefits derived therefrom.

Q47. When will DTE Gas lock in fixed-price purchases each month?

A47. The timing of each intra-month purchase is based on factors such as willing counterparties, creditworthiness, market liquidity, and other best-available market intelligence at the time of purchase. Utilization of these factors will ensure that intra-month purchases are executed in a reasonable and prudent manner. The Company will follow the guidelines described in Exhibit A-7 section 6.

Q48. How does DTE Gas plan to price its remaining supply requirements that are not fixed purchases?

A48. All gas that is not locked in at fixed prices will be priced utilizing market-based settled-index prices or at the NYMEX settlement price plus a fixed premium or minus a fixed discount based on the geographic purchase point, which is also known as fixed basis.

Q49. What is a market-based settled-index price?

A49. Market-based settled-index prices are determined by independent publishing companies that survey market participants a week before the delivery month as to

Line No.

the value of gas to be delivered during the month. The market-based settled-index prices are published industry wide.

Q50. What is the NYMEX settlement price?

A50. NYMEX is the world's largest physical-commodity futures exchange and is the industry-wide recognized price reference point for commodities including natural gas. NYMEX provides the North American market's collective assessment of the expected future values for natural gas. NYMEX trades reveal the value in dollars per Dth that the market places on gas delivered to the Henry Hub trading point, located in Louisiana, for each future delivery month. The NYMEX settlement price is determined on the last day that market participants can enter into transactions before the delivery month.

Q51. Why are either the market-based settled-index price or the NYMEX settlement price, plus a fixed premium or minus a fixed discount, the best methods for pricing remaining gas supplies that are not fixed purchases?

A51. These are the best methodologies to secure spot market pricing because they represent the most recent value the market places on gas immediately prior to the month of delivery.

<u>**Price Forecast**</u>

Q52. What methodology did DTE Gas use to forecast gas prices for this GCR Plan Case?

A52. The five-year price forecast, which is a long-term price projection for the market, is found on Exhibit A-8. Line 1 contains the average settlement price for the first five trading days of December 2021 for the NYMEX Henry Hub natural gas futures

Line
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contract for each respective delivery period. The remaining lines show the forecasted basis price differentials and resulting prices for the indicated purchase locations. All prices are stated in dollars per Dth. Throughout this testimony, I assume a simple average heating value of 1.052 Dth per Mcf. This heating value assumption is more fully addressed in the testimony of Witness Chapel.

Q53. Why did DTE Gas use the average settlement price for the first five trading days of December 2021 to forecast market prices?

A53. The average of the settlement prices on the first five trading days of December 2021 is the most recent natural gas traded prices at the time the Plan was finalized for filing in this Plan Case.

Q54. How did DTE Gas forecast the price of gas at geographic locations other than at Henry Hub?

A54. The price of gas at different geographic locations is measured through basis-price differentials. Basis-price differentials represent the difference in price for gas delivered at the indicated geographic location and the price for gas delivered at Henry Hub as traded on the NYMEX. Basis prices may be expressed as either a positive / premium (a price that is higher than Henry Hub) or a negative / discount (a price that is lower than Henry Hub) depending on the geographic location. The basis differential for DTE Gas's receipt points reflects prices both higher and lower than Henry Hub.

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Q55. What source is DTE Gas using for forecasted basis prices?

A55. DTE Gas is utilizing natural gas industry publications to forecast basis prices as well as other available market intelligence.

Q56. How are projected gas prices at different geographic supply points used in your gas supply forecast?

A56. These prices are used to calculate the cost of forecasted volumes that have not been fixed.

Q57. Are there any other purchases that DTE Gas has included in the Plan??

A57. Yes. Contracted Indexed Price deals are purchases that DTE Gas has included in the Plan. 50,000 Mcf per month of forecasted volumes that are purchased from DTE Gas Gathering (MGAT) at the Platt's Gas Daily Price Guide first-of-the-month DTE Gas city-gate published index price. However, the actual volumes may be more or less than 50,000 Mcf per month. This volume is shown on Exhibit A-10, page 1, line 3, with the corresponding price projection on line 11 of the same exhibit.

Q58. Does DTE Gas plan to purchase gas from any other affiliates during this Plan?

A58. Yes, DTE Gas has included 22.6 Bcf of fixed priced purchases from DTE Energy Trading at an average price of $2.72. The transactions are detailed in Exhibit A-28 Affiliate Transactions with DTE Energy Trading. These volumes were purchased as part of the VCA program and followed the procedures outlined in Exhibit A-7.

Q59. Where can additional information related to the above transactions be found?

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A59. Intervenors on record have access to the bid warehouse where detailed deal information is archived by deal number.[3]

Gas Supply Purchasing

Q60. What process does DTE Gas use to acquire its monthly gas supply?

A60. DTE Gas maintains an active list of more than 30 creditworthy suppliers with production in areas that connect to the Company's contracted interstate transportation capacity. Due to the continuous price volatility in the natural gas industry, DTE Gas does not issue formal RFPs (Requests for Proposal) for its supply requirements.

For its supply needs, the Company generally solicits three or more verbal offer prices from its list of creditworthy suppliers from the supply area that is required. DTE Gas will attempt to complete transactions with the supplier who provides the lowest price offer, but the Company also considers supplier diversity, supplier performance history, ability to deliver to alternate receipt points, and creditworthiness existing at the time of purchase in order to ensure a balanced and prudent gas supply plan.

Q61. What factors does DTE Gas consider when making decisions about purchasing its supply?

A61. DTE Gas considers an array of factors in monthly meetings or more often if necessary when making its supply decisions. These factors include, but are not

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[3] https://dteenergy.sharepoint.com/sites/DiscoveryPortal/BidSheets/Bid%20Sheets%20Library/Forms/AllItems.aspx)

limited to: weather forecasts, system requirements and operational capabilities, the forward NYMEX price curve, regional market basis prices, national storage levels as reported by the EIA, DTE Gas-owned storage levels, and industry periodicals and reports such as Gas Daily and the EIA Short Term Energy Outlook.

Q62. How does DTE Gas respond to gas purchases impacted by pipeline outages, maintenance or other Force Majeure events?

A62. The Company negotiates either a change in location (with the appropriate change in cost) or delivery period based on supplier capabilities and the Company's requirements.

Q63. What level of interstate firm transport capacity does DTE Gas rely on to meet its market requirements?

A63. DTE Gas maintains a portfolio of 400 MDth/day of firm transportation contracts for the winter operating season and 330 MDth/day for the summer storage injection season to meet supply requirements for normal weather, colder than normal weather, design day, and supplier of last resort.

Q64. What are the Company's total reservation charges for firm pipeline transportation capacity for the 2022-2023 GCR year?

A64. The Company's reservation charges for firm pipeline capacity for the 2022-2023 GCR year are approximately $59 million, as shown on Exhibit A-11, column (14), line 31. Witness Hardy uses these costs as the basis for the supplier of last resort (SOLR) reservation charge.

Q65. How will capacity-release revenues that DTE Gas receives be treated with respect to the proposed SOLR reservation charge?

A65. Any capacity-release revenues that DTE Gas receives will be credited back to customers, both GCR and GCC, in the same load-proportionate manner as the transportation-reservation costs were allocated.

Q66. What level of capacity-release revenues is DTE Gas estimating in this GCR Plan Case to include in the SOLR reservation charge?

A66. Due to the highly unpredictable nature of capacity-release revenues, DTE Gas is not predicting any capacity-release revenue to include in the SOLR reservation charge. DTE Gas does not expect capacity-release revenues to materially impact the SOLR reservation charge and any over/under recoveries that may occur will nevertheless be addressed in the GCR Reconciliation.

Q67. What are the total reservation charges for pipeline capacity that the Company intends to recover through the SOLR reservation charge for the 2022-2023 GCR year?

A67. The total amount of reservation charges to be recovered for pipeline capacity is approximately $59 million, as shown on Exhibit A-11, line 31, column (14).

Q68. Are there any other costs associated with the gas purchase portfolio?

A68. Yes, as described by Witness Bratu, DTE Gas obtained a Gas Supply Physical Call Option. The cost of the option, which is $250 thousand as shown on Exhibit A-11, line 30, columns (11 and 12) and the rationale and parameters for acquiring the option, are more thoroughly described in Witness Bratu's testimony.

TRANSPORTATION PORTFOLIO CHANGES

Q69. What pipeline capacity have you assumed in the GCR Plan Case for the period April 2022 through March 2023?

A69. Exhibit A-9 shows all interstate transport currently under contract and the related receipt points, capacities, and terms. Exhibit A-11 separates transportation costs by reservation and commodity charges. Exhibit A-11 also displays the total available capacity and forecasted monthly load utilization associated with each pipe.

Q70. What changes has DTE Gas made to its interstate pipeline capacity since its 2020-2021 GCR Plan Filing?

A70. a) **ANR Northern Zone Contract #122248 for 21 MDth/d.** This capacity transports gas from the ANR Marshfield interconnect with Viking Gas Transmission to the DTE Gas system at Menominee throughout the GCR year. DTE Gas renewed this capacity for a five-year term through March 31, 2027 to coincide with the renewal of the corresponding capacity held on Viking Gas Transmission.

b) **Viking Gas Transmission Contract # FT-A (AF0081) for 21 MDth/d.** This capacity transports gas from the Viking Gas Transmission interconnect with TransCanada Pipeline at Emerson. DTE Gas renewed this capacity for a five-year term through March 31, 2027 to coincide with the renewal of the corresponding capacity held on ANR Pipeline.

c) **NEXUS Gas Transmission Contract # 860003/00002 for 75 MDth/d.** Extended the alternate receipt point at Clarington for 37,500 dth/d through October 31, 2024.

d) **ANR Pipeline Contract # 122247 for 15 MDth/d.** DTE Gas did not exercise its right of first refusal (ROFR) rights and will allow this contract to expire on March 31, 2022.

Q71. Why did DTE Gas renew ANR Contract #122248 for 21 MDth/d?

A71. This capacity transports gas from the ANR Marshfield interconnect with Viking Gas Transmission to the DTE Gas system at Menominee citygate and was scheduled to expire on March 31, 2022. DTE Gas renewed this capacity for a term of five years through March 31, 2027 to coincide with the renewal of the corresponding capacity held on Viking Gas Transmission. This capacity was renewed because this 21 MDth/d requirement is necessary to service this isolated area of the DTE Gas system in the Upper Peninsula of Michigan.

Competitive bids were not solicited for this capacity due to the isolated nature of the service. This is the only transportation route capable of serving this specific portion of the DTE Gas system. ANR was asked if there was any available capacity from the Chicago Hub or on ANR SW field zone to service the Menominee area starting on 4/1/2022, and ANR stated that there was no capacity available. DTE Gas attempted to negotiate a discounted reservation rate with ANR, but DTE Gas was told that ANR would not be willing to offer any discounts on this leg of transportation.

Q72. Why did DTE Gas renew Viking Gas Transmission Contract # FT-A (AF0081) for 21 MDth/d?

A72. This capacity transports gas from the Emerson interconnect with TransCanada Pipeline to the Marshfield interconnect with ANR Pipeline and was scheduled to

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expire on March 31, 2022. DTE Gas renewed this capacity for a term of five years through March 31, 2027 to coincide with the renewal of the corresponding capacity held on ANR Pipeline. This capacity was renewed because this 21 MDth/d volume is necessary to feed into ANR Contract # 122248 to provide service to the isolated Menominee area of the DTE Gas system in the Upper Peninsula of Michigan. Additionally, a five-year term was elected because Viking has term-differentiated rates and the lowest cost reservation rate is for a five-year term vs maximum tariff rates for terms less than five years.

Q73. Why did DTE Gas renew the amended Clarington receipt point on NEXUS Gas Transmission Contract # 860003/00002 for 37,500 Dth/d?

A73. The Company renewed the amended receipt point allowing for receipt of 37,500 dth/d of natural gas at the Clarington point because it provided a projected savings of $5.8 million dollars versus receiving the entire 75,000 dth/d of natural gas at Kensington for the two years November 2022 - October 2024 as shown in Exhibit A-34 on line 50.

Q74. Why did the DTE Gas elect not to exercise its ROFR rights on ANR Pipeline Contract # 122247 for 15 MDth/d?

A74. The Company elected not to exercise its ROFR rights on this contract because it plans to contract for capacity on the Panhandle pipeline beginning in April 2022. The analysis shown in Exhibit A-30 shows GCR customers projected to save $1.7 million annually over the three-year deal. In addition, gas flowing on the Panhandle pipeline comes from the Appalachian region which shifts approximately 4% of the portfolio from the Mid-Continent and provides lower supply emissions.

Line No.

Energy Transfer has communicated the projected costs associated with this contract; however, it cannot initiate the contract offer until January 3, 2022. It anticipates submitting the request on that date for its standard internal review and approval process. The companies will then execute a contract after that is completed. Exhibits A 10-12 assume the execution of the contract at rates that were used in Exhibit A-30.

Q75. What changes does DTE Gas plan to make to its interstate pipeline contracts during the 2022-2023 GCR Plan year?

A75. As stated in the previous question, the Company plans to execute a three-year contract for capacity on the Panhandle Pipeline. In addition, the Company has 50,000 Dth/d of transportation on ANR Pipeline(Southwest fieldzone); 20,000 Dth/d (winter), 10,000 Dth/d (summer) of Vector capacity expiring on 10/31/2022; and 60,000 Dth/d (winter) of ANR (REX Shelbyville) capacity expiring on March 31, 2023 that it will be evaluating whether to renew or replace these contracts in order to continue to provide safe, diverse and reliable natural gas to its customers.

Q76. Is there regional diversity in the Company's current transportation portfolio?

A76. Yes, Table 4 shows the regional diversity and percentage of firm interstate-transportation contracts from each of the Company's supply sources for the GCR Plan Year.[4]

[4] 15 MDth/d of ANR SW is expected to be replaced by capacity on the Panhandle pipeline beginning April 1, 2022 decreasing the Mid-Continent percentage to 32% and increasing the Appalachia percentage to 38%

Table 4

Supply Basin	Percentage of Total	Winter Nov 21-Mar 22	Winter Nov 22-Mar23	Winter Nov 23- Mar 24
Canadian:				
	Great Lakes Gas Transmission	8%	8%	8%
	Viking/ANR	5%	5%	5%
	Vector	5%	5%	5%
	ANR Northern Zone/Alpena	13%	13%	13%
		30%	**30%**	**30%**
Mid-Continent:				
	ANR Southwest Leg[4]	19%	16%	16%
	Panhandle Eastern Pipeline	20%	16%	16%
		36%	**32%**	**32%**
Appalachian:				
	Panhandle Eastern Pipeline[4]	0%	4%	4%
	ANR Shelbyville	15%	15%	15%
	NEXUS - Kensington only	9%	9%	9%
	NEXUS - Clarington/TEAL	9%	9%	9%
		34%	**38%**	**38%**
Total All Pipelines		**100.0%**	**100.0%**	**100.0%**

Q77. Why is regional diversity of supply important to DTE Gas and its customers?

A77. DTE Gas's customers benefit from regional diversity of supply with increased supply reliability and mitigated price risk. Security of supply and increased options for supply sources are the primary reasons DTE Gas holds regionally diverse interstate transportation capacity. Supply basin diversity helps the Company mitigate adverse effects of major disruptions in the general natural gas industry supply chain. If supply becomes constrained in a particular basin, then a diverse supply portfolio helps in insulating DTE Gas and its customers from the risk of potential supply disruptions in that area. If we experience a colder than normal winter and need to compete with other utilities for additional supply, having varied sources of that supply increases the chances that the Company will be able to purchase less expensive gas than if the Company could only purchase from one location. This is accomplished through the Company's strategy of holding firm pipeline capacity.

400 MDth/d transportation

Q78. How much *Firm* transportation does the Company contract for?

A78. The Company contracts for 400 MDth/d of winter capacity and 330 MDth/d of summer capacity.

Q79. Why is there a difference between summer and winter capacity?

A79. The difference is that the Company has determined that 400 MDth/d of Firm transportation is required for Design Day requirements. Design Day requirements are described more fully in Witness Bratu's testimony.

Q80. In Q78, the word "*FIRM*" is italicized, is there a reason?

A80. Yes, the Company requires FIRM transportation versus interruptible service. All pipeline tariffs have a protocol for cutting volumes (which means curtailing the supply) based on the type of contracts. Supply can be cut for various reasons ranging from planned construction outages or an emergency, having a FIRM transportation contract means that DTE Gas will be in the last group to be cut and therefore least likely to experience loss of supply.

Q81. Are there other options that are equally as reliable and provide the same certainty as maintaining firm transportation capacity?

A81. No, purchasing gas on the spot market, buying interruptible contracts, purchasing interstate transport capacity release, do not provide the same level of certainty.

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Simply put, these other avenues of securing supply are interruptible, and by definition cannot fulfill the required need for primary firm service. DTE Gas holds primary firm interstate transportation capacity as an integral part, but not the entire part, of its supply portfolio to ensure firm, secure, and reliable flowing supply to its system, as well as ensuring the high level of availability of such supply as may be needed as SOLR. There is no certainty that the other avenues would be available when supply is needed, and there is a significant increase in supply risk with a supply portfolio that does not maintain at a minimum the quantity of primary firm interstate transport capacity that DTE Gas has historically maintained and proposes to maintain into the future, which the Commission has reviewed and approved in its previous GCR Plan cases. While there may be validity to the argument that these other avenues of supply could be less costly than holding firm pipeline capacity, such lower costs come at the expense of a lower level of reliability of service and potentially higher supply risk., which is direct conflict with the recommendations of the Statewide Energy Assessment (SEA) which advocates for more reliability.

Q82. What is the operational benefit of 400/d??

A82. The answer is different depending on whether it is on a design day or under normal operating procedures. On a design day, if the service territory is experiencing (or expected to experience) the extreme weather and low storage volumes where the Company believes it will need to provide Design Day volumes, it would purchase all 400 MDth/d of gas to flow through all the pipelines, resulting in all of the capacity being fully utilized thus providing reliability as recommended by the SEA. However, if Design Day criteria are not met, then the advantage of having the diverse supply options that the current portfolio provides, the Gas Supply team can

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review which pipeline supplies safe, reliable natural gas at a reasonable and prudent price. In addition, if one of the basins experience issues, the Company can pivot and acquire gas from a different basin thus providing redundancy in order to support our customer's needs.

Q83. Is it prudent for the Company to purchase all remaining requirements at MichCon Citygate?

A83. No. There are two issues with purchasing Citygate gas: interruptible transportation and gas withdrawn from storage.

Q84. Why is buying interruptible transportation not a safe and reliable option?

A84. The issue with interruptible transportation is that it is just that interruptible. As I mentioned before pipeline tariffs prioritize which contracts get cut first when there are supply curtailments. Interruptible contracts will be curtailed prior to Firm transportation contracts. If the Company purchases citygate gas from a third party, the Company cannot be sure that the gas has firm transportation from the supply area to citygate. By buying firm transportation and purchasing the gas at the supply zone, the Company ensures that its customers are the last ones that will have their supply cut if there is an outage.

Q85. Is it likely that interruptible contracts will always get cut?

A85. No, it is not, however the Company does not want to take on that risk. DTE Gas is responsible for providing customers with safe, reliable natural gas at a reasonable and prudent cost. Customers expect that when they turn their furnaces on, that the furnace will have gas supply. By buying firm transportation and purchasing the gas at the supply zone, the Company ensures that its customers are the last ones that will have their supply cut if there is an outage.

Q86. What is the issue with citygate and storage?

A86. Citygate purchases can be made via transportation (firm or interruptible) or from a marketer's storage account with one of the storage fields attached to the DTE Gas system. (Marketers cannot magically create natural gas and put it onto the system). The 400MDth/d requirement that system operations require for Design Day operations is new flowing supply. Gas that is in storage is deemed to be gas already in the DTE system as it came to the system in a prior period (even the prior day). As it is not incremental gas to the system it does not provide support to ensure safe, reliable supply to GCR customers on a Design Day.

Q87. Are there other issues with CityGate purchases?

A87. Yes, on an all-out region design day where weather is impacting Chicago, Dawn, the Northeast and other parts of the North America gas market having Firm transportation back to supply basins allows the Company to have more opportunities to purchase supply. The Company could purchase natural gas at the receipt points in the supply basins or along the path to the DTE Gas system wherever it makes most economic sense. As seen during winter storm Uri a significant portion of the country had extreme high prices. Fortunately for DTE Gas the MichCon citygate did not experience this volatility, however as weather becomes more extreme the Company wants to be prepared for events that have not occurred before.

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Q88. Is there a benefit to having additional pipelines provide supply to Michigan?

A88. Yes, anytime incremental supply to the region it will provide additional reliability and redundancy. In addition, due to the laws of supply and demand, incremental supply (without incremental demand) will decrease prices in the region. The Company has experienced this as NEXUS, Rover and REX have brought supply to the region driving MichCon basis lower.

Q89. Are there any other benefits to having Firm transportation back to supply basins?

A89. Yes, by having access to multiple basins the Company can utilize methane and other greenhouse gas emissions in the area and purchase lower emitting natural gas to help with its net zero initiative. This would be utilized on warmer than normal or normal weather, while still having the benefits to support customer needs during colder than normal or even Design Day requirements.

NEXUS Contract

Q90. When did DTE Gas first introduce NEXUS to the MPSC?

A90. DTE Gas first introduced the NEXUS pipeline project in Case U-17691, DTE Gas's 2015-2016 GCR Plan case. During that case, the Company utilized analysis provided by ICF Resources (report dated December 2014 and updated December 2015).

Q91. Why did DTE Gas select NEXUS transport capacity to secure gas supply from the Utica and Marcellus production region?

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A91. DTE Gas selected NEXUS because it provided the lowest delivered cost of gas on a greenfield pipeline from the Utica and Marcellus regions. DTE Gas agreed to be an anchor shipper on NEXUS and helped provide the support needed for NEXUS to get FERC approval to proceed with the new greenfield project.

Q92. Has the Commission approved the NEXUS contract previously?

A92. Yes. In U-20235 the Commission approved the NEXUS contract.

Q93. If the Commission approved the contract, why is the Company still including NEXUS in this case?

A93. Reading further in the U-20543 Order the Commission stated, "On a going forward basis, the Commission will expect to see evidence that the company has taken steps to minimize the cost of gas including efforts to renegotiate contracts…" This was a similar theme from the Commission's December 9, 2020 in U-20203 (DTE Electric's PSCR reconciliation case for the twelve months ending December 31, 2018). The Company along with DTE Electric began reevaluating the changes in the natural gas market since the initial introduction of the NEXUS pipeline based on the comments in the PSCR case (which were also quoted in the U-20543 Order).

Q94. When did DTE Gas begin this analysis?

A94. This analysis began in the 1st quarter of 2021 after DTE Electric received the Order in U-20203 as the Company awaited the pending Order in U-20543 (issued April 8, 2021) to proactively be responsive to the Commissions guidance Order U-20203, that likely would be incorporated in the U-20543 Order. DTE Gas did this proactively as the PFD in U-20543 commented on some of the concerns the

Commission brought up in the U-20203 Order (while also understanding that the two companies have different utilization, purchasing requirements and procurement strategies).

Q95. Is the natural gas market the same in 2021 as it was during the time of the original reports?

A95. No, back in 2014/2015 the ICF report projected gas prices to be between $5-10/Dth over the life of the NEXUS contract. In 2021, forward prices have reduced to $2 – 6/Dth over the life of the NEXUS contract.

Q96. How have NYMEX prices changed between 2014/2015 and the present?

A96. The April 2015 to March 2016 NYMEX price presented in U-17691 Exhibit A-8 was between $3.50 - 4.00 (page 1), the 5th-year of the 5-year forecast in that case (April 2019 to March 2020) was between $4.15 - 4.60 (page 5), and looking at the forecasts at the time, it was anticipated that natural gas prices would continue to rise. Contrast that with the NYMEX price outlook the Company filed in Case U-20816 Exhibit A-8, DTE Gas's 2021 - 2022 GCR case, in which the prices are more tightly bound in a $2.50 - $3.00 (page 1) range and the long-term outlook does not forecast prices to increase as dramatically.

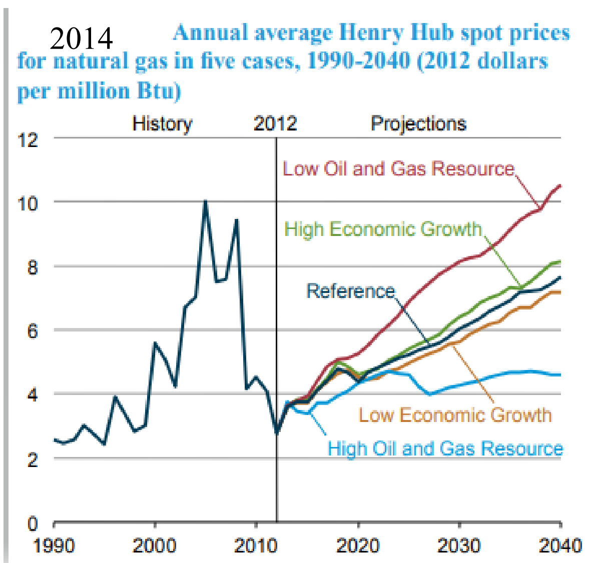
Q97. What factors are driving this price decrease?

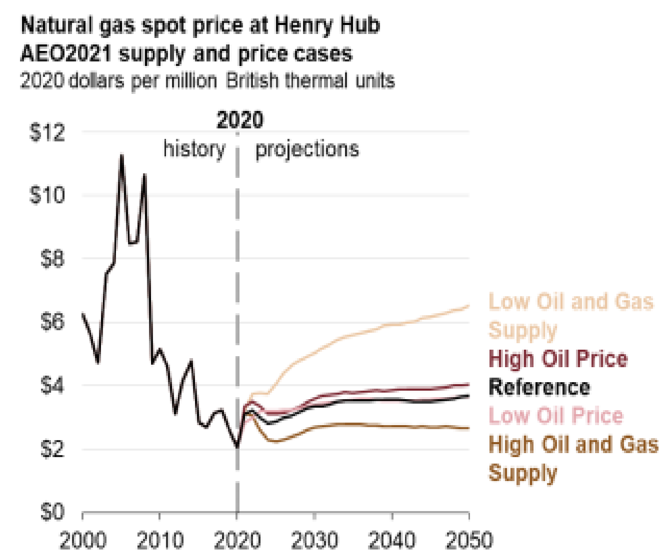
A97. During the past seven years, we have seen both improvements in technology as well as significant additional reserves that have dampened the outlook on the rise of natural gas prices. Due to this dynamic market shift, DTE Gas has contracted with

FTI Consulting in order to refresh the analysis that ICF produced in order to get an updated look at the benefits of the NEXUS agreement.

Q98. Are there any long-term projections showing this shift in market prices and production?

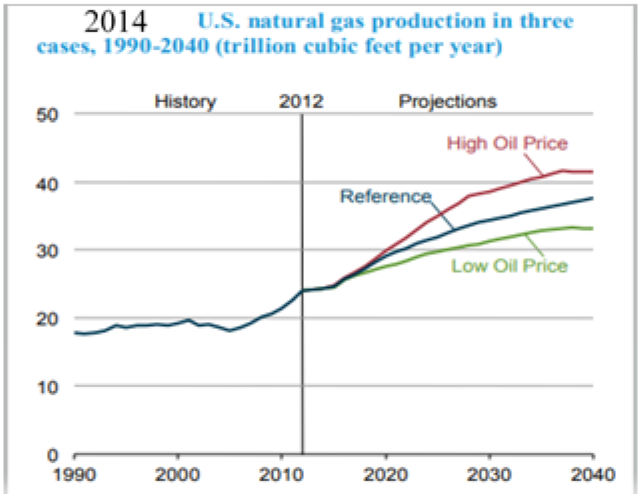
A98. Yes. The EIA annually publishes a long-term forecast for natural gas prices and in 2014[5] the projections were showing higher prices versus 2021.[6] As can be seen in the tables below, back in 2014 when DTEG was initially looking at NEXUS, gas prices were expected to steadily rise. In comparison, when you review the 2021 table, gas prices and the related projections have flattened out.

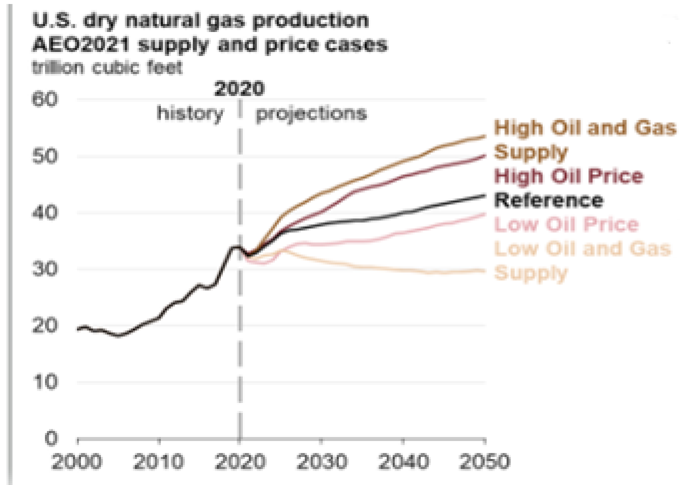




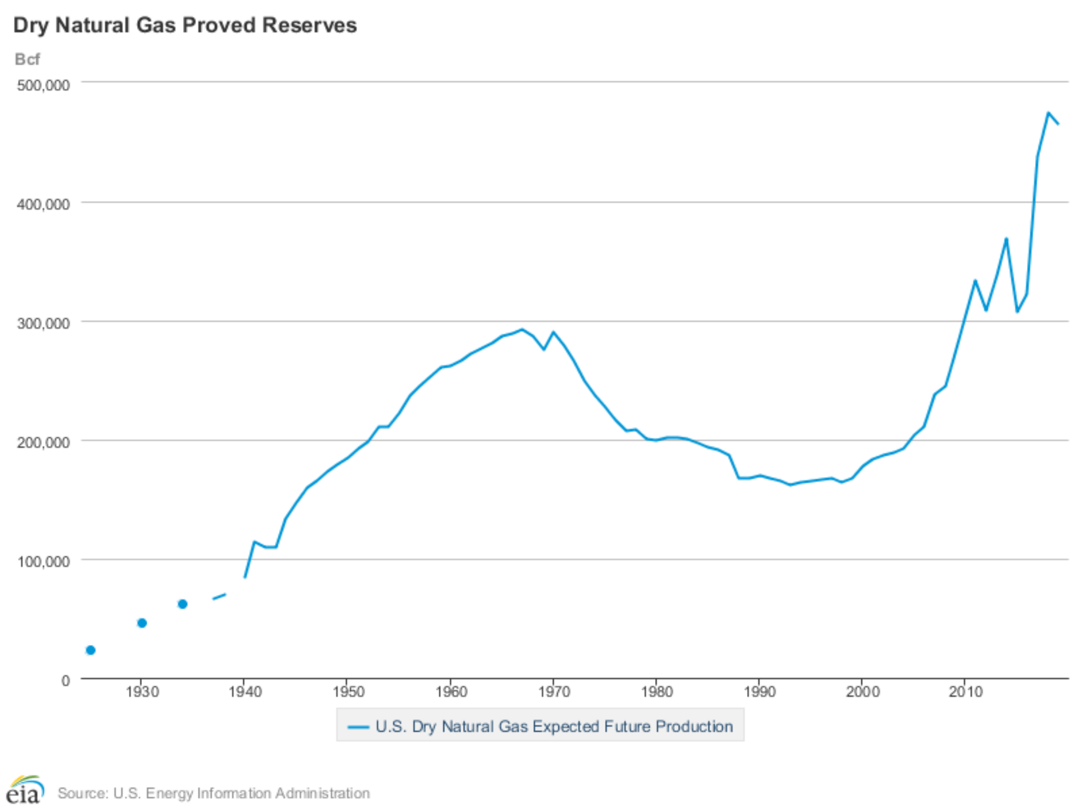
Conversely when you review the following two tables from the same two reports you see that the projected production of natural gas has significantly increased (key is the y axis scale).

[5] https://www.eia.gov/outlooks/archive/aeo14/pdf/0383(2014).pdf
[6] https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf





Also, the EIA shows that U.S. proved reserves has increased over 26% from almost 369 Tcf to over 465 Tcf from year end 2014 to year end 2019.[7,8]



[7] https://www.eia.gov/dnav/ng/NG_ENR_DRY_A_EPG0_R11_BCF_A.htm
[8] From 2014 to 2015 US proved reserves decreased form 369 Tcf to 308 Tcf

The combination of increased reserves and production has put downward pressure on natural gas prices.

The changes to the industry came after the analysis that ICF completed in 2014, as in Exhibit A - 26 Technology and Efficiency Gains Create A New Normal For U.S describes that beginning in mid-2013 and for three years Texas's oil production was dormant and then increased by 50% from 4.2 bcf/d to approximately 6.5 bcf/d in one year (2017 to 2018).

Q99. Are technological improvements causing the production numbers to increase?

A99. Yes, the article in Exhibit A-26 attributes the technological improvements to two main drivers for this production increase. The first is that producers have cut down the time to drill, frac and complete each well from 25-30 days down to 10-12 days. This almost doubles the output of each active rig.

Secondly, productivity gains per well have dramatically improved. Drilling, fracking, and completion technologies have advanced to provide the industry with more powerful rigs that can drill longer laterals. In addition, the advancements in analysis tools for identifying gas underneath the ground have allowed producers to drill into the formation's more prolific areas or "sweet spot" more accurately. On the fracking side, improvements in the fluids used have resulted in better fracking of the rocks, which allows for more gas and liquids to be recovered.

Q100. Is this technological improvement isolated to Texas?

A100. No, the improvements and efficiencies are not isolated to Texas and the benefits shown in Texas are also seen across the entire industry.

Q101. How is the Company addressing the concerns expressed by the Commission that the Company has not provided new data or updated the 2014 analysis on NEXUS and its impact on the Michigan natural gas market?

A101. During the first quarter 2021, the Company engaged FTI Consulting (FTI) to review the market dynamics and evaluate the benefits of the NEXUS pipeline. The scope of work was to develop historical simulations of the Upper Midwest gas markets since NEXUS went into service and then review the model in a simulation where NEXUS was not built, thus providing an "ex post" analysis of the Michigan gas market.

Q102. Has DTE Gas provided this analysis before?

A102. No. DTE Gas has the ability to look forward and analyze the environment based on current infrastructure and utilizing forward curves to value pipelines. The Company does not have the resources or expertise to do the complex what-if modelling of the natural gas marketplace that takes into account new projects that impact supply and demand levels or similarly to provide a robust analysis of how the market would be impacted had actual projects not been constructed and placed into service. Similar to 2014, DTE Gas looks to experts in the industry to supplement its team when it needs these types of analyses done.

Q103. Why is this analysis relevant now?

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A103. Based upon the information available and analysis completed at the time, the NEXUS agreement was appropriate to execute when the Company first entered into it. And while the statue indicates the threshold to establish prudency is based on the decisions made based on the information that the Company knew or should have known at the time; in this instance it is appropriate to consider ongoing effects of those decisions. The author of the article in Exhibit A-26 stated, "The reality, of course, is that it is one of the most high-tech industries on the face of the earth, led by engineers, geologists and other scientists who advance efficiencies and improve technologies each and every day." He was talking about the focus on the technology side of the knowledge base in the industry, but I think it can be expanded to be a reminder to us that the Company and the others in the marketplace are continuing to improve all aspects of the knowledge base and that even though approval is based on information available at the time of the decision, it is appropriate to refresh analysis from time to time to review how the marketplace has evolved.

Q104. Did the refreshed results that FTI provided show benefits to DTE Gas customers?

A104. Yes. The updated report showed that MichCon Citygate prices are down on average of $0.08 over the life of the contract due to the NEXUS pipeline being built. The analysis estimates that DTE Gas customers will save approximately $199 million between 2022 and 2038 and that all consumers in the state of Michigan will save roughly $1 billion due to the NEXUS pipeline being built.

Q105. What is driving the savings for DTE Gas and the residents of Michigan?

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A105. FTI modeled the North American gas markets and evaluated a scenario wherein NEXUS was not built. By doing so, it was able to estimate the amount of savings DTE Gas customers and all consumers would receive by comparing the costs in a status quo environment as well as the "No NEXUS" case. These savings are discussed in more detail in Witness Sosnick's testimony.

Q106. Are there any specific examples of price savings attributable to NEXUS?

A106. Yes. As discussed in previous cases, the MichCon city-gate index has historically traded at a premium to the NYMEX with a higher premium in the winter than the summer. As the Appalachian gas has increased supply to the region, the MichCon index has continued to decline, and essentially flipped from premium to a discount to the NYMEX index. In 2015 – 2017 the premium was essentially erased as the Rockies Express brought additional Appalachian gas west into Ohio which then interconnected with other pipelines to bring new gas to Michigan. Following up in 2018 when Rover and NEXUS were put in service with direct access to Michigan, MichCon basis turned negative.

Q107. Since NEXUS went in service has the basis ever been a premium?

A107. Yes, there was an outlier in November 2018. This was the first full month NEXUS was in service. There also was an outlier where the basis discount reached ($0.50). It is better to look at the average basis premium / discount by season to evaluate whether the basis is trading at a premium or discount as to smooth out individual month aberrations.

Q108. Do individual months (or days) ever provide insight to the benefits of NEXUS?

A108. Yes, In February 2021, when the country experienced extreme cold temperatures, which led to freeze-offs as well as record setting pricing. Cash prices in Oklahoma hit $999, Northern, Demarc peaked around $230 and NIPSCO topped $200. However, the high for MichCon city gate was under $8.00. This clearly shows another example of the benefits of having multiple sources of natural gas from different regions of the country coming into the state. The Company said one of the benefits of a new greenfield pipeline was to provide additional supply reliability and this is a good example of it.

Q109. The Commission expressed in its Order in U-20543 that it would like the DTE Gas to attempt to renegotiate existing contracts when expected contract benefits do not materialize. Has DTE Gas complied with the Commission's request?

A109. Yes, the Company complied with the Commission's request because it has reviewed the contract and determined that the expected contract benefits have materialized. The Commission did request the Company to renegotiate, but another key part of the Order reads, "As such, additional information regarding the market outlook at Kensington would be helpful in informing the Commission's review of the ongoing reasonableness over the full life of the NEXUS contract and its amendment." I believe these two requests go hand in hand. In order to determine if the Company would receive benefits from the contract the Company engaged an independent consultant, FTI Consulting Inc. (FTI), to provide guidance on the value of NEXUS. This was the first step that DTE Gas utilized to determine if the benefits of the NEXUS contract would continue to materialize. While there have been some delays that have affected liquidity and pricing at Kensington, overall, the NEXUS contract has achieved substantial benefits to DTE Gas customers. The Company has not concluded that it will not ultimately receive the expected benefits of the contract as originally anticipated in 2014.

In addition, contracts between counterparties (even affiliates[9]) are negotiated and executed at a point in time based on facts known by the parties at that point in time. There is always some inherent risk in any long-term contract that market or other changes may occur that may change expected outcomes. Because this risk is inherent in all long-term contracts, and all sophisticated parties accept this inherent risk, long-term contracts are not typically renegotiated when circumstances change unless there has been a breach of contract.

Q110. Does the fact that the two entities were affiliates give DTE Gas leverage to renegotiate the contract?

A110. No. First, the former DTE affiliate only owns 50% of NEXUS, so even if it was possible, the DTE affiliate does not have a majority stake in NEXUS. More troubling is the idea that because of the affiliation between the companies, NEXUS should be expected to treat DTE Gas differently from its other customers. If NEXUS were to do so, it would constitute a violation of both the MPSC's Code of Conduct and FERC's Standards of Conduct – which state that affiliates are not allowed to offer to provide unduly discriminatory service (service discrimination of any kind). This concept of providing another affiliate a benefit that is not available to all other companies in the marketplace is a clear example of what these

[9] At the time the contracts were executed, DTE Gas and NEXUS were affiliates. On July 1, 2021 DTMidstream (which owns 50% of NEXUS) was spun off from DTE Energy and effective that date, DTE Gas and NEXUS are no longer affiliates.

prohibitions are trying to prevent. In addition, as of July 1, 2021 DT Midstream (along with the NEXUS assets) was spun-off from DTE and therefore the two companies are no longer affiliates.

Q111. Has there been an appropriate time to renegotiate the NEXUS contract?

A111. Yes, during the Precedent Agreement phase there were updates to the contract due to construction and regulatory delays. The Company felt that the access to the additional low-cost supply that NEXUS would provide was adequate consideration for the amendment changes, especially considering the main reason for the delays was the lack of quorum at FERC which was outside of NEXUS's control. In addition, when DTE Gas wanted to modify the receipt point and acquired the ability to receive gas at Clarington versus Kensington. These negotiations were universal in that all shippers had the same ability to make these changes and NEXUS did not provide DTE Gas with any special treatment or benefit.

Q112. Has NEXUS filed its cost and revenue study (CRS) to the FERC?

A112. Yes, on October 13, 2021 NEXUS filed its CRS.

Q113. What were the costs and revenues in that study?

A113. "As set forth in detail in the Cost and Revenue Study, NEXUS' actual annual transportation service revenue was $306,549,093 for the twelve months ending June 30, 2021 against a cost of service for the same period of $522,872,562. <u>This is primarily due to the fact that no NEXUS shippers have contracts at the recourse rate (i.e., all shippers pay either negotiated or discounted rates)</u>. Thus, NEXUS is significantly under-recovering its cost of service."

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Q114. What kind of contract does DTE Gas have with NEXUS?

A114. DTE Gas has a negotiated rate contract with NEXUS.

Q115. Due to the negotiated rate contract, what is the impact to DTE Gas if NEXUS does try and file for higher rates?

A115. DTE Gas's negotiated rate would not change. Similar to the situation when the Company elected to have a fixed price contract versus a capital project tracker the rate DTE Gas will pay will not change until the contract expires.

Q116. Did the Commission's Order in U-20235 discuss the TEAL amendment?

A116. Yes, on page 6 of that Order the Commission states, "These costs will be examined in each reconciliation, where the utility will need to provide adequate support for the reasonableness and prudence of the amounts associated with the NEXUS Agreement and Amendment."

Q117. Has the Company provided evidence of the benefits of the Agreement and Amendment?

A117. Yes. The Company provided evidence in U-20236 where the Commission felt that NEXUS was a reasonable and prudent decision. In U-20236 the Company provided exhibits showing the projected savings of $4.3 million during the term of the amendment when the Company executed the agreement as well as actual savings of $6.0 million (November 2018 – December 2020), and as I mentioned earlier the Company renewed the TEAL amendment for two years with projected savings of $5.8 million between November 1, 2022 and October 31, 2024.

Q118. Are there any other benefits related to NEXUS?

A118. The benefit to GCR customers is also enhanced by lower distribution rates due to the higher rate NEXUS is paying DTE Gas above the cost DTE Gas pays NEXUS for Kensington to Ypsilanti transportation. On an annual basis, NEXUS pays DTE Gas $32.1 million in transportation. See Witness Decker's testimony in DTE Gas's General Rate Case, U-20642 at HJD-42 Line 8. The lease agreement revenue benefits all DTE Gas customers, including GCR customers.

In addition, NEXUS supplies have benefited all gas utilities in the state and thereby all customers in the state, as well as electric utilities with gas fired generation.

PROJECTED TOTAL GAS SUPPLY COSTS

Q119. What are DTE Gas's projected total gas purchase quantities and costs for the April 2022 through March 2023 period?

A119. DTE Gas's projected total gas purchase quantities and costs are summarized in Exhibit A-10. This exhibit reflects projected total purchases and subtotals for these categories: contracted fixed price, contracted indexed price, and supply not under contract. The totals of these subdivisions are added together to arrive at the total expected gas purchase quantity of approximately 143 MMDth (page 1, line 4, column (14) and a total expected gas purchase cost around $408 million (page 1, line 12, column (14) for the April 2022 through March 2023 period. These costs and volumes are prior to pipeline fuel retention, prior to conversion from Dth (energy quantity) to Mcf (volumetric quantity), and do not include pipeline transportation costs.

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Q120. What are DTE Gas's projected total transportation costs for the April 2022 through March 2023 GCR Plan Period?

A120. DTE Gas's projected total transportation costs are summarized in Exhibit A-11. This exhibit reflects projected transportation reservation and commodity costs by month. The total expected transportation cost is approximately $60 million (Exhibit A-11, page 1, line 43, column (14)) for the period April 2022 through March 2023.

Q121. What are DTE Gas's projected total supply costs and total delivered supply volumes for the period April 2022 through March 2023?

A121. Projected total supply costs are presented on Exhibit A-12 and reflect the sum of the projected gas purchases and transport costs. DTE Gas's projected total supply cost for the period April 2022 through March 2023 is approximately $468.2 million (Exhibit A-12, page 1, line 3, column (14). The total delivered supply volumes are presented on Exhibit A-10. DTE Gas's total delivered supply volume for the period April 2022 through March 2023 is approximately 134 Bcf, Exhibit A-10, (page 1, line 8, column (14)). This total delivered supply volume is the quantity delivered into DTE Gas's system after interstate pipeline fuel is removed and after conversion from Dth (energy quantity) to Mcf (volumetric quantity) at a heating value of 1.052 Dth/Mcf.

PROJECTED SUPPLY COSTS FOR LIFO VALUATION OF GAS IN STORAGE

Q122. What projections have you developed regarding DTE Gas's gas supply volumes and costs for the period January 2022 through March 2023?

A122. Table 5 shows the projected NYMEX, volumes and costs for the period January 2022 through March 2023. Furthermore, and consistent with the methods used throughout the GCR Plan, appropriate basis, fuel, transportation charges, and heating value adjustments were applied. The NYMEX prices below were used to calculate the purchase price for all volumes not already contracted at fixed prices pursuant to the FPP.

Table 5

Item	Jan-22	Feb-22	Mar-22
NYMEX	$3.962	$3.911	$3.778
Delivered Vol (MMcf)	9,860	7,604	11,776
Total Cost ($000)	$32,066	$26,229	$38,822

GAS SUPPLY STRATEGY FOR APRIL 2023 AND BEYOND

Q123. How does DTE Gas plan to purchase its required gas supply for April 2023 and beyond?

A123. DTE Gas's proposed natural gas supply acquisition strategy for April 2023 and beyond is essentially the same as that used for the April 2022 - March 2023 period. Specifically, DTE Gas's supply will be priced utilizing a mixture of fixed-price supply and market-based indexed price supply.

Q124. Does DTE Gas plan to execute any fixed price supply contracts during the Plan Period for gas to be delivered in April 2023 and beyond?

A124. Yes. Consistent with the Commission approved VCA methodology in the Company's 2010-2011 GCR Plan Case No. U-16146, and contained in every subsequent Commission-approved GCR Plan (Case Nos. U-16482, U-16921, U-17131, U-17332, U-17691, U-17941, U-18152, U-18412, U-20235, U-20543) through the Company's pending 2021-2022 GCR Plan Case No. U-20816, as detailed in Exhibit A-7, DTE Gas will continue to make fixed price purchases each month during the April 2022-March 2023 Period for approximately 3% of the total gas supply requirements to be delivered during the April 2023-March 2025 GCR Period. The table on Exhibit A-27 "Fixed Price Program Analysis – Purchase Percentages" summarizes the monthly and cumulative total fixed price purchases to occur by GCR delivery period.

Q125. Is DTE Gas reviewing any transportation portfolio changes during the Plan Period related to future GCR periods, specifically April 2023 and beyond?

A125. As mentioned earlier the Company has 60,000 Dth/d (winter) of ANR (REX Shelbyville) capacity expiring on March 31, 2023 that it will be evaluating whether to renew or replace this contract in order to continue to provide safe, diverse and reliable natural gas to its customers.

Q126. Does DTE Gas plan to change its transport capacity for April 2023 and beyond due to customers switching between GCR and GCC?

A126. No. DTE Gas does not plan to change its transport capacity if customers switch between GCR and GCC. DTE Gas intends to maintain a GCR/GCC portfolio of interstate transportation and city-gate supply that is sufficient to serve total GCR and GCC markets. This is necessary from a security of supply standpoint as DTE Gas is the SOLR for all customers, both GCR and GCC.

Q127. What projection of gas purchase and transportation costs have you made for the period April 2023 through March 2027?

A127. Projected gas purchase costs for the period April 2023 through March 2027 are calculated on pages 2 through 5 of Exhibit A-10. Projected transportation costs for that same period are calculated on pages 2 through 5 of Exhibit A-11 and the projected total supply costs (the sum of purchase and transport costs) are calculated on Exhibit A-12.

IMPACT OF DTE GAS NET ZERO COMMITMENT ON GAS SUPPLY STRATEGY

Q128. What is DTE Gas's position on greenhouse gases?

A128. As mentioned in DTE Gas's previous GCR case, Case U-20816, the Company issued a press release on June 24, 2020 that stated it was committed to reduce greenhouse gas emissions to net zero by 2050 for DTE Gas and by 2050 the Company will help reduce our customers' greenhouse emissions 35% from 2005.

Q129. What part of the Company's operations does this commitment impact?

A129. This commitment impacts all operations from procurement through gas delivery.

Q130. Will this commitment impact GCR customers?

A130. For DTE Gas to achieve this important milestone, we will need the cooperation of gas suppliers. In the short term, there will not be an impact to GCR customers. In the longer term, the Company will include measures to reduce methane emissions in our evaluation of supply, in addition to the current supplier evaluations based on basin, counterparty creditworthiness, supplier reliability, operational requirements and cost.

Q131. What has the Gas Supply team done since the announcement?

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A131. In 2021, the team was involved in a number of activities in order to understand where the industry is today and where it looks like it will go. The Company met with a number of its industry peers to ascertain their position on Responsibly Sourced Gas (RSG). We also met with a number of our suppliers and other industry participants to gather information on RSG, the various certifications for RSG and product offerings that include RSG.

Q132. What is RSG?

A132. RSG is a natural gas product which has undergone third party certification and regular monitoring to verify it has been produced in a way that meets the highest standards of responsibility with respect to air, water, land and community. In addition, a critical component of RSG for DTE will be focusing on RGS being a lower methane intensity natural gas product in comparison with other supply alternatives

Q133. What information did you gather from industry peers?

A133. There was a wide range of both familiarity and planning in this emerging space. Some industry peers have not contemplated a net zero strategy, some were in the infancy of contemplating the impact of more environmentally friendly emissions (i.e. reduced methane emissions, and RSG) and others had already procured contracts committing to RSG in their portfolio.

Q134. Were there any commonalities found amongst industry peers as it relates to the integration of RSG into the portfolio?

A134. The recurring theme that was identified through the conversations is that most of the utilities believe that certification (and third-party auditing) was required. The other utilities typically did not want to speculate on which certification to choose as this is the beginning stages of the market, but felt that as the market matured and developed some certifications may become more common than others.

Q135. Does DTE Gas believe certification is a necessity for procuring RSG?

A135. Yes, The Company agrees that certification and auditing would be required for it to purchase RSG.

Q136. How mature is the industry as it relates to the certification of RSG?

A136. The company concluded that though there is work being done in this space, the industry is still developing.

Q137. Is there currently uniformity in the certification process?

A137. In our research we identified five certifications and one registry. The table below describes the various certifications and which organization is promoting it. The performance attributes are an important differential. Certifications range on focusing only on Methane Intensity and others ae including other Environmental, Social and (Corporate) Governance (ESG) attributes.

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Certification	Est.	Organization	Performance Attributes
EO100™	2012	*Equitable Origin's* 100 (*EO100™*) Standard for Responsible Energy Development verifies production site emissions and multiple ESG measures including working conditions	Operators quantify and disclose emissions performance. Requires **independent 3rd party audits** and recertification every 3 years •*Not methane specific but working towards this with MiQ*
ISO 14001:2015	2015	*International Organization for Standardization* (ISO) is an NGO based in Switzerland. The standard requires an environmental management system to manage environmental impacts, meet regulatory compliance requirements and assess risk	Includes internal and ISO audits of adherence to globally recognized environmental management standards. Does not require specific technology or emissions quantification to achieve certification •*Not methane specific / no 3rd party audits*
IES TrustWell™	2016	Joint project of *Project Canary*, which continuously monitors on-site methane emissions & *International Environmental Standards* (FKA *Independent Energy Standards)*	Producers self-report risks to water, air, land and community. Includes independent verification of methane intensity using continuous methane monitoring technology •*Does not have 3rd party audits*
MiQ Standard	2021 (pilot)	Partnership between Rocky Mountain Institute (RMI) and SYSTEMiQ that plans to certify gas through quantitative evaluation and monitoring	Requires quantitative evaluation of methane intensity, monitoring technology deployment, and **independent 3rd party audits**
Platts MPC	2021	*Platts* recently proposed a *Methane Performance Certificate* based on Methane Intensity calculated under the NGSI protocol	Assigns letter grades A-F to producers based on metered data & Methane Intensity. The maximum threshold for certification is under review. •*Working with Xpansiv (below) to track NG through entire supply chain*
GTI Veritas	TBD	Gas Technology Institute (GTI) recently launched an effort to create a differentiated gas measurement and verification initiative	Methane intensity by supply chain segment
Xpansiv (Registry, not a certification)	2019	Xpansiv CBL Holding Group (XCHG) is a partnership between Xpansiv data refinery &	Enables producers to issue certificates with an auditable chain back to the source

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Q138. Has DTE Gas solidified the parameters and certification process it will adopt?

A138. The company is closely monitoring, evaluating and analyzing the different certification options that are available and others that have been proposed that are on the horizon. The Company has not committed to a specific certification process and will continue to analyze its option to determine the most prudent methodology in this space.

Q139. What industry groups or collaboratives is DTE Gas involved in?

A139. The Company is involved in the Natural Gas Supply Collaborative, Downstream Natural Gas Initiative, Next Generation Gas Coalition, One Future Coalition and the Gas Technology Institute's Veritas Initiative (via the One Future membership).

Q140. What is the (NGSC)?

A140. The NGSC is a voluntary collaborative of natural gas purchasers throughout North America that are promoting safe and responsible practices for natural gas supply. DTE is actively participating in the collaborative and I am a representative for the Company on this collaborative.

Q141. What is the Natural Gas Sustainability Initiative (NGSI)?

A141. While methane emissions intensity is a recognized means of measurement for methane emissions output in natural gas, the method of calculating and reporting intensity is not consistent across the natural gas industry. This lack of consistency is an obstacle to managing, tracking and providing transparency for the reduction of methane emissions, including measurement and tracking of our emission reduction goals. To address these inconsistencies in methane reporting, the NGSI was launched by the Edison Electric Institute (EEI) and American Gas Association

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(AGA) in 2018. The NGSI has developed a voluntary, industry-wide approach for companies to calculate methane emissions intensity by segment—the Methane Emissions Intensity Protocol (Protocol). DTE Energy was one of a small group of companies who participated in a pilot program sponsored by AGA and EEI to test the Protocol in June of 2020. Having completed the pilot, DTE is among the first to publicly report its methane emissions intensity results using the NGSI Protocol. Another goal of the NGSI protocol is to be all-inclusive of methane emissions. The protocol includes methods for calculating methane intensity for each of the following five segments of the natural gas value chain - production, gathering & boosting, processing, transmission & storage, and distribution. Many of the current reporting programs that are currently in place do not include emissions from sources upstream and downstream of a company's operations.

Q142. When was the NGSI protocol finalized and released?

A142. The NGSI Protocol was publicly announced by the EEI and AGA in February 2021 with updates in July 2021. The Protocol provides a uniform and standardized method for reporting and benchmarking methane emissions across the entire industry, from well-head to burner tip.

Q143. Who is expected to participate and utilize the protocol?

A143. The intent is to encourage upstream producers, processors and transporters in addition to EEI/AGA members to report their methane intensity using the NGSI protocol. It may be too early to determine if this is happening, but NGSC will be looking at the utilization of the NGSI protocol by the natural gas industry in 2022.

DTE Gas will encourage its suppliers that are not members to also utilize the protocol as well.

Q144. What information will be gathered by utilizing the NGSI protocol?

A144. The primary information that the NGSI protocol is gathering is methane intensity. NGSI breaks down the natural gas industry into five segments for reporting of methane emissions: Production, Gathering & Boosting, Processing, Transmission & Storage, and Distribution. The protocol recommends disclosure of total methane emissions, natural gas throughput and a unitless measure of methane emissions intensity (emissions/throughput).

Q145. Will DTE Gas use the data that is provided in the NGSI protocol to make gas procurement decisions?

A145. No. The Company will not use the NGSI protocol as a decision-making tool during this Plan Year. DTE Gas did ask its suppliers to voluntarily participate and submit the requested information.

Q146. Is it mandatory for companies to report based on the protocol?

A146. No, the NGSI cannot require companies to report under the new protocol, however, much of the information is similar to data filed with the EPA. The Company has sent letters to suppliers encouraging participation through voluntarily reporting.

Q147. What is the next step in the process for achieving this goal within the scope of GCR supply purchases?

A147. As mentioned earlier, the Company plans to identify which attributes are important to DTE Gas and its customers. To help identify supply availability as well as gather information, the Company is anticipating issuing a request for information (RFI) in the first half of 2022. The expectation is that the RFI will be open ended as to specific certification for RSG (but will have certification and audit requirements). As the Company writes the RFI it will determine the appropriate tenor for the request (monthly, seasonal or annual volumes).

Q148. Will the Company execute purchase(s) based on the RFI?

A148. Potentially. The primary goal of the RFI is to get information. DTE Gas feels the best way to get this information is to ensure its suppliers understand that the Company may execute transactions if it feels that there is appropriate value.

Q149. Is there a benefit to issuing an RFI with the intention of execution versus the intention only to glean information?

A149. DTE Gas is concerned that if it issues an RFI without an indication that it may execute the response will not be as meaningful.

Q150. How much of the portfolio would you anticipate the Company executing from the RFI?

A150. I cannot foresee a situation where the Company would purchase a material amount of the requirements. This would be the first foray of purchasing RSG for GCR customers so I would anticipate it being no more than 1 – 1.5% of the total requirements.

Q151. Why are you anticipating such a low percentage of the portfolio to be RSG in the 2021-2022 GCR year?

A151. I would anticipate minimal purchases because as I stated earlier the primary goal of the RFI is to get a further understanding of where the industry is in supplying RSG.

Q152. If the Company anticipates the volumes will be minimal, why not just issue exclusively an RFI versus including something with the possibility of execution?

A152. The Company is concerned that without the opportunity to execute there would be fewer responses.

Q153. Are there any other reasons the Company would not execute a greater percentage of the portfolio if the RFI provided favorable response?

A153. Yes, a common theme discussed by other utilities in other jurisdictions was that the reasonable and prudent standard for recovery includes latitude related to creditworthiness, diversity and reliable supply, however there are various interpretations as to whether this standard covers costs associated with environmental activity. The Company would like the Commission to offer guidance on whether Public Act 304's reasonable and prudent standard includes recovery of premiums for environmental benefits. If the Company does execute transactions from the RFI, it will identify any premiums associated with RSG in order to disclose in reconciliation so that the Commission will easily be able to understand the cost of the supply (which has historically been recovered in the GCR reconciliation) and any premiums (if applicable) for RSG in order to provide guidance on recovery. The Company believes that as the industry has evolved premiums paid for RSG attributes are reasonable and prudent similar to other environmental costs (CO2 scrubbers at a power plant) which are recoverable.

Q154. Does the company intend on implementing a RSG purchase strategy in the current plan year?

A154. No, the company is still in the exploration, analysis and development stages of developing a robust RSG purchase strategy. The company will potentially use the procurement of gas based on a RFI with RSG parameters to get a better understanding of the maturity of the industry. The insight gathered during the RFI process will aid in the development of a comprehensive RSG purchasing strategy.

Q155. Do you anticipate completing the journey to net zero during the 5-year Plan Period?

A155. Developing a cleaner portfolio is a high priority to the Enterprise. The Company will continue the standardized process of updating the Staff and Commission of its plans and intent through case filings. Any proposed changes will be identified and filed for review in accordance with the established regulatory process. At this time, no specific plan has been developed for the five-year period, and if one is developed it will be filed in the case for the corresponding Plan year. This is a long-term goal that we anticipate working on between now and 2050. There will be changes and updates along the way. The goal during the current Plan Period is to understand the certifications that are currently available, what attributes are being certified and developing a plan to include RSG in the portfolio.

Line
No.

Q156. In summary, what is the impact of the net zero goal for this GCR filing?

A156. In summary, the Company is planning a phased approach where during the current GCR year, it will reach out to suppliers and understand the current landscape of methane emissions. Then during the balance of the 5-year GCR Plan Period, it will work with its suppliers to help develop ways to begin to reduce and mitigate the carbon emissions from the Company's supply portfolio.

Q157. Does this complete your direct testimony?

A157. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE Gas Company for approval of a	)	
Gas Cost Recovery Plan, 5-year Forecast	)	Case No. U-21064
and Monthly GCR Factor for the 12 months	)	
ending March 31, 2023	)	
____	)	

EXHIBITS

OF

ERIC P. SCHIFFER

1) Proposed Methodology Description

a) Volume Cost Averaging (VCA) - A timing technique of buying an equal volume of natural gas, on a regular schedule, at a fixed price.

b) DTE Gas will commence purchases equal to 75% of the total GCR Period supply requirements spread equally over a 24-month period (i.e. the VCA Purchase Period) starting on January 1st which precedes the GCR Period by 27 months.

c) The purchases shall be complete by December 31st directly preceding the GCR Period.

d) Please see below for an example of the timeline associated with the April 1, 2021 through March 31, 2022 GCR Period.

VCA Purchases Start - January 1, 2019
37.5% of Purchases Complete - December 31, 2019
75% of Purchases Complete - December 31, 2020

2) Fixed Purchase Coverage Ratio

a) DTE Gas will achieve a fixed purchase coverage ratio of 75% of total GCR Period requirements on December 31st directly preceding the GCR Period.

3) VCA Purchase Limitations

a) The monthly VCA purchase shall not exceed 1/24 of 75% or ~ 3% of the total GCR Period purchase requirements (except as it relates to 3.b).

b) In the event forecasted GCR Period purchase requirements increase or decrease during the 24 month VCA Purchase Period, DTE Gas will either increase or decrease the VCA purchase volume equally over the remaining scheduled purchases so that the 75% fixed purchase requirement is met by December 31st directly preceding the GCR Period.

4) GCR Period Monthly Receipt Volumes

a) The monthly receipt volumes purchased for the GCR Period may vary due to varying monthly purchase requirements which is defined as volume shaping described more fully in paragraph 8) below.

5) GCR Period Purchase Requirements

a) GCR Period purchase requirements utilized to determine VCA purchases may be updated without limitation, to reflect the best available real time information at the time of purchase.

6) VCA Purchase Timing

a) DTE Gas may make multiple purchases or one single purchase at any time during the calendar month or thirty-one days following the monthly sign-off meeting at its own discretion, not to exceed the VCA purchase limitations described in paragraph 3).

b) Any purchase made within the calendar month or thirty-one days following the monthly sign-off meeting is in compliance with the fixed price guidelines and cannot be deemed unreasonable and imprudent solely on the basis that the purchase price was not the lowest price within the anticipated timeframe.

7) Purchase Price

a) The purchase price will be representative of physical fixed price supply at the specified receipt point purchase location, which will be inclusive of any market based premium or discount (i.e. physical basis) associated with the specific geographic purchase location.

8) Volume Shaping

a) DTE Gas will attempt to shape purchases consistent with the seasonal profile in place at the time of purchase.

b) Volume shaping may require DTE Gas to purchase varying receipt volumes for each month within the GCR Period in scope.

c) For example, if summer purchase requirements are greater than winter purchase requirements, DTE Gas will purchase proportionately more volumes in the summer than in the winter for each of the VCA purchases.

9) Force Majeure

a) DTE Gas may suspend the fixed price program for an indefinite period of time in the event of a Force Majeure.

10) VCA Transition Period (Assuming a January 1, 2011 Commission Order)

a) April 2011 – March 2012 GCR Period

i) DTE Gas will commence purchasing equal monthly balance of period volumes concurrent with a Commission Order and will continue each month through October 2011 to achieve a 75% fixed coverage ratio of winter only flowing supply by October 31, 2011. (Refer to Supplement 1 for illustrative purposes)

ii) Paragraphs 4) through 9) above apply to the April 2011 – March 2012 GCR Period.

b) April 2012 – March 2013 GCR Period

i) DTE Gas will commence purchasing equal monthly volumes concurrent with a Commission Order and will continue each month through March 2012 to achieve a 75% fixed coverage ratio of total GCR Period requirements by March 31, 2012. (Refer to Supplement 1 for illustrative purposes)

ii) Paragraphs 4) through 9) above apply to the April 2012 – March 2013 GCR Period.

c) In the event a Commission Order or Settlement Agreement is reached earlier than January 1, 2011, DTE Gas would commence purchases immediately which would extend the duration of the purchase period in order to achieve the targets described in paragraphs 10) a) i) and 10) b) i).

	Prices $/Dth (Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)
	Month	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**
1	**NYMEX Henry Hub Price**	3.6304	3.6176	3.6586	3.7106	3.7238	3.7108	3.7468	3.8446	4.0334	4.1344	4.0128	3.7228
	Supply Area Basis												
2	**MichCon city-gate**	(0.1820)	(0.1895)	(0.2115)	(0.2340)	(0.2357)	(0.2560)	(0.3001)	(0.2671)	(0.2431)	(0.3091)	(0.2149)	(0.2471)
3	**Emerson**	(0.4165)	(0.4165)	(0.4165)	(0.4165)	(0.4165)	(0.4165)	(0.4165)	(0.2025)	(0.2025)	(0.2025)	(0.2025)	(0.2025)
4	**Chicago city-gate**	(0.0180)	(0.0740)	(0.1020)	(0.0910)	(0.0910)	(0.0990)	(0.0850)	(0.0560)	0.2020	0.3700	0.3740	0.1480
5	**Panhandle Field**	(0.2970)	(0.3430)	(0.3250)	(0.2590)	(0.2690)	(0.2830)	(0.2990)	(0.1930)	(0.0830)	0.0470	0.0530	(0.0650)
6	**ANR SW Field**	(0.2120)	(0.2580)	(0.2340)	(0.2060)	(0.2060)	(0.2340)	(0.2340)	(0.1480)	(0.0360)	0.1600	0.1740	0.0360
7	**REX Z3**	(0.2100)	(0.2450)	(0.2490)	(0.2270)	(0.2292)	(0.2575)	(0.2116)	(0.1606)	(0.0326)	(0.0226)	0.0036	(0.0946)
8	**Kensington Plant (NEXUS)**	(0.2810)	(0.4390)	(0.4550)	(0.4035)	(0.4742)	(0.7640)	(0.7731)	(0.4206)	(0.3166)	(0.2801)	(0.2749)	(0.2896)
9	**Clarington (TEAL)**	(0.4470)	(0.6310)	(0.6400)	(0.6335)	(0.7142)	(1.0010)	(0.9891)	(0.6376)	(0.5276)	(0.3951)	(0.3899)	(0.3946)
10	**Rover**	(0.2300)	(0.2650)	(0.2690)	(0.2470)	(0.2492)	(0.2775)	(0.2316)	(0.1806)	(0.0526)	(0.0426)	(0.0164)	(0.1146)
	Supply Basin Price												
11	**MichCon city-gate**	3.4484	3.4281	3.4471	3.4766	3.4881	3.4548	3.4467	3.5775	3.7903	3.8253	3.7979	3.4757
12	**Emerson**	3.2139	3.2011	3.2421	3.2941	3.3073	3.2943	3.3303	3.6421	3.8309	3.9319	3.8103	3.5203
13	**Chicago city-gate**	3.6124	3.5436	3.5566	3.6196	3.6328	3.6118	3.6618	3.7886	4.2354	4.5044	4.3868	3.8708
14	**Panhandle Field**	3.3334	3.2746	3.3336	3.4516	3.4548	3.4278	3.4478	3.6516	3.9504	4.1814	4.0658	3.6578
15	**ANR SW Field**	3.4184	3.3596	3.4246	3.5046	3.5178	3.4768	3.5128	3.6966	3.9974	4.2944	4.1868	3.7588
16	**REX Z3**	3.4204	3.3726	3.4096	3.4836	3.4946	3.4533	3.5352	3.6840	4.0008	4.1118	4.0164	3.6282
17	**Kensington Plant (NEXUS)**	3.3494	3.1786	3.2036	3.3071	3.2496	2.9468	2.9737	3.4240	3.7168	3.8543	3.7379	3.4332
18	**Clarington (TEAL)**	3.1834	2.9866	3.0186	3.0771	3.0096	2.7098	2.7577	3.2070	3.5058	3.7393	3.6229	3.3282
19	**Rover**	3.4004	3.3526	3.3896	3.4636	3.4746	3.4333	3.5152	3.6640	3.9808	4.0918	3.9964	3.6082

Prices $/Dth

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)
	Month	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**
1	**NYMEX Henry Hub Price**	3.1616	3.0976	3.1368	3.1818	3.2002	3.1948	3.2344	3.3582	3.5928	3.7092	3.6342	3.3826
	Supply Area Basis												
2	**MichCon city-gate**	(0.1982)	(0.1882)	(0.2278)	(0.2307)	(0.2270)	(0.2650)	(0.2710)	(0.2495)	(0.2715)	(0.2255)	(0.1535)	(0.1438)
3	**Emerson**	(0.4105)	(0.4105)	(0.4105)	(0.4105)	(0.4105)	(0.4105)	(0.4105)	(0.0585)	(0.0585)	(0.0585)	(0.0585)	(0.0585)
4	**Chicago city-gate**	(0.0190)	(0.0890)	(0.0970)	(0.0660)	(0.0660)	(0.0960)	(0.1080)	(0.0430)	0.1850	0.4110	0.4110	0.1290
5	**Panhandle Field**	(0.2940)	(0.3580)	(0.3500)	(0.2920)	(0.3020)	(0.3060)	(0.3500)	(0.1965)	(0.1165)	(0.0325)	0.0155	(0.1105)
6	**ANR SW Field**	(0.1850)	(0.2490)	(0.2370)	(0.2130)	(0.2130)	(0.2330)	(0.2590)	(0.1975)	(0.1155)	0.0805	0.1645	0.0185
7	**REX Z3**	(0.2242)	(0.2462)	(0.2358)	(0.2227)	(0.2210)	(0.2430)	(0.2450)	(0.2325)	(0.0645)	0.0395	0.0355	(0.0438)
8	**Kensington Plant (NEXUS)**	(0.1287)	(0.2587)	(0.3493)	(0.2902)	(0.3405)	(0.6695)	(0.6465)	(0.4185)	(0.3250)	(0.2970)	(0.3185)	(0.2848)
9	**Clarington (TEAL)**	(0.4312)	(0.5632)	(0.5958)	(0.5327)	(0.6270)	(0.9240)	(0.8290)	(0.5685)	(0.5180)	(0.3725)	(0.3820)	(0.3883)
10	**Rover**	(0.2442)	(0.2662)	(0.2558)	(0.2427)	(0.2410)	(0.2630)	(0.2650)	(0.2525)	(0.0845)	0.0195	0.0155	(0.0638)
	Supply Basin Price												
11	**MichCon city-gate**	2.9634	2.9094	2.9090	2.9511	2.9732	2.9298	2.9634	3.1087	3.3213	3.4837	3.4807	3.2388
12	**Emerson**	2.7511	2.6871	2.7263	2.7713	2.7897	2.7843	2.8239	3.2997	3.5343	3.6507	3.5757	3.3241
13	**Chicago city-gate**	3.1426	3.0086	3.0398	3.1158	3.1342	3.0988	3.1264	3.3152	3.7778	4.1202	4.0452	3.5116
14	**Panhandle Field**	2.8676	2.7396	2.7868	2.8898	2.8982	2.8888	2.8844	3.1617	3.4763	3.6767	3.6497	3.2721
15	**ANR SW Field**	2.9766	2.8486	2.8998	2.9688	2.9872	2.9618	2.9754	3.1607	3.4773	3.7897	3.7987	3.4011
16	**REX Z3**	2.9374	2.8514	2.9010	2.9591	2.9792	2.9518	2.9894	3.1257	3.5283	3.7487	3.6697	3.3388
17	**Kensington Plant (NEXUS)**	3.0329	2.8389	2.7875	2.8916	2.8597	2.5253	2.5879	2.9397	3.2678	3.4122	3.3157	3.0978
18	**Clarington (TEAL)**	2.7304	2.5344	2.5410	2.6491	2.5732	2.2708	2.4054	2.7897	3.0748	3.3367	3.2522	2.9943
19	**Rover**	2.9174	2.8314	2.8810	2.9391	2.9592	2.9318	2.9694	3.1057	3.5083	3.7287	3.6497	3.3188

	Prices $/Dth (Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)
	Month	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**
1	**NYMEX Henry Hub Price**	2.9752	2.9256	2.9656	3.0186	3.0368	3.0348	3.0832	3.2268	3.4838	3.6186	3.5422	3.3058
	Supply Area Basis												
2	**MichCon city-gate**	(0.1063)	(0.1625)	(0.2015)	(0.2094)	(0.2120)	(0.2220)	(0.2520)	(0.2300)	(0.2190)	(0.1530)	(0.0695)	(0.1760)
3	**Emerson**	(0.3065)	(0.3065)	(0.3065)	(0.3065)	(0.3065)	(0.3065)	(0.3065)	(0.0145)	(0.0145)	(0.0145)	(0.0145)	(0.0145)
4	**Chicago city-gate**	0.0330	(0.0590)	(0.0710)	(0.0470)	(0.0470)	(0.0450)	(0.0490)	0.0070	0.1650	0.4050	0.4050	0.1310
5	**Panhandle Field**	(0.2845)	(0.3225)	(0.3185)	(0.2625)	(0.2705)	(0.2785)	(0.3025)	(0.0650)	(0.0370)	(0.0350)	(0.0370)	(0.0610)
6	**ANR SW Field**	(0.1875)	(0.2215)	(0.2175)	(0.1895)	(0.1895)	(0.2175)	(0.2155)	(0.1340)	(0.1040)	0.0020	0.0620	0.0120
7	**REX Z3**	(0.1818)	(0.2100)	(0.2010)	(0.1929)	(0.1975)	(0.2015)	(0.1795)	(0.1980)	(0.1260)	0.1000	0.0820	(0.0980)
8	**Kensington Plant (NEXUS)**	(0.1508)	(0.2610)	(0.3280)	(0.2079)	(0.2725)	(0.5870)	(0.5765)	(0.4595)	(0.3760)	(0.3060)	(0.3015)	(0.3235)
9	**Clarington (TEAL)**	(0.4443)	(0.6185)	(0.5815)	(0.4474)	(0.5520)	(0.8885)	(0.9100)	(0.5830)	(0.4775)	(0.4830)	(0.4565)	(0.5265)
10	**Rover**	(0.2018)	(0.2300)	(0.2210)	(0.2129)	(0.2175)	(0.2215)	(0.1995)	(0.2180)	(0.1460)	0.0800	0.0620	(0.1180)
	Supply Basin Price												
11	**MichCon city-gate**	2.8689	2.7631	2.7641	2.8092	2.8248	2.8128	2.8312	2.9968	3.2648	3.4656	3.4727	3.1298
12	**Emerson**	2.6687	2.6191	2.6591	2.7121	2.7303	2.7283	2.7767	3.2123	3.4693	3.6041	3.5277	3.2913
13	**Chicago city-gate**	3.0082	2.8666	2.8946	2.9716	2.9898	2.9898	3.0342	3.2338	3.6488	4.0236	3.9472	3.4368
14	**Panhandle Field**	2.6907	2.6031	2.6471	2.7561	2.7663	2.7563	2.7807	3.1618	3.4468	3.5836	3.5052	3.2448
15	**ANR SW Field**	2.7877	2.7041	2.7481	2.8291	2.8473	2.8173	2.8677	3.0928	3.3798	3.6206	3.6042	3.3178
16	**REX Z3**	2.7934	2.7156	2.7646	2.8257	2.8393	2.8333	2.9037	3.0288	3.3578	3.7186	3.6242	3.2078
17	**Kensington Plant (NEXUS)**	2.8244	2.6646	2.6376	2.8107	2.7643	2.4478	2.5067	2.7673	3.1078	3.3126	3.2407	2.9823
18	**Clarington (TEAL)**	2.5309	2.3071	2.3841	2.5712	2.4848	2.1463	2.1732	2.6438	3.0063	3.1356	3.0857	2.7793
19	**Rover**	2.7734	2.6956	2.7446	2.8057	2.8193	2.8133	2.8837	3.0088	3.3378	3.6986	3.6042	3.1878

DTE Gas Company
April 2022 - March 2027 GCR Plan Case
Projected NYMEX, Basis, and Supply Basin Prices

	Prices $/Dth (Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)
	Month	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**
1	**NYMEX Henry Hub Price**	2.8956	2.8498	2.8918	2.9358	2.9518	2.9438	2.9768	3.0868	3.3308	3.4608	3.3978	3.2278
	Supply Area Basis												
2	**MichCon city-gate**	(0.0800)	(0.1340)	(0.1740)	(0.1800)	(0.1800)	(0.1880)	(0.1680)	(0.2350)	(0.1710)	(0.0770)	(0.0530)	(0.0470)
3	**Emerson**	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.0145)	(0.0145)	(0.0145)	(0.0145)	(0.0145)
4	**Chicago city-gate**	0.0710	(0.0190)	(0.0290)	(0.0050)	(0.0050)	(0.0050)	(0.0070)	0.0835	0.2395	0.3475	0.3435	0.1775
5	**Panhandle Field**	(0.2670)	(0.3050)	(0.3010)	(0.2470)	(0.2530)	(0.2610)	(0.2870)	(0.0890)	(0.0710)	(0.0490)	(0.0510)	(0.0750)
6	**ANR SW Field**	(0.2580)	(0.2880)	(0.2880)	(0.2600)	(0.2600)	(0.2880)	(0.2840)	(0.1340)	(0.1040)	0.0020	0.0620	0.0120
7	**REX Z3**	(0.1215)	(0.1455)	(0.1335)	(0.1295)	(0.1295)	(0.1295)	(0.1155)	(0.1270)	(0.0290)	0.0890	0.0690	(0.0690)
8	**Kensington Plant (NEXUS)**	(0.0855)	(0.1935)	(0.2415)	(0.2715)	(0.3295)	(0.6420)	(0.6315)	(0.3970)	(0.3215)	(0.3375)	(0.3505)	(0.3550)
9	**Clarington (TEAL)**	(0.4485)	(0.5365)	(0.5245)	(0.5425)	(0.6445)	(0.9230)	(0.9465)	(0.6775)	(0.5820)	(0.5520)	(0.5355)	(0.5955)
10	**Rover**	(0.1415)	(0.1655)	(0.1535)	(0.1495)	(0.1495)	(0.1495)	(0.1355)	(0.1470)	(0.0490)	0.0690	0.0490	(0.0890)
	Supply Basin Price												
11	**MichCon city-gate**	2.8156	2.7158	2.7178	2.7558	2.7718	2.7558	2.8088	2.8518	3.1598	3.3838	3.3448	3.1808
12	**Emerson**	2.6051	2.5593	2.6013	2.6453	2.6613	2.6533	2.6863	3.0723	3.3163	3.4463	3.3833	3.2133
13	**Chicago city-gate**	2.9666	2.8308	2.8628	2.9308	2.9468	2.9388	2.9698	3.1703	3.5703	3.8083	3.7413	3.4053
14	**Panhandle Field**	2.6286	2.5448	2.5908	2.6888	2.6988	2.6828	2.6898	2.9978	3.2598	3.4118	3.3468	3.1528
15	**ANR SW Field**	2.6376	2.5618	2.6038	2.6758	2.6918	2.6558	2.6928	2.9528	3.2268	3.4628	3.4598	3.2398
16	**REX Z3**	2.7741	2.7043	2.7583	2.8063	2.8223	2.8143	2.8613	2.9598	3.3018	3.5498	3.4668	3.1588
17	**Kensington Plant (NEXUS)**	2.8101	2.6563	2.6503	2.6643	2.6223	2.3018	2.3453	2.6898	3.0093	3.1233	3.0473	2.8728
18	**Clarington (TEAL)**	2.4471	2.3133	2.3673	2.3933	2.3073	2.0208	2.0303	2.4093	2.7488	2.9088	2.8623	2.6323
19	**Rover**	2.7541	2.6843	2.7383	2.7863	2.8023	2.7943	2.8413	2.9398	3.2818	3.5298	3.4468	3.1388

	Prices $/Dth (Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)
	Month	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**
1	**NYMEX Henry Hub Price**	2.8328	2.8128	2.8608	2.9098	2.9258	2.9278	2.9648	3.0898	3.3298	3.4598	3.4148	3.2648
	Supply Area Basis												
2	**MichCon city-gate**	(0.0420)	(0.0920)	(0.1340)	(0.1400)	(0.1420)	(0.1460)	(0.1300)	(0.1630)	(0.1090)	(0.0830)	(0.0550)	(0.0570)
3	**Emerson**	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.2905)	(0.0145)	(0.0145)	(0.0145)	(0.0145)	(0.0145)
4	**Chicago city-gate**	0.1170	0.0290	0.0190	0.0410	0.0410	0.0430	0.0390	0.1660	0.3160	0.3580	0.3580	0.1840
5	**Panhandle Field**	(0.2590)	(0.2970)	(0.2930)	(0.2410)	(0.2450)	(0.2530)	(0.2790)	(0.0730)	(0.0550)	(0.0330)	(0.0350)	(0.0590)
6	**ANR SW Field**	(0.2580)	(0.2880)	(0.2880)	(0.2600)	(0.2600)	(0.2880)	(0.2840)	(0.1340)	(0.1040)	0.0020	0.0620	0.0120
7	**REX Z3**	(0.0655)	(0.0895)	(0.0775)	(0.0695)	(0.0695)	(0.0735)	(0.0555)	(0.0665)	0.0555	0.0935	0.0815	(0.0525)
8	**Kensington Plant (NEXUS)**	(0.1065)	(0.2265)	(0.2645)	(0.3045)	(0.3605)	(0.6670)	(0.6645)	(0.3970)	(0.3215)	(0.3375)	(0.3505)	(0.3550)
9	**Clarington (TEAL)**	(0.5175)	(0.6135)	(0.5915)	(0.6195)	(0.7195)	(0.9940)	(1.0235)	(0.5625)	(0.4630)	(0.5650)	(0.5405)	(0.6085)
10	**Rover**	(0.0855)	(0.1095)	(0.0975)	(0.0895)	(0.0895)	(0.0935)	(0.0755)	(0.0865)	0.0355	0.0735	0.0615	(0.0725)
	Supply Basin Price												
11	**MichCon city-gate**	2.7908	2.7208	2.7268	2.7698	2.7838	2.7818	2.8348	2.9268	3.2208	3.3768	3.3598	3.2078
12	**Emerson**	2.5423	2.5223	2.5703	2.6193	2.6353	2.6373	2.6743	3.0753	3.3153	3.4453	3.4003	3.2503
13	**Chicago city-gate**	2.9498	2.8418	2.8798	2.9508	2.9668	2.9708	3.0038	3.2558	3.6458	3.8178	3.7728	3.4488
14	**Panhandle Field**	2.5738	2.5158	2.5678	2.6688	2.6808	2.6748	2.6858	3.0168	3.2748	3.4268	3.3798	3.2058
15	**ANR SW Field**	2.5748	2.5248	2.5728	2.6498	2.6658	2.6398	2.6808	2.9558	3.2258	3.4618	3.4768	3.2768
16	**REX Z3**	2.7673	2.7233	2.7833	2.8403	2.8563	2.8543	2.9093	3.0233	3.3853	3.5533	3.4963	3.2123
17	**Kensington Plant (NEXUS)**	2.7263	2.5863	2.5963	2.6053	2.5653	2.2608	2.3003	2.6928	3.0083	3.1223	3.0643	2.9098
18	**Clarington (TEAL)**	2.3153	2.1993	2.2693	2.2903	2.2063	1.9338	1.9413	2.5273	2.8668	2.8948	2.8743	2.6563
19	**Rover**	2.7473	2.7033	2.7633	2.8203	2.8363	2.8343	2.8893	3.0033	3.3653	3.5333	3.4763	3.1923

Row	(Col. 1) Number Contract	(Col. 2) Transporter	(Col. 3) Service	(Col. 4) Receipt Point	(Col. 5) Delivery Point	(Col. 6) (Dth/Day) MDQ Winter	(Col. 7) (Dth/Day) MDQ Summer	(Col. 8) Date Start	(Col. 9) Date Term
1	108268	ANR Pipeline	ETS	SW Headstation	Group 1	10,000	10,000	11/1/2003	10/31/2022
2	108304	ANR Pipeline	ETS	SW Headstation	Group 2	15,000	15,000	11/1/2003	10/31/2022
3	109511	ANR Pipeline	FTS-1	SW Headstation	Sparta-Muskegon	25,000	25,000	11/1/2017	10/31/2022
4	122067	ANR Pipeline	FTS-1	SW Headstation	Menominee/WillowRun	14,000	14,000	11/1/2013	*3/31/2025*
5	122247	ANR Pipeline	FTS-1	SW Headstation	Willow Run	15,000	15,000	11/1/2013	3/31/2022
6	122065	ANR Pipeline	FTS-1	Alliance/ANR Int	Alpena	50,000	50,000	1/1/2014	4/30/2028
7	122248	ANR Pipeline	FTS-1	Marshfield	Menominee	21,000	21,000	11/1/2013	3/31/2027
8	132461	ANR Pipeline	FTS-1	REX Shelbyville	Willow Run	60,000	0	11/01/2020	03/31/2023
9	FT4634	Great Lakes Gas Transmission	FT	Emerson/Belle River	Various	10,130	10,130	04/01/05	Evergreen
10	FT4635	Great Lakes Gas Transmission	FT	Emerson/Belle River	Various	20,260	20,260	04/01/05	Evergreen
11	860003/00002	Nexus Gas Transmission, LLC[1]	FT-1	Kensington / Clarington	Ypsilanti	75,000	75,000	11/1/2022	10/31/2033
12	40104	Delivery Point Agreement	IT	Gaylord	Alpena	50,000	50,000	08/30/17	10/31/2027
	ASAT 62078	AEP Gas Transportation Agreement		Kalkaska	Various	100,000	100,000	11/01/2014	12/31/2022
13	17908	Panhandle Eastern Pipe Line	EFT	Field Zone	MCON/Southern	25,000	25,000	11/1/2003	10/31/2028
14	18474	Panhandle Eastern Pipe Line	FT	Field Zone	MCON/Southern	40,000	40,000	4/1/2002	3/31/2029
15	FT1-MCG-5676	Vector Pipeline	FT	Alliance	Milford Junction	20,000	10,000	11/1/2017	10/31/2022
16	FT-A #AF0081	Viking Gas Transmission	FT	Emerson	Marshfield	21,076	21,076	11/1/2013	3/31/2027
	Operational Capacity (Costs Included in Distribution Rates)								
17	111493	ANR Pipeline (Trufant I)	ETS	Detroit A&B	Group 3	400,000	400,000	07/01/05	06/01/51
18	112110	ANR Pipeline (Trufant II)	ETS	Detroit A&B	Group 3	200,000	200,000	11/01/17	06/01/51

Footnotes:
[1] NEXUS transport has an alternate receipt point at Clarington for 37,500 Dth/d from 11/1/2018 through 10/31/2024

DTE Gas Company
April 2022 - March 2027
Projected Purchase Volumes and Cost (Excluding Transportation Costs)

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)
		Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr22-Mar23
	Purchase Volume (Dth)													
1	Contracted Fixed Price	9,747,000	10,071,900	9,747,000	10,071,900	10,071,900	9,747,000	7,040,100	8,067,000	8,335,900	8,335,900	7,529,200	8,335,900	107,100,698
2	Not Under Contract	3,211,764	3,298,310	3,190,239	3,298,310	3,298,310	3,190,239	2,193,479	2,588,478	2,706,803	2,757,113	2,485,703	2,755,533	34,974,280
3	Contracted Indexed Price	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	600,000
4	Total Receipt (Dth)	13,008,764	13,420,209	12,987,239	13,420,209	13,420,209	12,987,239	9,283,579	10,705,478	11,092,703	11,143,013	10,064,903	11,141,433	142,674,978
5	Less Fuel	144,902	127,552	123,376	127,552	127,552	123,376	110,164	162,945	199,208	249,518	225,346	247,938	1,969,428
6	Total Delivered (Dth)	12,863,863	13,292,658	12,863,863	13,292,658	13,292,658	12,863,863	9,173,414	10,542,533	10,893,495	10,893,495	9,839,557	10,893,495	140,705,549
7	Heating Value Adjustment	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520
8	Total Delivered (Mcf)	12,228,006	12,635,606	12,228,006	12,635,606	12,635,606	12,228,006	8,719,976	10,021,419	10,355,033	10,355,033	9,353,191	10,355,033	133,750,522
	Purchase Cost ($)													
9	Contracted Fixed Price	24,306,585	25,116,805	24,306,585	25,116,805	25,116,805	24,306,585	15,056,653	23,052,248	23,820,655	23,820,655	21,515,431	23,820,655	279,356,468
10	Not Under Contract	10,898,780	11,137,097	10,861,349	11,433,621	11,405,854	10,683,551	7,290,575	9,706,834	10,890,591	11,635,656	10,214,634	10,181,499	126,340,041
11	Contracted Indexed Price	172,420	171,405	172,355	173,830	174,405	172,740	172,335	178,875	189,515	191,265	189,895	173,783	2,132,823
12	Total	35,377,785	36,425,307	35,340,289	36,724,256	36,697,063	35,162,877	22,519,563	32,937,957	34,900,762	35,647,577	31,919,960	34,175,938	407,829,332

DTE Gas Company
April 2022 - March 2027
Projected Purchase Volumes and Cost (Excluding Transportation Costs)

	(Col. 1)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 13)	(Col. 14)
		Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr23-Mar24
	Purchase Volume (Dth)													
1	Contracted Fixed Price	4,701,000	4,857,700	4,701,000	4,857,700	4,857,700	4,701,000	4,857,700	3,951,000	4,082,700	4,082,700	3,819,300	4,082,700	53,552,200
2	Not Under Contract	8,248,743	8,525,436	8,219,148	8,525,436	8,492,967	8,217,322	4,447,157	6,822,663	7,052,148	7,052,148	6,594,235	6,922,246	89,119,647
3	Contracted Indexed Price	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	600,000
4	Total Receipt (Dth)	12,999,743	13,433,136	12,970,148	13,433,136	13,400,667	12,968,322	9,354,857	10,823,663	11,184,848	11,184,848	10,463,535	11,054,946	143,271,847
5	Less Fuel	197,339	203,985	167,744	203,985	171,516	165,918	153,895	241,677	249,744	249,744	233,616	235,561	2,474,723
6	Total Delivered (Dth)	12,802,404	13,229,151	12,802,404	13,229,151	13,229,151	12,802,404	9,200,962	10,581,986	10,935,104	10,935,104	10,229,919	10,819,384	140,797,124
7	Heating Value Adjustment	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520
8	Total Delivered (Mcf)	12,169,586	12,575,238	12,169,586	12,575,238	12,575,238	12,169,586	8,746,162	10,058,922	10,394,586	10,394,585	9,724,258	10,284,586	133,837,570
	Purchase Cost ($)													
9	Contracted Fixed Price	11,096,550	11,466,435	11,096,550	11,466,435	11,466,435	11,096,550	11,466,435	11,697,600	12,087,520	12,087,520	11,307,680	12,087,520	138,423,231
10	Not Under Contract	24,300,824	24,460,514	23,783,950	25,022,741	25,151,176	23,576,867	12,750,896	21,343,025	24,574,819	25,637,455	23,656,905	22,671,674	276,930,845
11	Contracted Indexed Price	148,172	145,468	145,452	147,555	148,660	146,490	148,170	155,435	166,065	174,185	174,035	161,941	1,861,628
12	Total	35,545,545	36,072,417	35,025,952	36,636,731	36,766,271	34,819,907	24,365,500	33,196,060	36,828,404	37,899,160	35,138,620	34,921,135	417,215,704

DTE Gas Company
April 2022 - March 2027
Projected Purchase Volumes and Cost (Excluding Transportation Costs)

Case No.: U-21064
Exhibit No.: A-10
Witness: E. P. Schiffer

	(Col. 1)	(Col. 13)	(Col. 13)											(Col. 14)
		Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr24-Mar25
	Purchase Volume (Dth)													
1	Contracted Fixed Price	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Not Under Contract	12,956,230	13,389,839	12,956,230	13,389,839	13,389,839	12,926,172	9,245,531	10,490,320	10,840,904	10,939,609	9,877,266	10,939,609	141,341,389
3	Contracted Indexed Price	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	600,000
4	Total Receipt (Dth)	13,006,230	13,439,839	13,006,230	13,439,839	13,439,839	12,976,172	9,295,531	10,540,320	10,890,904	10,989,609	9,927,266	10,989,609	141,941,389
5	Less Fuel	197,593	204,247	197,593	204,247	204,247	167,535	79,599	145,135	149,984	248,690	224,603	248,690	2,272,162
6	Total Delivered (Dth)	12,808,637	13,235,592	12,808,637	13,235,592	13,235,592	12,808,638	9,215,932	10,395,185	10,740,919	10,740,919	9,702,663	10,740,919	139,669,228
7	Heating Value Adjustment	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520
8	Total Delivered (Mcf)	12,175,511	12,581,362	12,175,511	12,581,362	12,581,362	12,175,511	8,760,392	9,881,354	10,209,999	10,209,999	9,223,064	10,209,999	132,765,426
	Purchase Cost ($)													
9	Contracted Fixed Price	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Not Under Contract	35,887,338	35,654,448	34,857,667	37,032,501	37,114,991	35,147,689	25,147,256	31,358,705	35,621,493	38,702,425	34,462,907	34,914,788	415,902,207
11	Contracted Indexed Price	143,444	138,155	138,205	140,460	141,240	140,640	141,560	149,840	163,240	173,280	173,635	156,490	1,800,189
12	Total	36,030,781	35,792,604	34,995,871	37,172,961	37,256,231	35,288,329	25,288,816	31,508,545	35,784,733	38,875,705	34,636,542	35,071,278	417,702,395

(Col. 1)

		Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr25-Mar26
	Purchase Volume (Dth)													
1	Contracted Fixed Price	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Not Under Contract	12,959,788	13,393,447	12,950,931	13,384,359	13,384,359	12,922,669	9,327,363	10,373,296	10,720,512	10,825,348	9,772,527	10,825,348	140,839,946
3	Contracted Indexed Price	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	600,000
4	Total Receipt (Dth)	13,009,788	13,443,447	13,000,931	13,434,359	13,434,359	12,972,669	9,377,363	10,423,296	10,770,512	10,875,348	9,822,527	10,875,348	141,439,946
5	Less Fuel	206,873	213,769	198,016	204,680	204,680	169,754	140,526	138,599	143,237	248,073	224,038	248,073	2,340,316
6	Total Delivered (Dth)	12,802,915	13,229,679	12,802,915	13,229,679	13,229,679	12,802,915	9,236,837	10,284,697	10,627,275	10,627,275	9,598,490	10,627,275	139,099,630
7	Heating Value Adjustment	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520
8	Total Delivered (Mcf)	12,170,071	12,575,740	12,170,071	12,575,740	12,575,740	12,170,071	8,780,263	9,776,328	10,101,973	10,101,973	9,124,040	10,101,973	132,223,983
	Purchase Cost ($)													
9	Contracted Fixed Price	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Not Under Contract	34,916,860	34,885,716	34,100,180	35,954,988	36,033,812	34,038,618	24,506,862	29,613,264	33,786,319	36,851,440	32,717,947	33,794,943	401,200,948
11	Contracted Indexed Price	140,780	135,790	135,890	137,790	138,590	137,790	140,440	142,590	157,990	169,190	167,240	159,040	1,763,120
12	Total	35,057,640	35,021,506	34,236,070	36,092,778	36,172,402	34,176,408	24,647,302	29,755,854	33,944,309	37,020,630	32,885,187	33,953,983	402,964,067

(Col. 1)

		Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr26-Mar27
	Purchase Volume (Dth)													
1	Contracted Fixed Price													-
2	Not Under Contract	12,766,426	13,193,640	12,766,426	14,352,906	13,147,778	12,721,982	9,347,392	10,253,352	10,610,005	10,696,233	9,656,079	10,696,234	140,208,452
3	Contracted Indexed Price	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	600,000
4	Total Receipt (Dth)	12,816,426	13,243,640	12,816,426	14,402,906	13,197,778	12,771,982	9,397,392	10,303,352	10,660,005	10,746,233	9,706,079	10,746,234	140,808,452
5	Less Fuel	206,873	213,769	206,873	222,835	167,907	162,429	140,526	143,574	161,147	247,375	223,409	247,375	2,344,091
6	Total Delivered (Dth)	12,609,553	13,029,871	12,609,553	14,180,071	13,029,871	12,609,553	9,256,867	10,159,778	10,498,858	10,498,858	9,482,670	10,498,858	138,464,362
7	Heating Value Adjustment	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520	1.0520
8	Total Delivered (Mcf)	11,986,267	12,385,809	11,986,267	13,479,155	12,385,809	11,986,267	8,799,303	9,657,584	9,979,903	9,979,903	9,013,945	9,979,903	131,620,116
	Purchase Cost ($)													
9	Contracted Fixed Price	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Not Under Contract	33,722,936	34,025,812	33,337,844	38,460,395	35,316,032	33,445,458	24,441,453	29,954,265	34,131,737	36,140,032	32,283,872	33,569,324	398,829,161
11	Contracted Indexed Price	139,540	136,040	136,340	138,490	139,190	139,090	141,740	146,340	161,040	168,840	167,990	160,390	1,775,030
12	Total	33,862,476	34,161,852	33,474,184	38,598,885	35,455,222	33,584,548	24,583,193	30,100,605	34,292,777	36,308,872	32,451,862	33,729,714	400,604,191

DTE Gas Company
April 2022 - March 2027
Projected Transportation Utilization, Reservation Costs, and Usage Costs

Case No.: U-21064
Exhibit No.: A-11
Witness: E.P. Schiffer

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)
		Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr22-Mar23
	Transport Capacity (Dth/Day)													
1	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
2	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
3	Vector	10,000	10,000	10,000	10,000	10,000	10,000	10,000	20,000	20,000	20,000	20,000	20,000	
4	Panhandle Field Zone	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	
5	NEXUS - Kensington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
6	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
7	ANR Alliance	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
8	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	
9	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	
10	Total Delivered Volume	330,390	330,390	330,390	330,390	330,390	330,390	330,390	400,390	400,390	400,390	400,390	400,390	
	Source of Supply / Transport Utilization (Dth/Day)													
11	MichCon city-gate	201,667	201,613	201,667	201,613	201,613	201,667	94,275	1,667	1,613	1,613	1,786	1,613	
12	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
13	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
14	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
15	Panhandle Field Zone	62,757	36,793	36,739	36,793	36,793	36,739	31,941	49,361	80,000	80,000	80,000	80,000	
16	NEXUS - Kensington	11,482	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
17	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
18	ANR Alliance	-	-	-	-	-	-	-	50,000	19,400	19,400	19,237	20,846	
19	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	43,311	64,000	64,000	64,000	64,000	62,555	
20	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	
21	Total Delivered Volume	428,795	428,795	428,795	428,795	428,795	428,795	295,917	351,418	351,403	351,403	351,413	351,403	
	Reservation Cost ($)													
22	Great Lakes	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	
23	Viking/ANR Northern	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	
24	Vector	42,583	42,583	42,583	42,583	42,583	42,583	42,583	85,166	85,166	85,166	85,166	85,166	
25	Panhandle Field Zone	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	
26	NEXUS - Kensington	781,875	807,938	781,875	807,938	807,938	781,875	807,938	781,875	807,938	807,938	729,750	807,938	
27	NEXUS - Clarington	950,625	982,313	950,625	982,313	982,313	950,625	982,313	950,625	982,313	982,313	887,250	982,313	
28	ANR Alliance	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	
28	ANR SW	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	
29	ANR Shelbyville	-	-	-	-	-	-	-	485,280	485,280	485,280	485,280	485,280	
30	Physical Call Option	-	-	-	-	-	-	-	-	-	125,000	125,000	-	
31	Total Reservation Cost ($)	4,610,406	4,668,156	4,610,406	4,668,156	4,668,156	4,610,406	4,668,156	5,138,269	5,196,019	5,321,019	5,147,769	5,196,019	58,502,932
	Usage Cost ($)													
32	Great Lakes	9,792	10,118	9,792	10,118	10,118	9,792	10,118	10,009	10,792	14,614	15,028	12,029	
33	Viking/ANR Northern	16,935	17,499	16,935	17,499	17,499	16,935	17,499	16,935	17,499	17,499	15,806	17,499	
34	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
35	Panhandle Field Zone	81,334	39,775	38,403	39,775	39,775	38,403	31,504	59,230	113,444	113,444	102,466	113,444	
36	NEXUS - Kensington	413	1,395	1,350	1,395	1,395	1,350	1,395	1,350	1,395	1,395	1,260	1,395	
37	NEXUS - Clarington	2,700	2,790	2,700	2,790	2,790	2,700	2,790	2,700	2,790	2,790	2,520	2,790	
38	ANR Alliance	-	-	-	-	-	-	-	18,000	7,217	7,217	6,464	7,755	
39	ANR SW	45,120	46,624	45,120	46,624	46,624	45,120	31,552	45,120	46,624	46,624	42,112	45,571	
40	ANR Shelbyville	-	-	-	-	-	-	-	26,460	27,342	27,342	24,696	27,342	
41	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
42	Total Usage Cost ($)	156,293	118,201	114,300	118,201	118,201	114,300	94,858	179,804	227,103	230,925	210,350	227,825	1,910,362
43	Total Transport Cost ($)	4,766,699	4,786,357	4,724,705	4,786,357	4,786,357	4,724,705	4,763,013	5,318,073	5,423,122	5,551,944	5,358,119	5,423,843	60,413,293

DTE Gas Company
April 2022 - March 2027
Projected Transportation Utilization, Reservation Costs, and Usage Costs

Case No.: U-21064
Exhibit No.: A-11
Witness: E.P. Schiffer

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)
		Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr23-Mar24
	Transport Capacity (Dth/Day)													
1	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
2	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
3	Vector	10,000	10,000	10,000	10,000	10,000	10,000	10,000	20,000	20,000	20,000	20,000	20,000	
4	Panhandle Field Zone	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	
5	NEXUS - Kensington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
6	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
7	ANR Alliance	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
8	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	
9	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	
10	Total Delivered Volume	330,390	330,390	330,390	330,390	330,390	330,390	330,390	400,390	400,390	400,390	400,390	400,390	
	Source of Supply / Transport Utilization (Dth/Day)													
11	MichCon city-gate	201,667	201,613	201,667	201,613	201,613	201,667	86,450	1,667	1,613	1,613	1,786	1,613	
12	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	31,475	30,390	
13	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,750	21,000	
14	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
15	Panhandle Field Zone	80,000	80,000	80,000	80,000	80,000	80,000	68,265	80,000	80,000	80,000	82,857	80,000	
16	NEXUS - Kensington	-	-	35,321	-	37,500	37,500	37,500	37,500	37,500	37,500	38,839	37,500	
17	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	38,839	37,500	
18	ANR Alliance	-	-	-	-	-	-	-	20,676	20,742	20,742	21,379	29,409	
19	ANR SW	56,190	56,244	20,870	56,244	18,744	18,690	15,700	64,000	64,000	64,000	66,286	51,600	
20	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	62,143	60,000	
21	Total Delivered Volume	426,747	426,747	426,747	426,747	426,747	426,747	296,805	352,733	352,745	352,745	365,354	349,012	
	Reservation Cost ($)													
22	Great Lakes	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	
23	Viking/ANR Northern	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	
24	Vector	42,583	42,583	42,583	42,583	42,583	42,583	42,583	85,166	85,166	85,166	85,166	85,166	
25	Panhandle Field Zone	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	
26	NEXUS - Kensington	781,875	807,938	781,875	807,938	807,938	781,875	807,938	781,875	807,938	807,938	755,813	807,938	
27	NEXUS - Clarington	950,625	982,313	950,625	982,313	982,313	950,625	982,313	950,625	982,313	982,313	918,938	982,313	
28	ANR Alliance	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	
28	ANR SW	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	
29	ANR Shelbyville	-	-	-	-	-	-	-	485,280	485,280	485,280	485,280	485,280	
30	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
31	Total Reservation Cost ($)	4,610,406	4,668,156	4,610,406	4,668,156	4,668,156	4,610,406	4,668,156	5,138,269	5,196,019	5,196,019	5,080,519	5,196,019	58,310,682
	Usage Cost ($)													
32	Great Lakes	9,792	10,118	9,792	10,118	10,118	9,792	10,118	10,009	10,792	14,614	15,564	12,029	
33	Viking/ANR Northern	16,935	17,499	16,935	17,499	17,499	16,935	17,499	16,935	17,499	17,499	16,370	17,499	
34	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
35	Panhandle Field Zone	109,784	113,444	109,784	113,444	113,444	109,784	93,436	109,784	113,444	113,444	106,125	113,444	
36	NEXUS - Kensington	-	-	1,272	-	1,395	1,350	1,395	1,350	1,395	1,395	1,305	1,395	
37	NEXUS - Clarington	2,700	2,790	2,700	2,790	2,790	2,700	2,790	2,700	2,790	2,790	2,610	2,790	
38	ANR Alliance	-	-	-	-	-	-	-	7,443	7,716	7,716	7,183	10,940	
39	ANR SW	39,614	40,974	14,713	40,974	13,655	13,177	11,437	45,120	46,624	46,624	43,616	37,591	
40	ANR Shelbyville	-	-	-	-	-	-	-	26,460	27,342	27,342	25,578	27,342	
41	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
42	Total Usage Cost ($)	178,825	184,825	155,195	184,825	158,901	153,737	136,676	219,802	227,603	231,425	218,352	223,030	2,273,194
43	Total Transport Cost ($)	4,789,230	4,852,980	4,765,601	4,852,980	4,827,057	4,764,143	4,804,831	5,358,070	5,423,621	5,427,443	5,298,870	5,419,049	60,583,876

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)
		Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr24-Mar25
	Transport Capacity (Dth/Day)													
1	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
2	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
3	Vector	10,000	10,000	10,000	10,000	10,000	10,000	10,000	20,000	20,000	20,000	20,000	20,000	
4	Panhandle Field Zone	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	
5	NEXUS - Kensington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
6	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
7	ANR Alliance	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
8	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	
9	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	
10	Total Delivered Volume	330,390	330,390	330,390	330,390	330,390	330,390	330,390	400,390	400,390	400,390	400,390	400,390	
	Source of Supply / Transport Utilization (Dth/Day)													
11	MichCon city-gate	201,667	201,613	201,667	201,613	201,613	201,667	150,198	101,667	101,613	1,613	1,724	1,613	
12	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	29,342	30,390	
13	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	20,276	21,000	
14	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
15	Panhandle Field Zone	80,000	80,000	80,000	80,000	80,000	63,816	5,000	14,502	14,502	80,000	77,241	80,000	
16	NEXUS - Kensington	-	-	-	-	-	37,500	37,500	30,648	30,677	37,500	36,207	37,500	
17	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	36,207	37,500	
18	ANR Alliance	-	-	-	-	-	-	-	-	-	14,478	13,853	14,478	
19	ANR SW	56,398	56,452	56,398	56,452	56,452	35,082	15,700	50,800	50,800	64,000	61,793	64,000	
20	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	57,931	60,000	
21	Total Delivered Volume	426,955	426,955	426,955	426,955	426,955	426,955	297,288	346,506	346,481	346,481	334,575	346,481	
	Reservation Cost ($)													
22	Great Lakes	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	
23	Viking/ANR Northern	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	
24	Vector	42,583	42,583	42,583	42,583	42,583	42,583	42,583	85,166	85,166	85,166	85,166	85,166	
25	Panhandle Field Zone	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	
26	NEXUS - Kensington	781,875	807,938	781,875	807,938	807,938	781,875	807,938	781,875	807,938	807,938	729,750	807,938	
27	NEXUS - Clarington	950,625	982,313	950,625	982,313	982,313	950,625	982,313	950,625	982,313	982,313	887,250	982,313	
28	ANR Alliance	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	
28	ANR SW	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	
29	ANR Shelbyville	-	-	-	-	-	-	-	485,280	485,280	485,280	485,280	485,280	
30	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
31	Total Reservation Cost ($)	4,610,406	4,668,156	4,610,406	4,668,156	4,668,156	4,610,406	4,668,156	5,138,269	5,196,019	5,196,019	5,022,769	5,196,019	58,252,932
	Usage Cost ($)													
32	Great Lakes	9,792	10,118	9,792	10,118	10,118	9,792	10,118	10,009	10,792	14,614	15,028	12,029	
33	Viking/ANR Northern	16,935	17,499	16,935	17,499	17,499	16,935	17,499	16,935	17,499	17,499	15,806	17,499	
34	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
35	Panhandle Field Zone	132,000	136,400	132,000	136,400	136,400	105,296	8,525	2,619	2,706	113,444	102,466	113,444	
36	NEXUS - Kensington	-	-	-	-	-	1,350	1,395	1,103	1,141	1,395	1,260	1,395	
37	NEXUS - Clarington	2,700	2,790	2,700	2,790	2,790	2,700	2,790	2,700	2,790	2,790	2,520	2,790	
38	ANR Alliance	-	-	-	-	-	-	-	-	-	5,386	4,821	5,386	
39	ANR SW	39,761	41,125	39,761	41,125	41,125	24,733	11,437	35,814	37,008	46,624	42,112	46,624	
40	ANR Shelbyville	-	-	-	-	-	-	-	26,460	27,342	27,342	24,696	27,342	
41	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
42	Total Usage Cost ($)	201,187	207,932	201,187	207,932	207,932	160,805	51,765	95,640	99,279	229,094	208,708	226,509	2,097,970
43	Total Transport Cost ($)	4,811,592	4,876,088	4,811,592	4,876,088	4,876,088	4,771,211	4,719,920	5,233,909	5,295,297	5,425,113	5,231,476	5,422,528	60,350,901

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)
		Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr25-Mar26
	Transport Capacity (Dth/Day)													
1	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
2	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
3	Vector	10,000	10,000	10,000	10,000	10,000	10,000	10,000	20,000	20,000	20,000	20,000	20,000	
4	Panhandle Field Zone	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	
5	NEXUS - Kensington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
6	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
7	ANR Alliance	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
8	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	
9	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	
10	Total Delivered Volume	330,390	330,390	330,390	330,390	330,390	330,390	330,390	400,390	400,390	400,390	400,390	400,390	
	Source of Supply / Transport Utilization (Dth/Day)													
11	MichCon city-gate	193,874	193,874	201,667	201,613	201,613	201,667	102,572	101,667	101,613	1,613	1,786	1,613	
12	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
13	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
14	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
15	Panhandle Field Zone	80,000	80,000	72,207	72,261	72,261	34,707	5,000	7,700	7,700	80,000	80,000	80,000	
16	NEXUS - Kensington	-	-	-	-	-	37,500	37,500	33,767	33,812	37,500	37,500	37,500	
17	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
18	ANR Alliance	-	-	-	-	-	-	-	-	-	10,812	10,627	10,812	
19	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	64,000	50,800	50,800	64,000	64,000	64,000	
20	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	
21	Total Delivered Volume	426,764	426,764	426,764	426,764	426,764	426,764	297,962	342,823	342,815	342,815	342,803	342,815	
	Reservation Cost ($)													
22	Great Lakes	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	
23	Viking/ANR Northern	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	
24	Vector	42,583	42,583	42,583	42,583	42,583	42,583	42,583	85,166	85,166	85,166	85,166	85,166	
25	Panhandle Field Zone	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	
26	NEXUS - Kensington	781,875	807,938	781,875	807,938	807,938	781,875	807,938	781,875	807,938	807,938	729,750	807,938	
27	NEXUS - Clarington	950,625	982,313	950,625	982,313	982,313	950,625	982,313	950,625	982,313	982,313	887,250	982,313	
28	ANR Alliance	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	
28	ANR SW	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	
29	ANR Shelbyville	-	-	-	-	-	-	-	485,280	485,280	485,280	485,280	485,280	
30	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
31	Total Reservation Cost ($)	4,610,406	4,668,156	4,610,406	4,668,156	4,668,156	4,610,406	4,668,156	5,138,269	5,196,019	5,196,019	5,022,769	5,196,019	53,056,913
	Usage Cost ($)													
32	Great Lakes	9,792	10,118	9,792	10,118	10,118	9,792	10,118	10,009	10,792	14,614	15,028	12,029	
33	Viking/ANR Northern	16,935	17,499	16,935	17,499	17,499	16,935	17,499	16,935	17,499	17,499	15,806	17,499	
34	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
35	Panhandle Field Zone	132,000	136,400	119,142	123,205	123,205	57,267	8,525	12,705	13,128	113,444	102,466	113,444	
36	NEXUS - Kensington	-	-	-	-	-	1,350	1,395	1,216	1,258	1,395	1,260	1,395	
37	NEXUS - Clarington	2,700	2,790	2,700	2,790	2,790	2,700	2,790	2,700	2,790	2,790	2,520	2,790	
38	ANR Alliance	-	-	-	-	-	-	-	-	-	4,022	3,571	4,022	
39	ANR SW	45,120	46,624	45,120	46,624	46,624	45,120	46,624	35,814	37,008	46,624	42,112	46,624	
40	ANR Shelbyville	-	-	-	-	-	-	-	26,460	27,342	27,342	24,696	27,342	
41	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
42	Total Usage Cost ($)	206,546	213,431	193,688	200,236	200,236	133,163	86,951	105,838	109,818	227,731	207,457	225,145	1,885,096
43	Total Transport Cost ($)	4,816,952	4,881,587	4,804,094	4,868,392	4,868,392	4,743,569	4,755,107	5,244,107	5,305,836	5,423,749	5,230,226	5,421,164	54,942,009

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)
		Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr26-Mar27
	Transport Capacity (Dth/Day)													
1	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
2	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
3	Vector	10,000	10,000	10,000	10,000	10,000	10,000	10,000	20,000	20,000	20,000	20,000	20,000	
4	Panhandle Field Zone	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	
5	NEXUS - Kensington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
6	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
7	ANR Alliance	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
8	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	64,000	
9	ANR Shelbyville	-	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	
10	Total Delivered Volume	330,390	330,390	330,390	330,390	330,390	330,390	330,390	400,390	400,390	400,390	400,390	400,390	
	Source of Supply / Transport Utilization (Dth/Day)													
11	MichCon city-gate	187,428	187,428	187,428	201,613	201,613	201,667	103,219	101,667	101,613	1,613	1,786	1,613	
12	Great Lakes	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	30,390	
13	Viking/ANR Northern	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	
14	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
15	Panhandle Field Zone	80,000	80,000	80,000	80,000	28,316	28,262	5,000	14,502	14,502	80,000	80,000	80,000	
16	NEXUS - Kensington	-	-	-	22,919	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
17	NEXUS - Clarington	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	37,500	
18	ANR Alliance	-	-	-	-	-	-	-	-	-	6,670	6,491	6,670	
19	ANR SW	64,000	64,000	64,000	64,000	64,000	64,000	64,000	50,800	64,000	64,000	64,000	64,000	
20	ANR Shelbyville	-	-	-	-	-	-	-	45,301	32,168	60,000	60,000	60,000	
21	Total Delivered Volume	420,318	420,318	420,318	457,422	420,318	420,318	298,609	338,659	338,673	338,673	338,667	338,673	
	Reservation Cost ($)													
22	Great Lakes	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	213,405	
23	Viking/ANR Northern	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	224,985	
24	Vector	42,583	42,583	42,583	42,583	42,583	42,583	42,583	85,166	85,166	85,166	85,166	85,166	
25	Panhandle Field Zone	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	1,417,617	
26	NEXUS - Kensington	781,875	807,938	781,875	807,938	807,938	781,875	807,938	781,875	807,938	807,938	729,750	807,938	
27	NEXUS - Clarington	950,625	982,313	950,625	982,313	982,313	950,625	982,313	950,625	982,313	982,313	887,250	982,313	
28	ANR Alliance	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	286,450	
28	ANR SW	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	692,866	
29	ANR Shelbyville	-	-	-	-	-	-	-	485,280	485,280	485,280	485,280	485,280	
30	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
31	Total Reservation Cost ($)	4,610,406	4,668,156	4,610,406	4,668,156	4,668,156	4,610,406	4,668,156	5,138,269	5,196,019	5,196,019	5,022,769	5,196,019	58,252,932
	Usage Cost ($)													
32	Great Lakes	9,792	10,118	9,792	10,118	10,118	9,792	10,118	10,009	10,792	14,614	15,028	12,029	
33	Viking/ANR Northern	16,935	17,499	16,935	17,499	17,499	16,935	17,499	16,935	17,499	17,499	15,806	17,499	
34	Vector	-	-	-	-	-	-	-	-	-	-	-	-	
35	Panhandle Field Zone	132,000	136,400	132,000	136,400	48,278	46,632	8,525	2,619	1,770	113,444	102,466	113,444	
36	NEXUS - Kensington	-	-	-	853	1,395	1,350	1,395	1,350	1,395	1,395	1,260	1,395	
37	NEXUS - Clarington	2,700	2,790	2,700	2,790	2,790	2,700	2,790	2,700	2,790	2,790	2,520	2,790	
38	ANR Alliance	-	-	-	-	-	-	-	-	-	2,481	2,181	2,481	
39	ANR SW	45,120	46,624	45,120	46,624	46,624	45,120	46,624	35,814	46,624	46,624	42,112	46,624	
40	ANR Shelbyville	-	-	-	-	-	-	-	19,978	14,659	27,342	24,696	27,342	
41	Physical Call Option	-	-	-	-	-	-	-	-	-	-	-	-	
42	Total Usage Cost ($)	206,546	213,431	206,546	214,284	126,704	122,528	86,951	89,404	95,529	226,190	206,068	223,604	2,017,786
43	Total Transport Cost ($)	4,816,952	4,881,587	4,816,952	4,882,439	4,794,860	4,732,934	4,755,107	5,227,673	5,291,548	5,422,208	5,228,836	5,419,623	60,270,717

DTE Gas Company
April 2022 - March 2027
Projected Total Delivered Cost Including Transportation Cost ($)

(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)	(Col. 14)
	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Total
1 Commodity Cost	35,377,785	36,425,307	35,340,289	36,724,256	36,697,063	35,162,877	22,519,563	32,937,957	34,900,762	35,647,577	31,919,960	34,175,938	407,829,332
2 Transportation Cost	4,766,699	4,786,357	4,724,705	4,786,357	4,786,357	4,724,705	4,763,013	5,318,073	5,423,122	5,551,944	5,358,119	5,423,843	60,413,293
3 Total Delivered Cost	40,144,484	41,211,664	40,064,994	41,510,613	41,483,420	39,887,582	27,282,576	38,256,030	40,323,884	41,199,520	37,278,078	39,599,781	468,242,626
	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Total
4 Commodity Cost	35,545,545	36,072,417	35,025,952	36,636,731	36,766,271	34,819,907	24,365,500	33,196,060	36,828,404	37,899,160	35,138,620	34,921,135	417,215,704
5 Transportation Cost	4,789,230	4,852,980	4,765,601	4,852,980	4,827,057	4,764,143	4,804,831	5,358,070	5,423,621	5,196,019	5,080,519	5,196,019	59,911,070
6 Total Delivered Cost	40,334,776	40,925,397	39,791,553	41,489,712	41,593,328	39,584,050	29,170,332	38,554,130	42,252,026	43,095,179	40,219,139	40,117,154	477,126,774
	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Total
7 Commodity Cost	36,030,781	35,792,604	34,995,871	37,172,961	37,256,231	35,288,329	25,288,816	31,508,545	35,784,733	38,875,705	34,636,542	35,071,278	417,702,395
8 Transportation Cost	4,610,406	4,668,156	4,610,406	4,668,156	4,668,156	4,610,406	4,668,156	5,138,269	5,196,019	5,425,113	5,231,476	5,422,528	58,917,242
9 Total Delivered Cost	40,641,187	40,460,759	39,606,277	41,841,116	41,924,387	39,898,735	29,956,972	36,646,813	40,980,752	44,300,817	39,868,018	40,493,805	476,619,638
	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Total
10 Commodity Cost	35,057,640	35,021,506	34,236,070	36,092,778	36,172,402	34,176,408	24,647,302	29,755,854	33,944,309	37,020,630	32,885,187	33,953,983	402,964,067
11 Transportation Cost	4,816,952	4,881,587	4,804,094	4,868,392	4,868,392	4,743,569	4,755,107	5,244,107	5,305,836	5,423,749	5,230,226	5,421,164	60,363,173
12 Total Delivered Cost	39,874,592	39,903,093	39,040,164	40,961,169	41,040,794	38,919,976	29,402,409	34,999,961	39,250,146	42,444,379	38,115,413	39,375,147	463,327,240
	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Total
13 Commodity Cost	33,862,476	34,161,852	33,474,184	38,598,885	35,455,222	33,584,548	24,583,193	30,100,605	34,292,777	36,308,872	32,451,862	33,729,714	400,604,191
14 Transportation Cost	4,816,952	4,881,587	4,816,952	4,882,439	4,794,860	4,732,934	4,755,107	5,227,673	5,291,548	5,422,208	5,228,836	5,419,623	60,270,717
15 Total Delivered Cost	38,679,428	39,043,438	38,291,136	43,481,324	40,250,082	38,317,482	29,338,300	35,328,278	39,584,325	41,731,080	37,680,698	39,149,337	460,874,908

			75% VCA Method			Index Method			75% VCA Method less Index Method			
Line	Start Delivery	End Delivery	$/Dth	Year over Year Price Change (Volatility)	Annual Residential Gas Cost [1]	$/Dth	Year over Year Price Change (Volatility)	Annual Residential Gas Cost [1]	$/Dth	Annual Residential Gas Cost Above (Below) Index [1]	Total Cost Above (Below) Index [2]	Cumulative Total Cost Above (Below) Index [2]
	(col. a)	(col. b)	(col. c)	(col. d)	(col. e)	(col. f)	(col. g)	(col. h)	(col. i)	(col. j)	(col. k)	(col. l)
1	Apr-01	Mar-02	$ 3.04		$ 274	$ 3.18		$ 286	$ (0.14)	$ (13)	(20,101,313)	(20,101,313)
2	Apr-02	Mar-03	3.68	19%	332	4.07	25%	367	(0.39)	(35)	(56,466,666)	(76,567,979)
3	Apr-03	Mar-04	4.09	11%	368	5.13	23%	462	(1.04)	(94)	(150,287,938)	(226,855,917)
4	Apr-04	Mar-05	4.74	15%	427	6.27	20%	564	(1.53)	(138)	(221,109,886)	(447,965,803)
5	Apr-05	Mar-06	6.20	27%	558	9.10	37%	819	(2.90)	(261)	(419,468,085)	(867,433,888)
6	Apr-06	Mar-07	6.87	10%	619	6.73	-30%	606	0.14	12	20,058,739	(847,375,149)
7	Apr-07	Mar-08	8.03	16%	723	7.08	5%	638	0.95	85	137,010,693	(710,364,456)
8	Apr-08	Mar-09	8.53	6%	768	8.66	20%	779	(0.13)	(12)	(18,590,266)	(728,954,722)
9	Apr-09	Mar-10	7.50	-13%	675	3.98	-78%	359	3.52	317	508,532,991	(220,421,731)
10	Apr-10	Mar-11	6.74	-11%	606	4.13	4%	372	2.60	234	376,399,048	155,977,316
11	Apr-11	Mar-12	5.54	-20%	498	3.80	-8%	342	1.74	156	250,863,414	406,840,730
12	Apr-12	Mar-13	4.65	-17%	418	2.90	-27%	261	1.75	158	253,530,679	660,371,409
13	Apr-13	Mar-14	4.18	-11%	376	3.98	32%	358	0.20	18	28,508,004	688,879,413
14	Apr-14	Mar-15	3.93	-6%	354	4.02	1%	362	(0.09)	(8)	(12,808,448)	676,070,965
15	Apr-15	Mar-16	3.63	-8%	327	2.49	-48%	224	1.14	103	164,854,295	840,925,260
16	Apr-16	Mar-17	3.33	-9%	300	2.73	9%	245	0.60	54	87,340,135	928,265,395
17	Apr-17	Mar-18	3.10	-7%	279	3.03	11%	273	0.07	6	10,351,360	938,616,755
18	Apr-18	Mar-19	2.96	-5%	266	3.08	2%	277	(0.12)	(11)	(17,453,527)	921,163,228
19	Apr-19	Mar-20	2.66	-11%	239	2.34	-28%	210	0.32	29	46,687,262	967,850,490
20	Apr-20	Mar-21	2.50	-6%	225	2.21	-6%	199	0.29	26	42,039,173	1,009,889,663
21	**20-year Average**		**$ 4.79**	**13%**	**$ 432**	**$ 4.45**	**29%**	**$ 400**	**$ 0.35**	**$ 31**	**$ 50,494,483**	
22	**Volatility (95% Confidence Interval) [2]**			**26%**			**58%**					

(1) Based on average residential consumption of 90 Dth per year for the forecast year of 2021
(2) Annual volatility on line 20 is multiplied by two to account for 95% of the historical price outcomes.

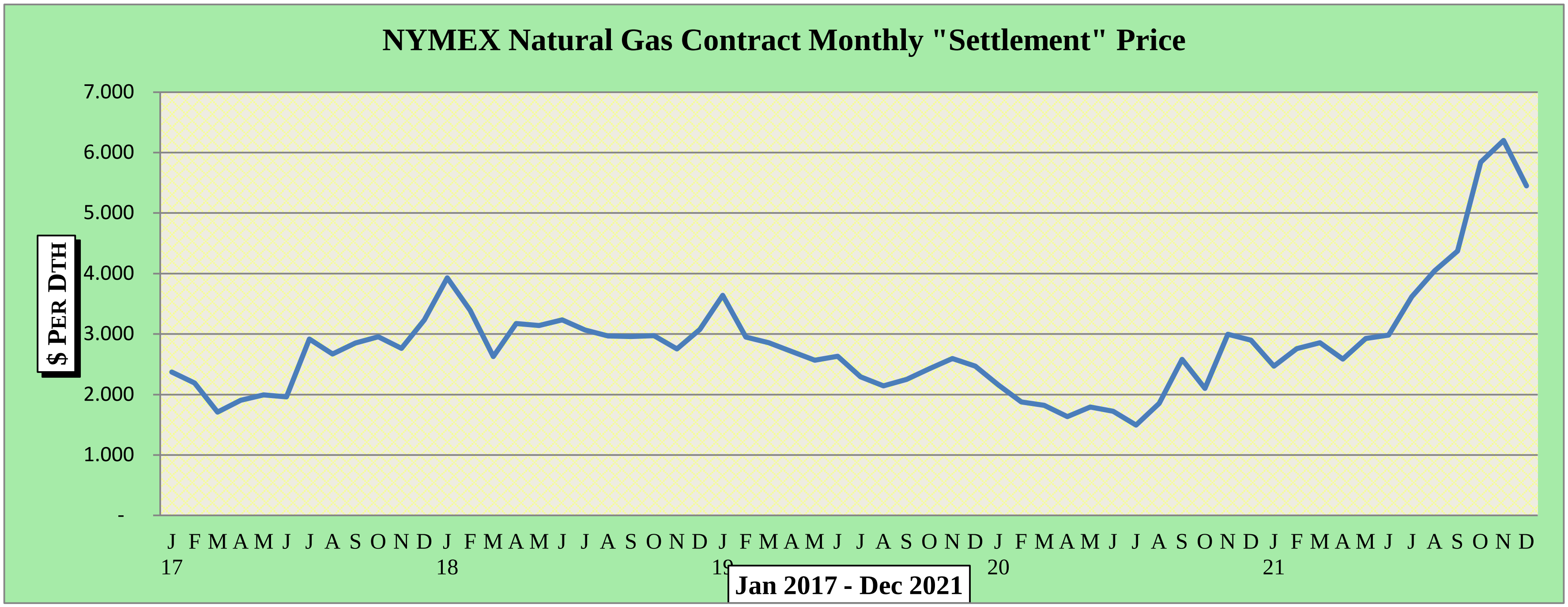
Line	Transaction Month	2022-23 GCR Delivery Period (FPP Coverage) Current Month Transaction	Cumulative Transactions	2023-24 GCR Delivery Period (FPP Coverage) Current Month Transaction	Cumulative Transactions	2024-25 GCR Delivery Period (FPP Coverage) Current Month Transaction	Cumulative Transactions
1	Dec-21		75%		37%		0%
2	Jan-22	0%	75%	3%	40%	3%	3%
3	Feb-22	0%	75%	3%	43%	3%	6%
4	Mar-22	0%	75%	3%	47%	3%	9%
5	Apr-22	0%	75%	3%	50%	3%	13%
6	May-22	0%	75%	3%	53%	3%	16%
7	Jun-22	0%	75%	3%	56%	3%	19%
8	Jul-22	0%	75%	3%	59%	3%	22%
9	Aug-22	0%	75%	3%	62%	3%	25%
10	Sep-22	0%	75%	3%	66%	3%	28%
11	Oct-22	0%	75%	3%	69%	3%	31%
12	Nov-22	0%	75%	3%	72%	3%	34%
13	Dec-22	0%	75%	3%	75%	3%	38%
14	Jan-23	0%	75%	0%	75%	3%	41%
15	Feb-23	0%	75%	0%	75%	3%	44%
16	Mar-23	0%	75%	0%	75%	3%	47%

	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)
	Delivery Year	Delivery Month	deal_num	Volumes	Cost	Rate
1	2022	Apr	8078026	393,000	740,805	1.89
2			8744738	348,000	803,880	2.31
3		May	8078026	406,100	765,499	1.89
4			8744738	359,600	830,676	2.31
5		Jun	8078026	393,000	740,805	1.89
6			8744738	348,000	803,880	2.31
7		Jul	8078026	406,100	765,499	1.89
8			8744738	359,600	830,676	2.31
9		Aug	8078026	406,100	765,499	1.89
10			8744738	359,600	830,676	2.31
11		Sep	8078026	393,000	740,805	1.89
12			8744738	348,000	803,880	2.31
13		Oct	8078026	406,100	765,499	1.89
14			8744738	359,600	830,676	2.31
15		Nov	8700813	339,000	862,755	2.55
16			8749094	342,000	885,780	2.59
17			8870607	345,000	915,975	2.66
18			9151846	423,000	1,620,090	3.83
19			9191158	360,000	1,362,600	3.79
20		Dec	8700813	350,300	891,514	2.55
21			8749094	353,400	915,306	2.59
22			8870607	356,500	946,508	2.66
23			9151846	437,100	1,674,093	3.83
24			9191158	372,000	1,408,020	3.79
25	2023	Jan	8700813	350,300	891,514	2.55
26			8749094	353,400	915,306	2.59
27			8870607	356,500	946,508	2.66
28			9151846	437,100	1,674,093	3.83
29			9191158	372,000	1,408,020	3.79
30		Feb	8700813	316,400	805,238	2.55
31			8749094	319,200	826,728	2.59
32			8870607	322,000	854,910	2.66
33			9151846	394,800	1,512,084	3.83
34			9191158	336,000	1,271,760	3.79
35		Mar	8700813	350,300	891,514	2.55
36			8749094	353,400	915,306	2.59
37			8870607	356,500	946,508	2.66
38			9151846	437,100	1,674,093	3.83
39			9191158	372,000	1,408,020	3.79
40		Apr	9085875	396,000	896,940	2.27
41			9153971	390,000	1,045,200	2.68
42		May	9085875	409,200	926,838	2.27
43			9153971	403,000	1,080,040	2.68
44		Jun	9085875	396,000	896,940	2.27
45			9153971	390,000	1,045,200	2.68
46		Jul	9085875	409,200	926,838	2.27
47			9153971	403,000	1,080,040	2.68
48		Aug	9085875	409,200	926,838	2.27
49			9153971	403,000	1,080,040	2.68
50		Sep	9085875	396,000	896,940	2.27
51			9153971	390,000	1,045,200	2.68
52		Oct	9085875	409,200	926,838	2.27
53			9153971	403,000	1,080,040	2.68
54		Nov	9193513	174,000	544,620	3.13
55			9247513	348,000	1,073,580	3.09
56		Dec	9193513	179,800	562,774	3.13
57			9247513	359,600	1,109,366	3.09
58	2024	Jan	9193513	179,800	562,774	3.13
59			9247513	359,600	1,109,366	3.09
60		Feb	9193513	168,200	526,466	3.13
61			9247513	336,400	1,037,794	3.09
62		Mar	9193513	179,800	562,774	3.13
63			9247513	359,600	1,109,366	3.09
				22,642,700	$ 61,495,805	$ 2.72

NYMEX NATURAL GAS CONTRACT SETTLEMENT HISTORY

Monthly Settlement Price

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YR AVG
2017	3.930	3.391	2.627	3.175	3.142	3.236	3.067	2.969	2.961	2.974	2.752	3.074	3.108
2018	2.738	3.631	2.639	2.691	2.821	2.875	2.996	2.822	2.895	3.021	3.185	4.715	3.086
2019	3.642	2.950	2.855	2.713	2.566	2.633	2.291	2.141	2.251	2.428	2.597	2.470	2.628
2020	2.158	1.877	1.821	1.634	1.794	1.722	1.495	1.854	2.579	2.101	2.996	2.896	2.077
2021	2.467	2.760	2.854	2.586	2.925	2.984	3.617	4.044	4.370	5.841	6.202	5.447	3.841



DTE Gas Company
April 2022 - March 2027 GCR Plan Case
Pipeline Expiring Capacity Outlook

Case No.: U-21064
Exhibit No.: A-30
Witness: E.P. Schiffer

PIPELINE Summary - Expiring Capacity on March 31, 2022

ROW	Expiring Capacity											
				Demand	Commodity		Primary	Primary		Operational	Seasonal	Possible
1	Pipeline	K#	MDQ	Rate	Rate	Fuel %	Receipt Pt.	Delivery Pt.	ROFR	Required	Service	Alternative
2	Viking	AF0081	21,076	0.176196	0.0129	0.14	Emerson	Marshfield	Y	Y	N	N
3	ANR	12248	21,000	0.188351	0.0114	0.54	Marshfield	Menominee	Y	Y	N	N
4	ANR	122247	15,000	0.40994	0.0229	1.79	ANR SW Field	Willow	Y	N	N	Y

ROW	**Current Pipeline - Renew Offer(s)**																	
				Demand	Commodity		Primary	Primary		Operational	Seasonal	Design Day	Liquidity		Annual			
	Pipeline	Term	MDQ	Rate	Rate	Fuel %	Receipt Pt.	Delivery Pt.	ROFR	Required	Service	Required	Ranking	LCD $/Dth	Resv. Fee	PRO'S	CON's	Recommendations
5	Viking	5 Years	21,076	0.176	0.0129	0.14	Emerson	Marshfield	Y	Y	N	Y	F	3.228	$ 964,674	Needed for Oper.	At Emerson2	YES - RENEW @ lower of Neg/Tarriff
6	ANR	5 Years	21,000	0.188	0.0114	0.54	Marshfield	Menominee	Y	Y	N	Y	F	3.228	$ 1,031,220	Needed for Oper.	Subject to Viking Cuts	YES - RENEW @ lower of Neg/Tarriff
7	ANR	3 Years	15,000	0.410	0.0229	1.79	ANR SW Field	Willow	Y	N	N	Y	G	3.313	$ 2,244,420	Field Supply	Are alternative	

ROW	**Alternative - Offer(s) To ANR SW to Willow Capacity**															To ANR SW		
				Demand	Commodity		Primary	Primary		Operational	Seasonal	Design Day	Liquidity		Annual			
	Pipeline	Term	MDQ	Rate	Rate	Fuel %	Receipt Pt.	Delivery Pt.	ROFR	Required	Service	Required	Ranking	LCD $/Dth	Resv. Fee	Variance	PRO'S	CON's
8	Nexus	3 Years	15,000	0.600	0.0057	1.02	Kensingston	Ypsilanti	Y	N	N	Y	P	3.512	$ 3,285,000	$ 1,040,580	None	Liquidity - Higher LCD
9	ANR	3 Years	15,000	0.266	0.0138	0.94	Westrick	Willow	Y	N	N	Y	G	3.220	$ 1,455,840	$ (788,580)	Lower LCD & Emissions	Market Hub
10	ANR	3 Years	15,000	0.266	0.0138	0.94	Shelbyville	Willow	Y	N	N	Y	G	3.240	$ 1,455,840	$ (788,580)	Lower LCD & Emissions	Market Hub
11	PEPL	3 Years	15,000	0.100	0.0057	0.39	Falcon	MCON	Y	N	N	Y	G	3.029	$ 549,143	$ (1,695,278)	Lowest LCD & Emissions	Market Hub - Final Sec 5 Rate
12	Vector	3 Years	15,000	0.140	0	0.71	Alliance	Milford	Y	N	N	Y	F	3.223	$ 766,500	$ (1,477,920)	Lower LCD	Market Hub
13	Vector	3 Years	15,000	0.140	0	0.29	Rover - FIN	Milford	Y	N	N	Y	F	3.091	$ 766,500	$ (1,477,920)	Lower LCD	Liquidity - Market Hub
14	Vector	3 Years	15,000	0.070	0	0	Dawn	Belle	?	N	N	Y	G	3.035	$ 383,250	$ (1,861,170)	Lower LCD	Liquidity Market Hub - BH -Joules
15	Call Option	3 Years	15,000	0.330	0	0	Willow	Willow	?	N	N	Y	G	3.035	$ 1,806,750	$ (437,670)	Lower LCD & Resv Fees	MCCG

100% LF Least Cost Delivered - Analysis by Pipeline Supplies - 3 Years April 2022 thru March 2025

Portfolio as
12/15/2021 9:44

Row	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
1	Item - Routes	PEPL Falcon(Rover)	Vector Rover	ANR Westrick(Rover)	Vector Alliance	ANR Shelbyville	ANR SW	Nexus - Kensington Only	Dawn Backhaul Vector	Call Options - 10 Day
2	MDQ (Dth/Day)	15,000	15,000	15,000	15,000	15,000	15,000	15,000		
3	ACQ (Dth)								-	-
4										
5	Receipt Point VC:									
6	**NYMEX AveA22M25**	$ 3.0592	$ 3.0592	$ 3.0592	$ 3.0592	$ 3.0592	$ 3.0592	$ 3.0592	$ 3.0592	$ 3.0592
7	Basis AveA22M25	$ (0.1476)	$ (0.1176)	$ (0.1476)	$ 0.0012	$ (0.1276)	$ (0.2301)	$ (0.1589)	$ (0.1005)	$ (0.1589)
8	Price AveA22M25	$ 2.9115	$ 2.9415	$ 2.9115	$ 3.0603	$ 2.9315	$ 2.8290	$ 2.8753	$ 2.9587	$ 2.9503
9										
10	First Pipe VC:									
11	Fuel Rate	0.39%	0.29%	0.97%	0.71%	0.97%	1.79%	1.02%	0.200%	0.000%
12	Fuel Cost	$ 0.0114	$ 0.0086	$ 0.0285	$ 0.0219	$ 0.0287	$ 0.0516	$ 0.0296	$ 0.0059	$ -
13	Tran. Com. Rate	$ 0.0057	$ 0.0013	$ 0.0138	$ 0.0013	$ 0.0138	$ 0.0229	$ 0.0070	$ -	$ -
14	First Pipe VC	$ 0.0171	$ 0.0099	$ 0.0423	$ 0.0232	$ 0.0425	$ 0.0745	$ 0.0366	$ 0.0059	$ -
15										
16	Second Pipe VC:									
17	Fuel Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%
18	Fuel Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Tran. Com. Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
20	Second Pipe VC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21										
22	Third Pipe VC:									
23	Fuel Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Fuel Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Tran. Com. Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Third Pipe VC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27										
28	Total Transport VC	$ 0.0171	$ 0.0099	$ 0.0423	$ 0.0232	$ 0.0425	$ 0.0745	$ 0.0366	$ 0.0059	$ -
29										
30	Variable COG Delivered	$ 2.9286	$ 2.9514	$ 2.9538	$ 3.0835	$ 2.9740	$ 2.9035	$ 2.9119	$ 2.9646	$ 2.9503
31										
32	Reservation Rate @ 100%LF									
33	First Pipe	$ **0.1003**	$ **0.1399**	$ **0.2659**	$ **0.1399**	$ **0.2659**	$ **0.4099**	$ **0.6000**	$ **0.0700**	$ **0.3333**
34	Second Pipe									
35	Third Pipe									
36	Total Reservation @ 100%LF	**$ 0.1003**	**$ 0.1399**	**$ 0.2659**	**$ 0.1399**	**$ 0.2659**	**$ 0.4099**	**$ 0.6000**	**$ 0.0700**	**$ 0.3333**
37										
38										
39	Total Transportation Rate@100% LF									
40										
41	Average COG Delivered	**$ 3.0289**	**$ 3.0913**	**$ 3.2198**	**$ 3.2234**	**$ 3.2399**	**$ 3.3134**	**$ 3.5119**	**$ 3.0346**	**$ 3.2836**
42	**Least Cost Delivered Ranking**	**1**	**2**	**3**	**4**	**5**	**6**	**7**		

TEAL/NEXUS Cost Analysis - 100% LF 1/5/2021

Portfolio as of 5/1/2021

Basis Source: DTE ERM

1 YRS - N22O23

Row		1 Years - N22O23 Col 1	Col 2
1	Item - Routes	NEXUS/TEAL Clarington @ $.695+$.15	NEXUS Kensington @ $.695
2	MDQ (MDth/Day)	37,500	37,500
3	ACQ (MDth)	5,662,500	5,662,500
4			
6	NYMEX - Ave	$ 2.6218	$ 2.6218
7	Ave Basis - Ave	$ (0.742)	$ (0.443)
8	Plus Premium	$ 0.10	$ 0.18
9	Price	$ 1.9795	$ 2.3589
10			
11	First Pipe VC:		
12	Fuel Rate	1.06%	1.02%
13	Fuel Cost	$ 0.0212	$ 0.0243
14	Tran. Com. Rate	$ -	$ -
15	First Pipe VC	$ 0.0212	$ 0.0243
16			
17	Second Pipe VC:		
18	Fuel Rate	1.02%	0.00%
19	Fuel Cost	$ 0.0206	$ -
20	Tran. Com. Rate		
21	Second Pipe VC	$ 0.0206	$ -
22			
23	Third Pipe VC:		
24	Fuel Rate	0.00%	0.00%
25	Fuel Cost	$ -	$ -
26	Tran. Com. Rate	$ -	$ -
27	Third Pipe VC	$ -	$ -
28			
29	Total Transport VC	$ 0.0418	$ 0.0243
30			
31	Variable COG Delivered	$ 2.0214	$ 2.3832
32	Variable Cost Ranking Only	2	3
33			
34	Reservation Rate @ 100%LF		
35	First Pipe	$ 0.6950	$ 0.6950
36	Second Pipe	$ 0.1500	
37	Third Pipe		
38	Total Transportation Rate@100% LF	$ 0.8450	$ 0.6950
39			
40	Capacity Release Credits		
41			
42	Average COG Delivered	**$ 2.866**	**$ 3.078**
43	Least Cost Delivered Ranking	1	2
44			
45	**Variance to Nexus Kensington**	**$ (0.212)**	
46			
47	**Variance to Teal Clarington**		**$ 0.212**
48			
49	**Annual Saving to Nexus Kensington - N22thruO23**	**$ 2,899,806.45**	
50	2 Year Contract	5,799,613	

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE Gas Company for approval of a	)	
Gas Cost Recovery Plan, 5-year Forecast	)	Case No. U-21064
and Monthly GCR Factor for the 12 months	)	
ending March 31, 2023	)	
______________________________________	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

LUCIAN BRATU

DTE GAS COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF LUCIAN BRATU

Line No.

Q1. What is your name and business address?

A1. My name is Lucian Bratu. My business address is One Energy Plaza, Detroit, Michigan 48226.

Q2. By whom are you employed and in what capacity?

A2. I am employed by DTE Gas Company (DTE Gas or Company) as a Senior Gas Supply & Planning Analyst in Gas Supply and Planning.

Q3. What is your educational background?

A3. I earned a Bachelor of Electromechanical Engineering Degree from Polytechnic University of Bucharest and a Master's Degree in Business Administration from University of Windsor.

Q4. Do you hold any professional designations?

A4. I earned a Professional Engineer certification from Professional Engineers Ontario (PEO), the licensing and regulation body for professional engineers in Ontario, Canada.

Q5. Have you had other applicable training?

A5. I have completed The Oxford Princeton Programme's "Overview of the North American Natural Gas Industry" and "North American Natural Gas Transportation and Storage" training.

Q6. What is your relevant business experience?

A6. After an engineering career in the automotive industry, in 2009 I was hired full time by Union Gas Limited, one of the two major natural gas distribution companies in Ontario, Canada at that time where I held positions of increased responsibility in Finance, Operations and Business Development. I was hired by DTE Energy in August 2015 as a full time Senior Strategist in the Emergency Preparedness & Response department of DTE Electric Company (DTE Electric) where I implemented engineering solutions and process changes to reduce power outage duration and restoration costs. In August 2017, I accepted a position in the Vegetation Management department where I designed and implemented an herbicide treatment program to control the vegetation in the right-of-way more effectively and at a reduced cost. In July 2018, I accepted a position with DTE Gas as a Senior Gas Supply & Planning Analyst in the Gas Supply and Planning Department.

Q7. What are your responsibilities as a Senior Gas Supply and Planning Analyst in Gas Supply and Planning?

A7. I am responsible for the planning of natural gas supplies necessary to reliably meet the requirements of DTE Gas's customers.

Q8. Have you previously testified or submitted testimony in any regulatory proceedings?

A8. Yes. I have sponsored testimony before the MPSC in Case Nos. U-20210, U-20235 U-20236, U-20543 and U-20544. I also adopted testimony in MPSC Case No. U-20076.

Purpose of Testimony

Q9. What is the purpose of your testimony in this proceeding?

A9. In my testimony, I will describe DTE Gas's operational plan for the 5-year period April 1, 2022 through March 31, 2027 and I will detail the operational plan year April 1, 2022 to March 31, 2023. My testimony will support DTE Gas's operational planning decisions as being reasonable and prudent and will cover the following topics:

1. **Normal Weather Operating Plan** – How the planned supply purchase requirements are developed for normal weather.
2. **Storage Plan** –Total storage field cyclable capacity of 135.1 Bcf has remained unchanged.
3. **GCR/GCC Storage Allocation** – The allocation of 71.9 Bcf of cyclable storage capacity to Gas Cost Recovery (GCR) and Gas Customer Choice (GCC) customers has remained unchanged.
4. **GCC Plan** – DTE Gas administers the GCC program in accordance with DTE Gas's GCC tariff.
5. **Design Day and Minimum Storage Balances –** How DTE Gas plans to meet projected peak day requirements.
6. **Colder than Normal Protection** – How the planned supply purchase requirements are adjusted for colder than normal (CTN) weather and that CTN exposure has increased from last year's GCR Plan case by 3.2 Bcf, from 24.2 Bcf to 27.4 Bcf.
7. **Warmer than Normal Weather Operating Plan** - How the planned supply purchase requirements are adjusted for warmer than normal weather.

8. **Other Operational Changes** - During the GCR year, factors influencing DTE Gas's operations are continually changing. Refinements to the plan will be based on current and projected market and operational conditions.
9. **Future Outlook** - There are no indications at this time that the operating plan for April 2023 through March 2027 will have any significant changes from the April 2022 through March 2023 operating plan.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes. I am supporting the following exhibits:

Exhibit	Description
A-13	Normal Weather Source and Disposition
A-14	Storage Capacity and Utilization
A-15	Peak Day Supply Mix
A-16	Colder-Than-Normal Storage Balances
A-17	Colder-Than-Normal Weather Source and Disposition (CTN)
A-18	Warmer-Than-Normal Weather Source and Disposition (WTN)
A-33	Reliability Improvement – Temporary Alternatives for Belle River Dehydration Unit Failure

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.

OPERATIONAL PLANNING

Q12. What data was used to develop the operating plan?

A12. DTE Gas develops its operating plan from four primary sources. These sources are:

1) market requirements as supported by Company Witness Mr. Chapel

2) peak winter day flowing supply
3) minimum winter storage balances developed in conjunction with peak day operations
4) CTN exposures

I provide support for the last three sources of data in my testimony.

Q13. Are there factors other than the four discussed above that are important to the development of DTE Gas's operating plan and supply purchasing pattern?

A13. Yes. In addition to reliably meeting customers' requirements, protecting for peak day operations, and CTN exposures, other factors that influence the supply purchasing pattern include the GCC supply delivery pattern, achieving target storage balances at the end of the injection season and at the end of the withdrawal season, storage operations, WTN exposures, and the operational constraints of DTE Gas's system.

NORMAL WEATHER OPERATING PLAN

Q14. What is the monthly supply volume that DTE Gas plans to purchase under normal weather conditions?

A14. The monthly supply volume that DTE Gas plans to purchase under normal weather conditions is identified on Exhibit A-13. This exhibit illustrates DTE Gas's normal weather operating plan based on the normal weather market requirements projected by Company Witness Chapel. As described by Company Witness Chapel, in his testimony at page GHC-6, DTE Gas utilizes a 15-year normal weather pattern to project customers' requirements. He also describes how DTE Gas assumes normal weather to be expected and it's use of 15-year normal heating degree-days (HDDs)

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for the operating plan April 2022 through March 2027, at page GHC-6 of his direct testimony. Heating degree-day (HDD) is a measurement meant to quantify the demand of energy needed to heat a building and is calculated as the number of degrees that the average daily temperature is lower than the 65° F.

Q15. Does DTE Gas expect that its actual monthly supply purchases will match those contained in Exhibit A-13?

A15. No, it does not. There are numerous factors that can influence monthly supply purchases and cause it to deviate from the plan. It is highly unlikely that DTE Gas will experience normal weather evenly throughout the year for the entire period considered in the plan illustrated in Exhibit A-13. Weather patterns tend to occur unevenly such that even if actual weather experienced was on average normal on an annual basis, the actual storage balances and monthly purchases would differ from those contained in DTE Gas's normal weather plan based on when during the year the weather deviates from normal. Therefore, on at least a monthly basis during the operating year, DTE Gas refines its planned supply volumes based on actual and projected market requirements, operational conditions including weather variations, actual storage balances, GCC migration, customer count, and changes in customer usage such as conservation. DTE Gas also updates its planned purchases during the plan year due to routine updated projections of lost gas, company use, gas in kind, and GCC enrollment levels. In addition, the Company updates the market forecast at least once during the plan year based on updated customer count and usage factors assumptions.

STORAGE PLAN

Q16. Where does DTE Gas secure its gas storage service?

A16. DTE Gas uses its own facilities for gas storage. DTE Gas owns and operates four gas storage fields in Michigan. The fields are located in different parts of the state and each storage field has unique operating characteristics. The Six Lakes (Taggart) field is located in central Michigan and is operated in a base load manner. The other three fields, Belle River, Columbus, and West Columbus are located on the eastside of the state in St. Clair County. Belle River and West Columbus are peaking fields, while Columbus is considered a base load field.

Q17. What is the difference between a base load storage field and a peaking storage field?

A17. The primary difference is the time required to inject or withdraw the full working volumes from the storage field. A base load field typically requires the entire summer injection season to refill and the entire winter withdrawal season to fully remove gas from storage. By contrast, peak storage fields equipped with the necessary compression and facilities, are capable of withdrawing gas at a much faster rate to meet peak demands than base load fields. The time to fill and empty peak storage fields is considerably shorter, with the actual timing dependent upon the characteristics of each field.

Q18. What is the capacity of DTE Gas's storage fields?

A18. DTE Gas's current aggregate cyclable working storage capacity is 135.1 Bcf, and has remained unchanged (Exhibit A-14, line 14, column (d)). Exhibit A-14 depicts DTE

Gas's cyclable working storage capacity and its utilization of total capacity by customer group.

Q19. Are there any factors that could affect this cyclable storage capacity of 135.1 Bcf?

A19. Yes. DTE Gas may actually inject or withdraw more or less than the 135.1 Bcf of current aggregate cyclable working storage gas. The maximum capacity may actually be higher or lower depending on numerous operating conditions and design assumptions. The maximum of this operating range may be constrained by system operating conditions, storage field performance and reservoir characteristics. For example, operating a base load field at the high end of its operating range could result in gas migration to the outer limits of the reservoir increasing the likelihood that a portion of the previously injected storage gas from that field may not be recoverable. In addition, during periods of warmer than normal weather, withdrawals from the base load storage field may be reduced. These withdrawals will be difficult to make up at a later time due to such constraints as available compression and maximum operating pressures. Other factors that affect the cycling capability of the storage fields include performance of DTE Gas's transmission systems, compressor stations, actual weather patterns, the duration of cold/warm weather, actual temperatures, supply deliveries, loads experienced, and the particular injection and withdrawal patterns of each storage field. System constraints and uneven weather patterns impact storage operations and must be taken into consideration in planning for the safe and efficient operation of the system.

Q20. How do storage operations affect the supply plan?

A20. Storage allows DTE Gas to buy steady daily volumes of gas supply. Changes in daily market volumes are balanced by storage withdrawals or injections. Storage withdrawals are most pronounced during the winter heating season when market requirements exceed supply. By contrast, injections are predominant during the summer when market requirements are low. Storage operations are especially critical during the deep winter months to protect for peak day operations and CTN exposures. DTE Gas designed its supply plan to meet the required minimum storage inventory balances to ensure specific storage withdrawal rates necessary to meet peak day sendout in combination with flowing supplies. Storage holds a portion of the CTN protection volumes and must be managed on both a seasonal and daily basis. Another critical time for storage operations occurs during WTN conditions at the end of the injection season (October) and at the beginning of the winter withdrawal season in November, when storage fields are near maximum capacity. Facility enhancement projects or other system constraints such as storage field pressures, available compression capacity, available storage field injection or withdrawal capability, and unforeseen pipeline integrity compliance could also affect the supply plan.

GCR/GCC STORAGE ALLOCATION

Q21. Does DTE Gas target a specific storage balance for GCR and GCC customers at the end of the storage injection season?

A21. Yes. DTE Gas plans for a specific storage balance on October 31 of each year, which is the end of the injection season. The targeted storage level, in addition to winter flowing supply, allows DTE Gas to meet normal winter market requirements and maintain planned minimum storage balances. The targeted storage balance includes the colder-than-normal protection (CTNP) gas held in storage.

Q22. What is the targeted storage balance for GCR and GCC customers by October 31, 2022?

A22. Total working gas in storage by October 31 for both GCR and GCC customers is planned at 70.1 Bcf regardless of the mix between GCR and GCC. See Exhibit A-13, page 6 of 10, line 7, column (f).

Q23. Has the targeted storage balance for GCR and GCC customers on October 31, 2022 changed since the 2021-2022 Plan Case?

A23. No, the target storage balance on October 31 for GCR and GCC combined is 70.1 Bcf, unchanged from the 2022-2023 Plan Case.

Q24. How much cyclable storage capacity does DTE Gas propose to allocate for use by GCR and GCC customers in 2022-2023?

A24. For 2022-2023, DTE Gas proposes to continue to allocate 71.9 Bcf of cyclable storage capacity to GCR/GCC customers (Exhibit A-14, line 16, column (d)). The details of DTE Gas's storage utilization are outlined in Exhibit A-14, lines 9-16. As detailed in this Exhibit, the 71.9 Bcf of storage capacity for 2022-2023 is comprised of 66.9 Bcf for both Normal and CTN working gas utilization (line 10), and 5 Bcf of WTN/contingency space (line 11), totaling 71.9 Bcf (line 16).

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Q25. Does this 71.9 Bcf storage allocation for 2022-2023 GCR Plan Year represent a change from the amount that DTE Gas allocated to GCR/GCC customers for the 2021-2022 GCR Plan Year?

A25. No. For the 2021-2022 GCR Plan Year, DTE Gas implemented a GCR/GCC cyclable storage allocation volume of 71.9 Bcf. This is also the same 71.9 Bcf of cyclable storage allocation that DTE Gas implemented for the prior 2020-2021 GCR Plan Year. Additionally, this is the same 71.9 Bcf of cyclable storage allocation ordered by the Commission on December 20, 2012, in the DTE Gas Rate Case Settlement in Case No. U-16999.

GCC PLAN

Q26. What are the specific supply parameters for the GCC program?

A26. Each month, based on a supplier's enrollment of customers, DTE Gas will provide each supplier with a daily flow volume that identifies the daily delivery requirement normally using the 1/365th +/- 10% of total normal weather annual GCC customer usage. Deliveries to the customer continue to be DTE Gas's responsibility. Operationally, DTE Gas will operate and deliver gas to the GCC customers as if they were DTE Gas sales customers.

Q27. How does DTE Gas manage its supply strategy in conjunction with the GCC program?

A27. The annual GCC volume reflected in the Plan is approximately 21.8 Bcf (Exhibit A-13, page 1 of 10, line 13, column (g)), which represents 124,088 customers. Because DTE Gas's GCC tariff identifies it as the supplier of last resort (SOLR), DTE Gas faces uncertainty in the event of a supplier defaulting or a customer returning to sales service. DTE Gas continually monitors the number of customers and their associated flow requirement moving between the GCC program and GCR sales. DTE Gas adjusts its final monthly purchases to reflect the volumes remaining under GCR sales. This approach allows DTE Gas to maintain sufficient daily winter flowing supply to meet the needs of its customers and a sufficient daily summer flowing supply to meet the volume requirements to fill storage sufficiently to meet operational plans.

DESIGN DAY AND MINIMUM STORAGE BALANCES

Q28. What assumptions does System Planning use when modeling Design Day operations for DTE Gas system?

A28. For operating conditions, system requirements on a Design Day assume that minimum storage balances, statewide coldest record temperatures, maximum midstream withdrawal rates, and high EUT withdrawal rates will occur simultaneously. Supply from a single storage field on the DTE Gas system can account for up to 35% of total system demand on a Design Day. Gas that is withdrawn from storage must flow through processing equipment to remove excess sediment and moisture so that it complies with pipeline quality standards, meaning that the gas is of the quality that it can be delivered to and utilized by our customers. In the current Design Day plan, processing equipment at critical storage fields are forecasted to be operating at their maximum capacity. Redundant units do not exist for these facilities at all storage fields.

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Q29. Are there contingencies in place to address operational challenges on a Design Day?

A29. DTE Gas periodically assesses the risks to the system and have contingencies in place to address operational challenges on a Design Day even as there is no imminent risk to the system. The following contingencies are included in the Design Day plan:

a. **Coverage through redundant lines**

Coverage through redundant lines help alleviate transport constraints that may occur when moving gas from one point to another on the transmission system. The primary transmission system experiences the highest throughput and is therefore the most critical part of the transmission system. It provides access to most of the large pipeline interconnects, storage, and production facilities on DTE Gas's system. It directly feeds the distribution systems supplying Southeast Michigan market areas and secondary transmission systems, which serve greater Michigan regions.

The DTE Gas primary transmission system transports gas to up to 70% of the total DTE Gas market. Almost every transport path within this system is comprised of redundant lines. Redundant lines serve as a duplicate feed to critical areas of the system and run in parallel to one another. If service is lost from one of these lines, gas can be rerouted through the alternate line.

b. **Reserve Compression**

Compression assets in critical locations are held in reserve to protect for unit outages.

c. **Coverage for temperature variance**

Design Day temperatures are derived by identifying the lowest daily mean temperatures experienced in the last sixty years in each of the sixteen separate regions throughout DTE Gas's service territory. The temperatures are applied coincidentally for added conservatism in the Design Day load calculation. Coincidental application means that we presume that the coldest temperature in each of the sixteen regions occurs on the same day. Temperatures are updated every time a new record is set, and the Company reviews inputs annually.

d. **Storage Deliverability**

In the event of storage equipment failure, DTE Gas would maximize other storage fields to their full capabilities. Stations could be reconfigured so that unprocessed storage gas could blend with processed gas from other fields to achieve the lowest moisture level possible under those conditions.

Q30. What flowing supplies will DTE Gas need to meet projected peak-day requirements?

A30. Total end-of-month peak-day requirements are identified on line 26 of Exhibit A-15. These requirements are provided by Company Witness Chapel (Exhibit A-5, page 2 of 2, line 6). For the 2022-2023 Plan Year, DTE Gas plans to hold 380 MMcf/d (400 MDth/day capacity assuming 1.052 MMBtu/Mcf heating value) of firm transportation contracts for the winter operating season to meet requirements for normal weather, colder than normal weather, design day, and SOLR. DTE Gas projects it will flow approximately 334 MMcf/d of GCR supply for January through March 2023, Exhibit A-15, line 2, to satisfy the projected normal winter requirements. Consequently, the amount of GCR flowing gas supply necessary to meet a design day will be approximately 413 MMcf/d. This volume is approximately 79 MMcf/d above the normal GCR flowing supplies, which may be purchased using a combination of:

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1) 66 MMcf/d of DTE Gas's remaining recallable firm transportation either on the first of month or spot day market, and
2) Citygate purchases, depending on the availability of gas in storage at the time. The remainder of the gas supply to serve January through March peak days will come from DTE Gas's storage.

Q31. Will DTE Gas utilize storage to satisfy peak day requirements?

A31. Yes. Approximately 66% of DTE Gas's supply on a January 2023 peak day will be provided from storage. Deliveries out of storage include deliveries to GCR, GCC, EUT, including Exelon. This percentage does not include deliveries for midstream services.

Q32. What are DTE Gas's planned colder-than-normal storage balances?

A32. The amount of DTE Gas's planned total storage balances for the CTN weather exposure is identified in Exhibit A-17. The minimum total balance as shown in Exhibit A-16, line 5, for January, February and March, is the planned quantity to meet the peak day deliveries.

Q33. Are DTE Gas's planned colder-than-normal storage balances inclusive of third-party gas in storage?

A33. Yes. Lines 2 and 3 of Exhibit A-16 represent estimated third-party storage balances at the end of January, February and March in 2023. During the operating year, the mix of the planned end-of-month volumes of DTE Gas and third-party customers' gas is constantly adjusted in response to weather and third-party activity. DTE Gas may be able to rely on additional third-party gas in inventory above what is included

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in Exhibit A-16, lines 2 through 4, and reduce winter purchases while maintaining peak-day minimum-storage balances necessary for storage deliverability. In any event, DTE Gas will maintain the peak-day minimum-storage balances for the 2022-2023 GCR plan year to provide the necessary peak-day withdrawal requirements from storage.

Q34. Are there other factors that DTE Gas considers when planning how to meet projected peak-day requirements?

A34. Yes. Besides analyzing the deliverability requirements and determining the pipeline supply and storage deliveries necessary to meet projected peak-day requirements, DTE Gas also develops contingency plans to address potential operations challenges, including failure of different key components of DTE Gas's system.

Q35. Following extreme weather events, has DTE Gas adopted measures to improve its system reliability, mitigate adverse conditions and lower the risk of gas shortages?

A35. Yes. For instance, after the Polar Vortex winter of 2013-2014, DTE Gas adopted a number of short term and long-term measures to address potential supply shortage and mitigate the risk of curtailments should a similar weather event occur.

The interim solutions were:

1. A 4.8 Bcf parking service was purchased in the 2014-2015 GCR year in MPSC Case No. U-17332-R to secure the necessary winter deliverability requirements for GCR and GCC customers.

2. A 2.1 Bcf parking service was purchased in the 2015-2016 GCR Plan, MPSC Case No. U-17691, to secure the necessary winter deliverability requirements for GCR and GCC customers.

To permanently improve system performance and reliability in the long term, DTE Gas:

1. Made capital improvements to the Columbus group storage fields and surface facilities. The Company drilled three new horizontal wells in the Columbus storage field, added a liquid extraction unit, improved liquid handling of existing filter /separator, and added a dehydration unit at the Columbus Compressor Station to enhance storage deliverability. The Commission approved these improvements in its December 2016 order in MPSC Case No. U-17999.
2. Enhanced the Belle River storage facility including a combination of additional compression and additional retained non-cyclable base gas. The Company constructed two new turbine driven compressor units and injected 1.9 Bcf of base gas at the Belle River storage field, as ordered in MPSC Case No. U-17999.

Q36. Was there a reliability assessment of DTE Gas's system performed following the released by the MPSC (Michigan Public Services Commission) of its Statewide Energy Assessment (SEA) report in September 2019?

A36. Yes. In the months following the SEA release DTE Gas performed an assessment and created a plan to improve DTE Gas's system reliability.

Q37. Did DTE Gas extend its collaboration with other Michigan utilities to increase the reliability of natural gas services to customers state-wide, as recommended by the Statewide Energy Assessment (SEA) report?

A37. Yes. DTE Gas and Consumers Energy entered into a Memorandum Of Understanding (MOU) to provide each other mutual assistance in case of emergency.

Q38. Were there any findings of DTE Gas's reliability assessment that impact future GCR Plans?

A38. Yes, a possible failure of the dehydration unit at Belle River storage field was identified as the potentially critical event that would impact DTE Gas' ability to serve its customers.

Q39. Is GCR/GCC mitigating the entire potential exposure that would result from a failure of the dehydration unit at Belle River storage field?

A39. No. The GCR/GCC customer group was allocated its share of the deliverability exposure that was directly attributable to a possible failure of the dehydration equipment at Belle River storage field based on its respective share of design day storage withdrawal requirements each month.

Q40. What is the evaluated GCR/GCC deliverability exposure attributable to a possible failure of the dehydration equipment at Belle River storage field?

A40. The evaluated GCR/GCC deliverability exposure attributable to a possible failure of the dehydration equipment at Belle River storage field is 318 MMcf/d for January 2023 and 306 MMcf/d for February 2023.

Line No.

Q41. How will the deliverability exposures described above be mitigated for winter 2022-23?

A41. Storage deliverability is an integral part of DTE Gas' supply portfolio.

The deliverability exposures for winter 2022-23 described above might be mitigated with a Gas Supply Physical Call Option for 250,000 Dth/d, or 237.6 MMcf/d for any 10 days in January 2023 and February 2023.

Q42. Is the Gas Supply Physical Call Option contract new for the 2022-2023 gas year?

A42. No. The Gas Supply Physical Call Option was purchased in September 2020 for a two year term covering 2020-2021 and 2021-2022 gas years with the possibility to extend it for another year if both parties mutually agree.

Q43. Why is the mitigated volume lower than the deliverability exposure for January and February?

A43. In the event that a failure with the dehydration unit at Belle River occurred, the Gas Supply Physical Call Option could mitigate at least 75% of the supply loss by the outage. The remaining 25% could be procured on the spot market. DTE Gas believes this is a prudent approach to ensure system reliability in the event of a failure of the dehydration unit at Belle River storage field.

Q44. What strategic alternatives were evaluated to improve system reliability?

A44. Five fundamental strategic alternatives were identified to improve system reliability by mitigating the GCR/GCC deliverability exposure described above. A team of representatives from Regulatory, Legal, Controllers Office, System Planning, Marketing and Gas Supply worked together to identify and analyze these alternatives. The alternatives were as follows:

a) Purchasing just-in-time gas when needed
b) Increasing base gas inventory thus enhancing storage fields deliverability
c) Purchasing gas in November - January to increase storage balances over the winter thus enhancing storage fields deliverability
d) Buying a deliverability service through third party parking of gas in the DTE Gas storage fields thus enhancing storage fields deliverability
e) Buying a Gas Supply Physical Call Option service that would be utilized when and as needed to replace storage withdrawal shortfall volumes

All fundamental strategic alternatives and its various iterations are identified in Exhibit A-33.

Q45. Please describe the strategic alternative of just-in-time gas purchases as mentioned above.

A45. The strategic alternative of purchasing gas just-in-time is a reactive solution that consists of purchasing the GCR/GCC volume of gas needed to ensure that natural gas service to GCR/GCC customers is maintained if the dehydration unit fails. The GCR/GCC gas will be purchased on the daily market only when the natural gas service disruption is imminent and only for the volume needed at that time. The maximum volume of GCR/GCC gas purchased just-in-time if Peak Day weather would occur during the winter is approximately 0.2 Bcf per day. This strategic alternative was rejected because it has the highest risk as the required volume might not be available when needed.

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Q46. Please describe the strategic alternative of increasing base gas inventory as mentioned above.

A46. The strategic alternative of increasing the base gas inventory consists of purchasing 9.4 Bcf of GCR/GCC non-cyclable working gas to increase the base gas inventory which in turn would increase storage deliverability. The gas would be purchased during the summer to hold in inventory through the entire gas year. This strategic alternative was rejected because of the high costs associated with it and lack of flexibility given the volume of gas needed.

Q47. Please describe the strategic alternative of purchasing gas to hold in storage until summer as mentioned above.

A47. The strategic alternative of purchasing gas to hold in storage until summer consists of GCR/GCC purchasing non-cyclable working gas to increase winter deliverability and mitigate the January, February and March deliverability exposure. The gas would be purchased during or prior to January and would be backed off gas purchases during the summer for the following gas year. The GCR/GCC volume needed is between 7.3 Bcf and 9.4 Bcf depending on the timing of gas purchases. This strategic alternative was rejected because of the high costs associated with it and lack of flexibility given the volume of gas needed.

Q48. Please describe the strategic alternative of buying a deliverability service through third party parking of gas as mentioned above.

A48. A park is a transaction that consists of DTE Gas paying a third party to park (i.e. store) gas in our storage facility for a specified amount of time. A contract is structured that defines how much gas is received, the price, when the gas will be parked (i.e. stored) and when the third party can withdraw their gas from our storage facility. Contract terms and conditions are defined between DTE Gas and the third party that the gas is procured from. The parked volume needed is between 7.3 Bcf and 9.4 Bcf depending on the timing when the gas will be delivered to DTE Gas to be parked (i.e. stored). This strategic alternative was rejected because of the high costs associated with it and lack of flexibility given the volume of gas needed.

Q49. Please describe the strategic alternative of buying a Gas Supply Physical Call Option service as mentioned above.

A49. A Gas Supply Physical Call Option is a transaction that functions much like an insurance policy: DTE Gas is paying a third party to "stand-by" and be ready to deliver up to a maximum daily quantity of gas to us at citygate when DTE Gas "calls on it" (i.e. DTE Gas requires it), for a limited number of days. DTE Gas can call for any quantity of gas up to the contracted maximum daily quantity on any given day during the agreed upon months up to the maximum number of days contracted. A nominal fixed fee is paid to the third party regardless of whether DTE Gas requests gas delivery or not. If the call option is executed, DTE will typically pay the market price plus a premium. This alternative was selected to improve system reliability because of its cost effectiveness, high reliability and high flexibility.

Q50. Which alternative did the company determine was the most reasonable and prudent?

A50. For the reasons described above, the Company determined that the Gas Supply Physical Call Option was the most reasonable and prudent.

Line No.

Q51. What are the terms of the Gas Supply Physical Call Option?

A51. DTE Gas purchased a Gas Supply Physical Call Option for 237.6 MMcf/d for any 10 days in January - February 2021, any 10 days in January - February 2022 and a renewal clause for any 10 days in January - February 2023. If DTE needs additional supply, it can execute the option for any quantity of gas up to 237.6 MMcf/d to be delivered by the supplier to DTE Gas during any 10 days of January and February (does not have to be consecutive days). DTE Gas pays a fixed $250,000 Demand Fee each year as a nominal premium which is not impacted by whether the gas is called for delivery or not. If the Gas Supply Physical Call Option is executed, DTE Gas will pay the MichCon gas price on the delivery day and a premium between $0.80 - $2.00 per Dth, depending on the quantity of gas delivered.

Q52. What costs associated with the Gas Supply Physical Call Option is DTE Gas asking to recover in this case?

A52. In this Plan filing, DTE Gas is asking to recover the Gas Supply Physical Call Option costs associated with the January - February 2023 term. The cost associated with years outside of the scope of this Plan are discussed in the filings relevant to those time periods.

Q53. Why did the Company believe it was reasonable and prudent to purchase a 237.6 MMcf/d Gas Supply Physical Call Option to improve its system reliability?

A53. The purchase of 237.6 MMcf/d Gas Supply Physical Call Option can solve a significant portion of the storage deliverability exposure allocated to GCR as described above and it was the most flexible, cost effective and lower risk alternative.

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Q54. Is the 237.6 MMcf/d Gas Supply Physical Call Option a long-term solution?

A54. No, the 237.6 MMcf/d Gas Supply Physical Call Option is a short-term interim solution while long term solutions are being identified and analyzed.

COLDER-THAN-NORMAL PROTECTION

Q55. What is a colder-than-normal protection (CTNP) volume?

A55. CTNP is a calculated volume of gas that allows DTE Gas to maintain the minimum storage balances identified in Exhibit A-16, line 5, should colder-than-normal weather persist over a sustained period, or otherwise higher than forecasted sendout occurs. The CTNP volume consists of storage gas and, if necessary, incremental purchases.

Q56. What is DTE Gas's planned maximum winter CTN exposure?

A56. DTE Gas's planned maximum winter CTN exposure for the 2022-2023 GCR plan year represents the incremental customer usage that may occur in the event DTE Gas were to again experience the coldest winter in its history. DTE Gas calculates its maximum winter CTN exposure using the actual monthly Heating Degree Days (HDD) experienced in 2013-2014, which is the coldest November through March winter period since 1951. These actual monthly HDDs from 2013-2014 were then applied to the forecasting model, which is more fully described by Company Witness Chapel, to calculate the winter markets if such weather were to occur now. The maximum CTN exposure represents the difference between the planned normal winter requirements and the maximum CTN requirements. The total colder-than-normal exposure volume for all GCC and GCR customers is 27.4 Bcf. Based on numerous prior Company proposals and Commission approvals, DTE Gas continues to prepare a CTN plan based on the coldest historical period since 1951 to make certain that the Company will be prepared and able to continue to provide reliable gas supply for its customers should it experience a level of severe cold weather that it has experienced in the past. DTE Gas considers all 70 years of weather history (1951-2020) in designing its Plans to ensure that customers will be protected for all possible weather extremes and weather patterns that have occurred.

Q57. Has DTE Gas's maximum CTN exposure changed since the 2021-2022 Plan Case?

A57. Yes. The maximum winter CTN exposure has increased from last year's Plan case by 3.2 Bcf, from 24.2 Bcf to 27.4 Bcf (Exhibit A-17, line 7, page 1 of 2, column (e)).

Q58. How is the level of CTNP volume supplied?

A58. For the winter of 2022-2023, DTE Gas plans to enter the winter season with 5 Bcf of gas in storage for CTNP. In addition, DTE Gas plans to mitigate a portion of the risk of the 27.4 Bcf CTN exposure with 3 Bcf of normal weather purchases in excess of normal weather requirements (made ratably) from November 2022 to March 2023. Furthermore, DTE Gas will monitor actual and projected CTN weather exposures throughout the winter and will obtain additional CTNP supply via incremental winter purchases if gas in storage is insufficient to meet the potential exposure and maintain necessary minimum storage balances. A CTN plan for the 2022-2023 winter is shown on Exhibit A-17.

Q59. How will DTE Gas determine when to purchase incremental supply for CTN?

A59. Timing of the incremental purchases, and whether these purchases will be first of month (FOM) or daily spot purchases, will depend upon the severity of the winter season, at what point in time the cold weather is actually experienced, supply liquidity, and projected storage balances. DTE Gas plans to limit mid-month daily spot purchases to the most operationally critical deep winter months of January through March. In order to minimize price and supply reliability risk, DTE Gas plans to purchase sufficient FOM quantities to limit daily spot purchases. If, after the month has begun, DTE Gas assesses that FOM flowing supply levels are not adequate to meet operational requirements based on actual and projected storage balances, potential cold weather exposures and weather forecasts, then it will begin to layer in day gas purchases. On a normal winter basis, DTE Gas plans to fill 334 MMcf/d of its 380 MMcf/d of firm pipeline entitlement and release 46 MMcf/d of recallable capacity that would be available for FOM or daily CTN gas purchases and/or peak-day requirements.

Q60. Does peak day and CTN planning end at March 31?

A60. No. DTE Gas plans for an end-of-month peak day based on the coldest historical temperatures from the 22nd of that month to the 7th of the following month. It is possible for an end of March peak day temperature to occur through the end of the first week in April when storage balances are at their minimums.

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Q61. Is it possible that DTE Gas will need to purchase incremental supply in April for CTN and/or peak day protection?

A61. Yes. Operating experience has shown that CTN winter weather could extend into a CTN April. Storage withdrawals for GCR/GCC could continue into the month of April, even under normal weather conditions. If GCR storage balances are projected to be at or near minimums, then DTE Gas may need to purchase incremental supply in April for CTN volumetric coverage and/or peak day protection in the same manner as described above for the deep winter months.

Q62. What is DTE Gas's plan if CTN, or otherwise higher than forecasted sendout, should occur during the summer months (April – October)?

A62. As the summer injection season progresses, if CTN weather or otherwise higher sendout occurs, then DTE Gas plans to increase its remaining planned summer purchases in order to achieve its planned normal end-of-injection-season storage target by October 31. For each remaining summer month, DTE Gas plans to evenly purchase its remaining planned summer purchases. However, if DTE Gas experiences higher sendout in October, then the October 31 storage balance will likely fall short of the normal weather target, thereby effectively consuming a portion of the CTNP held in storage. If this were to occur, then DTE Gas plans to replenish CTNP in November, with any remainder replaced in December, prior to entering the deep winter months of January - March. These replacement purchases, as described above, are subject to operational limitations, particularly scheduled compressor maintenance, potential WTN weather exposures, and available storage field injection capacity.

Line
No.

WARMER-THAN-NORMAL WEATHER OPERATING PLAN

Q63. What is DTE Gas's plan if warmer-than-normal weather, or otherwise lower than forecasted sendout, should occur during the summer months (April – October)?

A63. As the summer injection season progresses and warmer-than-normal conditions occur, or otherwise lower than forecasted sendout occurs, DTE Gas plans to evenly purchase the reduced remaining planned summer purchase requirements, subject to operational limitations, to achieve its planned normal end-of-injection season working-gas-storage target at October 31, 2022 of 70.1 Bcf. However, depending on the timing of the reduced sendout and the associated reduction to supply, a volume of gas associated with the September and primarily the October weather variation could remain in storage. DTE Gas reserves 5 Bcf of storage space to accommodate higher injections due to lower than expected sendout and other unpredictable system imbalances in September, October and early November. If DTE Gas experiences lower sendout than planned in October and expects to enter the winter operating season with significantly more GCR and GCC gas in storage above the normal weather injection season target, then November planned purchases may be reduced to permit operational flexibility necessary for compression maintenance, maximum daily flowing supply limitations, limitations on storage field injection capability, continued warmer-than-normal exposure, and storage field maximum capacity limitations.

Line
No.

Q64. What is DTE Gas's plan if warmer-than-normal weather occurs during the winter months (November – March)?

A64. DTE Gas's WTN Plan is provided in Exhibit A-18. It is based on the maximum WTN exposure from the 2011-2012 winter. As illustrated in Exhibit A-18, DTE Gas may begin to reduce flowing supply, if, as the winter progresses, warmer-than-normal weather continues, and storage balances continue to exceed Plan levels. Before any reduction in purchases is implemented, the estimated cumulative WTN surplus is reduced by 1 Bcf for margin of accuracy purposes. The WTN surplus is the excess amount of gas in storage above normal planned target. It includes the net result of a cumulative reduction in sendout resulting from WTN weather actually experienced in prior months offset by the cumulative reduction, if any, of purchases already made in prior months. A reduction in purchases would be at 50% of the cumulative WTN surplus for December purchases, and at a reduced percentage for the deep winter months of January through March, approximately in the range of 35-40% of the WTN surplus.

Q65. Are there limits to the WTN Plan supply reductions?

A65. Yes, DTE Gas must limit the reduction in flowing supply determined by the above factors to an amount that will result in sufficient flowing supply to meet contracted supply and the requirements of customers located in isolated regions, such as Michigan's Upper Peninsula, that can only be served by supply delivered from certain pipelines.

Q66. What will DTE Gas do if storage levels exceed plan levels on March 31?

A66. If by March 31, gas remains in storage above the Plan level, then DTE Gas plans to reduce its planned summer purchases in order to achieve its planned October 31 end-of-injection-season storage target. DTE Gas plans to evenly purchase each month the reduced summer purchase requirements, subject to operational limitations.

<u>OTHER OPERATIONAL CHANGES</u>

Q67. How likely is it that DTE Gas's Operational Plan will change during the 2022-2023 GCR Plan Year?

A67. During a typical GCR year, factors influencing DTE Gas's operations are continually changing. Such factors may include changes in weather, GCC migration, customer usage, customer count, supply liquidity, changes in inventory levels, and changes in operations. Therefore, before and during the 2022-2023 GCR Year, there is a reasonable likelihood that DTE Gas will continue to refine its operational plan based on current and projected market and operational conditions.

<u>FUTURE OUTLOOK</u>

Q68. Does DTE Gas's Operational Plan for the operating years April 2023-March 2027 differ from the 2022-2023 Operating Plan?

A68. At the time of the filing of the GCR Plan case for the 2022-2023 GCR Year, there are no indications that the operating plan will have any significant changes over the next five years. With regards to storage utilization, DTE Gas's GCR/GCC storage allocation plan for the operating years April 2022-March 2027 does not differ from the 2022-2023 GCR Plan Year. The Company is currently proposing to maintain a GCR/GCC cyclable storage allocation of 71.9 Bcf for 2022-2023 and all subsequent

Line No.

years of the 5-Year forecast period. However, at some point in the future, depending on increases or decreases in requirements or other operational factors, DTE Gas may decide to modify this storage allocation plan for the future operating years beginning with the 2023-2024 GCR Plan year.

Q69. Does this complete your direct testimony?

A69. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE Gas Company for approval of a	)	
Gas Cost Recovery Plan, 5-year Forecast, and	)	
Monthly GCR Factor for the 12 months ending	)	Case No. U-21064
March 31, 2023	)	

EXHIBITS

LUCIAN BRATU

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Year	MONTH	GCR Markets	Company Use Lost \(Found) Gas	GCR Sendout	GCC Markets	Total GCR & GCC Sendout	GCR Supply	GCC Supply	Total System Supply	Gas In Kind	Total Supply
1	2022	APRIL	10,141	571	10,712	1,484	12,196	12,228	1,910	14,138	540	14,679
2		MAY	4,752	496	5,249	785	6,034	12,636	1,974	14,610	597	15,207
3		JUNE	2,569	460	3,029	479	3,508	12,228	1,910	14,138	619	14,758
4		JULY	2,051	537	2,587	410	2,998	12,636	504	13,140	621	13,761
5		AUGUST	2,051	528	2,578	428	3,006	12,636	1,974	14,610	629	15,239
6		SEPTEMBER	2,384	734	3,118	674	3,792	12,228	1,910	14,138	576	14,714
7		OCTOBER	7,042	889	7,931	1,251	9,182	8,720	1,974	10,694	565	11,259
8		NOVEMBER	13,982	1,273	15,255	2,426	17,681	10,021	1,910	11,932	464	12,396
9		DECEMBER	21,361	1,295	22,657	3,653	26,310	10,355	1,974	12,329	531	12,860
10	2023	JANUARY	24,731	1,030	25,761	4,097	29,857	10,355	1,974	12,329	552	12,881
11		FEBRUARY	22,180	861	23,041	3,685	26,726	9,353	1,783	11,136	502	11,638
12		MARCH	17,622	516	18,137	2,764	20,901	10,355	1,974	12,329	471	12,800
13	**2022-23**	**OPY Total**	**130,866**	**9,189**	**140,055**	**22,137**	**162,192**	**133,751**	**21,773**	**155,524**	**6,668**	**162,192**

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

Line No.	Year	MONTH	(a) GCR Markets	(b) Company Use Lost \(Found) Gas	(c) GCR Sendout	(d) GCC Markets	(e) Total GCR & GCC Sendout	(f) GCR Supply	(g) GCC Supply	(h) Total System Supply	(i) Gas In Kind	(j) Total Supply
1	2023	APRIL	10,112	570	10,682	1,469	12,151	12,170	1,885	14,055	559	14,613
2		MAY	4,740	494	5,234	777	6,011	12,575	1,948	14,523	617	15,140
3		JUNE	2,559	458	3,017	474	3,491	12,170	1,885	14,055	609	14,663
4		JULY	2,042	536	2,578	406	2,984	12,575	834	13,410	610	14,019
5		AUGUST	2,043	526	2,569	423	2,993	12,575	1,948	14,523	618	15,141
6		SEPTEMBER	2,376	732	3,108	667	3,776	12,170	1,885	14,055	567	14,622
7		OCTOBER	7,020	886	7,906	1,237	9,144	8,746	1,948	10,694	556	11,250
8		NOVEMBER	13,938	1,252	15,190	2,401	17,591	10,059	1,885	11,944	457	12,400
9		DECEMBER	21,294	1,294	22,587	3,615	26,202	10,395	1,948	12,342	523	12,865
10	2024	JANUARY	24,651	1,027	25,678	4,054	29,731	10,395	1,948	12,342	541	12,883
11		FEBRUARY	22,947	858	23,804	3,646	27,451	9,724	1,822	11,546	502	12,048
12		MARCH	17,569	515	18,083	2,735	20,818	10,285	1,948	12,232	464	12,696
13	**2023-24**	**OPY Total**	**131,291**	**9,147**	**140,438**	**21,904**	**162,342**	**133,838**	**21,884**	**155,721**	**6,621**	**162,342**

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Year	MONTH	GCR Markets	Company Use Lost \(Found) Gas	GCR Sendout	GCC Markets	Total GCR & GCC Sendout	GCR Supply	GCC Supply	Total System Supply	Gas In Kind	Total Supply
1	2024	APRIL	10,085	570	10,655	1,453	12,108	12,176	1,871	14,047	545	14,592
2		MAY	4,729	494	5,223	769	5,992	12,581	1,934	14,515	602	15,117
3		JUNE	2,551	458	3,009	469	3,478	12,176	1,871	14,047	595	14,641
4		JULY	2,035	536	2,571	402	2,973	12,581	833	13,415	595	14,010
5		AUGUST	2,036	526	2,562	419	2,981	12,581	1,934	14,515	602	15,117
6		SEPTEMBER	2,370	732	3,102	660	3,762	12,176	1,871	14,047	549	14,595
7		OCTOBER	6,998	886	7,884	1,224	9,109	8,760	1,934	10,694	535	11,229
8		NOVEMBER	13,892	1,247	15,139	2,376	17,515	9,881	1,871	11,753	440	12,192
9		DECEMBER	21,223	1,274	22,497	3,577	26,073	10,210	1,934	12,144	506	12,649
10	2025	JANUARY	24,568	1,027	25,594	4,011	29,605	10,210	1,934	12,144	515	12,659
11		FEBRUARY	22,035	858	22,893	3,608	26,501	9,223	1,746	10,970	472	11,442
12		MARCH	17,513	515	18,027	2,706	20,734	10,210	1,934	12,144	443	12,587
13	**2024-25**	**OPY Total**	**130,034**	**9,122**	**139,156**	**21,674**	**160,831**	**132,765**	**21,666**	**154,432**	**6,399**	**160,831**

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Year	MONTH	GCR Markets	Company Use Lost \(Found) Gas	GCR Sendout	GCC Markets	Total GCR & GCC Sendout	GCR Supply	GCC Supply	Total System Supply	Gas In Kind	Total Supply
1	2025	APRIL	10,056	570	10,626	1,438	12,064	12,170	1,852	14,022	544	14,566
2		MAY	4,716	494	5,210	761	5,971	12,576	1,914	14,489	601	15,091
3		JUNE	2,542	458	3,000	464	3,464	12,170	1,852	14,022	593	14,615
4		JULY	2,028	536	2,564	398	2,961	12,576	814	13,390	592	13,982
5		AUGUST	2,028	526	2,555	415	2,969	12,576	1,914	14,489	600	15,089
6		SEPTEMBER	2,363	732	3,095	653	3,748	12,170	1,852	14,022	551	14,573
7		OCTOBER	6,975	886	7,861	1,212	9,072	8,780	1,914	10,694	541	11,235
8		NOVEMBER	13,843	1,172	15,015	2,351	17,366	9,776	1,852	11,628	438	12,067
9		DECEMBER	21,147	1,244	22,390	3,539	25,930	10,102	1,914	12,016	504	12,520
10	2026	JANUARY	24,478	1,027	25,504	3,969	29,473	10,102	1,914	12,016	513	12,529
11		FEBRUARY	21,956	858	22,814	3,570	26,384	9,124	1,729	10,853	471	11,324
12		MARCH	17,453	515	17,967	2,678	20,645	10,102	1,914	12,016	442	12,458
13	**2025-26**	**OPY Total**	**129,584**	**9,017**	**138,601**	**21,447**	**160,048**	**132,224**	**21,433**	**153,657**	**6,391**	**160,048**

Line No.	Year	MONTH	(a) GCR Markets	(b) Company Use Lost \(Found) Gas	(c) GCR Sendout	(d) GCC Markets	(e) Total GCR & GCC Sendout	(f) GCR Supply	(g) GCC Supply	(h) Total System Supply	(i) Gas In Kind	(j) Total Supply
1	2026	APRIL	10,024	570	10,594	1,423	12,017	11,986	1,834	13,820	540	14,360
2		MAY	4,703	494	5,197	753	5,950	12,386	1,895	14,281	598	14,878
3		JUNE	2,532	458	2,990	459	3,450	11,986	1,834	13,820	589	14,409
4		JULY	2,020	536	2,556	393	2,949	13,479	801	14,281	588	14,868
5		AUGUST	2,021	526	2,547	410	2,957	12,386	1,895	14,281	596	14,876
6		SEPTEMBER	2,356	732	3,087	647	3,734	11,986	1,834	13,820	547	14,367
7		OCTOBER	6,948	886	7,834	1,199	9,033	8,799	1,895	10,694	537	11,231
8		NOVEMBER	13,788	1,072	14,860	2,326	17,186	9,658	1,834	11,491	424	11,915
9		DECEMBER	21,063	1,194	22,256	3,502	25,758	9,980	1,895	11,875	489	12,363
10	2027	JANUARY	24,379	977	25,355	3,927	29,283	9,980	1,895	11,875	499	12,373
11		FEBRUARY	21,868	858	22,726	3,533	26,258	9,014	1,711	10,725	458	11,183
12		MARCH	17,386	515	17,901	2,650	20,551	9,980	1,895	11,875	427	12,302
13	**2026-27**	**OPY Total**	**129,087**	**8,817**	**137,904**	**21,222**	**159,126**	**131,620**	**21,215**	**152,835**	**6,291**	**159,126**

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

Case No.: U-21064
Exhibit: A-13
Witness: L. Bratu

Line No.	Year	Month	(a) GCR Storage To/(From)	(b) GCR Storage Balance	(c) GCC Storage To/(From)	(d) GCC Storage Balance	(e) GCR and GCC Storage To/(From)	(f) GCR and GCC Storage Balance
1	2022	APRIL	2,056	11,044	426	2,639	2,482	13,683
2		MAY	7,985	19,029	1,189	3,827	9,173	22,856
3		JUNE	9,818	28,847	1,431	5,259	11,249	34,106
4		JULY	10,669	39,516	94	5,353	10,763	44,869
5		AUGUST	10,686	50,202	1,546	6,899	12,232	57,101
6		SEPTEMBER	9,686	59,888	1,236	8,135	10,922	68,023
7		OCTOBER	1,354	61,242	723	8,858	2,077	70,100
8		NOVEMBER	(4,770)	56,472	(516)	8,342	(5,286)	64,815
9		DECEMBER	(11,770)	44,702	(1,679)	6,663	(13,450)	51,365
10	2023	JANUARY	(14,854)	29,848	(2,123)	4,541	(16,976)	34,389
11		FEBRUARY	(13,186)	16,663	(1,902)	2,639	(15,087)	19,301
12		MARCH	(7,311)	9,352	(790)	1,848	(8,101)	11,200
13	**2022-23**	**OPY Total**	**364**		**(364)**		**(0)**	

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

			(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	Month	GCR Storage To/(From)	GCR Storage Balance	Gas Customer Choice Storage To/(From)	Gas Customer Choice Storage Balance	GCR and GCC Storage To/(From)	GCR and GCC Storage Balance
1	2023	APRIL	2,046	11,398	416	2,265	2,463	13,663
2		MAY	7,958	19,356	1,171	3,436	9,129	22,792
3		JUNE	9,761	29,118	1,411	4,847	11,172	33,964
4		JULY	10,607	39,724	428	5,275	11,035	44,999
5		AUGUST	10,624	50,349	1,524	6,800	12,149	57,148
6		SEPTEMBER	9,628	59,977	1,218	8,017	10,846	67,994
7		OCTOBER	1,396	61,373	710	8,728	2,106	70,100
8		NOVEMBER	(4,675)	56,698	(516)	8,212	(5,191)	64,910
9		DECEMBER	(11,670)	45,028	(1,667)	6,545	(13,337)	51,573
10	2024	JANUARY	(14,742)	30,286	(2,106)	4,439	(16,848)	34,725
11		FEBRUARY	(13,578)	16,708	(1,824)	2,615	(15,402)	19,323
12		MARCH	(7,335)	9,373	(787)	1,828	(8,122)	11,200
13	**2023-24**	**OPY Total**	**21**		**(21)**		**0**	

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

			(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	Month	GCR Storage To/(From)	GCR Storage Balance	Gas Customer Choice Storage To/(From)	Gas Customer Choice Storage Balance	GCR and GCC Storage To/(From)	GCR and GCC Storage Balance
1	2024	APRIL	2,066	11,438	418	2,246	2,484	13,684
2		MAY	7,961	19,399	1,165	3,410	9,126	22,810
3		JUNE	9,761	29,161	1,402	4,813	11,164	33,974
4		JULY	10,605	39,766	432	5,244	11,037	45,010
5		AUGUST	10,622	50,388	1,515	6,759	12,136	57,147
6		SEPTEMBER	9,622	60,010	1,211	7,970	10,833	67,980
7		OCTOBER	1,412	61,421	709	8,679	2,121	70,100
8		NOVEMBER	(4,818)	56,603	(504)	8,175	(5,323)	64,778
9		DECEMBER	(11,781)	44,822	(1,643)	6,531	(13,424)	51,353
10	2025	JANUARY	(14,869)	29,953	(2,078)	4,454	(16,946)	34,407
11		FEBRUARY	(13,198)	16,755	(1,861)	2,592	(15,059)	19,348
12		MARCH	(7,375)	9,381	(773)	1,820	(8,147)	11,200
13	**2024-25**	**OPY Total**	**8**		**(8)**		**0**	

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Normal Weather Source and Disposition
(All volumes in Mmcf except where indicated otherwise.)

Case No.: U-21064
Exhibit: A-13
Witness: L. Bratu

Line No.	Year	Month	(a) GCR Storage To/(From)	(b) GCR Storage Balance	(c) Gas Customer Choice Storage To/(From)	(d) Gas Customer Choice Storage Balance	(e) GCR and GCC Storage To/(From)	(f) GCR and GCC Storage Balance
1	2025	APRIL	2,088	11,469	414	2,234	2,502	13,702
2		MAY	7,967	19,435	1,153	3,387	9,120	22,822
3		JUNE	9,763	29,199	1,388	4,775	11,151	33,973
4		JULY	10,604	39,803	416	5,191	11,020	44,994
5		AUGUST	10,621	50,423	1,499	6,690	12,120	57,113
6		SEPTEMBER	9,626	60,049	1,199	7,889	10,825	67,938
7		OCTOBER	1,460	61,510	702	8,591	2,162	70,100
8		NOVEMBER	(4,800)	56,709	(499)	8,092	(5,299)	64,801
9		DECEMBER	(11,784)	44,925	(1,626)	6,467	(13,410)	51,392
10	2026	JANUARY	(14,889)	30,036	(2,055)	4,411	(16,944)	34,447
11		FEBRUARY	(13,218)	16,818	(1,842)	2,570	(15,060)	19,388
12		MARCH	(7,423)	9,395	(764)	1,806	(8,187)	11,200
13	**2025-26**	**OPY Total**	**14**		**(14)**		**(0)**	

Line No.	Year	Month	GCR Storage To/(From) (a)	GCR Storage Balance (b)	Gas Customer Choice Storage To/(From) (c)	Gas Customer Choice Storage Balance (d)	GCR and GCC Storage To/(From) (e)	GCR and GCC Storage Balance (f)
1	2026	APRIL	1,932	11,327	411	2,216	2,343	13,543
2		MAY	7,787	19,113	1,142	3,358	8,929	22,472
3		JUNE	9,585	28,699	1,374	4,733	10,960	33,431
4		JULY	11,511	40,210	408	5,141	11,919	45,350
5		AUGUST	10,435	50,644	1,484	6,625	11,919	57,269
6		SEPTEMBER	9,446	60,091	1,187	7,812	10,633	67,903
7		OCTOBER	1,502	61,593	696	8,508	2,198	70,100
8		NOVEMBER	(4,779)	56,813	(492)	8,016	(5,271)	64,829
9		DECEMBER	(11,788)	45,026	(1,607)	6,408	(13,395)	51,434
10	2027	JANUARY	(14,877)	30,149	(2,033)	4,375	(16,910)	34,524
11		FEBRUARY	(13,254)	16,895	(1,821)	2,554	(15,075)	19,449
12		MARCH	(7,494)	9,401	(755)	1,799	(8,249)	11,200
13	**2026-27**	**OPY Total**	**7**		**(7)**		**0**	

Michigan Public Service Commission
DTE Gas Company
Storage Capacity and Utilization
(Volumes in Bcf)

Case No.: U-21064
Exhibit: A-14
Witness: L. Bratu
Page: 1 of 1

Line No.	(a) STORAGE CAPACITY	(b) W 2020-21	(c) W 2021-22	(d) W 2022-23
	Storage Field Cyclable Capacity			
1	Six Lakes	40.0	40.0	40.0
2	Belle River Mills	66.0	66.0	66.0
3	Columbus	16.3	16.3	16.3
4	West Columbus	12.9	12.9	12.9
5	Total Cyclable Storage Capacity	135.1	135.1	135.1
6				
7				
8				
9	**Storage Utilization**			
10	GCR & GCC customers	66.9	66.9	66.9
11	WTN/contingency space	5.0	5.0	5.0
12	End User Transport & Exelon	12.0	12.0	12.1
13	Storage Service	51.2	51.2	51.2
14	Total Cyclable Working Capacity	135.1	135.1	135.1
15	Total Cyclable Storage Capacity	135.1	135.1	135.1
16	Total GCR & GCC cyclable capacity (line 10+11)	71.9	71.9	71.9

Michigan Public Service Commission
DTE Gas Company
Peak Day Supply Mix
(Volumes in MMcfd)

Case No.: U-21064
Exhibit: A-15
Witness: L. Bratu

	(a)	(b)	(c)	(d)
		2022-23		
		END OF MONTH PEAK DAY REQUIREMENTS		
Line No.	**PEAK DAY SUPPLY**	**JANUARY**	**FEBRUARY**	**MARCH**
1	**SUPPLY**			
2	Total DTE Gas Normal GCR Purchases	334	334	334
3	Additional Requirements	79	78	79
4	**Subtotal GCR Supply**	413	412	413
5				
6	**GIK**	18	18	15
7				
8	**Gas Customer Choice (includes CTN)**	70	70	70
9				
10	**TOTAL GCR & GCC Flowing Supplies**	501	500	498
11				
12	**EUT Receipts**	337	360	259
13				
14				
15				
16	**TOTAL SUPPLY**	838	860	757
17				
18	**STORAGE WITHDRAWALS**			
19	Total Storage Withdrawal	2,427	1,876	1,206
20	Less Storage Service	832	520	31
21	**DTE Gas Storage Withdrawal**	1,595	1,357	1,175
22				
23	**Total Peak Day Flowing and Storage Supply**	2,433	2,216	1,931
24				
25	**LOAD REQUIREMENTS**			
26	Total Peak Day Requirements	2,421	2,204	1,919
27	Fuel	11	13	12
28	**Total Peak Day Requirements**	2,433	2,216	1,931
29				
30	Unallocated Supply	0	0	0
31				
32	**Design Temperatures (Detroit)**	-6°F	4°F	14°F

Michigan Public Service Commission
DTE Gas Company
Colder-Than-Normal Storage Balances
(All volumes in Bcf except where indicated otherwise)

	(a)	(b)	(c)	(d)
Line		**2022-23**		
No.	**PLANNED ACTIVITY**	**JANUARY**	**FEBRUARY**	**MARCH**
1	DTE Gas GCR/GCC Planned CTN Balance	25.2	10.7	3.2
2	End User Transportation Balance	5.2	3.2	0.4
3	Storage Service Balance	16.4	8.2	0.0
4	TOTAL PROJECTED STORAGE BALANCE	46.8	22.1	3.6
5	MINIMUM TOTAL BALANCE REQUIRED	46.8	22.1	3.6

Michigan Public Service Commission
DTE Gas Company
November 2022 - March 2023
Colder-Than-Normal Weather Source and Disposition (CTN)

Case No.: U-21064
Exhibit: A-17
Witness: L. Bratu

(All volumes in Mmcf except where indicated otherwise.)

2021-22 GCR %	86%
2021-22 GCC %	14%
Total	**100%**

Line No.	Year	Month	(a) Normal GCR Sendout	(b) Normal GCC Markets	(c) GCR CTN Volumes	(d) GCC CTN Volumes	(e) Total GCR/GCC CTN Volumes	(f) Total GCC & GCR Sendout (with CTN Vols.)	(g) Normal GCR Supply	(h) Normal GCC Supply	(i) Total Normal GCR/GCC Supply
1											
2	2022	NOVEMBER	15,255	2,426	2,255	382	2,637	20,318	10,021	1,910	11,932
3		DECEMBER	22,657	3,653	4,075	689	4,764	31,074	10,355	1,974	12,329
4	2023	JANUARY	25,761	4,097	5,959	1,008	6,967	36,825	10,355	1,974	12,329
5		FEBRUARY	23,041	3,685	4,831	817	5,649	32,375	9,353	1,783	11,136
6		MARCH	18,137	2,764	6,300	1,066	7,366	28,268	10,355	1,974	12,329
7		**Winter 20-21 Total**	**104,850**	**16,625**	**23,421**	**3,962**	**27,383**	**148,859**	**50,440**	**9,615**	**60,055**

Michigan Public Service Commission
DTE Gas Company
November 2022 - March 2023
Colder-Than-Normal Weather Source and Disposition (CTN)

Case No.: U-21064
Exhibit: A-17
Witness: L. Bratu

			(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
Line No.	Year	Month	GCR CTN Volumes Purchased	GCC CTN Volumes Purchased	Total GCR/GCC CTN Volumes Purchased	Total System Supply	Gas in Kind	GCR Storage		GCC Storage		GCR and GCC Total Storage		
								To/(From)	Balance	To/(From)	Balance	To/(From)	Balance	
1									61,242		8,858		70,100	
2	2022	NOVEMBER	0	0	0	12,396	464	(7,025)	54,217	(897)	7,961	(7,923)	62,178	
3		DECEMBER	2,255	382	2,637	15,497	531	(13,590)	40,627	(1,987)	5,974	(15,576)	46,601	**Min. Balance**
4	2023	JANUARY	4,075	689	4,764	17,645	552	(16,738)	23,889	(2,442)	3,532	(19,180)	27,422	25,200
5		FEBRUARY	5,959	1,008	6,967	18,606	502	(12,058)	11,831	(1,711)	1,821	(13,769)	13,653	10,700
6		MARCH	4,831	817	5,649	18,449	471	(8,780)	3,052	(1,039)	783	(9,818)	3,834	3,207
7		**Winter 20-21 Total**	**17,121**	**2,896**	**20,017**	**82,593**	**2,520**	**(58,191)**		**(8,076)**		**(66,266)**		

Michigan Public Service Commission
DTE Gas Company
November 2022 - March 2023
Warmer-Than-Normal Weather Source and Disposition (WTN)

Case No.: U-21064
Exhibit: A-18
Witness: L. Bratu

(All volumes in Mmcf except where indicated otherwise.)

2021-22 GCR %	86%
2021-22 GCC %	14%
Total	**100%**

Line No.	Year	Month	Normal GCR Sendout (a)	Normal GCC Markets (b)	GCR WTN Volumes (c)	GCC WTN Volumes (d)	Total GCR/GCC WTN Volumes (e)	GCR & GCC Sendout (with WTN Vols.) (f)	Normal GCR Supply (g)	Normal GCC Supply (h)	Total Normal GCR/GCC Supply (i)
1											
2	**2022**	NOVEMBER	15,255	2,426	(3,007)	(509)	(3,516)	14,165	10,021	1,910	11,932
3		DECEMBER	22,657	3,653	(2,626)	(444)	(3,070)	23,240	10,355	1,974	12,329
4	**2023**	JANUARY	25,761	4,097	(2,845)	(481)	(3,327)	26,531	10,355	1,974	12,329
5		FEBRUARY	23,041	3,685	(3,590)	(607)	(4,197)	22,528	9,353	1,783	11,136
6		MARCH	18,137	2,764	(7,349)	(1,243)	(8,592)	12,310	10,355	1,974	12,329
7		**Winter 19-20 Total**	**104,850**	**16,625**	**(19,417)**	**(3,285)**	**(22,702)**	**98,774**	**50,440**	**9,615**	**60,055**

Michigan Public Service Commission
DTE Gas Company
November 2022 - March 2023
Warmer-Than-Normal Weather Source and Disposition (WTN)

			(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	Year	Month	GCR WTN Purchase Volumes	GCC WTN Purchase Volumes	Total GCR/GCC WTN Purchase Volumes	Gas in Kind	Total Supply	GCR Storage		GCC Storage		GCR and GCC Total Storage	
								To/(From)	Balance	To/(From)	Balance	To/(From)	Balance
1									61,242		8,858		70,100
2	2022	NOVEMBER	0	0	0	464	12,396	(1,762)	59,480	(7)	8,851	(1,770)	68,331
3		DECEMBER	(1,076)	(182)	(1,258)	531	11,602	(10,221)	49,259	(1,417)	7,434	(11,638)	56,693
4	2023	JANUARY	(1,388)	(235)	(1,623)	552	11,258	(13,396)	35,863	(1,876)	5,558	(15,272)	41,421
5		FEBRUARY	(1,935)	(327)	(2,262)	502	9,376	(11,530)	24,333	(1,622)	3,936	(13,152)	28,269
6		MARCH	(2,555)	(432)	(2,988)	471	9,813	(2,518)	21,815	21	3,957	(2,497)	25,772
7		**Winter 19-20 Total**	**(6,954)**	**(1,176)**	**(8,131)**	**2,520**	**54,445**	**(39,427)**		**(4,902)**		**(44,329)**	

Michigan Public Service Commission
DTE Gas Company
April 2022- March 2023 GCR Plan
Reliability Improvement - Temporary Alternatives for Belle River Dehydration Unit Failure

Case No.: U-21064
Exhibit: A-33
Witness: L. Bratu

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.		Options	Requirement (Bcf)	Cost If not Peak Day weather occurs ($Million)	Cost If Peak Day weather occurs ($Million)	Recommendation	Comments
1	Case 1	Just in time purchase	0.2	$0.0	$1.3	Reject	1) **High risk supply** - the required volumes might not be available when needed 2) Prices could actually be higher than estimated
2	Case 2	Increase base gas inventory	9.4	$3.1	$3.1	Reject	1) High cost 2) Reduces Midstream available storage space which will reduce cost-offsetting revenues
3	Case 3	Nov purchases, back off summer 2021 purchase	9.4	$4.0	$4.0	Reject	1) High cost 2) Risk of cost increase if summer prices drop 3) Too much gas purchased in one month
4	Case 4	Dec purchases, back off summer 2021 purchase	9.4	$8.2	$8.2	Reject	1) High cost 2) Risk of cost increase if summer prices drop 3) Too much gas purchased in one month
5	Case 5	Jan purchases, back off summer 2021 purchase	7.3	$6.2	$6.2	Reject	1) High cost 2) Risk of cost increase if summer prices drop
6	Case 6	2 month Nov-Dec levelized purchase, back off summer 2021 purchase	9.4	$5.8	$5.8	Reject	1) High cost 2) Risk of cost increase if summer prices drop 3) Too much gas purchased in one month
7	Case 7	2 month Dec-Jan levelized purchase, back off summer 2021 purchase	8.2	$7.9	$7.9	Reject	1) High cost 2) Risk of cost increase if summer prices drop 3) Too much gas purchased in one month (Dec)
8	Case 8	3 month Nov-Jan levelized purchase, back off summer 2021 purchase	8.6	$7.0	$7.0	Reject	1) High cost 2) Risk of cost increase if summer prices drop
9	Case 9	Just in time park to summer 2021	0.2	$0.0	$0.2	Reject	1) **High risk supply** - the required volumes might not be available when needed 2) Prices could actually be higher than estimated
10	Case 10	Nov to summer park	9.4	$2.5	$2.5	Reject	1) High cost 2) Too much gas received in one month
11	Case 11	Dec to summer park	9.4	$5.8	$5.8	Reject	1) High cost 2) Too much gas received in one month
12	Case 12	Jan to summer park	7.3	$5.0	$5.0	Reject	1) High cost
13	Case 13	2 month Nov&Dec to summer park	9.4	$4.2	$4.2	Reject	1) High cost 2) Too much gas received in one month
14	Case 14	2 month Dec&Jan to summer park	8.2	$5.3	$5.3	Reject	1) High cost 2) To much gas received in one month (Dec)
15	Case 15	3 month Nov&Jan to summer park	8.6	$4.5	$4.5	Reject	1) High cost
16	Case 16	Jan-Feb 10 day gas supply call option	0.2	$0.25 fix cost	$1.8	Recommend	1) Cost effective 2) Most flexible 3) Reliable

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE Gas Company for approval of a	)	
Gas Cost Recovery Plan, 5-year Forecast, and	)	
Monthly GCR Factor for the 12 months ending	)	Case No. U-21064
March 31, 2023	)	
	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TIMOTHY J. KRYSINSKI

DTE GAS COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY J. KRYSINSKI

Line
No.

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

A1. My name is Timothy J. Krysinski. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC (DTE Energy) as a Principal Project Manager in the Regulatory Affairs Gas Strategy group.

Q2. What is your educational background?

A2. I have a Bachelor's Degree in Accounting and a Master of Science Degree in Finance. Both degrees were earned from Walsh College in Troy, Michigan.

Q3. Do you hold any professional designations?

A3. I am a Certified Public Accountant. My certification is from the Board of Examiners of the University of Illinois.

Q4. Have you had other regulatory training?

A4. I have attended seminars on regulatory topics held by the American Gas Association and the Edison Electric Institute. I also completed a two-day Regulatory and Rates seminar given by Electric Utility Consultants, Inc. (EUCI) and a week-long Advanced Regulatory Studies Program given by the Institute of Public Utilities.

Q5. What is your work experience?

A5. I joined DTE Energy in 2002 as part of the Controllers Budget, Forecast and Reporting group where I was primarily responsible for internal management reporting. Early in 2005, I accepted the position of Senior Project Analyst in the Facilities, Design and Construction organization where I managed the capital appropriation process in support of their asset preservation program. Late in 2005, I

Line No.

transferred back into the Asset Management department in a Senior Business Financial Analyst role. My initial focus was to assist with implementation of the first wave of the enterprise business solution (EBS) migration. Subsequent responsibilities included budget appropriations, capital project tracking, Sarbanes-Oxley compliance testing, and depreciation work. In 2009, I transferred to a decision support role for Distribution Operations where I provided financial support to the regional managers responsible for Service Operations. In June 2013, I moved to the Regulatory Accounting & Strategy group within the Controllers organization where my responsibilities included researching regulatory accounting issues, drafting white papers, and participating in case filings. In April 2015, I was asked to return to the Asset Management department to assist with conversion activities associated with the launch of the PowerPlan asset system. In July 2016, I transferred to the Regulatory Affairs organization. I was promoted to Principal Project Manager in May 2018. Prior to joining DTE Energy, I spent several years working at various positions in the Accounting department and in the Customer Service organization at TRW Occupant Safety Systems located in Washington, Michigan.

Q6. What are your responsibilities in your current position?

A6. My primary responsibilities are monitoring proceedings before the Federal Energy Regulatory Commission (FERC) and the Canada Energy Regulator (CER) with the purpose of participating in proceedings that could materially affect DTE Gas and its customers. Participation can mean filing comments, or filing as an intervenor, and/or active, ongoing participation in contested cases or settlement negotiations. Additional responsibilities include managing cases before the Michigan Public Service Commission (MPSC), providing witness testimony in DTE Gas's GCR

Line
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proceedings, providing regulatory support to witnesses in various proceedings before the MPSC, and researching issues related to Federal and State regulatory matters.

Q7. Have you previously testified before any regulatory body?

A7. Yes, I sponsored testimony to the MPSC in Case Nos. U-17762; U-17763; U-17941-R; U-18152; U-18412; U-20076; U-20210; U-20235; U-20236; U-20543; U-20544; and U-20816. I also adopted testimony in MPSC Case No. U-17691-R.

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Purpose of Testimony

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

A8. My testimony provides an overview of specific Federal regulatory issues that affect DTE Gas and activities conducted by DTE Gas to minimize costs incurred under its interstate pipeline transportation agreements. I also sponsor certain gas transportation cost assumptions that Witness Schiffer uses to develop the forecast of gas costs from DTE Gas's pipeline transporters. Specifically, my testimony addresses:

A) DTE Gas's Federal regulatory policies related to pipeline transporters;

B) The ongoing rate case proceeding of Panhandle Eastern Pipeline Company (Panhandle);

C) The forecast rates for ANR Pipeline Company's (ANR) firm transportation services, and the firm transportation rate forecast for DTE Gas's other transportation suppliers. These other pipelines are Viking Gas Transmission Company (Viking), Great Lakes Gas Transmission Limited (Great Lakes), Panhandle, NEXUS Gas Transmission, LLC (NEXUS), Vector Pipeline L.P. (Vector), and DTM Michigan Gathering Company (DTM Gathering).

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibit:

Exhibit	Description
A-19	Forecast ANR, Viking, Great Lakes, Panhandle, NEXUS, Vector, and DTM Gathering Rates.

Line
No.

Q10. Was this exhibit prepared by you or under your direction?

A10. Yes, it was.

A) Federal Regulatory Policies

Q11. What are DTE Gas's Federal regulatory policies as they relate to its interstate pipeline transporters?

A11. It is DTE Gas's policy to monitor all rate-related applications filed at the FERC and participate in proceedings that may impact DTE Gas's cost of gas transportation. DTE Gas also monitors FERC rulemaking proceedings affecting pipeline regulation and follows other FERC and CER activities that could ultimately affect DTE Gas's pipeline transporters.

B) Panhandle Section 5 and Section 4 proceedings

Q12. What action did FERC take in 2019 related to Panhandle Eastern Pipeline Company?

A12. On January 16, 2019, in Docket No. RP19-78-000, FERC initiated an investigation, pursuant to Section 5 of the Natural Gas Act (NGA), to determine whether the rates charged by Panhandle were just and reasonable and set the matter for hearing. Based upon a review of Panhandle's Form No. 501-G filing and other information on file with the Commission, FERC stated that Panhandle may be over-recovering its cost of service, causing Panhandle's rates to be unjust and unreasonable.

Q13. What subsequent actions were taken in Docket No. RP19-78-000, the Panhandle Section 5 case?

A13. On April 1, 2019 Panhandle filed a cost and revenue study which included actual costs for the 12-month period ending November 30, 2018. The cost and revenue study reflected an increase over Panhandle's currently existing rates. On May 20, 2019 FERC Trial Staff filed top sheets, which indicated that a significant decrease in rates should take place. FERC Trial Staff also offered a black box settlement option, which was greater than the top sheets – yet still was a decrease relative to current rates. Panhandle then offered a counter-settlement on June 5, 2019. Their counteroffer was higher than their original Section 5 as-filed amounts. When asked how they could support an increase over and above their as-filed Section 5 rates, Panhandle responded that they were now including a negative salvage depreciation component in their cost of service. Settlement talks stalled at that point. Lastly, on August 14, 2019 FERC Trial Staff filed their direct testimony in the Section 5 case. Their testimony reflected a decrease to the cost of service (below the top sheet amount and below their initial black box settlement offer). Table 1 below shows the timing of these actions in RP19-78-000, and the related cost of service amounts.

Table 1

Cost of Service Amounts

($000's)

1-Apr-19 RP19-78-000 Panhandle As-Filed	20-May-19 FERC Trial Staff Top Sheets	20-May-19 Trial Staff Black Box Settlement Offer	5-Jun-19 Panhandle Settlement Counter Offer	14-Aug-19 FERC Trial Staff Direct Testimony
$341,772	$255,755	$278,000	$363,547	$239,417

Q14. What event occurred on August 30, 2019?

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A14. On August 30, 2019 Panhandle filed a Section 4 general rate case in Docket No. RP19-1523-000. The Section 4 general rate case as-filed reflected a cost of service amount of $407.9 million. Panhandle stated that the principal factors supporting the increased cost of service include:

(a) establishment of a negative salvage rate and a terminal decommissioning expense;

(b) an increase in depreciation expense;

(c) an increase in taxes – other than income;

(d) an increase in return; and

(e) elimination of income taxes as a result of a change in corporate structure.

Q15. What change in corporate structure was Panhandle referring to in item (e) above?

A15. Panhandle announced that they "restructured" their corporate entity ownership structure effective July 1, 2019. Panhandle stated it is now an indirect subsidiary of a master limited partnership, and therefore is no longer owned by an entity subject to federal income tax.

Q16. Has FERC responded to the Panhandle Section 4 filing?

A16. Yes, FERC issued a Hearing and Suspension Order on September 30, 2019. The Order accepted Panhandle's tariff records and suspended the rates subject to refund and subject to the outcome of a hearing and technical conference - making them effective beginning March 1, 2020. The Order also denied Panhandle's request to terminate the Section 5 proceeding. Then on October 1, 2019, the Chief Judge issued

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an Order stating that the Section 4 and the Section 5 proceedings be consolidated - citing administrative efficiency as the main reason.

Q17. What impact does this Section 4 filing have on the transportation contract rates DTE Gas holds with Panhandle?

A17. As of March 1, 2020, the as-filed rates of the Section 4 filing went into effect and now DTE Gas is paying significantly higher rates for the same firm transportation service. DTE Gas has experienced an approximately 59% increase in rates. These rates are, however, subject to refund - if the rates that the FERC ultimately approves as just and reasonable - are lower than the Section 4 as-filed rates.

Q18. Has DTE Gas intervened in either the Section 5 or the Section 4 filings?

A18. Yes, DTE Gas is an intervenor and an active participant in both filings.

Q19. What specific actions has DTE Gas undertaken thus far?

A19. In addition to filing as an intervenor in both RP19-78-000 and RP19-1523-000, DTE Gas has collaborated with FERC Trial Staff, outside counsel, other Michigan-based intervenors (including Consumers Energy Company, the Michigan Public Service Commission Staff, and SEMCO Energy Gas Company), and other similarly-situated, long-haul shippers. The collaboration remains centered around advocating for just and reasonable rates for all shippers that have contract paths similar to DTE Gas.

Q20. Has DTE Gas filed any motions in either of the Panhandle proceedings?

A20. Yes, on September 20, 2019 DTE Gas along with the other Michigan Parties filed an answer in opposition to Panhandle's motion to terminate the Section 5 proceeding.

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Also, on October 30, 2019 the Michigan Parties filed a request for clarification or rehearing. The Motion sought clarification with respect to an issue raised in Paragraph 36 of the Hearing and Suspension Order, where the Commission denied Panhandle's Motion to terminate the Panhandle Section 5 Case. Lastly, on April 30, 2020, DTE Gas and the Michigan Parties filed an Answer in Opposition to Panhandle's (second) Motion to terminate the Section 5 Case. On June 18, 2020, FERC issued their Order addressing the Michigan Parties Motions - the motions were denied. Additionally, Panhandle's second motion to terminate the Section 5 proceeding was also denied.

Q21. What is the current status of the Panhandle settlement talks?

A21. DTE Gas and other interveners met with Panhandle (in Washington DC, and via phone conference) in the context of settlement negotiations. The last settlement conference was held via WebEx on April 23, 2020. At that conference, group discussions among all the parties took place, along with separate discussions and ALJ-lead breakout sessions designed to help the parties move toward settlement. In the end, it was recognized that the interveners and Panhandle remained far apart on key issues. On August 24, 2020 the settlement judge issued an order declaring an impasse – which was followed by an order from the Chief Judge (on August 25) terminating further settlement judge procedures. Litigation is not paused during settlement negotiations - meaning the Section 4 and Section 5 litigated cases proceed in parallel while the parties also pursue a possible settlement.

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Q22. What is the current status of the Panhandle trial proceeding?

A22. Virtual cross examination was held from August 25 through September 16, 2020. On September 18, 2020, Panhandle filed a motion to have the testimony of the FERC Trial Staff ROE witness stricken from the record. Panhandle claimed the FERC witness plagiarized his testimony by copying testimony from other FERC pipeline cases and using as his own. On October 6, 2020 the ALJ issued an order denying Panhandle's motion. The ALJ found that the ROE witness, "*applied consistently interpreted Commission policies to the unique facts involved in this proceeding and then drew his own independent conclusions based on his analytical experience.*" Further, on October 13, 2020 Panhandle filed a Petition for Rehearing with the D.C. Circuit Court of Appeals – asking for an appellate review of the June 18, 2020 Commission order that denied Panhandle's motion to terminate the Section 5 case. Most recently, the ALJ filed her Initial Decision on March 26, 2021, and exceptions followed by briefs opposing exceptions have been filed. Lastly, interveners (DTE Gas included) filed letters in the docket requesting that the Commission issue an order on the Initial Decision as soon as possible, and in any event no later than November 1, 2021, in order to ensure that ratepayers receive rate relief and access to refunds as soon as possible. As of the writing of this testimony, the Commission has not yet issued an order in these consolidated proceedings.

C) <u>Rate Forecast Summary for DTE Gas's Transportation Providers</u>

Q23. What assumptions have you provided to Witness Schiffer regarding DTE Gas's gas transportation rates from ANR during the forecast period?

A23. I assume that the settlement rates from ANR's last rate case (Docket No. RP16-440-000) will continue to apply to the maximum rate contracts that will be in effect at the

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beginning of the plan period on April 1, 2022. I assume that ANR's settlement rates will remain effective for the duration of the five-year plan. I also assume that ANR's fuel retention percentages in Docket No. RP20-636-000, and subsequently approved by the Commission on March 24, 2020, will be in effect through the end of the plan period. Lastly, I assume that the Electric Power Compression Charge (EPC Charge) filed in Docket No. RP20-636-000 will be in effect through the end of the plan period. The rates and fuel charges related to the ANR transportation contracts are shown in Exhibit A-19, page 1 of 7.

Q24. What do you assume regarding the discounted rate firm transport contracts that DTE Gas holds on ANR?

A24. I assume that the fixed discount rate that applies will remain unchanged during the plan period. I included ANR's discounted transportation rates in Exhibit A-19, page 1 of 7.

Q25. What assumptions have you provided to Witness Schiffer with respect to Viking transportation costs billed to DTE Gas?

A25. I assume that Viking's term-differentiated rates as filed in the Viking unopposed settlement (in Docket No. RP19-1340-000) which was approved by the Commission on July 1, 2020 will remain in effect through the end of the plan period. Exhibit A-19, page 2 of 7 includes my forecast of Viking rates starting April 1, 2022.

Q26. What do you assume regarding Viking's fuel charges?

A26. I assume that Viking's fuel charges during the plan period will be the same as those included in Viking's most recent fuel filing with the FERC, which is found in Docket

Line No.

RP22-4-000 (and was approved by the Commission on October 29, 2021) will remain in effect through the plan period. Exhibit A-19, page 2 of 7, shows the projected Viking rates starting April 1, 2022.

Q27. What assumptions have you provided to Witness Schiffer regarding the transport costs DTE Gas incurs on Great Lakes?

A27. I assume that the rates that were filed in Docket RP19-409-000 (the limited Section 4 reduction filed on December 6, 2018, and subsequently approved by FERC on January 31, 2019) will remain in effect for the duration of the plan period. Great Lake's forecast rates and fuel retention percentages are provided in Exhibit A-19, page 3 of 7.

Q28. What assumptions have you provided to Witness Schiffer regarding transportation fuel costs DTE Gas incurs on Great Lakes?

A28. Great Lakes revises its fuel charges monthly, and the monthly fuel charges can vary significantly due, in part, to the reconciliation of fuel over and under recoveries. So, I assume that Great Lake's average fuel retention percentages for the 12 months ending November 2021 will apply during the plan period. Great Lake's forecast rates and fuel retention percentages are provided in Exhibit A-19, page 3 of 7.

Q29. What assumptions have you provided to Witness Schiffer with respect to DTE Gas transportation costs on Panhandle?

A29. I assume that Panhandle's maximum tariff rates (as filed in their recent Section 4 general rate case in Docket No. RP19-1523-000) that went into effect on March 1, 2020 will remain in effect through the plan period.

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Q30. What assumptions do you provide with respect to Panhandle's fuel rates?

A30. I project that Panhandle's fuel rates during the plan period will be the same as the applicable fuel rate contained in Docket No. RP21-1181-000. This is Panhandle's most recent fuel filing which was accepted by the FERC on October 29, 2021. Panhandle's forecast transportation and fuel rates are contained in Exhibit A-19, page 4 of 7.

Q31. What assumptions have you provided to Witness Schiffer with respect to DTE Gas transportation costs on NEXUS?

A31. I assume that the rates contained in the Negotiated Rate Agreement (NRA) dated July 12, 2021, which was filed with the FERC on September 1, 2021, and accepted by FERC letter order on September 24, 2021 (Docket RP21-1091-000), will apply to the plan period. The forecast showing NEXUS's transportation rates are contained in Exhibit A-19, page 5 of 7.

Q32. What assumptions do you provide with respect to NEXUS's fuel rates?

A32. I assume that the Applicable Shrinkage Adjustment (ASA) percentages contained in NEXUS's latest ASA filing in Docket No. RP21-549-000 (filed on February 26, 2021 and subsequently accepted by the Commission on March 15, 2021) will apply for the plan period. The Applicable Shrinkage Adjustment percentages are shown on Exhibit A-19, page 5 of 7.

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Q33. What assumptions have you provided to Witness Schiffer with respect to Vector transportation costs?

A33. I assume that the discounted rate in FT Contract No. FT1-MCG-5676 will be in effect throughout the entire plan period.

Q34. What assumptions do you provide with respect to Vector's fuel rates?

A34. Vector revises its fuel rates and reconciles over and under recoveries on a monthly basis. Therefore, I based Vector's fuel charge forecast on Vector's average fuel retention percentages for the period between December 2020 and November 2021. Vector's forecast transportation and fuel rates are presented in Exhibit A-19, page 6 of 7.

Q35. What assumptions have you provided to Witness Schiffer with respect to DTE Gas transportation costs on DTM Gathering?

A35. I assume that the transportation agreement signed by DTE Gas and the associated contract rate as listed on the rate page dated July 18, 2016 will remain in effect throughout the plan period. The rate is presented on Exhibit A-19, page 7 of 7.

Q36. Does this conclude your pre-filed testimony?

A36. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE Gas Company for approval of a	)	
Gas Cost Recovery Plan, 5-year Forecast	)	Case No. U-21064
and Monthly GCR Factor for the 12 months	)	
ending March 31, 2023	)	
______________________________________	)	

EXHIBITS

OF

TIMOTHY J. KRYSINSKI

Michigan Public Service Commission
The DTE Gas Company
Forecast ANR, Viking, Great Lakes, Panhandle, NEXUS, Vector, and DTM Gathering Rates

Case No.: U-21064
Witness: T. J. Krysinski
Exhibit: A-19
Page: 1 of 7

Forecast ANR Rates ($/Dth); Reservation Rate is per Month

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Southeast Area		Southwest Area		Northern Area		Surcharges			Electric Compression
Line	Service/ Effective Date	Reservation	Usage	Reservation	Usage	Reservation	Usage	Reservation	Usage	Fuel %	Charge
1	Southwest Fixed Maximum Rate ETS Contracts Nos. 108268, 108304										
2	04/22 - 03/27			$9.7320	$0.0216			$0.0000	$0.0009	1.79%	$0.0010
3	Southwest to Georgetown Fixed Maximum Rate FTS-1 Contract No. 109511										
4	04/22 - 03/27			$11.0000	$0.0216			$0.0000	$0.0009	1.79%	$0.0010
5	Discounted Detroit to Group 3 ML-7 ETS Contract No. 112110										
6	04/22 - 03/27				/1	$0.8974	$0.0101	$0.0000	$0.0009	0.54%	$0.0010
7	Marshfield to Menominee Maximum Rate ML-7 FTS-1 Contract No. 122248										
8	04/22 - 03/27					$5.7290	$0.0101	$0.0000	$0.0009	0.54%	$0.0010
9	Alliance to Alpena Maximum Rate FTS-1 ML-7 Contract No. 122065										
10	04/22 - 03/27					$5.7290	$0.0101	$0.0000	$0.0009	0.54%	$0.0010
11	Southwest to Menominee (Winter) and Willow Run (Summer) Maximum Rate ML-7 FTS-1 Contract No. 122067										
12	04/22 - 03/27			$12.4690	$0.0216			$0.0000	$0.0009	1.79%	$0.0010
13	Winter-only Shelbyville to Willow Run FTS-1 Contract No. 132461										
14	11/22 - 03/27	$8.0880	$0.0128					$0.0000	$0.0009	0.94%	$0.0010

/1 Note ACA rate change means updated Reservation cost
=(0.9109)-(0.0012*365/12*0.37)
0.897395

Forecast Viking Rates ($/Dth); Reservation Rate is per Month

	(a)	(b)	(c)	(d)	(e)	(f)
				Surcharges		
Line	**Effective Date**	**Reservation**	**Usage**	**Reservation**	**Usage**	**Fuel %**
1	Maximum Rate Contract AF0081 - Category 3 Term of 5 or more Years					
2	04/22 - 03/27	$4.7580	$0.0136	$0.0000	$0.0012	0.94%

Michigan Public Service Commission
The DTE Gas Company
Forecast ANR, Viking, Great Lakes, Panhandle, NEXUS,
Vector, and DTM Gathering Rates

Forecast Great Lakes Rates ($/Dth); Reservation Rate is per Month

	(a)	(b)	(c)	(d)	(e)	(f)
				Surcharges		
Line	**Effective Date**	**Reservation**	**Usage**	**Reservation**	**Usage**	**Fuel %**
1	Maximum Rate Emerson to Central Zone Contract FT4634					
2	04/22 - 03/27	$4.5860	0.00544	$0.0000	$0.0012	1.62% (1)
3						1.97% (2)
4	Maximum Rate Emerson to Eastern Zone Contract FT4635					
5	04/22 - 03/27	$8.1860	0.00954	$0.0000	$0.0012	2.49% (3)

(1) Fuel for deliveries to Rapid River in the Central Zone (8 fuel segments).
(2) Fuel for deliveries to Mackinac, S.S. Marie, Pellston, and Gaylord in the Central Zone (10 fuel segments).
(3) Fuel for deliveries to Belle River in the Eastern Zone (13 fuel segments).

Michigan Public Service Commission
The DTE Gas Company
Forecast ANR, Viking, Great Lakes, Panhandle, NEXUS, Vector, and DTM Gathering Rates

Case No.: U-21064
Witness: T. J. Krysinski
Exhibit: A-19

Forecast Panhandle Rates ($/Dth); Reservation Rate is per Month

	(a)	(b)	(c)	(d)	(e)	(f)
				Surcharges		
Line	**Effective Date**	**Reservation**	**Usage**	**Reservation**	**Usage**	**Fuel %**
1	Field Zone to DTE Gas (801 to 900 miles) - Maximum Rate EFT Contract No. 17908					
2	04/22 - 03/27	$21.8544	$0.0538	$0.0000	$0.0012	3.65%
3	Field Zone to DTE Gas (801 - 900 miles) - Maximum Rate FT Contract No. 18474					
4	04/22 - 03/27	$20.6408	$0.0536	$0.0000	$0.0012	3.65%
5	PEPL RFALC to DTE MCON (0 - 100 miles) - Maximum Rate FT Contract					
6	04/22 - 03/27	$3.0508	$0.0046	$0.0000	$0.0012	0.34%

Michigan Public Service Commission
The DTE Gas Company
Forecast ANR, Viking, Great Lakes, Panhandle, NEXUS,
Vector, and DTM Gathering Rates

Forecast NEXUS Rates ($/Dth); Reservation Rate is per Month

	(a)	(b)	(c)	(d)	(e)	(f)
				Surcharges		
Line	**Effective Date**	**Reservation**	**Usage**	**Reservation**	**Usage**	**Fuel**
1	Meter # N4995 NEXUS Interconnect with TELP Mainline, Clarington, OH to Meter # N1001 Ypsilanti, MI					
2	04/22 - 03/27	$25.7021	$0.0000	$0.0000	$0.0012	2.07%
3	Meter # N2002 NEXUS Kensington Plant to Meter # N1001 Ypsilanti, MI					
4	04/22 - 03/27	$21.1396	$0.0000	$0.0000	$0.0012	1.02%

Forecast Vector Rates ($/Dth); Reservation Rate is per Month

	(a)	(b)	(c)	(d)	(e)	(f)
				Surcharges		
Line	**Effective Date**	**Reservation**	**Usage**	**Reservation**	**Usage**	**Fuel %**
1	Vector U.S. - Chicago to MichCon - Discounted FT Contract No. FT1-MCG-5676					
2	04/22 - 03/27	$4.2583	$0.0000	$0.0000	$0.0012	0.71%

Michigan Public Service Commission
The DTE Gas Company
Revised-Forecast ANR, Viking, Great Lakes, Panhandle, NEXUS, Vector, and DTM Gathering Rates

Case No.: U-21064
Witness: T. J. Krysinski
Exhibit: A-19

Forecast DTM Michigan Gathering Rates ($/Month); Usage Rate is ($/Dth)

	(a)	(b)	(c)	(d)	(e)	(f)
				Surcharges		
Line	**Effective Date**	**Reservation**	**Usage**	**Reservation**	**Usage**	**Fuel**
1	FT - Kalkaska-MichCon to Kalkaska-DTE Gas / Consumers-Goose Creek / Kalkaska-ANR / GLGT-Goose Creek - ASAT: 62078					
2	04/22 - 03/27	$300.0000	$0.03626	$0.0000	$0.0000	0.00% (1)
3	Construct Gaylord Interconnect Meter No. 80540					
4	04/22 - 03/27	$800.0000	$0.00000	$0.0000	$0.0000	0.00% (2)

(1) Reservation charge - monthly administrative charge for each agreement executed for transportation service.
(2) Reservation charge - monthly charge to pay for meter facility build.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of DTE Gas Company for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2023	))))))	Case No. U-21064

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ANDREA R. HARDY

DTE GAS COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ANDREA R. HARDY

Line No.

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

A1. My name is Andrea R. Hardy. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services LLC ("DTE Energy" or "DTE") within Regulatory Affairs as a Principal Project Manager.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Gas Company.

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Chemical Engineering with a double major in Economics from Northwestern University in 2011 and a Master of Business Administration Degree from University of Chicago in 2015.

Q4. What work experience do you have?

A4. I have been employed full time by DTE since 2015. From 2015 to 2021, I performed project financial modeling and provided strategic analysis as an Associate and Senior Associate in DTE's Power & Industrial group. I am currently a Principal Project Manager in the Regulatory Affairs DTE Gas Strategy department. Prior to joining DTE in 2015, I spent four years working as an engineer in the nuclear industry.

Q5. What are your current responsibilities with DTE?

A5. My current responsibilities include supporting DTE Gas's GCR cases as well as other project work largely focused on DTE Gas's regulatory strategy and operations.

Q6. Have you been involved in any prior regulatory proceedings?

A6. No, I have not been involved in any prior regulatory proceedings.

<u>Purpose of Testimony</u>

Q7. What is the purpose of your testimony in this proceeding?

A7. My testimony addresses:

1) The calculation of DTE Gas's proposed April 2022 through March 2023 monthly base GCR factor;

2) The contingency mechanism and its implementation;

3) The five-year forecasted cost of gas; and

4) The administration of DTE Gas's Supplier of Last Resort (SOLR) Reservation Charge.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Description</u>
A-20	Derivation of April 2022 through March 2023 GCR Factor
A-21	Forecasted Cost of Gas April 2022 – March 2027
A-22	Calculation of LIFO Rate and Storage Costs
A-23	Proposed Monthly GCR Factor Ceiling Price Adjustment (Contingency) Mechanism Tariff Sheet
A-24	Calculations and Derivation of Contingent Factor +\$1 and +\$2
A-26	Calculation of Reservation Charge Applied to GCC and GCR Customers

Line No.

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

A9. Yes, they were.

APRIL 2022 THROUGH MARCH 2023 MAXIMUM BASE GCR FACTOR

Q10. What is DTE Gas's proposed maximum base GCR factor (GCR factor) for April 2022 through March 2023?

A10. DTE Gas proposes a maximum base GCR factor of $3.29 per Mcf for the April 2022 through March 2023 operational year ("GCR Year" or "Year"). This maximum factor can be adjusted monthly to reflect changes in DTE Gas's cost of gas resulting from higher gas commodity market prices as discussed later in my testimony.

Q11. How is the GCR factor of $3.29 per Mcf calculated?

A11. The GCR factor is calculated by dividing the Adjusted Cost of Gas Less Reservation Charge Revenue incurred for the Year plus any estimated over or (under) recovery from the prior GCR Period by the Year's Adjusted Sales Volumes. The detailed calculations used to determine the GCR factor are included in Exhibit A-20. This methodology has been used to calculate the GCR factor and all its components in DTE Gas's previous GCR cases.

Q12. What are Reservation Charge Revenues?

A12. The Reservation Charge Revenue is collected to recover cost related to transportation capacity reserved on interstate pipelines.

Q13. Are the Reservation Charge revenues removed from the Adjusted Cost of Gas?

A13. Yes, the Reservation Revenue is calculated on Exhibit A-20, lines 18-22, and totals $54 million, which is shown on line 22. The Reservation Charge revenue is subtracted from the Adjusted Cost of Gas, shown on line 17, to produce the Adjusted Cost of Gas Less Reservation Charge Revenue, which is $402 million, shown on line 23.

Q14. Why are Reservation Charge revenues removed from the Adjusted Cost of Gas?

A14. The revenues received through the Reservation Charge are removed from the Adjusted Cost of Gas because they are treated as an offset to the GCR Cost of Gas Sold. The pipeline reservation costs remain a part of the GCR costs for GCR reconciliation purposes. See the order in case U-17313 dated April 15, 2014.

Q15. What are the components of the Adjusted Cost of Gas?

A15. The Adjusted Cost of Gas includes: 1) the Total Booked Cost of Gas Sold and 2) the March 2023 Unbilled Revenue Adjustment.

Q16. What are the components of the Total Booked Cost of Gas Sold?

A16. The Total Booked Cost of Gas Sold, calculated in Exhibit A-20, includes the cost of: 1) Purchased Gas; 2) Gas (To)/From Storage; 3) Company Use Gas; 4) Lost and Unaccounted for Gas; and 5) Gas in Kind.

Q17. How is the cost of gas injected into or withdrawn from storage calculated?

A17. DTE Gas uses annual last in, first out (LIFO) accounting to calculate its cost of gas. Each calendar year's LIFO rate is calculated by dividing the annual cost of purchased gas by the total annual volume of purchased gas for that year. If, on a net basis, gas

Line No.

is injected into storage in a calendar year, then an increment is created. The increment is priced using that year's LIFO rate and a LIFO layer is created. If, on a net basis, gas is withdrawn from storage in the calendar year, then there is a decrement. The cost of storage gas withdrawn for a decrement is calculated using the most recent LIFO layer or layers injected into storage. The calculation of LIFO rates and cost of storage for January 2022 through March 2027 is included in detail in Exhibit A-22.

Q18. What is the cost of 2022 storage in this GCR period?

A18. A net decrement is forecasted for calendar year 2022. This decrement is priced at the forecasted 2021 LIFO rates and is calculated on page 2 of Exhibit A-22. The cost of storage gas for the calendar year is calculated on page 1, in lines 15 through 28. The impact of storage gas for the period April through December 2022, a $126 million decrease in the cost of gas, is calculated by summing the cost of storage gas for those months.

Q19. What is the cost of storage gas for the January through March 2023 period?

A19. The cost of storage gas used during the January through March 2023 period is based on the projected $3.53 per Mcf LIFO rate for 2023. In these three months, 35 Bcf is withdrawn and included in the 2022/2023 GCR Year's cost of gas at a total cost of $125 million. The net impact of storage gas for the GCR Year is a $2 million increase to the cost of gas. See Exhibit A-22, column (b), Line 42.

Q20. Have you included any provision for an over- or (under)recovery from the 2021–2022 GCR period?

Line No.

A20. Yes. At the time of this filing, DTE Gas projects that it will incur an under-recovery of $27.4 million from the 2021– 2022 GCR period.

Q21. What rate is used to calculate the cost of gas used by the Company, lost and unaccounted for, and received in kind?

A21. The jurisdictional rate[1] is used to calculate these costs. This rate, $3.50 per Mcf, calculated in Exhibit A-20, reflects the average cost of gas purchased for the Year.

Q22. What is the Unbilled Revenue Adjustment?

A22. The Unbilled Revenue Adjustment recognizes the revenue that will be accrued for volumes that are delivered to GCR customers in March 2023 but are not billed until April 2023 at the April 2023 GCR factor. This adjustment is calculated in lines 11 through 15 in Exhibit A-20.

Q23. Why is it necessary to adjust the Total Booked Cost of Gas Sold by the Unbilled Revenue Adjustment?

A23. The Unbilled Revenue Adjustment is necessary because the volumes of gas that are sold in March 2023 but not billed until April 2023 are still part of the 2022 – 2023 GCR Year. These revenues will be billed at the 2023 – 2024 GCR factor, so the value of those revenues is subtracted from the Total Booked Cost of Gas Sold.

Q24. How are the Adjusted Sales Volumes calculated on Exhibit A-20?

A24. The Adjusted Sales Volumes are calculated by subtracting the March 2022 Unbilled Volume Balance from the Year's Billed Sales Volumes. This adjustment for March

[1] Jurisdictional Rate is the Cost of Purchased Gas divided by the Volumes Purchased as defined in DTE Gas Tariff Section C7.1 (2).

2022 unbilled volumes recognizes that the revenues related to volumes delivered to GCR customers in March 2022 but billed for in April 2022 will be included in the 2021 - 2022 GCR reconciliation.

FORECASTED COST OF GAS

Q25. How did you calculate the forecasted cost of gas for the operational years April 2023 – March 2027 included in Exhibit A-21?

A25. To calculate the forecasted cost of gas for the operational years April 2023-March 2027, I used the same methodology and sources I used to calculate Exhibit A-20. This exhibit shows DTE Gas's forecasted cost of gas for the four remaining operational years of this GCR plan case.

CONTINGENCY MECHANISM

Q26. What is DTE Gas's contingency mechanism?

A26. DTE Gas streamlined the process in case U-20543 for GCR Plan Year 2020-2021 to use a matrix to determine the contingency factor each month based upon the mechanism that was previously approved in case U-16146. The mechanism allows DTE Gas to mitigate an under-recovery that would result from an increase in natural gas commodity market prices above those used to determine the base factor in the GCR Plan. Without a contingency mechanism, the incremental costs resulting from such a price increase cannot be recovered during the current GCR year using the maximum base GCR factor. Any under-recovery resulting from increases in market prices would be rolled forward into the next year's GCR calculation, shifting costs from one year to another. DTE Gas's contingency mechanism mitigates this cost shifting by allowing the Maximum Allowable GCR factor to reflect increases in GCR costs due to increasing market prices. The tariff sheet containing the contingency Maximum Allowable GCR factor matrix is provided in Exhibit A-23.

Q27. Has DTE Gas changed the methodology used to calculate its Maximum Allowable GCR factor amounts?

A27. Yes, we have updated the months that are used to determine the Maximum Allowable GCR Factor. Previously, we used the full two calendar years that the GCR year spans. Upon further review, an increase in gas costs during January, February, or March preceding the current GCR year will cause a reduction in GCR costs. This happens because an increase in gas costs during those months causes the LIFO rate of the first calendar year to increase, but there is a net injection into storage for the April – December period of the GCR year that falls in the first calendar year so an increase in the LIFO rate reduces costs. With the exception of excluding these three months from the calculation, the method of calculation remains the same. Rather than requiring a series of mathematical calculations each month, we completed the mathematical equations and populated the contingent factor matrix with the resulting maximum GCR factors. DTE Gas uses the single-input methodology first approved by the Commission in DTE Gas's 2010 - 2011 GCR Plan, Case No. U-16146, to develop its incremental contingency GCR amounts. The Commission has approved this methodology in each GCR Plan since that case. This method determines the factor needed, based on current market prices, to recover increased costs from that point in time forward. This method evaluates a single NYMEX strip to estimate the impact of changes in market prices not only on the current Year's purchases but also on the storage activity that is priced at LIFO. A Contingency Multiplier (Multiplier) is used to establish the Maximum Allowable GCR factors necessary based on changes in prices. The tariff sheet D-4.00 Monthly GCR Factor Ceiling Price Adjustment (Contingency) Mechanism was developed using the Multiplier.

Q28. How is the Multiplier calculated?

A28. First, the Company estimates gas costs for $1.00 per Dth and $2.00 per Dth NYMEX increases above Plan levels (provided by Company witness Schiffer). Using the same methodology shown in Exhibit A-20, I calculate two GCR factors based on these cost estimates. These calculations are performed in Exhibit A-24. The Company then compares the resultant GCR factors and uses them to calculate the impact of the NYMEX change on the GCR factor as shown in Table 1 below.

Table 1 Calculation of Fractional Multiplier

NYMEX	Resulting GCR Factor per Mcf	Change per Mcf
Based on April 2022 – December 2023 NYMEX	$3.29	
+$1.00 per Dth	$3.60	$0.31
+$2.00 per Dth	$3.96	$0.36
Average GCR Change per $1.00 NYMEX Change		$0.333
Multiplier ($0.333/$1.00, rounded)		33%

The Multiplier is then multiplied by $0.10 to arrive at the contingent factor for a $0.10 per Dth NYMEX increase, $0.033 per Mcf. Finally, the Company adds an incremental $0.033 per Mcf, rounded to the nearest penny, to the base GCR factor to establish the Maximum Allowable GCR factors on DTE Gas's tariff sheet D-4.00, included on Exhibit A-23.

Q29. Is DTE Gas proposing a Maximum Allowable GCR factor of $6.29 per Mcf ($3.29 per Mcf base GCR Factor + $3.00 per Dth Maximum NYMEX change)?

A29. No, DTE Gas is proposing only to reflect those costs that will be incurred if market prices increase. Even if prices increased by $3.00 per Dth, or more, DTE Gas's resultant maximum contingent factor would be well below the base maximum GCR factor plus \$3.00 per Dth, \$6.29 per Mcf. If prices increased \$3.00 per Dth above plan levels, then DTE Gas's maximum contingent GCR factor will be \$4.28 per Mcf shown on Exhibit A-24, page 2.

Q30. How has the process for determining the monthly Maximum Allowable GCR factor changed?

A30. No, DTE Gas will use the same process approved in U-20543, which includes calculating the factors to adjust for the impact that incremental increases in NYMEX have on the cost of gas. This is then used to populate the Contingency Matrix, allowing a simple comparison of the current NYMEX strip to the Matrix to determine the appropriate Maximum Allowable GCR factor.

Q31. Does the Contingency Mechanism still operate symmetrically?

A31. Yes. The NYMEX strip will indicate the appropriate maximum GCR factor, regardless whether that factor is greater than or less than the current GCR factor.

Q32. Why are prices from months outside of the Plan period included in the NYMEX averages calculated?

A32. April through December 2023 are included because they are used to derive LIFO rates. Because a large quantity of gas is withdrawn from storage in January - March 2023 at the 2023 LIFO rate, changes in NYMEX for April - December 2023 will influence the cost of storage during the plan year and impact the GCR factor.

Line No.

Q33. Why are no adjustments to the market price purchases made for prices that will be fixed during the year?

A33. It is impossible to know the price of any volumes fixed during the GCR year. Valuing the fixed volumes during the year at current market prices, is the best estimate of their cost during the GCR year.

Q34. How does DTE Gas plan to implement this factor?

A34. Prior to each month (March for April, June for July and so on), DTE Gas will make an informational filing with the MPSC, in this docket, calculating the current NYMEX prices and the corresponding Maximum Allowable GCR factor.

SUPPLIER OF LAST RESORT (SOLR)

Q35. What is the Supplier of Last Resort?

A35. The Supplier of Last Resort supplies Gas Customer Choice (GCC) customers' gas requirements should an alternative gas supplier fail to do so or if customers return to GCR supply from Gas Customer Choice. DTE Gas agreed to fulfill this role for GCC customers as a part of its voluntary GCC program. DTE Gas's responsibility for this role is contained in Section F of its tariff, paragraph F1.19. This charge was first approved by the Commission in its April 15, 2014 Order in Case No. U-17131 and was approved in each subsequent GCR Plan case.

Q36. Have you calculated the Reservation Charge?

A36. Yes, Exhibit A-26 calculates the Reservation Charge on an unbilled basis. Lines 1-7 adjust the Pipeline Reservation Cost to reflect the March 2023 unbilled revenue that will be collected at the 2023-2024 rate. The unbilled balance was taken from

Exhibit A-4. Line 15 presents the total GCR and GCC March 2022 unbilled volume balance and because any revenues associated with those volumes will be accrued into the 2021-2022 GCR year, those volumes are excluded from the calculation of the Reservation Charge. The adjusted Pipeline Reservation Cost, line 8, is divided by the April 2022 - March 2023 Adjusted Sales Volume, line 16, to produce the April 2022 – March 2023 GCR Reservation Charge, line 24, of an average rate of $0.40 per Mcf.

Q37. Have you calculated the Reservation Charge (RC) to include the 30% discount for GCC customers as directed by the Commission?

A37. Yes, I have. As described above, Exhibit A-26, lines 1-17 calculated the Reservation Charge in the manner the Company employed in prior cases. Lines 18-19 calculate a GCC RC that reflects a discount of 30%, which is $0.27 per Mcf. Lines 19-21 calculate the Reservation Charge revenue that will be received from GCC customers.

Q38. Does the Reservation Charge remove the pipeline costs from the GCR process?

A38. No, it does not. The revenue received through the Reservation Charge reduces the GCR Cost of Gas Sold.

Q39. Can the Reservation Charge be adjusted within the GCR year?

A39. Yes, but it can only be reduced. There are two main reasons DTE Gas might lower the Reservation Charge during the GCR year. While pipeline costs do not normally vary from year to year, GCR and GCC usage does. Although DTE Gas could not increase the rates if volumes were below projected levels, if volumes were higher than anticipated and a large over-recovery were anticipated, then DTE Gas might

Line No.

lower the rates. Likewise, if DTE Gas forecasts an over-recovery from the Reservation Charge, then it may lower the actual charge billed from the maximum allowable rate.

Q40. Does this conclude your direct testimony?

A40. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE Gas Company for approval of a	)	
Gas Cost Recovery Plan, 5-year Forecast	)	Case No. U-21064
and Monthly GCR Factor for the 12 months	)	
ending March 31, 2023	)	
	)	

EXHIBITS

OF

ANDREA R. HARDY

Michigan Public Service Commission
DTE Gas Company
Derivation of April 2022 through March 2023 GCR Factor

Case No.: U-21064
Exhibit: A-20
Witness: A. R. Hardy

Line	Description			(a)		(b)
	Calculation of Jurisdictional Rate					
1	Cost of Purchased Gas		$	468,243		
2	Volume of Purchased Gas			133,751		
3	Jurisdictional Rate	Line 1 / Line 2	$	3.50		
	Calculation of Total Booked Cost of Gas Sold					
4	Cost of Purchased Gas				$	468,243
5	Cost of Gas (To)/From Storage				$	1,807
6	Company Use, Lost and Unaccounted For and Gas in Kind					
7	Gas in Kind	A-13, Pg 1, Line 13, Col (i)		6,668		
8	Lost and Unaccounted For / Co Use	A-13, Pg 1, Line 13, Col (b)		(9,189)		
9	Total	(Line 7 + Line 8) * Line 3		(2,521)	$	(8,825)
10	**Total Booked Cost of Gas Sold**				**$**	**461,225**
	Calculation of March 2023 Unbilled Revenue Adjustment					
11	2023 - 2024 Net Cost of Gas Sold		$	470,491		
12	2023 - 2024 Annual Billed Sales	A-4, Pg 1, Line 27, Col (4)		131,536		
13	2023 - 2024 Average GCR Cost of Gas	Line 11 / Line 12	$	3.58		
14	March 2023 Unbilled Volume Balance	A-4, Pg 1, Line 26, Col (6)		(9,166)		
15	**March 2023 Unbilled Revenue Adjustment**	Line 13 * Line 14				**(32,813)**
16	**2021 - 2022 GCR Underrecovery**					**27,400**
17	**Adjusted Cost of Gas**	Line 10 + Line 15 + Line 16			**$**	**455,812**
	Calculation of Reservation Revenue Offset					
18	GCR Pipeline Reservation Rate	A-26 Line 24	$	0.40		
19	GCR Adjusted Sales Volume	Line 26		121,893		
20	GCR Reservation Charge Revenue	Line 18 * Line 19	$	(48,757)		
21	GCC Reservation Charge Revenue	A-26 Line 21		(5,528)		
22	Total Reservation Charge Revenue	Line 23 + Line 24				**(54,285)**
23	**Adjusted Cost of Gas Less Reservation Charge Revenue**	Line 17 + Line 22				**401,527**
	Calculation of Adjusted Sales Volumes					
24	April 2022 - March 2023 Billed Sales Volumes	A-4, Pg 1, Line 14, Col (4)		131,118		
25	March 2022 Unbilled Volume Balance	A-4, Pg 1, Line 1, Col (6)		(9,225)		
26	**April 2022 - March 2023 Adjusted Sales Volumes**	Line 18 + Line 19				**121,893**
27	**April 2022 - March 2023 GCR Factor**	Line 26 / Line 23				**3.29**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources:

Gas In Kind	A-13
LAUF / Co. Use / GIK (2)	A-13
Billed/Unbilled Sales	A-4
Purchased Gas Volumes (3)	A-10
Purchased Gas Costs (4)	A-12
Storage Costs (5)	A-22
Cost of Gas (6)	A-21

Michigan Public Service Commission
DTE Gas Company
Forecasted Cost of Gas
April 2023 - March 2024

Case No.: U-21064
Exhibit: A-21
Witness: A. R. Hardy

Line	Description		(a)	(b)
	Calculation of Jurisdictional Rate			
1	Cost of Purchased Gas		$ 477,800	
2	Volume of Purchased Gas		133,838	
3	Jurisdictional Rate	Line 1 / Line 2	$ 3.57	
	Calculation of Total Booked Cost of Gas Sold			
4	Cost of Purchased Gas			$ 477,800
5	Cost of Gas (To)/From Storage			$ 1,709
6	Gas in Kind	A-13, Pg 2, Line 13, Col (i)	6,621	
7	Lost and Unaccounted For / Co Use	A-13, Pg 2, Line 13, Col (b)	(9,147)	
8	Cost of GIK, LAUF, and Co. Use	(Line 6 + Line 7) * Line 3	(2,526)	$ (9,018)
9	**Total Booked Cost of Gas Sold**	Line 4 + Line 5 + Line 8		**$ 470,491**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources

LAUF / Co. Use / GIK	A-13
Purchased Gas Volumes	A-10
Purchased Gas Costs	A-12
Storage Costs	A-22

Line	Description		(a)	(b)
	Calculation of Jurisdictional Rate			
1	Cost of Purchased Gas		$ 478,053	
2	Volume of Purchased Gas		132,765	
3	Jurisdictional Rate	Line 1 / Line 2	$ 3.60	
	Calculation of Total Booked Cost of Gas Sold			
4	Cost of Purchased Gas			$ 478,053
5	Cost of Gas (To)/From Storage			$ (1,830)
6	Gas in Kind	A-13, Pg 3, Line 13 col (i)	6,399	
7	Lost and Unaccounted For / Co Use	A-13, Pg 3, Line 13 col (b)	(9,122)	
8	Cost of GIK, LAUF, and Co. Use	(Line 6 + Line 7) * Line 3	(2,723)	$ (9,803)
9	**Total Booked Cost of Gas Sold**	Line 4 + Line 5 + Line 8		**$ 466,420**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources

LAUF / Co. Use / GIK	A-13
Purchased Gas Volumes	A-10
Purchased Gas Costs	A-12
Storage Costs	A-22

Line	Description		(a)	(b)
	Calculation of Jurisdictional Rate			
1	Cost of Purchased Gas		$ 463,327	
2	Volume of Purchased Gas		132,224	
3	Jurisdictional Rate	Line 1 / Line 2	$ 3.50	
	Calculation of Total Booked Cost of Gas Sold			
4	Cost of Purchased Gas			$ 463,327
5	Cost of Gas (To)/From Storage			$ (1,115)
6	Gas in Kind	A-13, Pg 4, Line 13 col (i)	6,391	
7	Lost and Unaccounted For / Co Use	A-13, Pg 4, Line 13 col (b)	(9,017)	
8	Cost of GIK, LAUF, and Co. Use	(Line 6 + Line 7) * Line 3	(2,626)	$ (9,192)
9	**Total Booked Cost of Gas Sold**	Line 4 + Line 5 + Line 8		**$ 453,020**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources

LAUF / Co. Use / GIK	A-13
Purchased Gas Volumes	A-10
Purchased Gas Costs	A-12
Storage Costs	A-22

Michigan Public Service Commission
DTE Gas Company
Forecasted Cost of Gas
April 2026 - March 2027

Line	Description		(a)	(b)
	Calculation of Jurisdictional Rate			
1	Cost of Purchased Gas		$ 460,875	
2	Volume of Purchased Gas		131,620	
3	Jurisdictional Rate	Line 1 / Line 2	$ 3.50	
	Calculation of Total Booked Cost of Gas Sold			
4	Cost of Purchased Gas			$ 460,875
5	Cost of Gas (To)/From Storage			$ 20,996
6	Gas in Kind	A-13, Pg 5, Line 13 col (i)	6,291	
7	Lost and Unaccounted For / Co Use	A-13, Pg 5, Line 13 col (b)	(8,817)	
8	Cost of GIK, LAUF, and Co. Use	(Line 6 + Line 7) * Line 3	(2,526)	$ (8,842)
9	**Total Booked Cost of Gas Sold**	Line 4 + Line 5 + Line 8		**$ 473,029**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources

LAUF / Co. Use / GIK	A-13
Purchased Gas Volumes	A-10
Purchased Gas Costs	A-12
Storage Costs	A-22

Michigan Public Service Commission
DTE Gas Company
Calculation of LIFO Rate and Storage Costs

Case No.: U-21064
Exhibit: A-22
Witness: A. R. Hardy

Purchased Gas / LIFO Calculation

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		2022		2023		2024		2025		2026		2027	
Line		Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost
1	January	10,066	37,281	10,355	41,200	10,395	43,327	10,210	44,301	10,102	42,444	9,980	41,731
2	February	9,092	33,929	9,353	37,278	9,724	40,437	9,223	39,868	9,124	38,115	9,014	37,681
3	March	10,066	36,471	10,355	39,600	10,285	40,340	10,210	40,494	10,102	39,375	9,980	39,149
4	April	12,228	40,144	12,170	40,335	12,176	40,842	12,170	39,875	11,986	38,679		
5	May	12,636	41,212	12,575	40,925	12,581	40,669	12,576	39,903	12,386	39,043		
6	June	12,228	40,065	12,170	39,792	12,176	39,807	12,170	39,040	11,986	38,291		
7	July	12,636	41,511	12,575	41,490	12,581	42,049	12,576	40,961	13,479	43,481		
8	August	12,636	41,483	12,575	41,593	12,581	42,132	12,576	41,041	12,386	40,250		
9	September	12,228	39,888	12,170	39,584	12,176	40,060	12,170	38,920	11,986	38,317		
10	October	8,720	27,283	8,746	29,170	8,760	30,009	8,780	29,402	8,799	29,338		
11	November	10,021	38,256	10,059	38,554	9,881	36,742	9,776	35,000	9,658	35,328		
12	December	10,355	40,324	10,395	42,252	10,210	41,080	10,102	39,250	9,980	39,584		
13	Total	132,911	$ 457,846	133,497	$ 471,773	133,526	$ 477,495	132,539	$ 468,055	131,974	$ 462,249	28,974	$ 118,561
14	LIFO Rate		$ 3.44		$ 3.53		$ 3.58		$ 3.53		$ 3.50		$ 4.09

Gas (To)/From Storage

		2022		2023		2024		2025		2026		2027	
		Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost
15	January	15,286	$ 52,585	14,854	$ 52,433	14,742	$ 52,777	14,869	$ 52,487	14,889	$ 52,111	14,877	$ 60,846
16	February	13,530	46,543	13,186	46,545	13,578	48,610	13,198	46,588	13,218	46,263	13,254	54,208
17	March	7,771	26,732	7,311	25,808	7,335	26,259	7,375	26,032	7,423	25,982	7,494	30,649
18	April	(2,056)	(7,074)	(2,046)	(7,224)	(2,066)	(7,395)	(2,088)	(7,370)	(1,932)	(6,762)		
19	May	(7,985)	(27,467)	(7,958)	(28,092)	(7,961)	(28,501)	(7,967)	(28,122)	(7,787)	(27,254)		
20	June	(9,818)	(33,774)	(9,761)	(34,457)	(9,761)	(34,946)	(9,763)	(34,464)	(9,585)	(33,549)		
21	July	(10,669)	(36,701)	(10,607)	(37,441)	(10,605)	(37,966)	(10,604)	(37,432)	(11,511)	(40,289)		
22	August	(10,686)	(36,761)	(10,624)	(37,504)	(10,622)	(38,026)	(10,621)	(37,491)	(10,435)	(36,521)		
23	September	(9,686)	(33,321)	(9,628)	(33,988)	(9,622)	(34,448)	(9,626)	(33,980)	(9,446)	(33,062)		
24	October	(1,354)	(4,657)	(1,396)	(4,928)	(1,412)	(5,053)	(1,460)	(5,155)	(1,502)	(5,257)		
25	November	4,770	16,408	4,675	16,502	4,818	17,250	4,800	16,945	4,779	16,727		
26	December	10,898	37,487	11,670	41,195	11,575	41,438	11,784	41,598	11,788	41,256		
27	Decrement	873	2,881	-	-	206	709	-	-	-	-		
28	Total	873	$ 2,881	(326)	$ (1,152)	206	$ 709	(103)	$ (364)	(101)	$ (353)	35,624	$ 145,704

GCR Operational Storage for Cost of Gas (To)/From Storage

		2022 - 2023		2023 - 2024		2024 - 2025		2025 - 2026		2026 - 2027	
		Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost
29	April	(2,056)	(7,074)	(2,046)	$ (7,224)	(2,066)	$ (7,395)	(2,088)	$ (7,370)	(1,932)	$ (6,762)
30	May	(7,985)	(27,467)	(7,958)	(28,092)	(7,961)	(28,501)	(7,967)	(28,122)	(7,787)	(27,254)
31	June	(9,818)	(33,774)	(9,761)	(34,457)	(9,761)	(34,946)	(9,763)	(34,464)	(9,585)	(33,549)
32	July	(10,669)	(36,701)	(10,607)	(37,441)	(10,605)	(37,966)	(10,604)	(37,432)	(11,511)	(40,289)
33	August	(10,686)	(36,761)	(10,624)	(37,504)	(10,622)	(38,026)	(10,621)	(37,491)	(10,435)	(36,521)
34	September	(9,686)	(33,321)	(9,628)	(33,988)	(9,622)	(34,448)	(9,626)	(33,980)	(9,446)	(33,062)
35	October	(1,354)	(4,657)	(1,396)	(4,928)	(1,412)	(5,053)	(1,460)	(5,155)	(1,502)	(5,257)
36	November	4,770	16,408	4,675	16,502	4,818	17,250	4,800	16,945	4,779	16,727
37	December	10,898	37,487	11,670	41,195	11,575	41,438	11,784	41,598	11,788	41,256
38	Decrement	873	2,881	-	-	206	709	-	-	-	-
39	January	14,854	52,433	14,742	52,777	14,869	52,487	14,889	52,111	14,877	60,846
40	February	13,186	46,545	13,578	48,610	13,198	46,588	13,218	46,263	13,254	54,208
41	March	7,311	25,808	7,335	26,259	7,375	26,032	7,423	25,982	7,494	30,649
42	Total	(364)	$ 1,807	(21)	$ 1,709	(8)	$ (1,830)	(14)	$ (1,115)	(7)	$ 20,996

Note: All Volumes in MMCF @ 14.65 and Costs in '000s unless otherwise noted; There may be slight deviations in data with other exhibits due to rounding error.

Sources

Purchase Gas Costs	A-12	Cost Model
Purchase Gas Volumes	A-10	Cost Model
Storage Volumes	A-13	
Jan - March Base Year To From Storage		Other Input file
Volumes and Costs	Testimony of Witness Eric Schiffer	

Michigan Public Service Commission
DTE Gas Company
LIFO Layers and Decrement Cost Calculation

Line		(a)	(b)	(c)	(d)	(e)	(f)
					Beginning Storage Balance December 31, 2020		
						MMcf	**Cost / Mcf**
1					Per 1956	37,141	$ 0.28415
2					1956	14,928	$ 0.34313
3					1957	19,356	$ 0.38716
4					2002	1,259	$ 4.34650
5					2014	5,338	$ 5.18100
					2018	3,490	$ 3.31680

2021 Projected Storage Activity

Line		(Increment) / Decrement					
6	2021	(1,485)					
		LIFO Layer Impact			**Ending Storage Balance December 31, 2021**		
		MMcf	$ / Mcf	Cost in $000s		MMcf	Cost / Mcf
7	2021	(1,485)	$ 3.30000	$ (4,901)	Per 1956	37,141	$ 0.28415
8	Total	(1,485)		$ (4,901)	1956	14,928	$ 0.34313
9					1957	19,356	$ 0.38716
10					2002	1,259	$ 4.34650
11					2014	5,338	$ 5.18100
12					2018	3,490	$ 3.31680
					2021	1,485	$ 3.30000

2022 Projected Storage Activity

Line		(Increment) / Decrement					
13	2022	873					
		LIFO Layer Impact			**Ending Storage Balance December 31, 2022**		
14		MMcf	$ / Mcf	Cost in $000s	Pre 1956	37,141	$ 0.28415
15	2021	873	$ 3.30000	2,881	1956	14,928	$ 0.34313
16	Total	873		$ 2,881	1957	19,356	$ 0.38716
17					2002	1,259	$ 4.34650
18					2014	5,338	$ 5.18100
19					2018	3,490	$ 3.31680
20					2021	612	$ 3.30000
21							

2023 Projected Storage Activity

Line		(Increment) / Decrement					
22	2023	(326)					
		LIFO Layer Impact			**Ending Storage Balance December 31, 2023**		
23		MMcf	$ / Mcf	Cost in $000s	Pre 1956	37,141	$ 0.28415
24	2023	(326)	$ 3.44000	$ (1,122)	1956	14,928	$ 0.34313
25	Total	(326)		$ (1,122)	1957	19,356	$ 0.38716
26					2002	1,259	$ 4.34650
27					2014	5,338	$ 5.18100
28					2018	3,490	$ 3.31680
29					2021	612	$ 3.30000
30					2023	326	$ 3.44000

Michigan Public Service Commission
DTE Gas Company
LIFO Layers and Decrement Cost Calculation

2024 Projected Storage Activity

Line		(a)	(b)	(c)	(d)	(e)	(f)
		(Increment) / Decrement					
1	2024	206			**Ending Storage Balance** December 31, 2024		
		LIFO Layer Impact				MMcf	Cost / Mcf
2		MMcf	$ / Mcf	Cost in $000s	Pre 1956	37,141	$ 0.28415
3	2023	206	$ 3.44000	$ 709	1956	14,928	$ 0.34313
4	Total	206		$ 709	1957	19,356	$ 0.38716
5					2002	1,259	$ 4.34650
6					2014	5,338	$ 5.18100
7					2018	3,490	$ 3.31680
8					2021	612	$ 3.30000
9					2023	120	$ 3.44000
10							

2025 Projected Storage Activity

Line		(a)	(b)	(c)	(d)	(e)	(f)
		(Increment) / Decrement					
11	2025	(103)			**Ending Storage Balance** December 31, 2025		
		LIFO Layer Impact				MMcf	Cost / Mcf
12		MMcf	$ / Mcf	Cost in $000s	Pre 1956	37,141	$ 0.28415
13	2025	(103)	$ 3.53000	$ (364)	1956	14,928	$ 0.34313
14	Total	(103)		$ (364)	1957	19,356	$ 0.38716
15					2002	1,259	$ 4.34650
16					2014	5,338	$ 5.18100
17					2018	3,490	$ 3.31680
					2021	612	$ 3.30000
18					2023	120	$ 3.44000
19					2025	103	$ 3.53000
20							
21							

2026 Projected Storage Activity

Line		(a)	(b)	(c)	(d)	(e)	(f)
		(Increment) / Decrement					
22	2026	(101)			**Ending Storage Balance** December 31, 2026		
		LIFO Layer Impact				MMcf	Cost / Mcf
23		MMcf	$ / Mcf	Cost in $000s	Pre 1956	37,141	$ 0.28415
24	2026	(101)	$ 3.50000	$ (353)	1956	14,928	$ 0.34313
25	Total	(101)		$ (353)	1957	19,356	$ 0.38716
26					2002	1,259	$ 4.34650
27					2014	5,338	$ 5.18100
28					2018	3,490	$ 3.31680
29					2021	612	$ 3.30000
30					2023	120	$ 3.44000
31					2025	103	$ 3.53000
32					2026	101	$ 3.50000

D4. MONTHLY GCR FACTOR CEILING PRICE ADJUSTMENT (CONTINGENCY) MECHANISM

The Maximum Allowable GCR factors listed on Sheet No. D-3.00 may change on a monthly basis, for the remaining months of the April ***2022*** through March ***2023*** GCR Plan year, contingent upon the NYMEX futures prices. The Maximum Allowable GCR factor the base GCR factor of $3.29 per Mcf.

Current NYMEX Strip: The simple average of the actual NYMEX monthly natural gas futures contract settlement prices, ($/MMBtu) for April ***2022*** through December ***2023*** averaged over the first five trading days of the month prior to implementation. Closing prices may be used for months that are no longer trading on NYMEX.

By the fifteenth of each month, the Company shall file with the Michigan Public Service Commission an updated maximum allowable GCR factor. The filing shall include all supporting documents necessary to verify the Current NYMEX Strip including published NYMEX futures price sheets for the first five trading days of the month, such sheet being an authoritative source used by the gas industry. The filing shall be incorporated into the GCR Plan docket, Case No. ***U-21064***, with notice provided to all intervenors.

Current NYMEX Strip between		*Maximum Allowable GCR factor $/Mcf*
$0.00	*$3.65*	*$3.29*
$3.66	*$3.75*	*$3.32*
$3.76	*$3.85*	*$3.36*
$3.86	*$3.95*	*$3.39*
$3.96	*$4.05*	*$3.42*
$4.06	*$4.15*	*$3.46*
$4.16	*$4.25*	*$3.49*
$4.26	*$4.35*	*$3.52*
$4.36	*$4.45*	*$3.55*
$4.46	*$4.55*	*$3.59*
$4.56	*$4.65*	*$3.62*
$4.66	*$4.75*	*$3.65*
$4.76	*$4.85*	*$3.69*
$4.86	*$4.95*	*$3.72*
$4.96	*$5.05*	*$3.75*

Current NYMEX Strip between		*Maximum Allowable GCR factor $/Mcf*
$5.06	*$5.15*	*$3.79*
$5.16	*$5.25*	*$3.82*
$5.26	*$5.35*	*$3.85*
$5.36	*$5.45*	*$3.88*
$5.46	*$5.55*	*$3.92*
$5.56	*$5.65*	*$3.95*
$5.66	*$5.75*	*$3.98*
$5.76	*$5.85*	*$4.02*
$5.86	*$5.95*	*$4.05*
$5.96	*$6.05*	*$4.08*
$6.06	*$6.15*	*$4.12*
$6.16	*$6.25*	*$4.15*
$6.26	*$6.35*	*$4.18*
$6.36	*$6.45*	*$4.21*
$6.46	*$6.55*	*$4.25*
$6.56	*<*	*$4.28*

(Continued on Sheet No. D-4.00)

	(a)	(b)	(c)	(d)	(e)		(f)
Line	Description				Source		
1	Fractional Multiplier				Hardy Testimony Q28		33%
2	Incremental GCR per $0.10 / Dth Change				Hardy Testimony Q28	$	0.033
3	Base GCR Factor in Mcf				Exhibit A-20	$	3.29
4							
	Plan NYMEX Average in Dth						
5	Source: A-8			Plan NYMEX			
6		2022	2023	Average			
7	Jan		$ 4.134				
8	Feb		$ 4.013				
9	Mar		$ 3.723				
10	Apr	$ 3.630	$ 3.162				
11	May	$ 3.618	$ 3.098				
12	Jun	$ 3.659	$ 3.137				
13	Jul	$ 3.711	$ 3.182				
14	Aug	$ 3.724	$ 3.200				
15	Sep	$ 3.711	$ 3.195				
16	Oct	$ 3.747	$ 3.234				
17	Nov	$ 3.845	$ 3.358				
18	Dec	$ 4.033	$ 3.593				
19	Average			$ 3.56			

Michigan Public Service Commission
DTE Gas Company
Contingency Calculations
All NYMEX in Dth, GCR in $ per Mcf

	(a)	(b)		(c)	(d)	(e)	(f)
Line	NYMEX				GCR		
1	Change	Effective Band			Amount[1]	Authorized factor[2]	
2	$0.00			$3.65	$0.00	$3.29	
3	$0.10	$3.66	-	$3.75	$0.03	$3.32	
4	$0.20	$3.76	-	$3.85	$0.07	$3.36	
5	$0.30	$3.86	-	$3.95	$0.10	$3.39	
6	$0.40	$3.96	-	$4.05	$0.13	$3.42	
7	$0.50	$4.06	-	$4.15	$0.17	$3.46	
8	$0.60	$4.16	-	$4.25	$0.20	$3.49	
9	$0.70	$4.26	-	$4.35	$0.23	$3.52	
10	$0.80	$4.36	-	$4.45	$0.26	$3.55	
11	$0.90	$4.46	-	$4.55	$0.30	$3.59	
12	$1.00	$4.56	-	$4.65	$0.33	$3.62	
13	$1.10	$4.66	-	$4.75	$0.36	$3.65	
14	$1.20	$4.76	-	$4.85	$0.40	$3.69	
15	$1.30	$4.86	-	$4.95	$0.43	$3.72	
16	$1.40	$4.96	-	$5.05	$0.46	$3.75	
17	$1.50	$5.06	-	$5.15	$0.50	$3.79	
18	$1.60	$5.16	-	$5.25	$0.53	$3.82	
19	$1.70	$5.26	-	$5.35	$0.56	$3.85	
20	$1.80	$5.36	-	$5.45	$0.59	$3.88	
21	$1.90	$5.46	-	$5.55	$0.63	$3.92	
22	$2.00	$5.56	-	$5.65	$0.66	$3.95	
23	$2.10	$5.66	-	$5.75	$0.69	$3.98	
24	$2.20	$5.76	-	$5.85	$0.73	$4.02	
25	$2.30	$5.86	-	$5.95	$0.76	$4.05	
26	$2.40	$5.96	-	$6.05	$0.79	$4.08	
27	$2.50	$6.06	-	$6.15	$0.83	$4.12	
28	$2.60	$6.16	-	$6.25	$0.86	$4.15	
29	$2.70	$6.26	-	$6.35	$0.89	$4.18	
30	$2.80	$6.36	-	$6.45	$0.92	$4.21	
31	$2.90	$6.46	-	$6.55	$0.96	$4.25	
32	$3.00	$6.56	-		$0.99	$4.28	
33							

1 Fractional Multiplier * NYMEX Change
2 Base factor plus incremental contingency amount

Michigan Public Service Commission
DTE Gas Company
Derivation of April 2022 through March 2023 GCR Factor + $1

Case No.: U-21064
Exhibit: A-24
Witness: A. R. Hardy

Line	Description			(a)		(b)
	Calculation of Jurisdictional Rate					
1	Cost of Purchased Gas		$	503,817		
2	Volume of Purchased Gas			133,751		
3	Jurisdictional Rate	Line 1 / Line 2	$	3.77		
	Calculation of Total Booked Cost of Gas Sold					
4	Cost of Purchased Gas				$	503,817
5	Cost of Gas (To)/From Storage				$	14,627
6	Company Use, Lost and Unaccounted For and Gas in Kind					
7	Gas in Kind	A-13, Pg 1, Line 13, Col (i)		6,668		
8	Lost and Unaccounted For / Co Use	A-13, Pg 1, Line 13, Col (b)		(9,189)		
9	Total	(Line 7 + Line 8) * Line 3		(2,521)	$	(9,505)
10	**Total Booked Cost of Gas Sold**				**$**	**508,939**
	Calculation of March 2023 Unbilled Revenue Adjustment					
11	2023 - 2024 Net Cost of Gas Sold		$	572,769		
12	2023 - 2024 Annual Billed Sales	A-4, Pg 1, Line 27, Col (4)		131,536		
13	2023 - 2024 Average GCR Cost of Gas	Line 11 / Line 12	$	4.35		
14	March 2023 Unbilled Volume Balance	A-4, Pg 1, Lime 26, Col (6)		(9,166)		
15	**March 2023 Unbilled Revenue Adjustment**	Line 13 * Line 14				**(39,871)**
16	**2021 - 2022 GCR Underrecovery**					**27,400**
17	**Adjusted Cost of Gas**	Line 10 + Line 15 + Line 16			**$**	**496,468**
	Calculation of Reservation Revenue Offset					
18	GCR Pipeline Reservation Rate	A-26 Line 24	$	0.40		
19	GCR Adjusted Sales Volume	Line 26		121,893		
20	GCR Reservation Charge Revenue	Line 18 * Line 19	$	(48,757)		
21	GCC Reservation Charge Revenue	A-26 Line 21		(5,528)		
22	Total Reservation Charge Revenue	Line 23 + Line 24				**(54,285)**
23	**Adjusted Cost of Gas Less Reservation Charge Revenue**	Line 17 + Line 22				**442,183**
	Calculation of Adjusted Sales Volumes					
24	April 2022 - March 2023 Billed Sales Volumes	A-4, Pg 1, Line 14, Col (4)		131,118		
25	March 2022 Unbilled Volume Balance	A-4, Pg 1, Line 1, Col (6)		(9,225)		
26	**April 2022 - March 2023 Adjusted Sales Volumes**	Line 18 + Line 19				**121,893**
27	**April 2022 - March 2023 GCR Factor**	Line 26 / Line 23				**3.63**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources:

Gas In Kind	A-13
LAUF / Co. Use / GIK (2)	A-13
Billed/Unbilled Sales	A-4
Purchased Gas Volumes (3)	A-10
Purchased Gas Costs (4)	A-10
Storage Costs (5)	A-22
Cost of Gas (6)	A-24

Michigan Public Service Commission
DTE Gas Company
Forecasted Cost of Gas
Derivation Contingent Factor + $1
April 2023 - March 2024

Case No.:	U-21064
Exhibit:	A-24
Witness:	A. R. Hardy
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Line	Description		(a)	(b)
	Calculation of Jurisdictional Rate			
1	Cost of Purchased Gas		$ 567,519	
2	Volume of Purchased Gas		133,838	
3	Jurisdictional Rate	Line 1 / Line 2	$ 4.24	
	Calculation of Total Booked Cost of Gas Sold			
4	Cost of Purchased Gas			$ 567,519
5	Cost of Gas (To)/From Storage			$ 15,959
6	Gas in Kind	A-13, Pg 2, Line 13, Col (i)	6,621	
7	Lost and Unaccounted For / Co Use	A-13, Pg 2, Line 13, Col (b)	(9,147)	
8	Cost of GIK, LAUF, and Co. Use	(Line 6 + Line 7) * Line 3	(2,526)	$ (10,710)
9	**Total Booked Cost of Gas Sold**	Line 4 + Line 5 + Line 8		**$ 572,769**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources	
LAUF / Co. Use / GIK	A-13
Purchased Gas Volumes	A-10
Purchased Gas Costs	A-10
Storage Costs	A-22

Michigan Public Service Commission
DTE Gas Company
Derivation Contingent Factor + $1
Calculation of LIFO Rate and Storage Costs

Case No.: U-21064
Exhibit: A-24
Witness: A. R. Hardy
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		(a)	(b)	(c)	(d)	(e)	(f)
		Purchased Gas / LIFO Calculation					
		2022		**2023**		**2024**	
Line		**Volume**	**Cost**	**Volume**	**Cost**	**Volume**	**Cost**
1	January	10,066	37,281	10,355	44,007	10,395	50,429
2	February	9,092	33,929	9,353	39,814	9,724	47,082
3	March	10,066	36,471	10,355	42,405	10,285	47,312
4	April	12,228	43,406	12,170	48,634	12,176	53,849
5	May	12,636	44,560	12,575	49,501	12,581	54,109
6	June	12,228	43,305	12,170	48,061	12,176	52,814
7	July	12,636	44,859	12,575	50,065	12,581	55,489
8	August	12,636	44,832	12,575	50,136	12,581	55,572
9	September	12,228	43,128	12,170	47,851	12,176	53,036
10	October	8,720	29,526	8,746	33,667	8,760	39,304
11	November	10,021	40,895	10,059	45,427	9,881	47,283
12	December	10,355	43,081	10,395	49,354	10,210	51,971
13	Total	132,911	$ 485,272	133,497	$ 548,922	133,526	$ 608,248
14	LIFO Rate		**$ 3.65**		**$ 4.11**		**$ 4.56**

		Gas (To)/From Storage					
		2022		**2023**		**2024**	
		Volume	**Cost**	**Volume**	**Cost**	**Volume**	**Cost**
15	January	15,286	$ 55,795	14,854	$ 61,048	14,742	$ 67,225
16	February	13,530	49,384	13,186	54,192	13,578	61,917
17	March	7,771	28,364	7,311	30,048	7,335	33,447
18	April	(2,056)	(7,505)	(2,046)	(8,411)	(2,066)	(9,419)
19	May	(7,985)	(29,144)	(7,958)	(32,708)	(7,961)	(36,303)
20	June	(9,818)	(35,836)	(9,761)	(40,119)	(9,761)	(44,512)
21	July	(10,669)	(38,942)	(10,607)	(43,593)	(10,605)	(48,359)
22	August	(10,686)	(39,005)	(10,624)	(43,666)	(10,622)	(48,435)
23	September	(9,686)	(35,355)	(9,628)	(39,573)	(9,622)	(43,877)
24	October	(1,354)	(4,941)	(1,396)	(5,737)	(1,412)	(6,436)
25	November	4,770	17,410	4,675	19,213	4,818	21,972
26	December	10,898	39,776	11,670	47,963	11,575	52,781
27	Decrement	873	2,881	-	-	206	847
28	Total	873	$ 2,881	(326)	$ (1,341)	206	$ 847

		GCR Operational Storage for Cost of Gas (To)/From Storage					
		2022 - 2023		**2023 - 2024**		**2024 - 2025**	
		Volume	**Cost**	**Volume**	**Cost**	**Volume**	**Cost**
29	April	(2,056)	(7,505)	(2,046)	$ (8,411)	(2,066)	$ (9,419)
30	May	(7,985)	(29,144)	(7,958)	(32,708)	(7,961)	(36,303)
31	June	(9,818)	(35,836)	(9,761)	(40,119)	(9,761)	(44,512)
32	July	(10,669)	(38,942)	(10,607)	(43,593)	(10,605)	(48,359)
33	August	(10,686)	(39,005)	(10,624)	(43,666)	(10,622)	(48,435)
34	September	(9,686)	(35,355)	(9,628)	(39,573)	(9,622)	(43,877)
35	October	(1,354)	(4,941)	(1,396)	(5,737)	(1,412)	(6,436)
36	November	4,770	17,410	4,675	19,213	4,818	21,972
37	December	10,898	39,776	11,670	47,963	11,575	52,781
38	Decrement	873	2,881	-	-	206	847
39	January	14,854	61,048	14,742	67,225	-	-
40	February	13,186	54,192	13,578	61,917	-	-
41	March	7,311	30,048	7,335	33,447	-	-
42	Total	(364)	$ 14,627	(21)	$ 15,959	(35,449)	$ (161,741)

Note: All Volumes in MMCF @ 14.65 and Costs in '000s unless otherwise noted; There may be slight deviations in data with other exhibits due to rounding error.

Sources

Purchase Gas Costs	A-10	Cost Model
Purchase Gas Volumes	A-10	Cost Model
Storage Volumes	A-13	
Jan - March 2019 Purchase Volumes and Costs	Testimony of Witness Eric Schiffer	

Michigan Public Service Commission
DTE Gas Company
Derivation Contingent Factor + $1
LIFO Layers and Decrement Cost Calculation

	(a)	(b)	(c)	(d)	(e)	(f)
				Beginning Storage Balance		
				December 31, 2020		
Line					**MMcf**	**Cost / Mcf**
1				Per 1956	37,141	$ 0.28415
2				1956	14,928	$ 0.34313
3				1957	19,356	$ 0.38716
4				2002	1,259	$ 4.34650
5				2014	5,338	$ 5.18100
				2018	3,490	$ 3.31680

2021 Projected Storage Activity

Line		(Increment) / Decrement
6	2021	(1,485)

Line		LIFO Layer Impact MMcf	$ / Mcf	Cost in $000s	Ending Storage Balance December 31, 2021	MMcf	Cost / Mcf
7	2021	(1,485)	$ 3.30000	$ (4,901)	Per 1956	37,141	$ 0.28415
8	Total	(1,485)		$ (4,901)	1956	14,928	$ 0.34313
9					1957	19,356	$ 0.38716
10					2002	1,259	$ 4.34650
11					2014	5,338	$ 5.18100
12					2018	3,490	$ 3.31680
13					2021	1,485	$ 3.30000

2022 Projected Storage Activity

Line		(Increment) / Decrement
14	2022	873

Line		LIFO Layer Impact MMcf	$ / Mcf	Cost in $000s	Ending Storage Balance December 31, 2022	MMcf	Cost / Mcf
15					Pre 1956	37,141	$ 0.28415
16	2021	873	$ 3.30000	$ 2,881	1956	14,928	$ 0.34313
17	Total	873		$ 2,881	1957	19,356	$ 0.38716
18					2002	1,259	$ 4.34650
19					2014	5,338	$ 5.18100
20					2018	3,490	$ 3.31680
21					2021	612	$ 3.30000
22							

2023 Projected Storage Activity

Line		(Increment) / Decrement
22	2023	(326)

Line		LIFO Layer Impact MMcf	$ / Mcf	Cost in $000s	Ending Storage Balance December 31, 2023	MMcf	Cost / Mcf
23					Pre 1956	37,141	$ 0.28415
24	2023	(326)	$ 4.11000	$ (1,341)	1956	14,928	$ 0.34313
25	Total	(326)		$ (1,341)	1957	19,356	$ 0.38716
26					2002	1,259	$ 4.34650
27					2014	5,338	$ 5.18100
28					2018	3,490	$ 3.31680
29					2021	612	$ 3.30000
30					2023	326	$ 4.11000

Michigan Public Service Commission
DTE Gas Company
Derivation of April 2022 through March 2023 GCR Factor + $2

Case No.: U-21064
Exhibit: A-24
Witness: A. R. Hardy
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Line	Description			(a)		(b)
	Calculation of Jurisdictional Rate					
1	Cost of Purchased Gas		$	539,391		
2	Volume of Purchased Gas			133,751		
3	Jurisdictional Rate	Line 1 / Line 2	$	4.03		
	Calculation of Total Booked Cost of Gas Sold					
4	Cost of Purchased Gas				$	539,391
5	Cost of Gas (To)/From Storage				$	27,447
6	Company Use, Lost and Unaccounted For and Gas in Kind					
7	Gas in Kind	A-13, Pg 1, Line 13, Col (i)		6,668		
8	Lost and Unaccounted For / Co Use	A-13, Pg 1, Line 13, Col (b)		(9,189)		
9	Total	(Line 7 + Line 8) * Line 3		(2,521)	$	(10,161)
10	**Total Booked Cost of Gas Sold**				**$**	**556,677**
	Calculation of March 2023 Unbilled Revenue Adjustment					
11	2023 - 2024 Net Cost of Gas Sold		$	674,689		
12	2023 - 2024 Annual Billed Sales	A-4, Pg 1, Line 27, Col (4)		131,536		
13	2023 - 2024 Average GCR Cost of Gas	Line 11 / Line 12	$	5.13		
14	March 2023 Unbilled Volume Balance	A-4, Pg 1, Line 26, Col (6)		(9,166)		
15	**March 2023 Unbilled Revenue Adjustment**	Line 13 * Line 14				**(47,020)**
16	**2021 - 2022 GCR Underrecovery**					**27,400**
17	**Adjusted Cost of Gas**	Line 10 + Line 15 + Line 16			**$**	**537,057**
	Calculation of Reservation Revenue Offset					
18	GCR Pipeline Reservation Rate	A-26 Line 24	$	0.40		
19	GCR Adjusted Sales Volume	Line 26		121,893		
20	GCR Reservation Charge Revenue	Line 18 * Line 19	$	(48,757)		
21	GCC Reservation Charge Revenue	A-26 Line 21		(5,528)		
22	Total Reservation Charge Revenue	Line 23 + Line 24				**(54,285)**
23	**Adjusted Cost of Gas Less Reservation Charge Revenue**	Line 17 + Line 22				**482,772**
	Calculation of Adjusted Sales Volumes					
24	April 2022 - March 2023 Billed Sales Volumes	A-4, Pg 1, Line 14, Col (4)		131,118		
25	March 2022 Unbilled Volume Balance	A-4, Pg 1, Line 1, Col (6)		(9,225)		
26	**April 2022 - March 2023 Adjusted Sales Volumes**	Line 18 + Line 19				**121,893**
27	**April 2022 - March 2023 GCR Factor**	Line 26 / Line 23				**3.96**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources:

Gas In Kind	A-13
LAUF / Co. Use / GIK (2)	A-13
Billed/Unbilled Sales	A-4
Purchased Gas Volumes (3)	A-10
Purchased Gas Costs (4)	A-10
Storage Costs (5)	A-22
Cost of Gas (6)	A-24

Michigan Public Service Commission
DTE Gas Company
Forecasted Cost of Gas
Derivation Contingent Factor + $2
April 2023 - March 2024

Case No.: U-21064
Exhibit: A-24
Witness: A. R. Hardy
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Line	Description		(a)	(b)
	Calculation of Jurisdictional Rate			
1	Cost of Purchased Gas		$ 657,239	
2	Volume of Purchased Gas		133,838	
3	Jurisdictional Rate	Line 1 / Line 2	$ 4.91	
	Calculation of Total Booked Cost of Gas Sold			
4	Cost of Purchased Gas			$ 657,239
5	Cost of Gas (To)/From Storage			$ 29,853
6	Gas in Kind	A-13, Pg 2, Line 13, Col (i)	6,621	
7	Lost and Unaccounted For / Co Use	A-13, Pg 2, Line 13, Col (b)	(9,147)	
8	Cost of GIK, LAUF, and Co. Use	(Line 6 + Line 7) * Line 3	(2,526)	$ (12,402)
9	**Total Booked Cost of Gas Sold**	Line 4 + Line 5 + Line 8		**$ 674,689**

Note: All Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Sources

LAUF / Co. Use / GIK	A-13
Purchased Gas Volumes	A-10
Purchased Gas Costs	A-10
Storage Costs	A-22

Michigan Public Service Commission
DTE Gas Company
Derivation Contingent Factor + $2
Calculation of LIFO Rate and Storage Costs

Case No.: U-21064
Exhibit: A-24
Witness: A. R. Hardy

Purchased Gas / LIFO Calculation

		(a)	(b)	(c)	(d)	(e)	(f)
		2022		2023		2024	
Line		Volume	Cost	Volume	Cost	Volume	Cost
1	January	10,066	37,281	10,355	46,814	10,395	57,531
2	February	9,092	33,929	9,353	42,349	9,724	53,726
3	March	10,066	36,471	10,355	45,211	10,285	54,285
4	April	12,228	46,668	12,170	56,932	12,176	66,855
5	May	12,636	47,908	12,575	58,076	12,581	67,548
6	June	12,228	46,545	12,170	56,330	12,176	65,820
7	July	12,636	48,207	12,575	58,641	12,581	68,929
8	August	12,636	48,180	12,575	58,679	12,581	69,012
9	September	12,228	46,368	12,170	56,119	12,176	66,012
10	October	8,720	31,770	8,746	38,165	8,760	48,600
11	November	10,021	43,533	10,059	52,299	9,881	57,823
12	December	10,355	45,837	10,395	56,456	10,210	62,862
13	Total	132,911	$ 512,698	133,497	$ 626,071	133,526	$ 739,002
14	LIFO Rate		**$ 3.86**		**$ 4.69**		**$ 5.53**

Gas (To)/From Storage

		2022		2023		2024	
		Volume	Cost	Volume	Cost	Volume	Cost
15	January	15,286	$ 59,005	14,854	$ 69,663	14,742	$ 81,525
16	February	13,530	52,225	13,186	61,840	13,578	75,088
17	March	7,771	29,996	7,311	34,288	7,335	40,562
18	April	(2,056)	(7,937)	(2,046)	(9,597)	(2,066)	(11,422)
19	May	(7,985)	(30,820)	(7,958)	(37,323)	(7,961)	(44,025)
20	June	(9,818)	(37,898)	(9,761)	(45,780)	(9,761)	(53,981)
21	July	(10,669)	(41,182)	(10,607)	(49,745)	(10,605)	(58,646)
22	August	(10,686)	(41,249)	(10,624)	(49,828)	(10,622)	(58,738)
23	September	(9,686)	(37,389)	(9,628)	(45,157)	(9,622)	(53,211)
24	October	(1,354)	(5,226)	(1,396)	(6,547)	(1,412)	(7,806)
25	November	4,770	18,411	4,675	21,925	4,818	26,646
26	December	10,898	42,064	11,670	54,732	11,575	64,009
27	Decrement	873	2,881	-	-	206	967
28	Total	873	$ 2,881	(326)	$ (1,530)	206	$ 967

GCR Operational Storage for Cost of Gas (To)/From Storage

		2022 - 2023		2023 - 2024		2024 - 2025	
		Volume	Cost	Volume	Cost	Volume	Cost
29	April	(2,056)	(7,937)	(2,046)	$ (9,597)	(2,066)	$ (11,422)
30	May	(7,985)	(30,820)	(7,958)	(37,323)	(7,961)	(44,025)
31	June	(9,818)	(37,898)	(9,761)	(45,780)	(9,761)	(53,981)
32	July	(10,669)	(41,182)	(10,607)	(49,745)	(10,605)	(58,646)
33	August	(10,686)	(41,249)	(10,624)	(49,828)	(10,622)	(58,738)
34	September	(9,686)	(37,389)	(9,628)	(45,157)	(9,622)	(53,211)
35	October	(1,354)	(5,226)	(1,396)	(6,547)	(1,412)	(7,806)
36	November	4,770	18,411	4,675	21,925	4,818	26,646
37	December	10,898	42,064	11,670	54,732	11,575	64,009
38	Decrement	873	2,881	-	-	206	967
39	January	14,854	69,663	14,742	81,525	-	-
40	February	13,186	61,840	13,578	75,088	-	-
41	March	7,311	34,288	7,335	40,562	-	-
42	Total	(364)	$ 27,447	(21)	$ 29,853	(35,449)	$ (196,207)

Note: All Volumes in MMCF @ 14.65 and Costs in '000s unless otherwise noted; There may be slight deviations in data with other exhibits due to rounding error.

Sources

Purchase Gas Costs	A-10	Cost Model
Purchase Gas Volumes	A-10	Cost Model
Storage Volumes	A-13	
Jan - March 2019 Purchase Volumes and Costs	Testimony of Witness Eric Schiffer	

Michigan Public Service Commission
DTE Gas Company
Derivation Contingent Factor + $2
LIFO Layers and Decrement Cost Calculation

Case No.: U-21064
Exhibit: A-24
Witness: A. R. Hardy
Page: Page 10 of 10

Line		(a)	(b)	(c)	(d)	(e)	(f)
					Beginning Storage Balance December 31, 2020		
						MMcf	**Cost / Mcf**
1					Per 1956	37,141	$ 0.28415
2					1956	14,928	$ 0.34313
3					1957	19,356	$ 0.38716
4					2002	1,259	$ 4.34650
5					2014	5,338	$ 5.18100
					2018	3,490	$ 3.31680

2021 Projected Storage Activity

Line		(Increment) / Decrement					
6	2021	(1,485)					
		LIFO Layer Impact			**Ending Storage Balance** December 31, 2021		
		MMcf	$ / Mcf	Cost in $000s		MMcf	Cost / Mcf
7	2021	(1,485)	$ 3.30000	$ (4,901)	Per 1956	37,141	$ 0.28415
8	Total	(1,485)		$ (4,901)	1956	14,928	$ 0.34313
9					1957	19,356	$ 0.38716
10					2002	1,259	$ 4.34650
11					2014	5,338	$ 5.18100
12					2018	3,490	$ 3.31680
13					2021	1,485	$ 3.30000

2022 Projected Storage Activity

Line		(Increment) / Decrement					
14	2022	873			**Ending Storage Balance** December 31, 2022		
		LIFO Layer Impact				MMcf	Cost / Mcf
15		MMcf	$ / Mcf	Cost in $000s	Pre 1956	37,141	$ 0.28415
16	2021	873	$ 3.30000	2,881	1956	14,928	$ 0.34313
17	Total	873		$ 2,881	1957	19,356	$ 0.38716
18					2002	1,259	$ 4.34650
19					2014	5,338	$ 5.18100
20					2018	3,490	$ 3.31680
21					2021	612	$ 3.30000
22							

2023 Projected Storage Activity

Line		(Increment) / Decrement					
22	2023	(326)			**Ending Storage Balance** December 31, 2023		
		LIFO Layer Impact				MMcf	Cost / Mcf
23		MMcf	$ / Mcf	Cost in $000s	Pre 1956	37,141	$ 0.28415
24	2023	(326)	$ 4.69000	$ (1,530)	1956	14,928	$ 0.34313
25	Total	(326)		$ (1,530)	1957	19,356	$ 0.38716
26					2002	1,259	$ 4.34650
27					2014	5,338	$ 5.18100
28					2018	3,490	$ 3.31680
29					2021	612	$ 3.30000
30					2023	326	$ 4.69000

Michigan Public Service Commission
DTE Gas Company
Calculation of Reservation Charge
Applied to GCC and GCR Customers

Case No.: U-21064
Exhibit: A-26
Witness: A. R. Hardy
Page: 1 of 1

Volumes in MMcf @14.65 and Costs in '000s unless otherwise noted.

Line No.	(a) Description	(b)	(c)	(d) Source
	Calculation of Reservation Charge			
1	2022 - 2023 Pipeline Reservation Cost (PRC)		$ 58,503	A-11, pg 1, Line 31, Col (14)
2	**Calculation of March 2023 Unbilled Revenue Adjustment**			
3	2023 - 2024 Pipeline Reservation Cost	$ 58,311		A-11, pg 2, Line 31, Col (14)
4	2023 - 2024 GCR + GCC Sales	153,003		A-1, pg 1, Line 13, Col (a)
5	2023 - 2024 Average Reservation Rate	$ 0.38		Line 3 / Line 4
6	March 2023 GCR + GCC Unbilled Volume Balance	(10,636)		A-4, Pg 1, Line 13, Col 6 + Col 14
7	**March 2023 GCR + GCC Revenue Adjustment**		**$ (4,054)**	Line 5 * Line 6
8	Adjusted Pipeline Reservation Cost		$ 54,449	Line 1 - Line 7
9	April 2022 - March 2023 Billed Sales Volumes			
10	GCR	131,118		A-20 Line 24
11	GCC	21,932		A-4, pg 1, Line 14, Col (12)
12	Total Billed Sales (GCR + GCC)	153,050		Line 9 + Line 10
13	March 2022 GCR Unbilled	(9,225)		A-4, pg 1, Line 1, Col (6)
14	March 2022 GCC Unbilled	(1,458)		A-4, pg 1, Line 1, Col (14)
15	March 2022 GCR +GCC Unbilled Volume Balance	(10,683)		Line 13+Line 14
16	April 2022 - March 2023 Adjusted Sales Volumes		142,367	Line 12 + Line 15
17	April 2022 - March 2023 Reservation Base Rate	$ 0.38		Line 8 / Line 16
18	30% Discount	$ (0.11)		-30%* Line 17
19	**GCC RC Rate**		**$ 0.27**	Line 17 + Line 18
20	GCC Volume	20,474		Line 11 +Line 14
21	GCC Revenue	$ 5,528		Line 19 * Line 20
22	Net GCR Pipeline Cost	$ 48,921		Line 8 - Line 21
23	GCR Adjusted Sales Volume	121,893		Line 10 + Line 13
24	**GCR RC Rate**		**$ 0.40**	Line 22 / Line 23

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Gas Company** for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2023	))))))	Case No. U-21064

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KENNETH A. SOSNICK

DTE GAS COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KENNETH A SOSNICK

Line
No.

Q1. Please state your name and business address.

A1. My name is Kenneth Sosnick (he/him/his). My business address is 200 State Street, Boston, Massachusetts 02109.

Q2. On whose behalf are you testifying?

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

Q3. By whom are you employed and in what capacity?

A3. I am a Managing Director in the Power & Utilities practice at FTI Consulting, Inc. (FTI).

Q4. Please describe FTI and its Power & Utilities practice.

A4. FTI is a worldwide consulting firm dedicated to helping organizations manage change, mitigate risk, and resolve disputes. Our Power & Utilities practice brings these services to firms in regulated and competitive energy industries. The services we provide our utility clients include expert testimony, regulatory advice, support for strategic decision-making, and advice regarding investments and capital allocation. Our team is comprised of former utility executives, regulators, investors, and financial analysts that combine for hundreds of years of experience in the regulated energy space.

Q5. Please summarize your educational background.

A5. I hold a Bachelor of Science in Accounting from Indiana University of Pennsylvania.

Line No.

Q6. Please describe your work experience.

A6. I have been with FTI since February 2019. Previously, I consulted with Concentric Energy Advisors, Inc. in Marlborough, MA, consulted with MRW & Associates in Oakland, CA and was a subject matter expert and testifying witness in the Office of Administrative Litigation at the Federal Energy Regulatory Commission ("FERC").

Q7. Have you previously sponsored testimony before utility commissions?

A7. Yes. I have appeared as a testifying expert before utility regulators in New Hampshire, North Carlina and before FERC. Additionally, I have been retained in several instances to advise state regulators and their staff, including assignments on behalf of utility regulators in California, District of Columbia, Maryland, and Michigan.

Q8. Have you previously testified before the Commission?

A8. Yes. I adopted testimony on behalf of DTE Electric in Cases No U-20528 and. U-20826 and DTE Gas in U-20236 as well as filed rebuttal in U-20236. Prior to that, I testified before the New Hampshire Public Utilities Commission, the District of Columbia Public Service Commission, and the Federal Energy Regulatory Commission. I have also been retained as an expert on natural gas and competitive markets for civil disputes, administrative proceedings, and arbitrations.

<u>Purpose of Testimony</u>

Q9. What is the purpose of your testimony in this proceeding?

A9. The Company has asked me to estimate the impacts to DTE Gas customers specifically, and customers in Michigan generally, from the development of the NEXUS Gas Transmission pipeline (NEXUS). To do so, the team at FTI and I developed long-run simulations of relevant gas markets, including the Upper Midwest and supply regions, from whose results we estimated how NEXUS is expected to affect the delivered cost of gas that will be paid by consumers in Michigan. My analysis and results are described in detail in Exhibit A-32, FTI Report "NEXUS Pipeline Impacts Analysis." The purpose of my testimony is to introduce and summarize that report.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. I am sponsoring the following exhibit(s):

Exhibit	Description
A-31	K. A. Sosnick Curriculum Vitae
A-32	FTI Report "NEXUS Pipeline Impacts Analysis"

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes.

Q12. Can you please briefly summarize the primary conclusions you reached based on your analysis?

A12. Yes. My testimony describes an analysis I contributed to and oversaw that shows that NEXUS will decrease natural gas prices in Michigan significantly. Decreases in prices create savings for all the gas consumers in the state, including customers of DTE Gas, DTE Electric, and customers of other utilities. Those savings are greater than the costs of the contract that DTE Gas executed for long-term firm transportation entitlements on NEXUS. My primary conclusion, therefore, is that the Company's execution of its contracts for NEXUS supply have been very

Line No.

beneficial to its customers. Later in my testimony, I also describe additional reliability and environmental benefits that create additional value for DTE Gas customers and all Michigan consumers.

Q13. How large are the projected savings?

A13. For the period 2022 to 2038, the total savings to Michigan's gas customers is approximately $1 billion, which includes $199 million in savings to customers of DTE Gas. As I explain later in my testimony, the team at FTI and I also estimated savings under an alternative scenario in which demand is assumed to increase and the savings are even greater.

Q14. How is the rest of your testimony organized?

A14. *First*, I briefly describe the NEXUS system and the entitlements held by the Company. *Second*, I explain the simulations I developed to forecast delivered prices with and without NEXUS in service. *Third,* I explain how I used those forecasts to estimate the savings to Michigan customers attributable to NEXUS and summarize my results. *Fourth*, I explain some of the similarities and differences among the analyses I conducted and those previously commissioned by DTE Gas. *Fifth*, I identify additional benefits, other than cost savings, that NEXUS creates for customers. Finally, *sixth*, I discuss my conclusions.

The NEXUS System

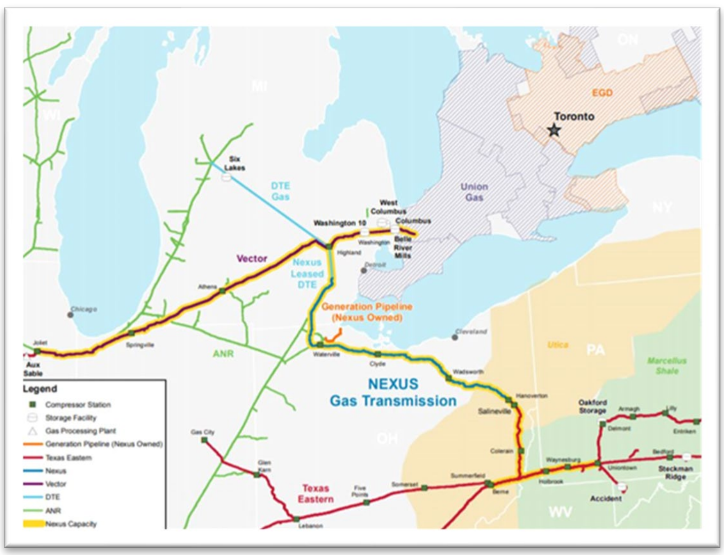
Q15. Can you describe the NEXUS pipeline?

A15. Yes. NEXUS is an approximately 250-mile natural gas transmission pipeline designed to transport up to 1.4 billion cubic feet per day (Bcf/d) of natural gas from receipt points in eastern Ohio to existing pipeline system interconnects in

Line
No.

southeastern Michigan. In Southeast Ohio, NEXUS can receive gas from gas suppliers operating in the Marcellus and Utica Shale plays and from interconnections with the Texas Eastern Transmission (TETCO) and Tennessee Gas Pipeline (TGP) systems. In Michigan, NEXUS provides deliverability to interconnects with the DTE Gas transmission system at its interconnect in Ypsilanti, Michigan, and to the Vector Pipeline (Vector).

Figure 1. NEXUS Map[1]



Q16. What is the current status of NEXUS?

A16. It is operational. In October 2018, the system was placed into service allowing flows north from Kensington, Ohio into Michigan. Additional capacity to Clarington, Ohio, was developed as a separate, incremental project, the Texas Eastern Appalachian Lease (TEAL), which is a 950,000 dekatherm per day (Dth/d) pipeline from Clarington to Kensington. TEAL is also in service.

[1] Source: DTE Midstream

Line No.

Q17. What entitlements does DTE Gas hold on NEXUS?

A17. DTE Gas holds a contract entitling it to receive gas at Kensington and deliver it to Ypsilanti until 2033. The contract's Maximum Daily Quantity (MDQ) is currently 37,500 Dth/d and will increase to 75,000 Dth/d in 2022. Through 2022, the Company can receive 37,500 Dth/d at Clarington[2]. Additional detail regarding the Company's entitlements is included in Exhibit A-32.

Q18. What rates does DTE Gas pay under these agreements?

A18. The transportation rates are \$0.695/Dth from Kensington to NEXUS-Ypsilanti and \$0.15/Dth from Clarington to Kensington. There is an additional fuel charge that is currently 1.26%.

Simulation Analyses

Q19. Can you summarize this simulation analyses section of your testimony?

A19. In this section, I describe simulation analyses that were developed whose primary purpose was to forecast gas prices in Michigan, Ohio, and Ontario. Below, I explain how a set of price forecasts was developed, which I refer to as the *Base Case* and which reflects expected market conditions. Those results were then compared to a separate set of forecasts, the *No NEXUS Case*, from which NEXUS was removed but all other inputs were held constant. This comparison is intended to estimate the impact NEXUS will have on delivered prices in and around Michigan.

[2] Subsequent to the report being developed DTE Gas extended the term of the TEAL capacity through October 31, 2024. This has no impact on the results of the analysis as it was assumed that it would be renewed.

Q20. What impact did you find?

A20. Prices at the MichCon CityGate and Dawn (Ontario) were lower in the *Base Case*, which indicates that NEXUS reduces prices in and around Michigan.

Q21. Why does NEXUS reduce prices in and around Michigan?

A21. Gas flowing on NEXUS includes production from shale gas deposits in Ohio, Pennsylvania, and West Virginia, where gas is abundant and where prices are among the lowest in North America. Historically, prices in and around Michigan have been higher than in Appalachia, sometimes considerably so. Because of its cost advantage, Appalachian gas flowing on NEXUS for delivery to Michigan displaces more expensive supplies, reducing prices.

Q22. Can you explain how you estimated the magnitude of the price reduction?

A22. I and the team at FTI conducted simulations of the gas market using GPCM™, an industry-standard software tool designed for that purpose. Specifically, two simulations were developed. First, the *Base Case* is a "business as usual" outlook insofar as it reflects current expectations regarding supply, demand, pipeline infrastructure, and other factors, including NEXUS. The specific inputs utilized are discussed in Exhibit A-32. A *No NEXUS Casen* was then run, in which the NEXUS pipeline is removed from the simulation, but all other inputs are held constant. Comparing the prices from the *Base Case* to those from the *No NEXUS Case* allowed the impact on prices attributable to NEXUS to be estimated. A sensitivity analysis was also conducted to estimate the benefits of NEXUS under higher demand conditions, which I describe later in my testimony.

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Q23. What is GPCM™?

A23. GPCM™ allows for the simulation of the operation of the natural gas system at a highly granular level including flows across pipelines, production by gas suppliers, consumption by gas customers, the utilization of storage, and the other various interactions between supply, demand, and infrastructure from which market prices are set. It is the industry-standard application for this purpose and is in widespread use among pipelines, utilities, regulators, and consultancies.

Q24. Where does the data that serves as inputs to the simulations come from?

A24. From a variety of sources. GPCM™ comes loaded with a range of operational and economic data from the software vendor, which FTI updates on an ongoing basis. Custom datasets developed by FTI that are included in the simulations include those related to supply, demand, infrastructure projects, transportation costs, and other variables.

Q25. What time period did you simulate?

A25. Simulations for ten years beginning in 2022 were run. Forecasts were then extended through linear extrapolation through 2038, the year in which the Company's entitlements end.

Q26. Why did you take this approach instead of running 20-year simulations?

A26. Long-term forecasts are often based on extrapolation of nearer-term forecasts, one reason for which is that doing so reduces the need to speculate on discrete events and their timing in the future. This issue applies most specifically to new gas infrastructure, which is simultaneously important and difficult to predict. Although

I find it highly likely that new gas projects will be built in the mid-2030s and beyond, it cannot be yet known where they will be built, how large they will be, or when they will be commercialized. My approach of combining a shorter forecast with extrapolation for periods farther into the future attempts to balance the need to incorporate expected changes to the system into forecasts with the desire to avoid biasing results with speculative or arbitrary assumptions.

Q27. Can you provide your *Base Case* price forecasts?

A27. Average annual prices under the *Base Case* forecast for Dawn, Ontario (Dawn), the MichCon Citygates (MichCon), Clarington, and Kensington are shown below:

Table 1. Average Annual *Base Case* Prices *($/MMBtu)*

	Dawn	MichCon	Clarington	Kensington
2022	$2.65	$2.68	$2.19	$2.35
2023	$2.52	$2.56	$2.05	$2.22
2024	$2.50	$2.55	$2.05	$2.24
2025	$2.59	$2.63	$2.06	$2.27
2026	$2.62	$2.67	$2.05	$2.28
2027	$2.70	$2.73	$2.11	$2.33
2028	$2.79	$2.83	$2.19	$2.41
2029	$2.95	$2.99	$2.29	$2.52
2030	$3.04	$3.09	$2.37	$2.61
2031	$3.18	$3.22	$2.46	$2.72
2032	$3.29	$3.33	$2.54	$2.81
2033	$3.40	$3.44	$2.61	$2.90
2034	$3.52	$3.55	$2.69	$2.99
2035	$3.63	$3.67	$2.78	$3.08
2036	$3.76	$3.80	$2.86	$3.18
2037	$3.88	$3.92	$2.95	$3.28
2038	$4.01	$4.05	$3.04	$3.38

Q28. Was the reasonableness of the *Base Case* validated?

A28. Yes.

Q29. How?

A29. Among the ways the team at FTI validated the *Base Case* results was by comparing the prices for key indices to prevailing forward gas prices and by comparing my outlook of gas consumption by sector in Michigan to other available forecasts.

Q30. Can you please explain?

A30. Forward gas prices that settled on February 25, 2021 for a large number of pricing indices in markets in and around Michigan were retrieved, including Dawn, MichCon, Consumers Citygate (Consumers CG) and Chicago Citygate (Chicago CG). The team at FTI and I also retrieved prices from the regions where NEXUS sources its gas, including, Dominion South Point (Dominion South), receipts into TETCO Market Zone 2 (TETCO M2), and the 200 leg of Zone 4 on the Tennessee Gas Pipeline (TGP Z4 200L). By comparing the forward prices to the *Base Case* forecasts, it was determined whether the two were in general agreement regarding future price levels. Detailed comparisons of the *Base Case* price to the futures are shown in Exhibit A-32.

Q31. Did you validate the Kensington and Clarington prices in the same manner?

A31. Yes. Kensington is priced based on the TGP Z4 200L price while Clarington gas is priced based on the TETCO M2 price. Those prices were used to validate the reasonableness of the forecast.

Q32. Can you explain the demand forecasts to which you compared the *Base Case* outlook?

A32. FTI compared the forecasts of gas consumption in the East North Central "ENC" region, the U.S. census region that includes Michigan, from the two most recent Annual Energy Outlooks ("AEO"), which are developed by the Energy Information Administration ("EIA"), to the demand forecasts I developed using GPCM™. Specifically, forecast growth rates for the Company's demand were compared to the ENC forecast for gas consumption for generation and also the DTE Gas forecasts of consumption by customer type (*e.g.* residential, commercial, or industrial) to the corresponding forecasts in the AEOs. Results are shown below. In each instance, the comparison indicates that the outlooks were sufficiently consistent with each other that they validated the *Base Case* demand outlook. Additional detail about the comparison is provided in Exhibit A-32.

Table 2. Comparison of Base Case and AEO Consumption Forecasts

Sector	Forecast	Area	*Units*	2022	2038	Growth rate
Total	2021 AEO	ENC	*Tcf*	4.3	5.4	1.4%
	2020 AEO	ENC	*Tcf*	4.6	5.4	1.0%
	FTI	Michigan	*Bcf*	980	1,167	1.1%
Residential	2021 AEO	ENC	*Tcf*	1.3	1.2	-0.6%
	2020 AEO	ENC	*Tcf*	1.3	1.1	-0.7%
	FTI forecast	Michigan	*Bcf*	106	94	-0.8%
Industrial	2021 AEO	ENC	*Tcf*	1.2	1.4	1.0%
	2020 AEO	ENC	*Tcf*	1.4	1.5	0.6%
	FTI	Michigan	*Bcf*	73	90	1.3%
Commercial	2021 AEO	ENC	*Tcf*	0.7	0.8	0.4%
	2020 AEO	ENC	*Tcf*	0.8	0.8	0.0%
	FTI	Michigan	*Bcf*	74	73	-0.1%
Electric	2021 AEO	ENC	*Tcf*	1.1	2.0	3.8%
	2020 AEO	ENC	*Tcf*	1.2	2.0	3.1%
	FTI	Michigan	*Bcf*	69	111	3.0%

Q33. What was your next step after validating the results of the *Base Case*?

A33. I next ran the *No NEXUS Case* and calculated the difference in prices. The *No NEXUS Case* has the same inputs as the *Base Case* with the one exception that NEXUS is removed.

Q34. Can you explain the difference in prices between the *Base Case* and the *No NEXUS Case?*

A34. Prices in the areas where NEXUS delivers gas are lower in the *Base Case* than in the *No NEXUS Case.* For example, the MichCon price is roughly $0.08/MMBtu (3%) lower, on average, in the *Base Case*, as shown in Table 3. The Dawn price is also lower, but to a smaller extent. The change in prices for Dominion South is also shown in Table 3. That price is, on average, lower in the *No NEXUS Case*, as are the prices of other Appalachian indices, because NEXUS increases demand for local production which, all else equal, puts upward pressure on prices. Additional detail from the forecasts is provided in Exhibit A-32.

Table 3. Summary of Price Impacts for MichCon, Dawn, and Dominion South (*$/MMBtu)*

	Base Case	*No NEXUS*	Price Change
MichCon	$3.16	$3.24	$0.08
Dawn	$3.12	$3.18	$0.06
Dominion South	$2.23	$2.19	($0.04)

<u>Calculation of Benefits</u>

Q35. Can you summarize your calculations in this section of your testimony?

A35. In this section of my testimony I explain the estimated total savings to customers in Michigan that results from the price changes estimated from the price forecasts

I discuss above. The benefits quantified are the benefits to DTE Gas of being able to purchase gas at either Kensington or Clarington, the additional savings that DTE Gas will realize from the reduction in local prices caused by NEXUS, and the savings from the same source that other consumers in Michigan will benefit from. I then explain how I deducted the cost of holding NEXUS entitlements from these savings to calculate a total benefit attributable to NEXUS of $1 billion for the period 2022-2038. Finally, I explain how the results of an alternative simulation shows that benefits could be even higher than that if demand and/or prices increase in the future.

Q36. How does NEXUS create savings for the Company?

A36. Gas cost reductions are achieved through two mechanisms. *First*, DTE Gas' entitlement allows it to purchase gas at Kensington and Clarington instead of in Michigan. Prices in Kensington and Clarington are typically lower, so this reduces the purchase price. *Second*, if NEXUS did not exist, prices in Michigan would be higher, as I discuss above, meaning that all of DTE Gas' purchases in Michigan would be made at a higher price. To the extent that the Company's cost to hold its NEXUS entitlement is less than the reduction in costs that NEXUS creates by these two mechanisms, net savings are created.

Q37. Have you calculated these savings?

A37. Yes. Net savings each year are shown in Table 4.

Line No.

Table 4. DTE Gas Savings *($millions)*

	Energy Savings	Contract Costs	Net Savings
2022	$33.7	($21.1)	$12.6
2023	$31.2	($21.1)	$10.1
2024	$21.5	($21.1)	$0.3
2025	$23.2	($21.1)	$2.1
2026	$25.7	($21.1)	$4.6
2027	$27.3	($21.1)	$6.2
2028	$28.2	($21.1)	$7.0
2029	$29.4	($21.1)	$8.3
2030	$30.3	($21.1)	$9.3
2031	$34.4	($21.1)	$13.3
2032	$35.7	($21.1)	$14.5
2033	$37.0	($21.1)	$15.9
2034	$38.4	($21.1)	$17.3
2035	$39.8	($21.1)	$18.7
2036	$41.4	($21.1)	$20.2
2037	$42.9	($21.1)	$21.8
2038	$34.6	($17.6)	$17.0
Total	$554.5	($355.1)	$199.4

Over the period indicated, the NEXUS agreement creates $199 million in savings for DTE Gas residential, commercial, and industrial customers.

Q38. Did you also find estimated savings arise for other customers in Michigan from NEXUS?

A38. Yes. The estimate of the savings for the non-DTE customers is based on the change in Michigan delivered prices. Because there is no one price index that captures all of the Michigan market, an average was used of the difference each month between the *Base Case* and the *No NEXUS Case prices* for Consumers CG, Dawn, Chicago CG, and Emerson. That differential, on average, was approximately $0.06/MMBtu. For each month of the forecast, I calculated the savings by multiplying the average price change by the forecast of non-DTE consumption.

Q39. Can you summarize your results?

A39. The total estimated savings associated with NEXUS for all Michigan gas customers for the period 2022-2038 are approximately $1 billion.

Table 5. Savings Estimate *($millions)*

DTE Electric	$11
DTE Gas	$199
Non-DTE	$808
Total	$1,018

Alternative Case

Q40. Did FTI simulate any other scenarios?

A40. Yes, a *High Demand Case* was developed in which a roughly 8% increase to demand for the ENC states was applied, held all other factors constant with the *Base Case*, and then the *High Demand Case* with and without NEXUS was performed. Using the results of the compared prices, the benefits to Michigan consumers were calculated in the same manner as I describe above.

Q41. What were the results?

A41. That savings attributable to NEXUS increased considerably even though the price effect is relatively small. Prices at MichCon, for example, went up by an average of about $0.15/MMBtu during January and February but only by about $0.02/MMBtu overall, compared to the *Base Case*. Regardless, the change was enough to significantly increase the savings calculated by comparing the *High Demand Case* prices with and without NEXUS included in the simulation. The overall benefits rose to over $1.2 billion, an increase of roughly 24%.

Q42. How would you characterize this finding?

Line No.

A42. It is important. It means that NEXUS provides a useful hedge that helps reduce Michigan's exposure to long-term changes in prices. This result also suggests that the investment in NEXUS creates benefits under fundamentally different market conditions. As I explain above, my analysis indicates that NEXUS creates significant benefits for gas consumers in Michigan in the current, low price environment. That the investment performs even better when prices increase means that there are unlikely to be any changes to market pricing paradigms that would push the investment "out of the money." Finally, this finding suggests that even modest increases in gas prices could lead to significant extra benefits.

Comparison to the November 2015 Report

Q43. How do your findings and conclusions compare with the 2015 ICF Study that you previously referenced?

A43. The findings and conclusions of this FTI study are generally consistent with those described in the 2015 ICF Study. My analyses show that NEXUS creates savings for DTE Gas customers, which is the same result described in the November 2015 Report.

Q44. Your estimates of benefits are lower than those shown in the November 2015 Report; do you have any explanation as to why that is?

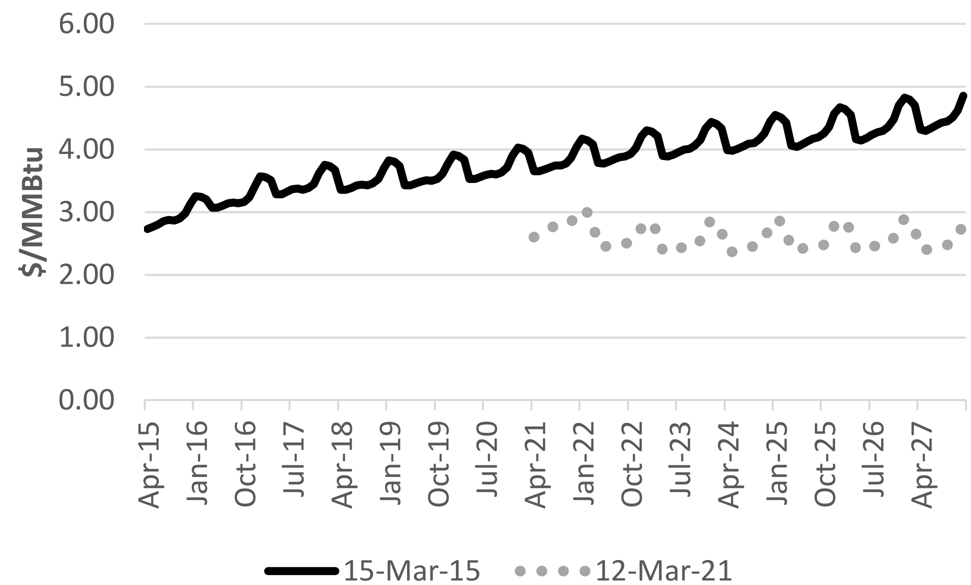
A44. While I did not prepare the November 2015 Report, I have reviewed it and have identified some important differences. Among the most obvious of these is that market prices were considerably higher at the time that report was developed than they are now. Table 6 shows average annual MichCon prices since 2014, during which time they have declined significantly. For example, in 2020, prices were, on average, 34% lower than they had been in 2015 and 67% lower than they were in 2014.

Table 6. Average Annual MichCon Prices *($/MMBtu)*

2014	$5.72
2015	$2.83
2016	$2.49
2017	$2.93
2018	$3.00
2019	$2.36
2020	$1.87

Expectations regarding future prices were also considerably different at the time the November 2015 Report was written. Figure 2 compares the forward curve prices for the Henry Hub, an important benchmark of North American gas prices, that settled on the New York Mercantile Exchange (NYMEX) in March 2015 to settlements for the same product from March 2021. The former reflects an expectation that prices would follow a strong upward trajectory, quickly rising above $3/MMBtu and continuing to climb from there. The 2021 curve, on the other hand, indicates an expectation of prices that actually decline moderately over time.

Figure 2. Henry Hub Forward Curves *($/MMBtu)*



Q45. Why does this matter?

A45. Because, all else equal, gas infrastructure tends to be most valuable when prices are highest. This tendency is confirmed by my findings from the *High Demand Case*.

Q46. Are there indications of consistency between the NEXUS benefits estimate from the November 2015 Report and your NEXUS benefits estimate?

A46. Yes, there are. When evaluated on a percentage basis, the estimate of the price reduction in this study is not dissimilar to the one shown in the November 2015 Report. Over the forecast period, the forecasts indicates that average MichCon prices are reduced by NEXUS by approximately 2.5%, from $3.24/MMBtu to $3.16/MMBtu. The November 2015 Report indicated that prices would be lower by $0.21/MMBtu because of NEXUS, which is larger than FTI's projected change, but which indicates only a 3.6% change in the average MichCon price.

Table 7. Price Change Comparison *($/MMBtu)*

	FTI	ICF
Base	$3.16	$5.87
No NEXUS	$3.24	$6.08
Change	$0.08	$0.21
% change	2.5%	3.6%

Q47. What conclusions have you reached about the November 2015 Report?

A47. It is unreasonable to require perfect accuracy in hindsight in order for a forecast to be acceptably precise. Instead, it is necessary to understand the context in which a forecast was made and analyze the degree to which it aligns with available information and prevailing market expectations at the time it was made. In the case of the November 2015 Report, the higher forecast of market prices reflected broader sentiments held by the industry that are reflected in the NYMEX curves shown in Figure 2 and elsewhere. Since there seems to be a positive correlation between overall price levels and magnitude of the benefits that NEXUS generates, higher estimates of those benefits are also logical. I have not identified any basis by which to conclude that the analysis described in the November 2015 Report was unreasonable nor that the Company was unreasonable in relying on its findings when it made its decision to execute contracts on NEXUS. Moreover, the key conclusion from those two studies remains the same: NEXUS creates savings that are greater than its costs.

Other benefits

Q48. Has NEXUS reduced gas prices in Michigan since it has been in service?

A48. Yes, it has.

Line No.

Q49. What is your basis for the assertion that NEXUS has reduced gas prices in Michigan since it has been in service?

A49. The observation that the market conditions which create the expected reductions during the forecast have also been emergent since NEXUS came online. Most important among these is the fact that gas prices in Appalachia are lower than they are in Michigan and also lower than in many of the other basins from which gas flows to the Upper Midwest. The flows of inexpensive gas into Michigan from NEXUS have necessarily displaced deliveries of more expensive supplies, which has reduced prices in Michigan in the sense that they would be higher had NEXUS never been built.

Q50. Can you say how large these price reductions have been?

A50. If all else were equal, I would expect the magnitude of the price reduction to be generally similar to that observed during the forecast period. That being said, the period since NEXUS was commercialized is a short one during which some extraordinary events have occurred. Most notably, the COVID-19 pandemic brought changes to markets that included significant reductions in gas demand. Notwithstanding the impacts of the pandemic, NEXUS flowed significant volumes of competitively priced gas, without which prices in Michigan certainly would have been higher during this period.

Q51. Other than reducing gas costs, does NEXUS provide any other benefits for Michigan gas consumers?

A51. Yes, NEXUS provides a number of other benefits, one of the most important of which is better fuel security. There are only a relatively small handful of interstate pipelines that serve Michigan and, of those, many of the largest and most important were designed to source gas in the same region and follow a similar path to the market. PEPL, the ANR Pipeline, and Northern Natural Gas Company (NNG) are among Michigan's most important sources of energy and each were designed to source gas in and around Texas for transportation to the Upper Midwest. This means that disruptions in certain producing areas or transmission corridors could have outsized effects. NEXUS creates a short, direct path from Appalachia to Michigan, which creates an important degree of diversity and reduces the likelihood that an event currently difficult to foresee could threaten reliability in Michigan. Additionally, gas pipelines can suffer from mechanical failures which are infrequent, but which have the potential to be very impactful since Michigan's capacity to bring gas into the market is spread among a relatively small number of pipelines, each of which has a correspondingly large share of the total delivery capability. As a result, a single mechanical failure can have widespread effects. A new pipeline that is largely unconnected to other systems creates operational redundancies that improve the chances Michigan could avoid critical supply disruptions even when pipeline emergencies occur.

Q52. Are there other benefits that should also be considered?

A52. Yes, additional benefits from NEXUS include enhanced competitiveness for Michigan's electric generation fleet. Lower gas prices reduce costs for gas-fired generators in Michigan whether they hold NEXUS entitlements or not. This means that, all else equal, the Company's generators and other gas-fired generators in Michigan will be called upon to run more often in wholesale markets, and, when they do run, their margins will be greater. NEXUS also creates environmental benefits in the sense that economic supplies of natural gas are a necessary precondition for the deployment of new and efficient gas-fired generation, which, in turn, allows for the displacement of coal-fired generation in Michigan and, potentially, elsewhere, while also providing an important tool for managing the intermittency of renewable generators being added to the system in increasing amounts.

Q53. Does NEXUS also improve reliability?

A53. Yes. Michigan's reliability is necessarily enhanced from having another pipeline in service since the likelihood of an impactful outage from a failure on a single system is lower. Additionally, NEXUS enhances the diversity of Michigan's gas supplies, which creates economic benefits since NEXUS sources gas in Appalachia, where prices are low, but also reliability benefits since the effects of a supply disruption specific to one region would be potentially mitigated.

Q54. Has the Commission recognized the importance of reliability benefits from new pipeline projects in the past?

A54. Yes. The Commission recently approved SEMCO Energy Company's (SEMCO's) Marquette Connector Pipeline, which was motivated, in part, by SEMCO's desire to increase the diversity of its supplies and not become unduly reliant on any one system. The Commission cited the factors for its approval, including the project's ability to "increase the reliability of natural gas service to many of SEMCO's customers [and] provide much-needed redundancy in the event of a pipeline rupture."[3] NEXUS provides these same benefits.

[3] Order Approving Settlement Agreement, Filing number U-18202-0061.

Line
No.

Conclusions

Q55. Can you summarize your primary conclusions?

A55. My primary conclusion is that the NEXUS pipeline brings many benefits for DTE Gas and the state of Michigan, and the benefits Michigan's gas consumers will realize far outweigh its costs. I expect savings totaling $199 million for DTE Gas customers and $1 billion for all Michigan consumers over the period 2022-2038. Additionally, my modeling shows that savings could be considerably higher under certain conditions.

Q56. Does this conclude your testimony?

A56. Yes.

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Professional Affiliations

Energy Bar Association
FERC Practice Committee
FERC Liquids Committee
FERC Natural Gas Pipeline Committee

Education

B.S., Accounting, Indiana University of Pennsylvania

Mr. Sosnick has over 18 years of experience with electric utility, natural gas pipeline and crude/product pipeline industry matters before the Federal Energy Regulatory Commission ("FERC"), state regulators, as well civil litigation proceedings and management consulting engagements.

Prior to joining FTI, Mr. Sosnick spent over 8 years as a consultant extensively engaged in the natural gas, crude/product and electricity markets. His work has included analysis of onshore and offshore natural gas pipeline and crude/product pipeline cost of service rates, levelized rates, market-based rates, discounted and negotiated rates, incremental vs. rolled-in project costs, Certificate Proceedings, allocation of corporate overhead costs, master-limited partnership income taxes, throughput/system rate design quantities, fuel recovery mechanisms, NGA Section 5 rate complaints, Return on Equity calculations under the DCF/Risk Premium/CAPM/Expected Earnings methods, depreciation rate and negative salvage rate calculations, Asset Retirement Obligations, FERC Form 1 and 2 filing requirements as well as being proficient in the application of FERC's Uniform System of Accounts.

Mr. Sosnick has prepared expert testimony and provided expert advisory services for clients in proceedings at FERC, state commissions as well as expert reports assessing and quantifying damages in civil litigation, conducted strategic analysis for a large energy company considering alternatives for its existing pipeline and storage portfolio, written a whitepaper on the impacts of the Tax Cuts and Jobs Act on FERC regulated assets as well as a whitepaper on the impacts of FERC Orders in SFPP, LP Docket No. IS08-390 related to Master Limited Partnerships and other pass-through entities income tax allowance. In addition, he conducted confidential buy-side valuations and assessments of regulated electric and natural gas utilities in the U.S.

Mr. Sosnick spent 10 years at FERC in which he spent two years as an auditor in the Office of Enforcement, and eight years as an expert witness and one of the lead technical staff negotiators on major electric utility proceedings, interstate natural gas pipeline and crude/product pipeline in the Office of Administrative Litigation. Mr. Sosnick's insights were incorporated into the revision of the FERC Form 2 in Docket No. RM07-9-000, which lead to the FERC-initiated Section 5 natural gas pipeline proceedings.

Mr. Sosnick currently teaches multiple courses in coordination with EUCI, and previously taught at the New Mexico State University Center for Public Utilities Practical and Regulatory Training for the Natural Gas Interstate Pipeline Industry specifically addressing FERC requirements for determining "Just and Reasonable" rates.

PROFESSIONAL EXPERIENCE

- *FTI Consulting,* Managing Director, Boston, MA, 2019 – Present
- *Concentric Energy Advisors,* Senior Project Manager, Marlborough MA, 2015 – 2019
- *MRW & Associates, LLC, Energy Consultants,* Senior Project Manager, Oakland, CA, 2013 – 2015
- *Federal Energy Regulatory Commission,* Energy Industry Analyst, Office of Administrative Litigation, Washington, D.C., 2005 – 2013
- *Federal Energy Regulatory Commission,* Auditor, Office of Enforcement, Washington, D.C., 2003 – 2005

FTI CONSULTING

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SELECTED PROJECTS

Cost of Service

Mr. Sosnick assists clients, state regulatory agencies, and other experts developing and refining cost of service models regarding rate base calculations, appropriate levels of operations and maintenance expenses, appropriate levels of directly assigned or allocated affiliated or parent company overhead costs, the application of cost allocation procedures in the allocation of costs between jurisdictional activities, between non-jurisdictional and jurisdictional activities or amongst separate jurisdictional systems.

Natural Gas Experience

- Paiute Pipeline Company, Docket Nos. RP05-163-000 and RP09-406-000
- El Paso Natural Gas Company, Docket No. RP06-369-000
- Transcontinental Pipeline Company, Docket Nos. RP06-569-000 and RP12-993-000
- Black Marlin Pipeline Company, Docket No. RP07-39-000
- Sea Robin Pipeline Company (Section 4 Rate Case & Hurricane Surcharge), Docket Nos. RP07-513-000 and RP09-995-000
- Portland Natural Gas Transmission System, Inc., Docket No. RP08-306-000: Filed testimony on behalf of FERC Trial Staff on Cost-of-Service Issues
- UTOS, Docket No. RP10-1393
- Florida Gas Transmission Company, LLC, Docket No. RP10-21-000: Filed testimony on behalf of FERC Trial Staff on Cost-of-Service Issues
- Northern Natural Gas Company, Docket No. RP10-148-000: Filed testimony on behalf of FERC Trial Staff on Cost-of-Service Issues under Section 5 of the NGA
- Kinder Morgan Interstate Gas Transmission, Docket No. RP11-1494-000
- Tuscarora Gas Transmission Company, Docket No. RP11-1823-000: Filed testimony on behalf of FERC Trial Staff
- Tennessee Gas Pipeline Company, Docket No. RP11-1566-000
- Trailblazer Pipeline Company, Docket No. RP11-2168-000
- Stingray Pipeline Company, Docket No. RP11-1957-000
- Northern Natural, Docket No. RP11-1781-000
- National Fuel Supply Corporation, Docket No. RP12-88-000
- MIGC, Docket No. RP12-122-000
- Wyoming Interstate Company, Docket No. RP13-184-000
- Southern Star Central Pipeline Company, Docket No. RP13-941-000
- Saltville Gas Storage, Docket No. RP14-251-000
- Sea Robin Pipeline Company, Docket No. RP14-247-000
- Williston Basin Pipeline Company, Docket No. RP14-118-000
- HIOS Pipeline Company, Docket No. RP14-218-000
- Mojave Pipeline Company, Docket No. RP14-1275-000
- Saltville Gas Storage, Docket No. RP14-251-000
- Florida Gas Transmission, Docket No. RP15-101-000
- Alliance Pipeline Company, Docket No RP15-1022-000
- Gulf South Pipeline Company, Docket No. RP15-65-000: Filed testimony on the behalf of Atmos Energy Corporation on Cost-of-Service Issues

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Natural Gas Experience-Continued

- Columbia Gas Pipeline, Docket No. RP16-314-000
- KO Transmission Company, Docket No. RP16-1097-000: Filed testimony on behalf of KO Transmission and served as the Rate Case Filing/Settlement Coordinator
- ANR Pipeline Company, Docket No. RP16-440-000
- Columbia Gas Transmission, Docket No. RP16-302-000
- ECA/Greylock Pipeline, Docket No. CP16-35-000: Initial rates for intrastate pipeline becoming a FERC regulated interstate pipeline
- Natural Gas Pipeline Company of America, Docket No. RP17-303-000
- Great Lakes Gas Transmission, Docket No. RP17-598-000
- Eastern Shore Pipeline Company, Docket No. RP17-363-000
- Mississippi River Transmission, Docket No. RP18-923-000; Filed testimony on the behalf of Spire Missouri, Inc. on Cost of Service, Cost Allocation, Affiliate Issues
- Empire Pipeline Company, Docket No. RP18-940-000
- Transcontinental Gas Pipeline, Docket No. RP18-1126-000
- Texas Eastern Transmission Company, Docket No. RP19-343-000
- Saltville Gas Storage, Docket No. RP18-1115-000
- East Tennessee Natural Gas Company, Docket Nos. RP19-63-000 and RP19-64-000; RP20-980-000
- Northern Natural Gas Company, Docket Nos. RP19-59-000 and RP19-1353-000; Filed testimony on the behalf of CenterPoint Energy, Inc. on Cost of Service, Cost Allocation, Affiliate Issues
- Panhandle Eastern Pipeline Company, Docket No. RP19-78-000
- National Fuel Gas Supply, Docket No. RP19-1426-000
- Kinetica Deepwater Express, Docket Nos. RP19-53-000 and RP19-1634-000
- Dominion Energy Cove Point, Docket No. RP20-467-000; Filed testimony on the behalf of the FPS Customer Group on Cost of Service, Cost Allocation and Rate Design
- Transcontinental Gas Pipeline, Docket Nos. RP20-614-000 and RP20-618-000; Filed testimony on behalf of Transco's Zone 4/5 Shipper Group relating to Transco's Cash-out Mechanism
- Bridge-Line-LIGG Section 311 Filing, Docket No. PR20-48-000
- Columbia Gas Transmission, Docket No. RP20-1060-000
- Florida Gas transmission, Docket No. RP21-441-000
- Energy North, Docket No. DG 20-105; Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
- Midwestern Gas Transmission Company, Docket No. RP21-525-000
- Southern Star Central Gas Pipeline, Inc., Docket. No. RP21-778-000
- Developed Section 7 Initial Rates for facilities to support LNG exporting for a confidential client.
- Confidential Client, FERC Form 501-G Filing Assistance

Electric Experience

- AEP, Docket No. ER05-751-000: Reviewed costs for AEP's Voltage Control from Generation Source Service on behalf of FERC Trial Staff
- Michigan Electric Transmission Company, Docket Nos. ER06-56-000 and ER06-56-002: Filed testimony on behalf of FERC Trial Staff and participated in the development of initial Formula Rates

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Electric Experience-Continued

- Duke Energy Vermillion, LLC, Docket No. ER05-123-000: Reviewed the cost-of-service study for Duke Vermillion's Reactive Power Voltage Control from Generation Source Service on behalf of FERC Trial Staff
- GenOn Power Midwest, LP (Now NRG), Docket No. ER12-1901-000: Led FERC team that reviewed the cost-of-service study underlying the Reliability Must Run (RMR) contract as well as ensuring FERC precedent was followed in the determining the RMR rate for the GenOn generating facilities.
- SDG&E, Docket No. ER05-853-000: Reviewed the cost of service and balancing authority to ensure compliance with FERC precedent as well as ensuring that SDG&E and CASIO agreed with the commitments in the filing.
- Southern California Edison Company, Docket No. ER05-763-000: Reviewed the cost of service and balancing authority to ensure compliance with FERC precedent as well as ensuring that SCE and CASIO agreed with the commitments in the filing.
- Berkshire Power Company, LLC, Docket No. ER05-1179-000: Reviewed the cost-of-service study underlying the RMR contract as well as ensuring FERC precedent was followed in the determining the RMR rate for the Berkshire generating facility.
- Milford Power Company, LLC, Docket No. ER05-163-000: Reviewed the cost-of-service study underlying the RMR contract as well as ensuring FERC precedent was followed in the determining the RMR rate for the Milford generating facility.
- City of Anaheim, Docket No. ER11-3594-000: Led FERC Trial Staff review of the inputs of the Anaheim cost of service filing for accuracy as well as being in accordance with FERC precedent.
- City of Banning, Docket No. ER11-3962-000: Led FERC Trial Staff review of the inputs of the Anaheim cost of service filing for accuracy as well as being in accordance with FERC precedent.
- Delmarva Power and Light Company, Docket No. ER18-903-000: Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs.
- Potomac Electric Power Company, Docket No. ER18-905-000: Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs.
- Baltimore Gas & Electric Company, Docket No. ER17-528-000; Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs.
- Nebraska Public Power District, Docket No. EL18-194-000; Filed an Affidavit supporting NPPD's complaint against Tri-State Generation and Transmission Association, Inc. and SPP's 2018 ATRR filing for Tri-State.
- Confidential Client; Review of multiple entities RTO/ISO Formula Rates to ensure compliance with current FERC precedent.
- Delmarva Power and Light Company, Potomac Electric Power Company, Baltimore Gas & Electric Company, Docket No. ER19-5-000; Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs.
- Tri-State Generation and Transmission Association, Inc. Docket Nos. ER20-686-000, ER20-688-001, ER20-726-000 and EL20-25-000, Tri-State Initial FERC Rates, Terms and Tariff

Liquids Experience

- SFPP L.P., Docket No. OR03-5-000: Filed testimony on behalf of FERC Trial Staff addressing directly assigned or allocated affiliated or parent company overhead costs, the application of cost allocation procedures in the allocation of costs between jurisdictional activities, between non-jurisdictional and jurisdictional activities or amongst separate jurisdictional systems.
- SFPP L.P., Docket No. OR03-5-001: Filed testimony on behalf of FERC Trial Staff addressing the appropriate income tax allowance after the Exxon Circuit Court review as well as the levels of

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Liquids Experience-Continued

directly assigned or allocated affiliated or parent company overhead costs, the application of cost allocation procedures in the allocation of costs between jurisdictional

- activities, between non-jurisdictional and jurisdictional activities or amongst separate jurisdictional systems.
- SFPP L.P., Docket No. IS08-390-002: Filed testimony on behalf of FERC Trial Staff addressing the appropriate levels of directly assigned or allocated affiliated or parent company overhead costs, the application of cost allocation procedures in the allocation of costs between jurisdictional

  activities, between non-jurisdictional and jurisdictional activities or amongst separate jurisdictional systems.
- SFPP L.P., Docket No. IS09-437-000: Filed testimony on behalf of FERC Trial Staff addressing the appropriate levels of directly assigned or allocated affiliated or parent company overhead costs, the application of cost allocation procedures in the allocation of costs between jurisdictional activities, between non-jurisdictional and jurisdictional activities or amongst separate jurisdictional systems.

Cost Allocation and Rate Design.

Mr. Sosnick assists clients, regulatory agencies, and other experts developing and refining cost allocation and rate design models.

Natural Gas Experience

- ANR Pipeline Company, Docket No. RP07-439-000: Filed testimony on behalf of FERC Trial Staff reviewing the appropriateness of ANR’s 2.6 Bcf of storage gas sale
- El Paso Natural Gas Company, Docket No. RP08-426-000: Filed testimony on behalf of FERC Trial Staff on El Paso’s Cost Allocation and Rate Design
- Sea Robin Pipeline Company, LLC, Docket Nos. RP10-422-000 & RP09-995-000: Filed testimony on behalf of FERC Trial Staff
- Wyoming Interstate Company, Docket No. RP13-184-000
- Southern Star Central Pipeline Company, Docket No. RP13-941-000
- Sea Robin Pipeline Company, Docket No. RP14-247-000
- HIOS Pipeline Company, Docket No. RP14-218-000
- Saltville Gas Storage, Docket No. RP14-251-000
- Mojave Pipeline Company, Docket No. RP14-1275-000
- Florida Gas Transmission, Docket No. RP15-101-000
- Gulf South Pipeline Company, Docket No. RP15-65-000: Filed testimony on the behalf of Atmos Energy Corporation on Cost Allocation and Rate Design Issues
- Columbia Gas Pipeline, Docket No. RP16-314-000
- KO Transmission Company, Docket No. RP16-1097-000: Filed testimony on behalf of KO Transmission and served as the Rate Case Filing/Settlement Coordinator
- ANR Pipeline Company, Docket No. RP16-440-000
- Columbia Gas Transmission, Docket No. RP16-302-000
- ECA/Greylock Pipeline; Docket No. CP16-35-000: Initial rates for intrastate pipeline becoming FERC regulated interstate pipeline
- Natural Gas Pipeline Company of America, Docket No. RP17-303-000
- Great Lakes Gas Transmission, Docket No. RP17-598-000
- Eastern Shore Pipeline Company, Docket No. RP17-363-000

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Natural Gas Experience-Continued

- Mississippi River Transmission, Docket No. RP18-923-000; Filed testimony on the behalf of Spire Missouri on Cost Allocation and Rate Design Issues
- Empire Pipeline Company, Docket No. RP18-940-000
- Transcontinental Gas Pipeline, Docket No. RP18-1126-000
- Saltville Gas Storage, Docket No. RP18-1115-000
- East Tennessee Natural Gas Company, Docket Nos. RP19-63-000 and RP19-64-000
- Northern Natural Gas Company, Docket Nos. RP19-59-000 and RP19-1353-000; Filed testimony on the behalf of CenterPoint Energy Resources Corp. on Cost Allocation and Rate Design Issues
- National Fuel Gas Supply, Docket No. RP19-1426-000
- Kinetica Deepwater Express, Docket Nos. RP19-53-000 and RP19-1634-000
- Dominion Energy Cove Point, Docket No. RP20-467-000; Filed testimony on the behalf of the FPS Customer Group on Cost of Service, Cost Allocation and Rate Design
- Transcontinental Gas Pipeline, Docket Nos. RP20-614-000 and RP20-618-000; Filed testimony on behalf of Transco's Zone 4/5 Shipper Group relating to Transco's Cash-out Mechanism
- Bridge-Line-LIGG Section 311 Filing, Docket No. PR20-48-000
- Columbia Gas Transmission, Docket No. RP20-1060-000
- Florida Gas transmission, Docket No. RP21-441-000
- Midwestern Gas Transmission Company, Docket No. RP21-525-000
- Southern Star Central Gas Pipeline, Inc., Docket. No. RP21-778-000
- Confidential Client, FERC Form 501-G Filing Assistance
- Developed Section 7 Initial Rates for facilities to support LNG exporting for a confidential client
- Pacific Gas & Electric, Docket No. A.13-12-012: Participated in PG&E's 2015 Gas Accord, reviewing cost allocation and tariff issues related to Core Transport Aggregators

Electric Experience

- Pacific Gas & Electric, Docket No. ER05-116: Reviewed the rate design for wholesale distribution service to ensure compliance with FERC precedent as well as ensuring that PG&E and Western agreed with the commitments in the filing
- Michigan Electric Transmission Company, Docket Nos. ER06-56-000 and ER06-56-002: Filed testimony on behalf of FERC Trial Staff and participated in the development of initial Formula Rates
- City of Anaheim, Docket No. ER11-3594: Led FERC Trial Staff review of the inputs of the Anaheim gross load calculation filing for accuracy as well as being in accordance with FERC precedent
- City of Banning, Docket No. ER11-3962-000: Led FERC Trial Staff review of the inputs of the Anaheim gross load calculation filing for accuracy as well as being in accordance with FERC precedent
- Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc. (collectively, the "Entergy Operating Companies"), Docket Nos.
- ER95-112-012, ER95-112-013, ER96-586-007, and ER96-586-008: Reviewed the inputs of the Entergy filing for accuracy as well as being in accordance with FERC formula rate precedent
- Oklahoma Gas and Electric Company, Docket No. ER08-281-000: Led FERC Trial Staff review of the filing for accuracy as well as being in accordance with FERC formula rate precedent

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Electric Experience-Continued

- Midwest Independent Transmission System Operator, Inc., Docket No. ER12-715-003: Filed testimony on behalf of FERC Trial Staff addressing the appropriate Exit Fees to be paid by DEO/DEK and ATSI leaving MISO and joining PJM
- Nebraska Public Power District, Docket No. El18-194-000; Filed an Affidavit supporting NPPD's complaint against Tri-State Generation and Transmission Association, Inc. and SPP's 2018 ATRR filing for Tri-State.
- Confidential Client: Review of multiple entities RTO/ISO Formula Rates to ensure compliance with current FERC precedent
- Delmarva Power and Light Company, Potomac Electric Power Company, Baltimore Gas & Electric Company, Docket No. ER19-5-000; Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs.
- Tri-State Generation and Transmission Association, Inc. Docket Nos. ER20-686-000, ER20-688-001, ER20-726-000 and EL20-25-000, Tri-State Initial FERC Rates, Terms and Tariff

Regulatory Policy and Strategic Analysis.

Utilizing his background in accounting, regulatory affairs, and the nuances of the energy sector Mr. Sosnick has helped clients ensure they are charging or paying appropriate rates, under terms and conditions that are just, reasonable and not unduly discriminatory or preferential. In addition, Mr. Sosnick helps clients develop safe, reliable and efficient energy infrastructure that serves the public interest.

Natural Gas Experience

- Strategic analysis for a large energy company considering alternatives for its existing pipeline and storage portfolio
- PG&E, Docket No. A.13-06-011: Participated in their Interstate Pipeline Capacity proceeding, for Core Transport Aggregators
- Confidential buy-side valuation and assessment of a regulated combination electric and natural gas utility in the U.S.
- Prepared expert report assessing and quantifying damages in litigation regarding the revenue sharing provisions of an Asset Management Agreement
- Strategic analysis of FERC's Form 501-G Final Order for a FERC regulated asset

Electric Experience

- Assisted in the formation of the Small Utility Distribution Company tariff language and operating agreement formed by the California Independent System Operator
- Developed GAAP to FERC accounting mapping for a new electric transmission provider
- Wisconsin Public Service Corporation, Led FERC Trial Staff review of the Wind-Up plan, costs, amortization and customers affected by the underlying the sale of the Kewaunee Nuclear Power Plant owned by Wisconsin Public Service Corp. Additionally, he ensured FERC precedent was followed in the determining the accounting for the costs included in the final settlement Written a whitepaper on the impacts of the Tax Cuts and Jobs Act on FERC regulated assets
- Assessed impacts of FERC Formula Rate challenge for a Transmission Owner in SPP
- Delmarva Power and Light Company, Docket No. ER18-903-000: Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs
- Potomac Electric Power Company, Docket No. ER18-905-000: Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs
- Baltimore Gas & Electric Company, Docket No. ER17-528-000; Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs

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Electric Experience-Continued

- Nebraska Public Power District, Docket No. El18-194-000; Filed an Affidavit supporting NPPD's complaint against Tri-State Generation and Transmission Association, Inc. and SPP's 2018 ATRR filing for Tri-State.
- Confidential Client; Review of multiple entities RTO/ISO Formula Rates to ensure compliance with current FERC precedent
- Delmarva Power and Light Company, Potomac Electric Power Company, Baltimore Gas & Electric Company, Docket No. ER19-5-000; Reviewed the FERC Formula Rate proposal for pass-through of tax savings of the TCJA as well as historical FAS 109 related costs.
- Tri-State Generation and Transmission Association, Inc. Docket Nos. ER20-686-000, ER20-688-001, ER20-726-000 and EL20-25-000, Tri-State Initial FERC Rates, Terms and Tariff

Liquids Experience

- Liquids Shippers Group, Airlines for America and the National Propane Gas Association, Docket No. RM15-19-000: Filed an affidavit in the Petition for a Rulemaking
- Colonial Pipeline Company, Docket No. OR16-17-000: Filed an Affidavit regarding Colonial Pipeline's Pro-Rationing Policy
- SFPP, L.P., Opinion No. 511 & 511A: Examined Corporate Overhead Allocation methodologies of. for its compliance with Federal Energy Regulatory Commission policy
- Constructed a whitepaper on the impacts of FERC Orders in SFPP, LP Docket No. IS08-390 related to Master Limited Partnership and other pass-through entities income tax allowance

Tariffs

- Analyzed Open Access Transmission Tariff formula rates to verify conformity to FERC's Uniform System of Accounts and the structure of their formula had FERC's approval
- Participated in the review and refunding of Southern Company's RTO Development Costs that were collected erroneously through their Open Access Transmission Tariff, Unit Power Sales Agreements, and Transmission Service Agreements
- Confidential Client; Review of a SPP Member's ATRR to provide an opinion on the appropriateness of the inclusion of certain costs
- Confidential Client; Review of multiple entities RTO/ISO Formula Rates to ensure compliance with current FERC precedent
- Served the role of advisor to clients to internal FERC Trial Staff on settlements on FERC wholesale electric, liquid pipeline and natural gas pipelines Tariff matters

Negotiations

- Coordinated Pre-filing Settlement negotiations on behalf of a firm storage customer in a state rate proceeding in the western US
- Facilitated the settlement of the refund amounts associated with the sale and related costs of the portion of the Kewaunee Nuclear Power Plant owned by Wisconsin Public Service Corp.
- California Independent System Operator Corporation, ER05-150: Reviewed the Utility Distribution Company Operating Agreement to ensure compliance with FERC precedent and coordinated with all parties to confirm understanding of commitments being filed
- PG&E, ER05-130: Reviewed the CASIO requirements and Western Interconnection Agreement as well as the FERC precedent to assist TPUD and PG&E to reach a settlement resolving the interconnection issue
- KO Transmission Company, Docket No. RP16-1097-000: Filed testimony on behalf of KO Transmission and served as the Rate Case Filing/Settlement Coordinator

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Negotiations-Continued

- Served the role of lead FERC Trial Staff Technical Witness on settlements on FERC wholesale electric, liquid pipeline and natural gas pipelines related to cost of service and cost allocation and rate design

Presentations

- Panelist—EBA Energizer—FERC Pass-Through Taxation and Income Tax Allowance Recovery Policy Discussion
- Panelist EBA-Section 5 Perspectives, January 2018
- FC Intelligence-Natural Gas Impact, Transportation Options and Regulatory Oversight, May 2016
- Western States Association of Tax Administrators, four presentations between 2015 to 2017
- Panelist, "Will Fracking Change the Gas Pipeline Flows in Ways that Affect Rate Design and Cost Allocation?" EBA Mid-Year Meeting, November 2014

Courses Taught

- FERC Natural Gas 101, FERC Natural Gas Pipeline Cost of Service, Cost Allocation and rate Design, FERC Natural Gas Pipeline Rate Case Process—Presenter--EUCI, Inc., 2013 to present
- New Mexico State University Center for Public Utilities Practical and Regulatory Training for the Natural Gas Interstate Pipeline Industry at the Sheraton Uptown in Albuquerque, NM specifically addressing FERC requirements for determining "Just and Reasonable" rates (Cost of Service Ratemaking), five presentations between 2007 to 2011
- Centra Gas/Manitoba Hydro-On-site in Winnipeg, Canada--Two-day course on FERC Electric and Natural Gas Rates and Regulatory Oversight

MARCH 31, 2021

NEXUS Pipeline Impacts Analysis

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INTRODUCTION

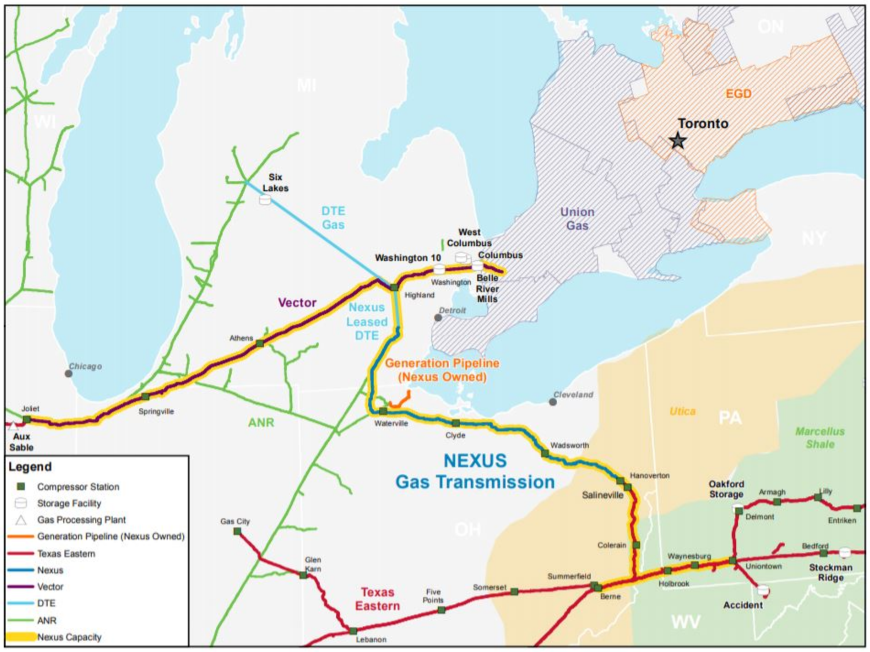
The Power & Utilities practice at FTI Consulting Inc. ("FTI") has been engaged by DTE Gas and DTE Electric (collectively, the "DTE Utilities" or the "Companies") to analyze the impacts of the Nexus Gas Transmission pipeline ("NEXUS") on natural gas prices in Michigan and the savings in gas costs that accrue to customers in that state as a result. To do so, a team of experts from FTI developed simulations of the North American gas markets to forecast market prices in Michigan and elsewhere for the period 2022 to 2038 (the "Forecast Period"), whose end coincides with the termination of the longest-dated entitlements held on NEXUS by the DTE Utilities. Analysis of those prices indicates that NEXUS will create total savings of approximately $1 billion to customers over that time.

This report describes the methods and results FTI used to estimate savings attributable to NEXUS, additional analyses that indicate that savings could be higher if market prices increase in the future, and also additional benefits from NEXUS other than gas cost savings that accrue to customers from the pipeline's commercialization.

The NEXUS System

NEXUS is a roughly 250-mile pipeline that provides access for consumers in Ohio, Michigan, and Ontario to abundant and economical shale gas supplies. The system receives gas from Marcellus Shale and Utica Shale production areas for delivery to customers in the Upper Midwest via connections with the DTE Gas Transmission System and the Vector Pipeline. NEXUS also enhances shippers' ability to utilize gas storage, including the facilities located at Dawn, Ontario. Initially, the Kensington gas processing plant in Ohio ("Kensington") was envisioned as the southern terminus of the project. Later, it was determined to expand further south via the Texas East Appalachia Lease ("TEAL") project, which included capacity to a new interconnect with the Texas Eastern ("TETCO") system in Clarington, Ohio ("Clarington"). The entire system, including TEAL, began shipping gas in October 2018. NEXUS can transport up to 1.4 Billion Cubic Feet per Day ("Bcf/d") of gas.

Figure 1. NEXUS System[1]



Both of the DTE Utilities hold entitlements on NEXUS. DTE Electric has an entitlement for 30,000 Dth/d to receive gas at Kensington and move it to the interconnect with the DTE Gas System in Ypsilanti, Michigan. In 2022, the size of its entitlement increases to 75,000 Dth/d, the timing of which is designed to coincide with commercialization of the Blue Water Energy Center ("BWEC"), a combined cycle generation facility currently under construction. The DTE Electric contract also allows it to receive 15,000 Dth/d of that capacity at either Clarington or Kensington until 2022. DTE Electric's capacity contract expires in 2038.

DTE Gas has an entitlement for 75,000 Dth/d that expires in 2033. Under its agreement, DTE Gas can receive up to half of its receipts at Clarington through 2022, after which point its contract calls for all receipts to be made at Kensington; however, FTI is aware of ongoing discussions between DTE Gas and NEXUS to further amend its agreement to extend the period during which it can receive gas at Clarington. For this reason, FTI has assumed that DTE Gas will receive half its entitlement at Clarington and half at Kensington for the entirety of the Forecast Period. This assumption is consistent with recent filings DTE Gas has made before the Commission.

Table 1 shows how the DTE Utilities' NEXUS entitlements change over time. Note that the periods reflect the time periods covered in this analysis; both the DTE Electric and DTE Gas contracts began prior to January 2022.

[1] *Source*: DTE Midstream

Table 1. NEXUS Entitlements by Time Period (Dth/d)

Start	End	Quantity	Receipt Point
DTE Electric			
January 2022	May 2022	15,000 15,000	Kensington/Clarington Kensington
June 2022	October 2022	15,000 60,000	Kensington/Clarington Kensington
November 2022	May 2037	75,000	Kensington
June 2037	October 2038	30,000	Kensington
DTE Gas			
January 2022	October 2022	37,500 37,500	Kensington/Clarington Kensington
November 2022	October 2033	75,000	Kensington

Both DTE Electric and DTE Gas pay a negotiated reservation rate of $0.695/Dth for service from Kensington to NEXUS-Ypsilanti. Both also pay a negotiated reservation rate of $0.15/Dth for receipts at Clarington. Each of the DTE Utilities' agreements also includes a fuel charge, which is currently approximately 1.3%.

Summary of Conclusions

An important motivation for this study is the desire to update previous analyses of the value of NEXUS in the context of current and upcoming proceedings before the Michigan Public Service Commission. Previously, the DTE Utilities have relied on a report dated November 2015 (the "November 2015 Report") to help explain the benefits that NEXUS creates for Michigan ratepayers. That study is now several years old and gas markets have undergone significant changes since it was developed. To capture the effect of these changes and to develop an updated estimate of the savings that NEXUS provides, FTI conducted long-run simulations using a customized version of GPCM, the industry-standard platform for the analysis of natural gas markets in North America.[2] The results of those simulations and related analyses support the following conclusions:

- NEXUS reduces the DTE Utilities cost of gas purchases by approximately $867 million between 2022 and 2038. Over that time, they will pay roughly $657 million for their contracts on NEXUS, meaning that their net savings is approximately $210 million.
- Other gas consumers in Michigan also benefit from NEXUS because it reduces prices in Michigan. Those savings will total approximately $808 million 2022-2038. Therefore, the total savings to customers in the state is approximately $1 billion.
- These amounts are in addition to the savings that consumers in Michigan have already realized since NEXUS has been placed into service.

[2] https://rbac.com/

- If gas prices increase, savings attributable to NEXUS will likely be greater, perhaps by a significant amount.
- In addition to reducing gas costs, NEXUS creates other benefits, including diversity of fuel supply, the value of which FTI has not attempted to quantify but that are nonetheless important.

The remainder of this report is organized as follows. *First,* the simulation analyses that FTI conducted are described in detail. *Second*, the calculations of benefits to customers based on the simulation results are explained and summarized. *Third*, an alternative scenario that demonstrates that NEXUS benefits increase in a higher demand, higher price market is presented. *Fourth*, other benefits that are significant but that are not quantified in this study are identified. Finally, *fifth*, key conclusions and findings are summarized.

Market Analysis

FTI's analytical approach is centered on the development of detailed simulations of the gas markets in Michigan, Appalachia, and surrounding areas that provide a realistic outlook for production, consumption, and the utilization of pipeline infrastructure. The simulation that includes NEXUS, referred to as the *Base Case*, is intended to represent a "business as usual" outlook, against which the results of alternative scenarios can be analyzed. The process by which FTI validated the reasonableness of the *Base Case* is described later in this section.

Once the *Base Case* was finalized, a *No Nexus Case* was run, in which NEXUS was removed from the simulation while all other inputs were held constant. Delivered prices in and around Michigan are higher in the *No Nexus Case*. Since the removal of NEXUS is the only change, the difference in the prices between the two cases is the estimate of NEXUS' impact on the current market and becomes the basis for the calculations of benefits.[3]

All the simulations were conducted on a monthly basis for ten years, from January 2022 to December 2031. FTI then extrapolated results from that ten-year forecast through 2038.

Modeling Overview

FTI developed the simulations described in this document using a customized version of GPCM that the Power & Utilities team has developed and maintains for that purpose. GPCM is the leading tool to simulate gas markets and is in widespread use by pipeline companies, banks, investors, and regulators, including the Federal Energy Regulatory Commission ("FERC"), and others.[4] The software includes a network model based on equilibrium economics whose inputs and assumptions are developed regarding gas producers' ability to supply gas at various price levels, consumers' willingness to buy gas at various price levels, and costs from transporting and/or storing gas using existing and planned infrastructure, the cost of which is defined by published rates as well as observational data that relates costs and discounting to system utilization levels. In other words, as in the real world, suppliers will produce more

[3] In other words, the prices in the *No NEXUS Case* indicate what prices would be had NEXUS never been constructed.

[4] Additional detail regarding GPCM is included as Appendix 1. GPCM Description.

when prices are high and less when prices are low, consumers are assumed to also be responsive to price to some degree, and infrastructure owners can be expected to discount the cost of transportation or storage compared to maximum tariff rates when demand for their services is low and less when it is high. These dynamics are captured in supply and demand curves for gas as well as for transportation and storage whose parameters, including price, production, and consumption levels as well as elasticities, are based on empirical data collected in the market, as are the characteristics of pipeline and storage facilities on the system (capacity, connections, etc.). Simulation solutions are generated based on convergence to a set of conditions at which the amount of gas produced by suppliers is equal to the amount of gas consumed by customers i.e. the intersection of supply and demand curves or clearing prices. Because physical constraints impose finite limitations on the flow of gas across the system, prices will be lower in locations where there is abundant, inexpensive supplies of gas compared to demand and higher in areas in which demand is higher and the availability of gas production, transportation, or both is limited.

Customers are modeled individually based on their expected consumption patterns; for example, DTE Gas and DTE Electric are each represented as individual entities in GPCM, with customer-specific demand assumptions that are based on both historic and forecast data, system interconnections based on the real-world configuration of the DTE Gas Transportation System and the other gas infrastructure in and around the Companies' service territory (and the entire North American pipeline system), and other relevant data. Suppliers are modeled with similar levels of granularity, as are pipelines and storage facilities. For example, the configuration of NEXUS in the model includes the three zones NEXUS uses for ratemaking; connections with other pipelines, customers, and suppliers based on the system's actual configuration; and other data captured in regulatory filings and public databases. In total, the GPCM database used for this study includes more than 150 gas supply areas; nearly 500 consumers, including utilities, industrials, Liquefied Natural Gas ("LNG") export facilities, and others; almost 300 pipelines, each of which are modeled at similar levels of granularity as is NEXUS; and roughly 450 gas storage facilities. With each simulation, the model reports production, consumption, flows across each segment of infrastructure, and pricing for most publicly available indices, among other data.

Base Case **Simulations**

For the *Base Case*, FTI modeled supply and demand outlooks based on publicly available data and internal analyses. Assumptions regarding the development of new pipeline infrastructure also rely on current information. Of particular note for this analysis are projects designed to provide takeaway capacity from the Marcellus and Utica shales. With the completion of NEXUS and the commercialization of the Energy Transfer Partners Rover project ("ET Rover"), there are no large projects designed to provide Appalachian gas a new east-to-west path to new markets.

The outlook accounts for the cancellation of some high-profile projects that would have also added new delivery out of the region, including the Constitution pipeline and the Atlantic Coast Pipeline, both of which were abandoned by their developers in 2020 (although Constitution had been bogged down by a number of permitting challenges for some time).[5,6] FTI has also made the decision to not include the Mountain Valley Pipeline even though it has received its required approvals from the FERC, based on that project's recent, persistent delays. Thus, the number of projects providing new delivery out of the mid-Atlantic region expected to be developed in the next several years is relatively small. Table 2 lists planned and recent system expansions of relevance to the Marcellus and Utica areas that are included in the *Base Case*, along with their capacities and in-service dates ("ISDs"). Both NEXUS and TEAL are intentionally excluded from Table 2.

Table 2. Base Case Pipeline Projects *(MMCf/d)*

Project	ISD	Capacity
Columbia Gulf Xpress	2018	860
Mountaineer Xpress	2018	2,700
Columbia WB Xpress	2018	1,300
Atlantic Sunrise	2018	1,700
ET Rover	2018	3,250
Columbia Leach Xpress	2018	1,530
Eastern Sore 2017 Expansion	2018	61
Birdsboro (DTE)	2019	79
Adelphia Gateway	2021	350
Appalachia to Market (TETCO)	2021	18
PennEast	2021	1,000
Transco Leidy South	2021	582
Vector BWEC Pipeline	2022	180

Aside from the BWEC Pipeline project on Vector, which is a lateral project to support DTE Electric's new generation facility, there are no pipeline expansions planned in Michigan nor have there been any large projects recently completed. The most recent pipeline project in the region is SEMCO Energy Gas Company's Marquette Connector, a new lateral connection from its distribution system to Great Lakes Gas Transmission ("GLGT"), which went into service in 2019.[7]

Once FTI ran the forecast using these assumptions, one way in which the *Base Case* simulation was validated was by comparing the resulting price forecasts to available forwards. Specifically, FTI compiled forward curves from February 25, 2021, which are reported by OTC Global Holdings, L.P. and accessed through S&P Global Market Intelligence ("S&P"), which it compared to the *Base Case* forecast. Below, monthly forecasts for Dominion South Point ("Dominion South"), Texas Eastern Market Zone 2 ("TETCO M2"), and the Tennessee Gas Pipeline Zone 4, 200 Leg ("TGP Z4-200L").

[5] https://napipelines.com/williams-partners-abandon-constitution-pipeline-project/
[6] https://atlanticcoastpipeline.com/news/2020/7/5/dominion-energy-and-duke-energy-cancel-the-atlantic-coast-pipeline.aspx
[7] https://www.uppermichiganssource.com/content/news/SEMCOs-Marquette-Connector-Pipeline-construction-ahead-of-schedule-561245611.html?ref=611

Figure 2. Base Case Forecast vs. Forward Pricing: Dominion South

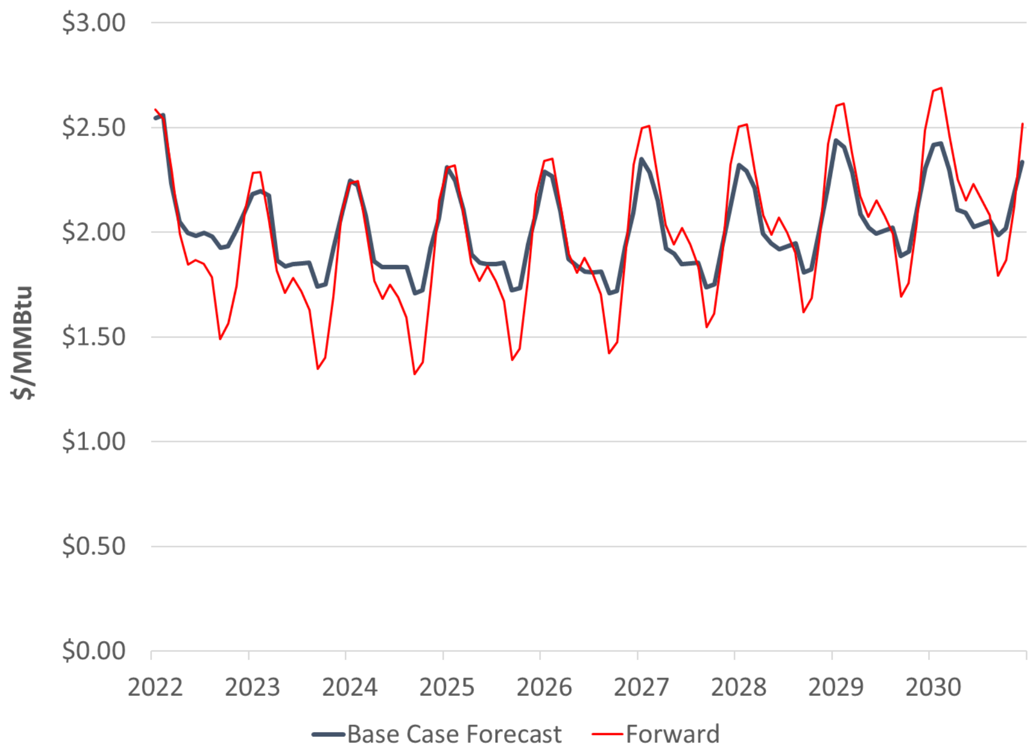


Figure 3. Base Case Forecast vs. Forward Pricing: TETCO M2

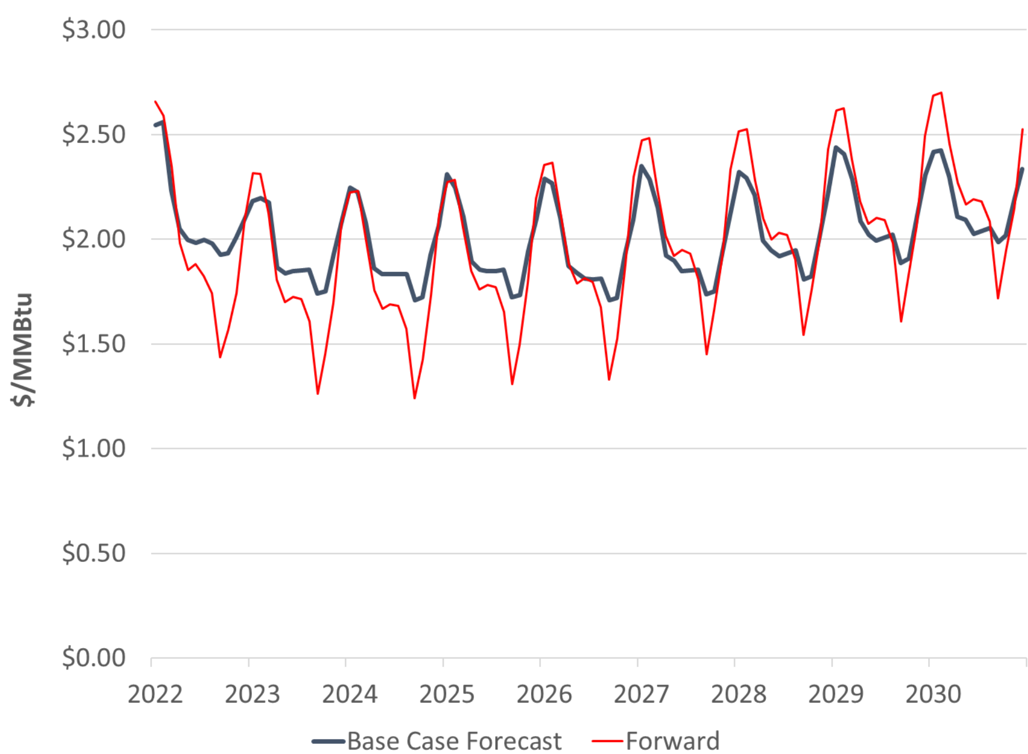
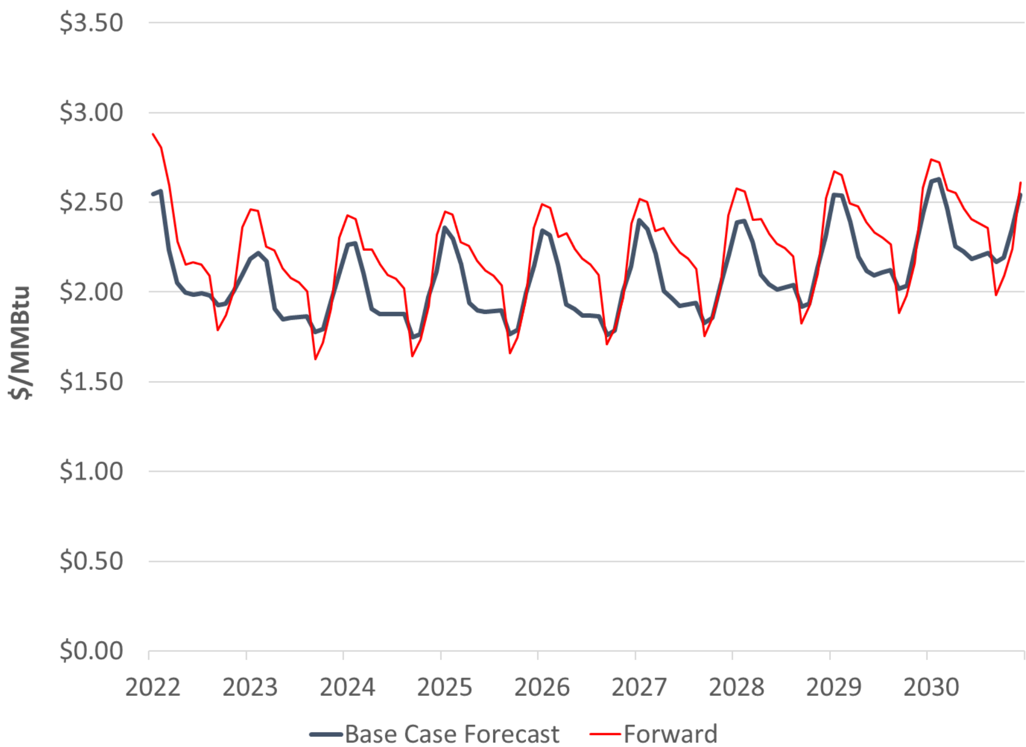


Figure 4. Base Case Forecast vs. Forward Pricing: TGP Z4-200L



FTI also calibrated the *Base Case* simulation based on expected prices at Kensington and Clarington. To do so, FTI synthesized forward prices for each location based on pricing relationships to other indices, TGP Z4 200L and TETCO M2, respectively.

Figure 5. Base Case Forecast vs. Forward Pricing: Kensington

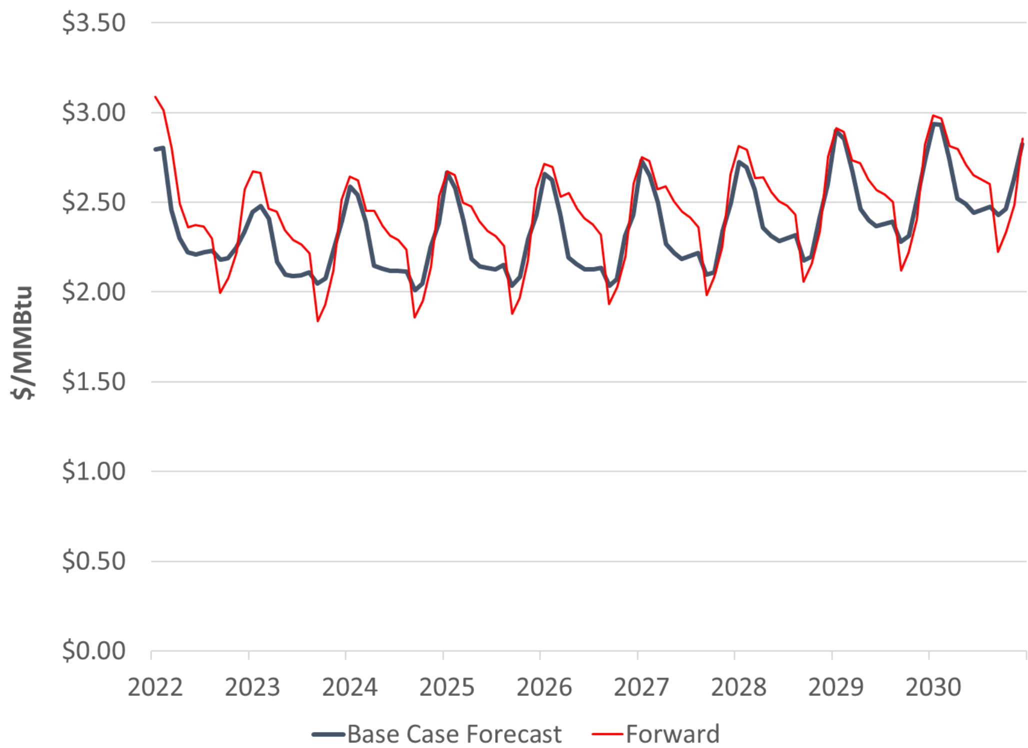
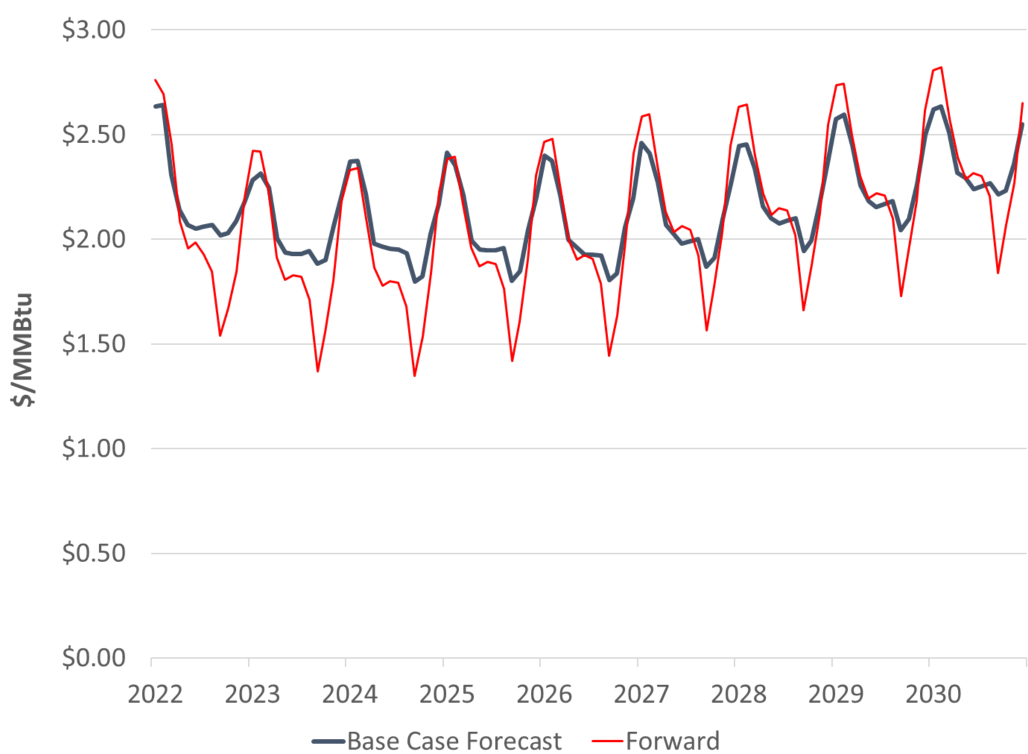


Figure 6. Base Case Forecast vs. Forward Pricing: Clarington



FTI also compared pricing points in the areas where NEXUS delivers, including MichCon, Dawn, and the Consumers Energy Citygate ("Consumers").

Figure 7. Base Case Forecast vs. Forward Pricing: MichCon

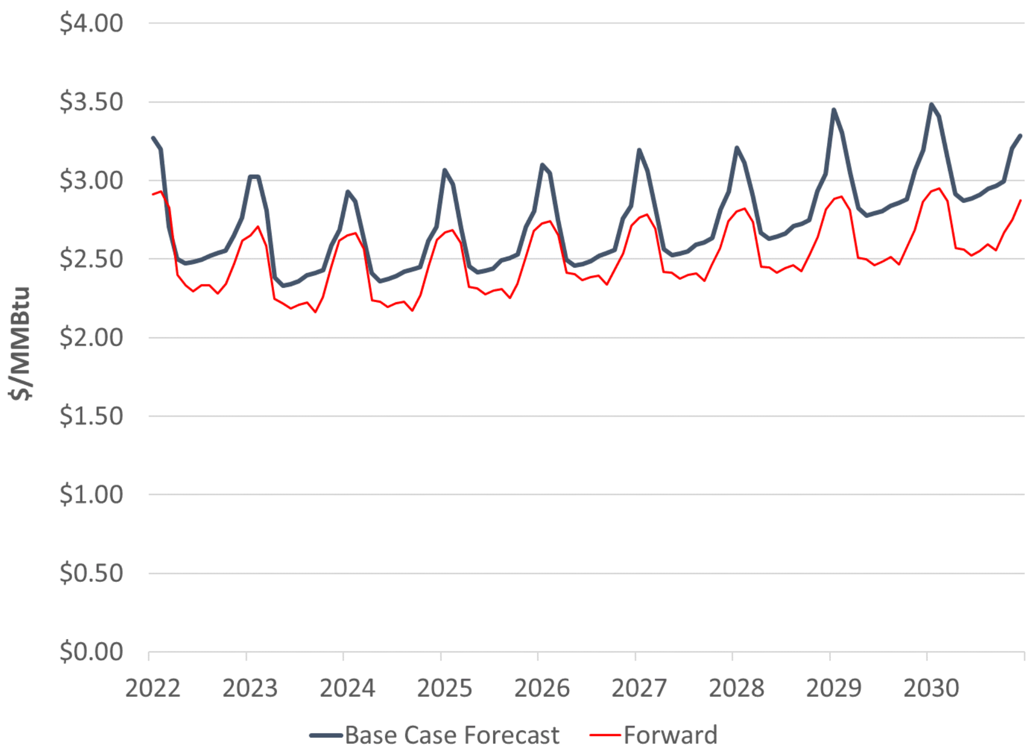


Figure 8. Base Case Forecast vs. Forward Pricing: Dawn

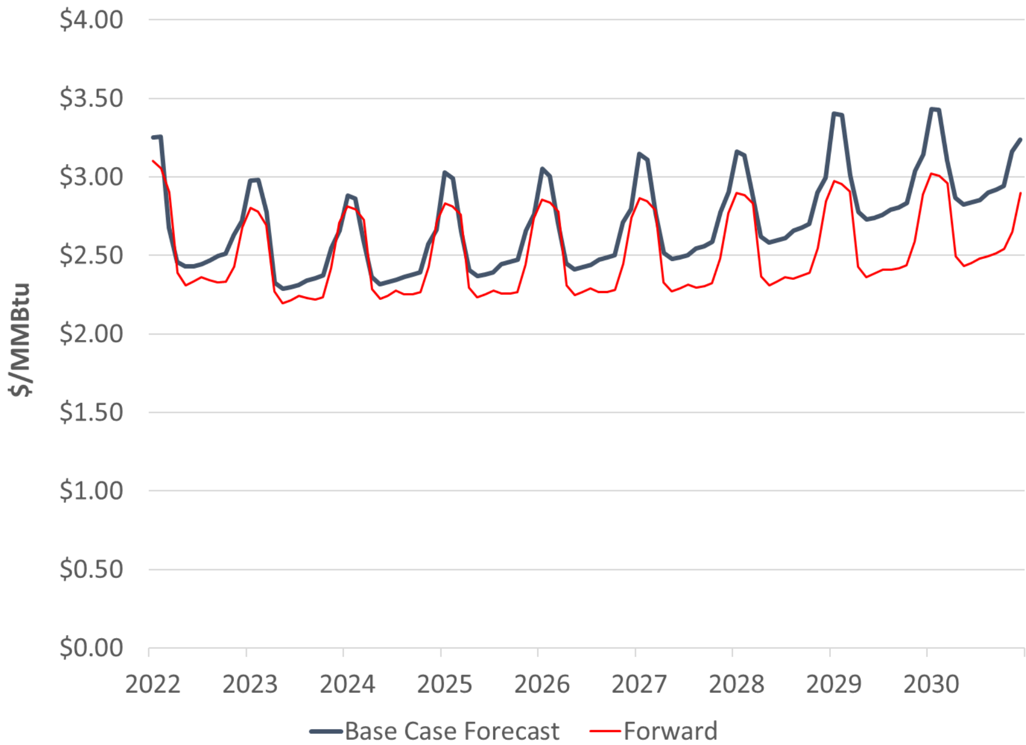
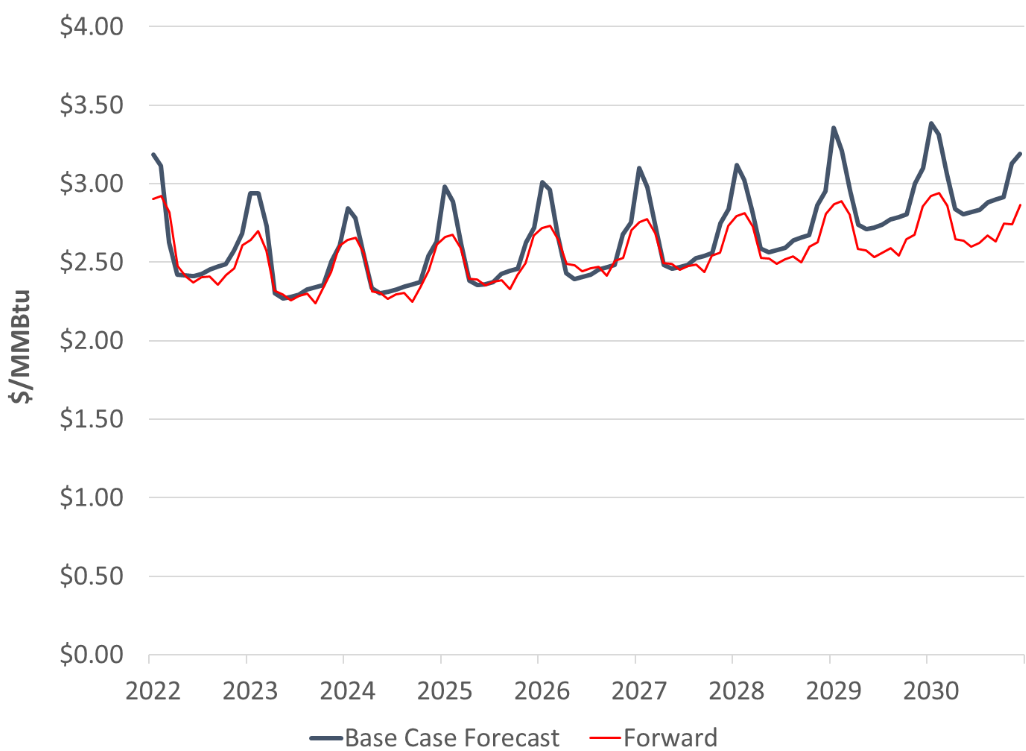


Figure 9. Base Case Forecast vs. Forward Pricing: Consumers



The Base Case forecast was also validated by comparing the demand outlook with recent versions of the Annual Energy Outlook ("AEO"), which is published each year by the Energy Information Agency ("EIA"). The AEO includes a series of forecasts that reflect EIA's current projections for energy prices, production, consumption, and other outcomes, differentiated by geographic area, under various scenarios. FTI compared the Base Case demand forecast for Michigan to "Reference Case" demand forecast from each of the last two AEOs, which were published in 2020 ("AEO2020") and 2021 ("AEO2021"). The AEO forecasts are for the East North Central ("ENC") region, the U.S. census region that includes Michigan, Illinois, Indiana, Ohio, and Wisconsin. Therefore, the Base Case forecast is not directly compared to the ENC outlook but, rather, annual rates of growth in annual gas consumption are compared for each of DTE's Residential, Commercial, and Industrial customers and DTE Electric were compared to the corresponding forecasts for ENC consumption from the AEOs. Results are shown in Table 3 below.

Table 3. Base Case and AEO Demand Forecast Comparison

Sector	**Forecast**	**Area**	**Units**	**2022**	**2033**	**2038**	**Growth Rate *(2022-2038)***
Total	2021 AEO	ENC	Tcf	4.3	5.0	5.4	1.4%
	2020 AEO	ENC	Tcf	4.6	4.9	5.4	1.0%
	Base Case	Michigan	Bcf	979.7	1,096.8	1,166.7	1.1%
Residential	2021 AEO	ENC	Tcf	1.3	1.2	1.2	-0.6%
	2020 AEO	ENC	Tcf	1.3	1.2	1.1	-0.7%
	Base Case	Michigan	Bcf	106.3	99.7	93.9	-0.8%
Industrial	2021 AEO	ENC	Tcf	1.2	1.3	1.4	1.0%
	2020 AEO	ENC	Tcf	1.4	1.4	1.5	0.6%
	Base Case	Michigan	Bcf	73.4	85.1	89.5	1.3%
Commercial	2021 AEO	ENC	Tcf	0.7	0.8	0.8	0.4%
	2020 AEO	ENC	Tcf	0.8	0.8	0.8	0.0%
	Base Case	Michigan	Bcf	74.1	73.8	72.9	-0.1%
Electric	2021 AEO	ENC	Tcf	1.1	1.7	2.0	3.8%
	2020 AEO	ENC	Tcf	1.2	1.5	2.0	3.1%
	Base Case	Michigan	Bcf	69.0	93.1	111.4	3.0%

These data show general consistency between the *Base Case* and the AEO forecasts for each customer segment. All three forecasts indicate moderate growth in total consumption is expected through 2038, driven by strong growth in gas consumption for electric generation and offset by declines in residential growth. The *Base Case* forecasts for Industrial and Commercial demand also align reasonably well with the AEO projections. Note that Table 3 also includes data for 2030, showing the general agreement among the forecasts in the middle of the Forecast Period as well.

Average annual prices from the *Base Case* for selected points are shown in Table 4.

Table 4. Base Case Annual Prices *($/MMBtu)*

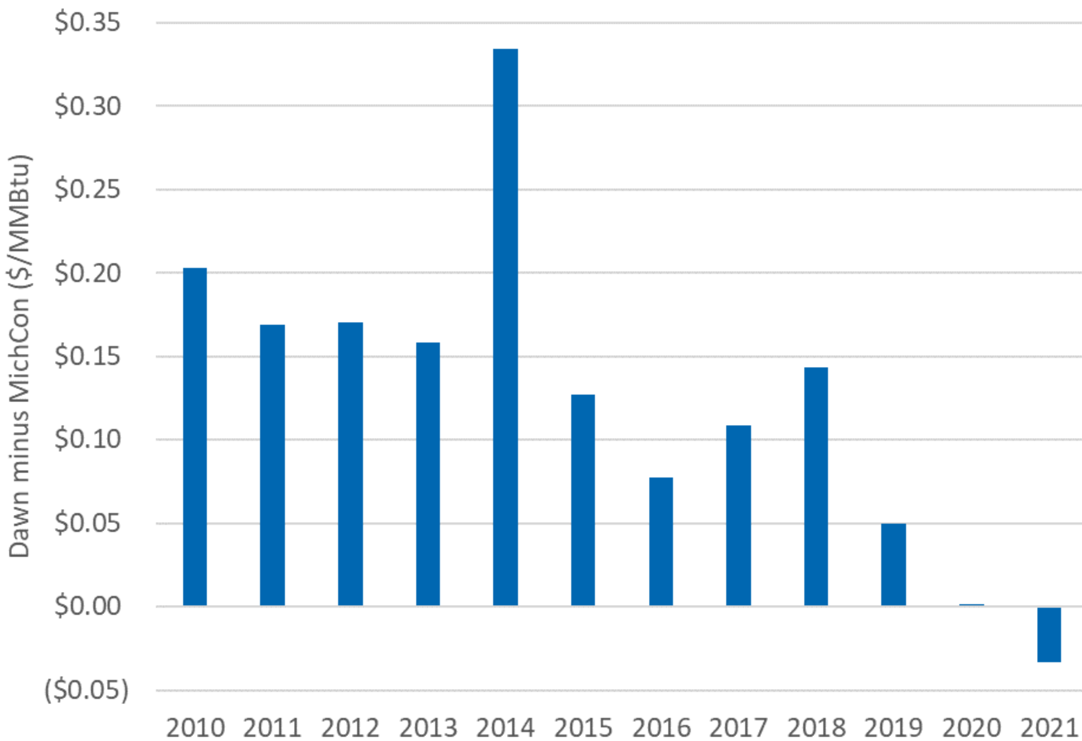
	Dawn	MichCon	Clarington	Kensington
2022	$2.65	$2.68	$2.19	$2.35
2023	$2.52	$2.56	$2.05	$2.22
2024	$2.50	$2.55	$2.05	$2.24
2025	$2.59	$2.63	$2.06	$2.27
2026	$2.62	$2.67	$2.05	$2.28
2027	$2.70	$2.73	$2.11	$2.33
2028	$2.79	$2.83	$2.19	$2.41
2029	$2.95	$2.99	$2.29	$2.52
2030	$3.04	$3.09	$2.37	$2.61
2031	$3.18	$3.22	$2.46	$2.72
2032	$3.29	$3.33	$2.54	$2.81
2033	$3.40	$3.44	$2.61	$2.90
2034	$3.52	$3.55	$2.69	$2.99
2035	$3.63	$3.67	$2.78	$3.08
2036	$3.76	$3.80	$2.86	$3.18
2037	$3.88	$3.92	$2.95	$3.28
2038	$4.01	$4.05	$3.04	$3.38

The Upper Midwest prices, MichCon and Dawn, increase at a higher rate than do the other prices shown, indicating that even though prices will remain low compared to historical levels, regional delivery constraints will continue to create price separation to other areas.

Also noteworthy is the evolving relationship between the MichCon and Dawn prices. Historically, Dawn gas has been priced at a premium to gas at MichCon; however, the *Base Case* forecast indicates an inversion of that relationship. This outlook represents a continuation of recent trends between those prices, whereby the spread has decreased consistently and, recently, reversed. Figure 10 shows the average annual spread between Dawn and MichCon since 2010.[8]

[8] Data for 2021 are a year-to-date average through March 23.

Figure 10. Average Annual Spread from Dawn to MichCon[9]



No Nexus Simulations

In the *No Nexus* case, flows on NEXUS are eliminated while all other factors are held constant. From Michigan's perspective, the result is that access to the lowest priced sources of gas (the Marcellus and Utica shales) is reduced and the market is compelled to import gas from other sources that are either farther away such as the Haynesville Shale, located mostly in Texas and Louisiana, or the Niobara Shale, which is in the Rockies, or from local production from the Antrim Shale, which is nearby but more expensive.

One result of the supply shift is an increase in local prices. Figure 11 shows the average annual change in the MichCon price in the *No NEXUS* case compared to the *Base Case*. On average, the differential is roughly $0.08/MMBtu.

[9] FTI analysis using data from S&P.

Figure 11. Change in Annual MichCon Prices

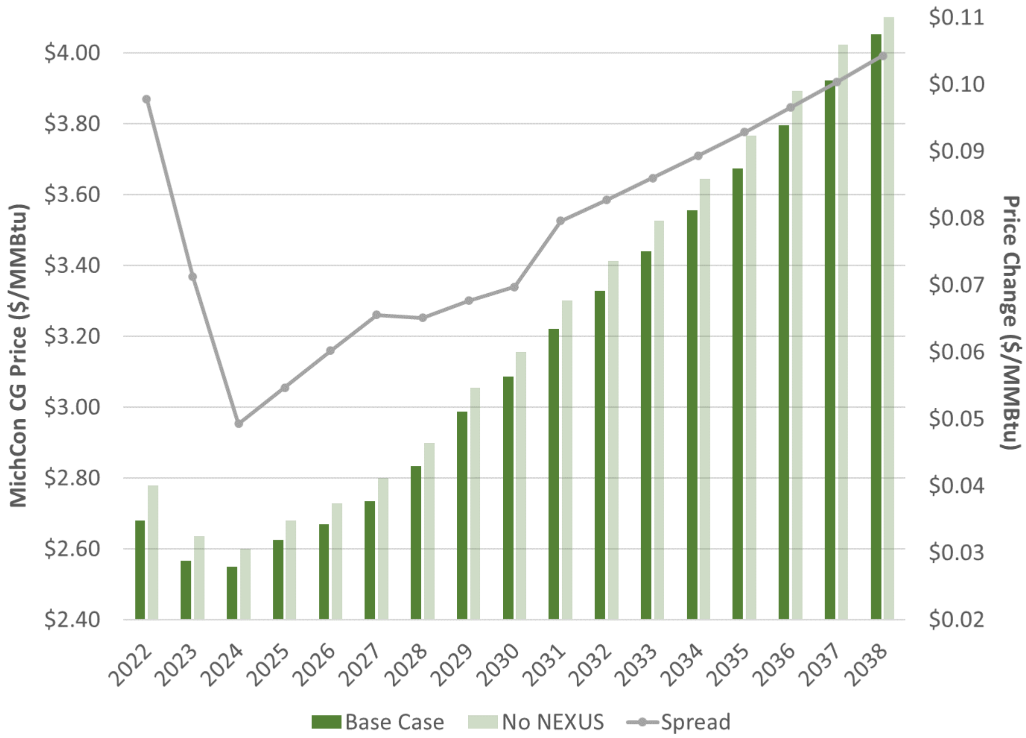
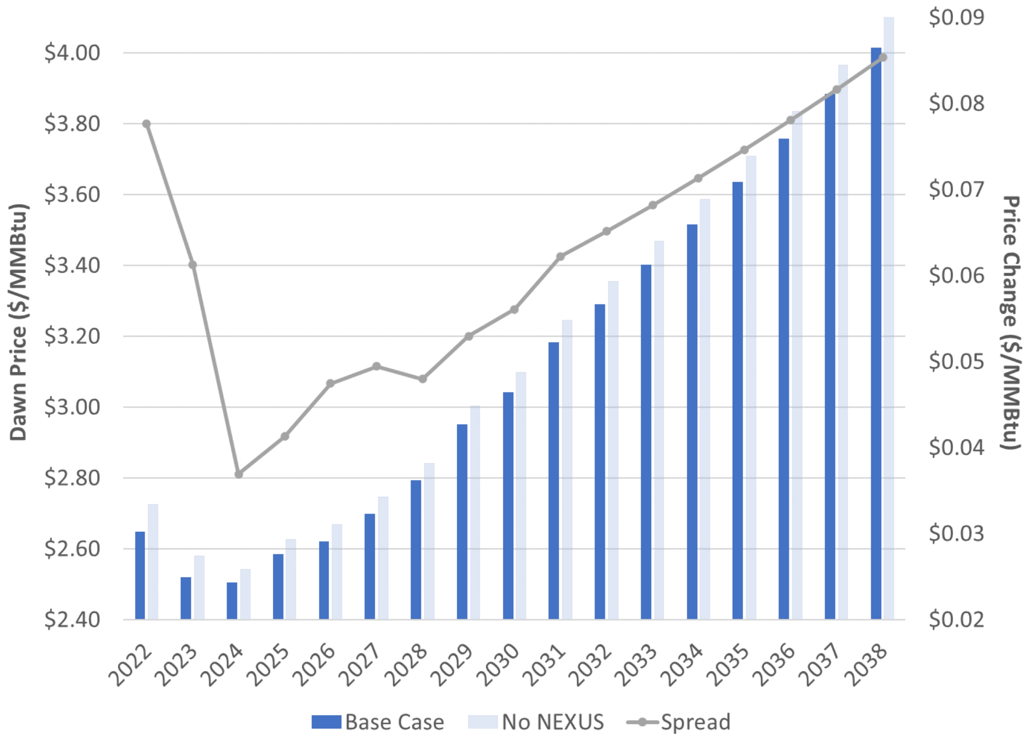


Figure 12 shows a similar comparison for Dawn, where the spread between the *No NEXUS Case* and the *Base Case* is lower, averaging roughly $0.06/MMBtu over the forecast period. Prices at Dawn are less sensitive to the impact from NEXUS because it is farther away from NEXUS receipts and because Dawn is subject to other market influences that may be more pronounced on the Canadian side of the border, including, for example, flows on the TransCanada Pipeline Line ("TCPL") system.

Figure 12. Change in Annual Dawn Prices



In some locations, the opposite price response occurs, and prices are higher in the *Base Case*. This is the case in some supply areas, where NEXUS increases demand. For example, Table 5 shows that prices at Dominion South and TGP Z4 200L each increased as a result of NEXUS being placed into service.

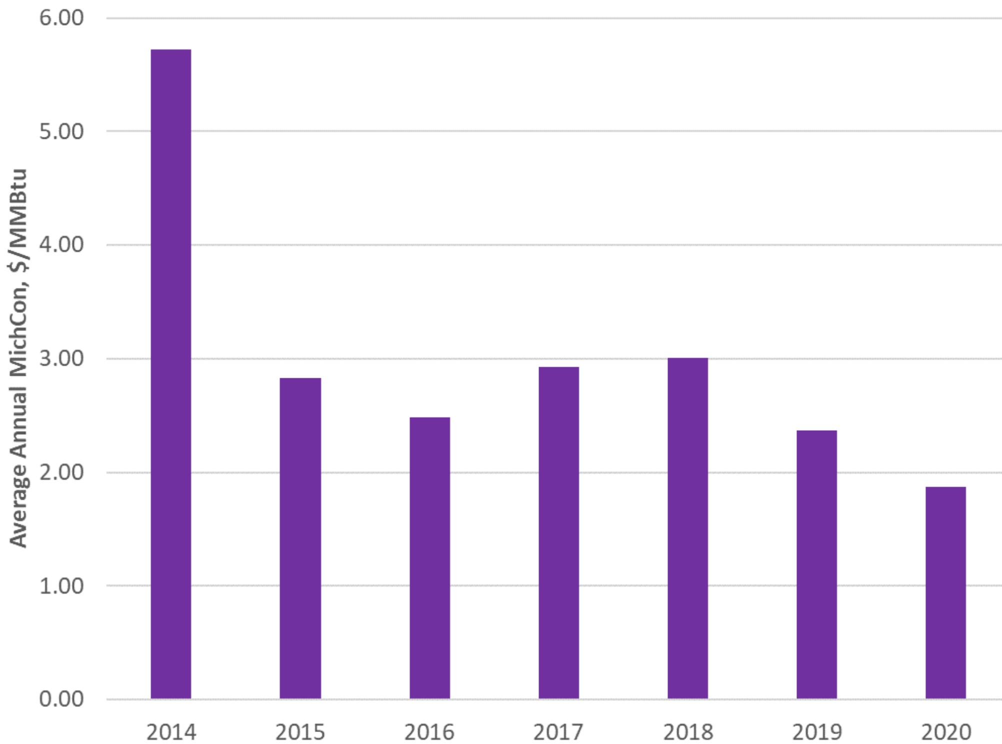
Table 5. Average Change (2022-2038) in Selected Prices *($/MMBtu)*

	Base Case	***No NEXUS***	**Price Change**	**% Change vs. Base**
MichCon	$3.16	$3.24	$0.08	2.5%
Dawn	$3.12	$3.18	$0.06	2.0%
Dominion South	$2.23	$2.19	($0.04)	-1.7%
TGP Z4 200L	$2.41	$2.38	($0.03)	-1.3%

Comparison to Results Reported in the November 2015 Report

These results differ meaningfully from those described in the November 2015 Report. In that study, NEXUS was found to cause a larger difference in delivered prices, which, in turn, created more savings. One reason for the difference – likely the most significant – is the fact that gas prices were higher around the time the November 2015 Report was developed than they are now. For example, the average MichCon prices for 2014 and 2015 were $5.72/MMBtu and $2.83/MMBtu, respectively. By 2020, the average price at MichCon had fallen below $2/MMBtu. Average annual prices since 2014 are shown below.

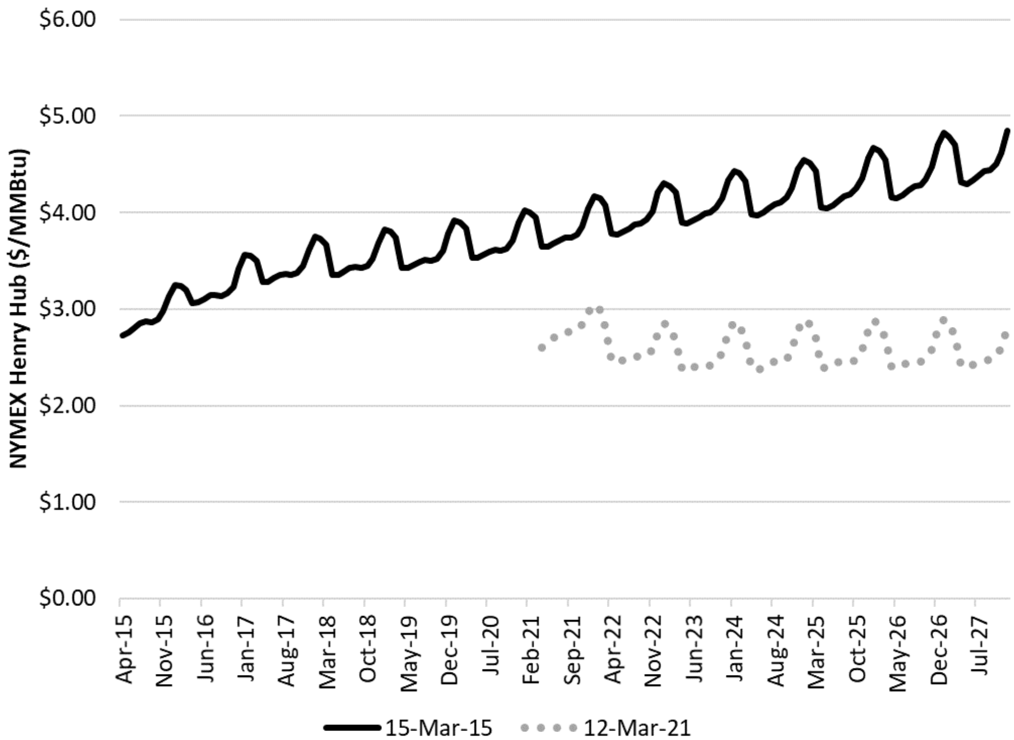
Figure 13. Average Annual MichCon Prices, 2014-2020[10]



Expectations for future prices were also considerably higher in 2015 than they are at present. Figure 14 shows the New York Mercantile Exchange ("NYMEX") forward curves for the Henry Hub, historically the benchmark index for North American gas, that settled on March 15, 2015 and on March 12, 2021. The curve from 2015 is considerably higher and indicates that the cost of gas is expected to increase at a rapid pace into the future. For example, the 2021 settlements indicate that the Henry Hub price in 2027, the last year included in both curves, is expected to average $2.58/MMBtu while the 2015 settlements indicate $4.45/MMBtu, more than 75% higher.

10 Analysis by FTI using data from S&P.

Figure 14. NYMEX Henry Hub Futures, 2015 vs. 2021



One implication of the current, lower price environment is that price changes attributable to new infrastructure are likely to be smaller.

Another, closely related reason for the difference in the outlooks presented in the two studies may be the unexpected response to Appalachian gas producers to low prices. Production levels from suppliers in the Marcellus and Utica regions over the last several years have surprised many industry observers, who believed that low prices would cause producers to curtail their output. Instead, production has generally remained strong and although some declines have been observed since the beginning of 2020, they may be attributable to impacts from the COVID-19 pandemic.

Finally, the disposition of supply into Michigan, both historically and in terms of the long-term outlook, has clearly changed. The November 2015 Report indicates that, absent NEXUS, only about a third of the gas brought to Michigan would be from Appalachia, with gas from sources in the west representing the state's largest sources of supply.[11] At the time, that outlook was generally supported by more competitive pricing for gas from the Western Canadian Sedimentary Basin ("WCSB"), from which a significant amount of gas for the Upper Midwest is sourced and delivered via TCPL, the Northern Border system and smaller systems that connect with TCPL, including Alliance and GLGT. More recently, supplies from WCSB have become less competitive compared to shale gas from the mid-Atlantic and also compared to supplies from other areas whose favorable economics have supported recent growth, such

[11] p. 22.

as the Haynesville or Niobara formations or the Permian Basin. It may be the case, then, that when the November 2015 Report was presented to the Commission that NEXUS would be expected to provide a path to Michigan that would allow for the displacement of gas that was considerably more expensive than Michigan's current supplies. Some of the non-Appalachian supplies that Michigan can access, including, for the example, Haynesville gas, may be more expensive than Marcellus and Utica gas, but the difference may be smaller than it was when the November 2015 Report was developed. As a result, the expected impact from NEXUS could be somewhat less than had been expected at that time.

These important differences notwithstanding, the findings described in this document and those described in the November 2015 Report share important consistencies. In particular, the November 2015 Report found that NEXUS was expected to decrease the MichCon price by roughly 3.6%, on average, over its forecast period, a result that generally similar the forecast of a 2.5% reduction that FTI has found in this study. Table 6 shows a comparison.

Table 6. Comparison of Results to November 2015 Report, Average MichCon Prices *($/MMBtu)*

	FTI Study	November 2015 Report
Base	$3.16	$5.87
No NEXUS	$3.24	$6.08
Change	$0.08	$0.21
% change	2.5%	3.6%

While some of the forecasts described in the November 2015 Report are now inconsistent with current expectations, it is not appropriate to evaluate their accuracy based entirely on hindsight and without context. Market conditions when that study was developed, particularly with regard to the considerably higher spot and forward gas prices, clearly align with a higher price outlook which, in turn, results in higher benefits. Now, with market prices lower, the benefits attributable to NEXUS are decreased. These differences notwithstanding, similarities between the two studies, particularly the expected percentage reductions in delivered prices and the simple fact that both forecasts found NEXUS to provide significant impacts that create ratepayer sayings, may serve to validate both studies while also demonstrating that NEXUS delivers benefits under a wide range of market conditions.

Calculation of NEXUS Benefits

Benefits attributable to NEXUS accrue in different ways for different customers, depending on whether they hold entitlements on NEXUS, on other systems, or both, among other factors. This section discusses the derivation of the benefits attributable to each of DTE Electric, DTE Gas, and other customers in Michigan from the results of the simulation analyses.

As contract holders, savings for DTE Electric and DTE Gas emerge from their ability to source gas upstream on NEXUS instead of in or closer to Michigan and also from the fact that other purchases are made at reduced prices. The following example illustrates the mechanics of how savings are realized.

The *Base Case* forecast for November 2028 is $2.93/Dth for MichCon and $2.41/Dth for Kensington.[12] The *No NEXUS Case* forecast for the same month is $3.03/Dth for MichCon. That same month, DTE Electric's consumption is expected to be approximately 6.6 million Dth, of which about 2.3 million Dth can be bought at Kensington under Company's NEXUS entitlement. DTE Electric's cost of that gas is therefore $0.62/Dth lower than what it would otherwise have to pay since those purchases would be made at the *No NEXUS* MichCon price had NEXUS had not been built. The cost of gas for the month is further reduced by comparing the MichCon price from the *Base Case* of $2.93/Dth to the MichCon price from the *No NEXUS Case* of $3.03/Dth, resulting in cost savings of about $0.10/Dth for the 4.4 million Dth of expected spot volumes, or $445,000. The fuel charge on NEXUS volumes for the month is 1.26%, a cost of approximately $70,000. For the month, the total savings are greater than the cost of the NEXUS entitlement and fuel costs, and delivered costs are reduced by approximately $213,000.

Table 7. November 2028 Savings Calculation Example

Demand	Dth	6,613,337	*a*
Entitlement	Dth	2,250,000	*b*
Reservation rate	$/Dth	($0.695)	*c*
Contract cost	$	($1,563,750)	*d=b*c*
MichCon Price (*No NEXUS)*	$/Dth	$3.03	*e*
Kensington Price	$/Dth	$2.41	*f*
Savings	$/Dth	$0.62	*g=e-f*
Savings	$	$1,400,486	*h=g*b*
Non-contracted Volumes	Dth	4,363,337	*i*
MichCon Price (*No NEXUS)*	$/Dth	$3.03	*e*
MichCon Price	$/Dth	$2.93	*j*
Savings	$/Dth	$0.10	*k=e-j*
Savings	$	$444,529	*l=i*k*
Contract Rate	%	1.26%	*m*
Fuel Cost	$	($68,371)	*n = b*f*m*
Savings	**$**	**$212,893**	***o=d+h+l+n***

By repeating this calculation for this month forecast period, FTI determined that for the period 2022-2038, the gas price savings to DTE Electric is approximately $312 million. After accounting for NEXUS entitlement costs of $302 million, the analysis demonstrates that total savings for DTE Electric customers is approximately $11 million. Annual results are shown below:

[12] 1 Dth = 1MMBtu

Table 8. DTE Electric Net Savings by Year *($,millions)*

	Benefits	Contract Costs	Net
2022	$12.4	($16.5)	($4.2)
2023	$14.3	($19.0)	($4.8)
2024	$12.0	($19.1)	($7.1)
2025	$14.1	($19.0)	($5.0)
2026	$15.7	($19.0)	($3.3)
2027	$16.1	($19.0)	($2.9)
2028	$16.7	($19.1)	($2.4)
2029	$18.3	($19.0)	($0.7)
2030	$18.8	($19.0)	($0.3)
2031	$20.7	($19.0)	$1.7
2032	$21.9	($19.1)	$2.8
2033	$22.7	($19.0)	$3.7
2034	$23.7	($19.0)	$4.6
2035	$24.6	($19.0)	$5.6
2036	$25.7	($19.1)	$6.6
2037	$20.7	($12.4)	$8.3
2038	$14.0	($6.3)	$7.7

The same general approach was followed to estimate benefits for DTE Gas, except that additional steps had to be taken to account for its transportation portfolio by identifying the relevant market index for delivery points associated with each contract. For example, DTE Gas holds a contract with GLGT that specifies delivery points at or near the Emerson meter station near the U.S.-Canada border, where gas is typically valued based on the Emerson, Viking GL ("Emerson") index. Therefore, for the gas that DTE Gas will flow using that contract, the benefit of NEXUS is based on the difference in the Emerson prices in the *Base Case* and *No NEXUS Case*. Table 9 shows the DTE Gas transportation portfolio and the pricing index selected to analyze the benefits for gas flowed under each contract.[13]

[13] DTE Gas holds additional contracts on the ANR system that are intentionally excluded because their cost is recovered via distribution rates.

Table 9. DTE Gas Transportation Portfolio *(Dth/d)*

Pipeline	Qty	Index
NEXUS - Kensington	37,500	Kensington
NEXUS - Clarington	37,500	Clarington
GLGT	30,390	Emerson
Viking/ANR	21,000	Emerson
Vector	20,000	Chicago CG
Panhandle	65,000	Panhandle, TX-OK
ANR Alliance	50,000	Chicago CG
ANR SW	79,000	ANR, OK
ANR Mainline 3 ("ML3")[14]	60,000	REX Z3

As detailed in the GCR filing, all of these contracts except the one on GLGT expire by 2033. FTI has made the simplifying assumption that each will be renewed at the same terms for the duration of the forecast period. This includes the NEXUS contract, which is assumed to continue to be effective through October 2038 (the end date of the DTE Electric contract). Over that period, the total benefit to DTE Gas is approximately $555 million with net savings of $199 million. Annual totals are shown below.

Table 10. DTE Gas Net Savings by Year *($,millions)*

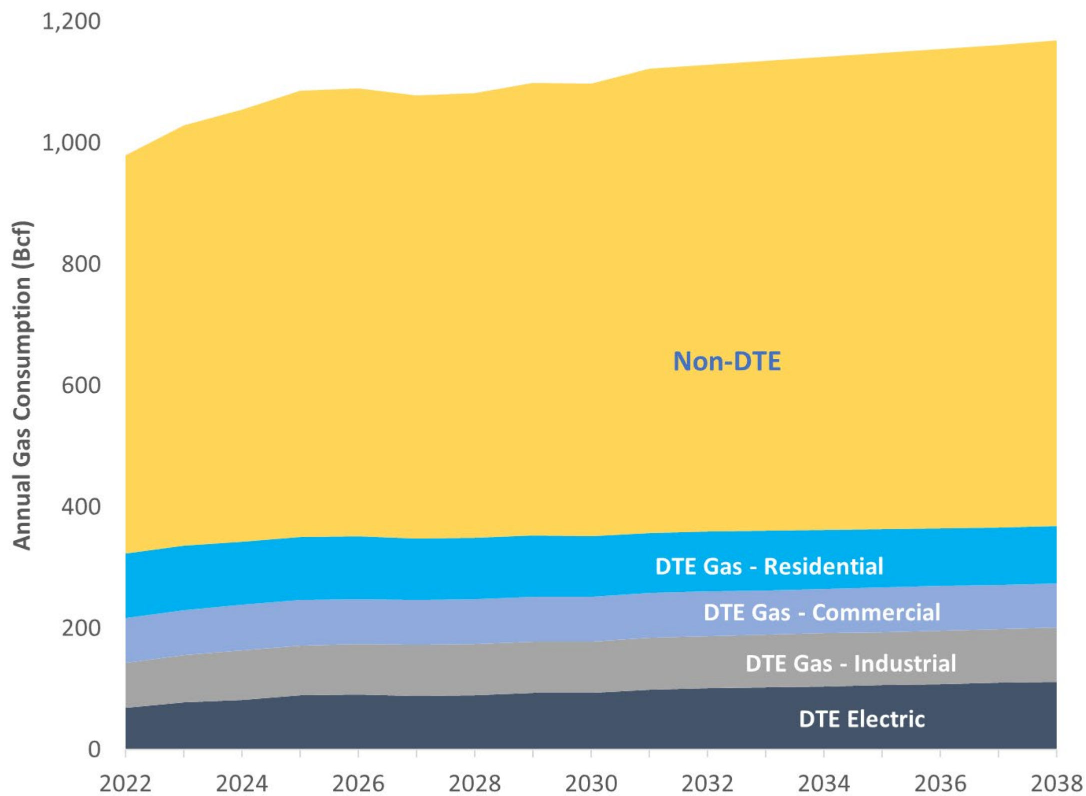
	Benefits	Contract Costs	Net
2022	$33.7	($21.1)	$12.6
2023	$31.2	($21.1)	$10.1
2024	$21.5	($21.1)	$0.3
2025	$23.2	($21.1)	$2.1
2026	$25.7	($21.1)	$4.6
2027	$27.3	($21.1)	$6.2
2028	$28.2	($21.1)	$7.0
2029	$29.4	($21.1)	$8.3
2030	$30.3	($21.1)	$9.3
2031	$34.4	($21.1)	$13.3
2032	$35.7	($21.1)	$14.5
2033	$37.0	($21.1)	$15.9
2034	$38.4	($21.1)	$17.3
2035	$39.8	($21.1)	$18.7
2036	$41.4	($21.1)	$20.2
2037	$42.9	($21.1)	$21.8
2038	$34.6	($17.6)	$17.0

[14] The contract for capacity on ANR ML3 each winter, from November through March, only.

In addition to the DTE Utilities, other customers who buy gas in Michigan because their delivered costs are lower than they would be without NEXUS because of the downward pressure the incremental supplies into the market put on clearing prices. This benefits the consumers who buy spot gas priced at a Michigan index and also customers who hedge since using transportation contracts, since over time, reductions in Michigan gas prices should translate to reductions in the cost of pipeline transportation into the region of roughly the same magnitude.

To calculate these benefits, FTI first developed a non-DTE consumption forecast by subtracting the DTE Utilities' consumption from the statewide forecast. The resulting outlook, differentiated between DTE and non-DTE consumption, is shown below.

Figure 15. Consumption Outlook by Type



Savings for the non-DTE customers are created by the change in spot prices attributable to NEXUS. FTI used the average of differentials between the *Base Case* and the *No NEXUS Case* for each of Consumers CG, Dawn, Chicago CG, and Emerson. For month, the average reduction in those prices was multiplied by the forecast of non-DTE consumption shown in Figure 15. The results indicate that savings to non-DTE gas customers is expected to total approximately $808 million.

Table 11. Non-DTE Savings by Year *($,millions)*

	Savings
2022	$55.1
2023	$48.2
2024	$27.6
2025	$31.0
2026	$34.5
2027	$37.0
2028	$37.5
2029	$39.7
2030	$41.5
2031	$49.3
2032	$51.8
2033	$53.8
2034	$55.8
2035	$58.0
2036	$60.2
2037	$62.4
2038	$64.8

The non-DTE savings are large because they are not offset by any contract costs and because there are so many non-DTE customers. Therefore, on a unit basis, the change in delivered costs these customers realize is small, but because they comprise two-thirds of the entire state, those small savings are multiplied across large amounts of consumption.

Combined across all three customers types, the total benefit attributable to NEXUS over the forecast period is approximately $1 billion.

Table 12. Total Benefits by Year (*$, millions)*

	DTE Electric	DTE Gas	Non-DTE	Total
2022	($4.2)	$12.6	$55.1	$63.6
2023	($4.8)	$10.1	$48.2	$53.5
2024	($7.1)	$0.3	$27.6	$20.9
2025	($5.0)	$2.1	$31.0	$28.2
2026	($3.3)	$4.6	$34.5	$35.8
2027	($2.9)	$6.2	$37.0	$40.4
2028	($2.4)	$7.0	$37.5	$42.1
2029	($0.7)	$8.3	$39.7	$47.3
2030	($0.3)	$9.3	$41.5	$50.5
2031	$1.7	$13.3	$49.3	$64.3
2032	$2.8	$14.5	$51.8	$69.1
2033	$3.7	$15.9	$53.8	$73.4
2034	$4.6	$17.3	$55.8	$77.8
2035	$5.6	$18.7	$58.0	$82.3
2036	$6.6	$20.2	$60.2	$87.0
2037	$8.3	$21.8	$62.4	$92.6
2038	$7.7	$17.0	$64.8	$89.5
Total	$10.5	$199.4	$808.3	$1,018.2

HIGH DEMAND SCENARIO

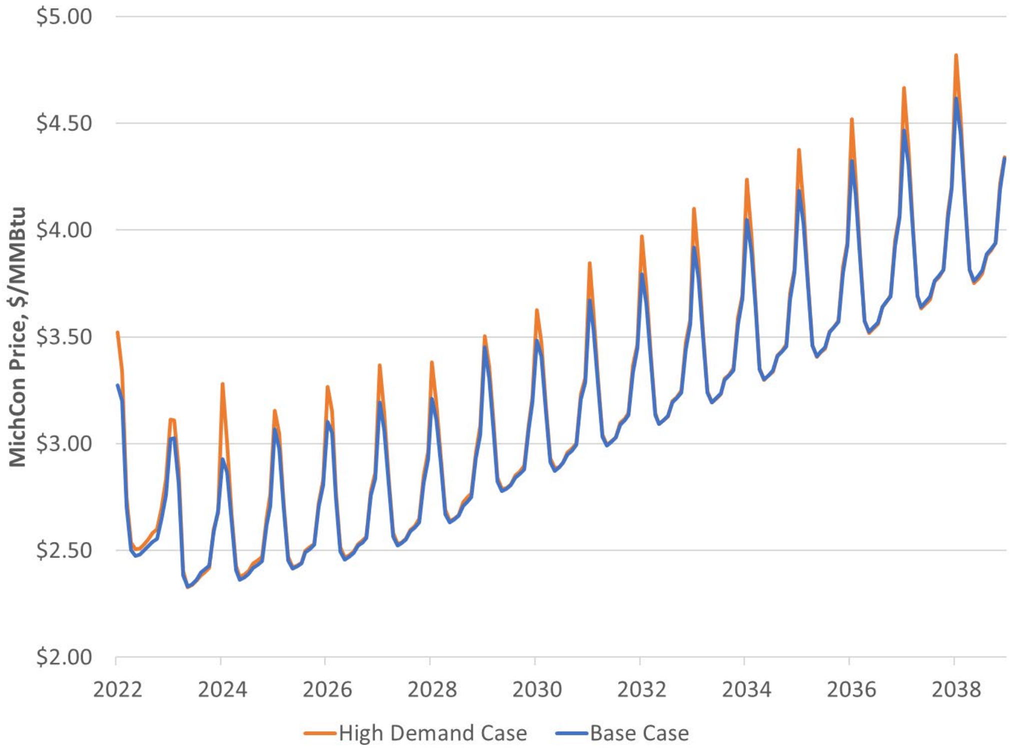
FTI also developed a high demand scenario in which gas demand was increased for the five ENC states based on an analysis of historic Heating Degree Day ("HDD") data. The simulations were executed using this higher demand outlook with and without NEXUS using the same general approach applied to the *Base Case* and the *No NEXUS Case.*

The DTE Utilities provided FTI with weighted average HDD information for the past fifteen years, 2006-2020. Over that period there were an average of 6,490 HDDs per year in DTE's service territory. To develop the adder, FTI identified the five years in that set with the highest HDDs (which are, in order from highest to lowest, 2014, 2007, 2013, 2009, and 2019). Among those five years, HDDs were 8% higher than the overall average. The *High Demand Case* was therefore created by increasing demand in all sectors and in all months throughout the year in the ENC states by that amount while holding all other inputs constant.[15]

Figure 16 shows the MichCon outlook for the *High Demand Case* compared to the *Base Case.* There is a noticeable increase during the coldest winter months, when gas demand and prices are generally highest, with little or no increase during the non-peak months.

[15] The inputs held constant are from the *Base Case*. In other words, this iteration of the *High Demand Case* includes NEXUS.

Figure 16. MichCon Price Forecast Comparison



For the period 2022 through 2038, the average increase in the *High Demand Case* over the *Base Case* for January and February is $0.15/MMBtu while the average for the remaining months is $0.02/MMBtu.

Despite the relatively small change in market prices, there is a significant increase in the benefits to Michigan ratepayers attributable to NEXUS under this alternative demand outlook. FTI calculated the benefits in the same manner as described above for the *Base Case.* Doing so involved running the *High Demand Case*, configuring a separate simulation in which NEXUS was excluded but all other variables were held constant, and comparing the results in the same manner as is described above. The result was a sizeable increase in benefits attributable to NEXUS; the value of NEXUS to customers in Michigan increases by about 20% when the higher demand assumption is utilized.

Table 13. Comparison of NEXUS Benefits Under High Demand Case ($, millions)

	Base Demand	**High Demand**
Total Benefits	$1,018	$1,264

This finding is significant because it suggests that not only does NEXUS provide a useful hedge against price increases in the future but that the investment in NEXUS may a very attractive upside. The *Base Case* results indicate that NEXUS creates significant savings when prices are low. If it is the case that prices are more likely to increase than decrease for some or all of the forecast period – a reasonable proposition given that gas prices are currently near historic lows – then the NEXUS investment may confer considerable additional value and that potential outcome is offset by very little risk.

Other Benefits

In addition to the gas cost reductions calculated under each scenario analyzed in this report, NEXUS provides other important benefits to Michigan ratepayers that are either primarily qualitative or whose calculation is beyond the scope of these analysis. These benefits include, but are not limited to the following:

- **Electric Generation Benefits**. Lower gas prices reduce costs for gas-fired generators in Michigan whether they hold NEXUS entitlements or not. This means, all else equal, that DTE's generators will be called upon to run more often by MISO, and, when they do run, their margins will be greater.
- **Reliability.** The addition of an entirely new path to supply sources reduces the likelihood of a major shortfall that could impact the reliability of the gas or electric systems in the event of an outage or other contingency event on one of the pipelines that serves Michigan.
- **Environmental Benefits.** Secure, economic supplies of natural gas are a necessary precondition for the deployment of new and efficient gas-fired generation, which, in turn, allows for the displacement of coal-fired generation in Michigan and, potentially, elsewhere and also provides an important tool for managing the intermittency of renewable generators being added to the system in increasing amounts.

Conclusions

The primary conclusion of this study is that NEXUS will create significant savings for Michigan gas consumers. For the period 2022-2038, FTI expects those savings to exceed $1 billion. If market prices increase in the future, those savings could be even greater.

APPENDIX 1. GPCM DESCRIPTION

GPCM® Product Description and Introduction

1.0 Purpose

GPCM® is RBAC's GPCM Natural Gas Market Forecasting System™. Originally known as the Gas Pipeline Competition Model, GPCM is a combination software-database system, whose purpose is to enable its users to build models for analysis of natural gas economics, including the sectors of production, transportation, storage, marketing, and sales to distributors and other large customers. GPCM is the latest in a series of systems and models built by Dr. Robert E. Brooks from the mid-1970s through the present. Making use of the latest PC hardware and software technology as well as advanced computational algorithms, it enables analysts to do more at their desktop than has ever been possible in the past using mainframe computers with earlier, similar software tools.

2.0 Model Structure

Mathematically, GPCM is a network model. It can be diagrammed as a set of "nodes" and "arcs". Nodes represent production regions, pipeline zones and interconnects, storage facilities, delivery points, and customers or customer groups. The connections between these nodes are called "arcs". They represent transactions and flows. Some of these are supplier deliveries to pipelines, transportation across zones and from one zone to another, transfers of gas by one pipeline to another, delivery of gas into storage, storage of gas from one period to another, withdrawal of gas from storage, and pipeline deliveries of gas to customers.

In general an arc has four input attributes and two output attributes. The inputs are cost (which may depend on transaction volume), a minimum, a maximum, and a loss factor (representing fuel use and miscellaneous losses). The outputs are the amount of the transaction (the flow) and the economic rent associated with the flow. The latter is defined mathematically as the economic value of a unit increase (decrease) in the upper (lower) bound. It generally applies to pipeline transportation and storage capacity and represents the marginal value of increased capacity.

The economic value of a solution to this problem is identified in economic theory to be the sum of producer and consumer surplus. These concepts are defined for price sensitive supplies and demands. We assume that each supply source and each customer has a well-defined supply or demand curve. The forms for these curves can be quite general. GPCM only requires the quantity to decrease with increasing price for demand curves and to increase with increasing price for supply curves.

The objective function for this "equilibrium" solution has been shown by Nobel Prize winning economist Paul Samuelson to consist of three terms: the integral of the demand price function over demand minus the integral of the supply price function over supply and minus the sum of the transportation and storage costs. By dividing the applicable range of possible prices into a number of small steps, we can approximate the integrals in the objective function by linear terms of the form p * delta q, where delta q is the additional demand (or supply) resulting from the small price change. Because of the form of the supply and demand functions and the objective function, each of these terms will be brought into the solution in an economically sensible order to produce an economically efficient, market-clearing solution. That is, the cheaper supplies will be used before more expensive ones and the customers willing to pay more will be served before those willing to pay less. Thus we are able to use a "linear programming" approach to solve a highly non-linear, complex model of market clearing behavior in the natural gas industry.

3.0 Transportation and Storage Tariff Structure

In general, each transportation and storage transaction cost is parameterized by five values: a unit demand charge, unit firm commodity charge, unit interruptible commodity charge, a "full discount quantity" (FDQ) and a "zero discount quantity" (ZDQ). The cost model for such transactions assumes that, for a price, some amount of the capacity could be reserved for certain customers. The cost of such capacity reservations will be the unit demand charge times the capacity reserved plus the unit firm commodity charge times the amount actually used. The cost for interruptible service (interruptible commodity charge) will be lower on average than the total cost for firm service, but higher than the firm commodity charge. The model says that if demand for the capacity is higher than the ZDQ, the pipeline will be able to charge the full interruptible rate for transportation. If not then it will have to discount. The amount of the discount in this model is maximal when demand falls to FDQ or lower: then the price of transportation is equal to the firm commodity charge. The discount declines linearly as demand increases from the FDQ up to the ZDQ. For all demand greater than or equal to ZDQ, the price is the full interruptible commodity charge, i.e. no discounting is required.

Storage transactions work the same way. There are three storage transactions: injection, storage, and withdrawal. Injection and withdrawal have the structure just defined. Storage has a simpler structure: a constant unit cost per period, which may be zero. The user may model a situation where gas is transported to a storage location on one rate schedule, injected and withdrawn under another, and delivered to another location under a third. The user may also model a "bundled" structure involving movement from one location to the storage location and then downstream to yet a third, all under the same rate structure.

Marketers are modeled as a single undifferentiated sector in GPCM. This sector is assumed to mediate all transactions in the model. It is the sector which makes the market by linking gas supply to gas demand through the pipeline and storage system.

The bulk of the economic rent due to capacity restrictions is generally distributed to the marketing sector. The assumption is basically that the marketers are able to buy at market conditions, sell at market conditions, and acquire transportation at prices fixed in the short term. Therefore, short term economic rents will not be acquired by the pipeline sector and will go to the marketing sector. Suppliers and customers owning Firm Transportation earn the remainder of these rents. Their rents may be earned by reselling their capacity to others or by using the F/T themselves.

4.0 User Interface

The user interface is the principal analysis tool contained in the GPCM system. It consists of a set of queries, macros, modules, forms, and reports contained in a Microsoft Access file. The user interacts with this interface through Access "Forms". Forms contain data from the database and controls such as button for causing actions to be done. The data displayed in forms is stored in database tables in a separate Access file. These tables are "attached" to the user interface so that they can be viewed and modified by the analyst.

5.0 Database

The database file consists of a number of data tables for input and output. The data inputs are primarily of three types: tables representing the basic entities of the model (suppliers, supply regions, customers, demand regions, pipeline zones, storage facilities), tables relating these entities representing the structural linkages in the model (the arcs), and the quantitative data representing supplies, demands, tariffs, capacities, fuel use, etc. The GPCM user typically populates the database via Windows clipboard copy-paste operations from Excel or other spreadsheets. Alternatively, the user can utilize GPCM's built-in data import routines.

6.0 RBAC Network Optimizer

RBAC Network Optimizer is a specialized linear programming algorithm designed specifically to solve network models such as that used in GPCM™. In benchmarking tests on a large variety of such problems, it has proven to be world class in speed and functionality. RBAC Network Optimizer has been extended to handle the linearized approximations of non-linear supply, demand, and transportation cost functions required for the solution of the GPCM model.

7.0 Outputs

GPCM contains powerful and flexible tabular and graphical output capabilities. In addition the entire solution can be exported to an Excel spreadsheet for further analysis and reporting.

Following is a list of the pre-packaged screen and hardcopy reports available in GPCM:

- Results Summary / Detail
- Pipeline Usage Summary
- Supplier Deliveries Detail / Summary
- Customer Receipts Detail / Summary
- Supplier Revenue Report
- Customer Cost Report
- Transport Results Detail
- Transport Zone Prices
- Transport Zone Basis
- Interconnect Basis
- Transport Revenue
- Storage Revenue
- Transport Zone Utilization
- Transport Link Utilization
- Storage Utilization
- Storage Balance

Report 9 allows the user to find the basis (market price spread) between any two pipeline zones identified in the model in any period of the scenario. The report has a graphical capability which allows the user to produce a time series plot of the basis forecast over the forecast horizon of the case.

The Results Summary Report is an aggregate report of the gas and dollar flows among the various sectors of the gas industry. It shows the forecast aggregate average supply price, average unit return to the marketing sector, average transportation and storage cost per unit delivered, and average cost to customers represented in the model. There is also a graphical routine which allows the user to produce histograms comparing any of the elements of the case summary report for various cases.

Finally, GPCM has a general purpose graphing capability the analyst can use to plot time series of inputs and / or outputs either one at a time or overlayed against each other. For example, the analyst could plot the time series of market clearing prices in two different regions in the same scenario or in multiple scenarios in order to get a visual perspective on their relative values.

Related Offerings from RBAC

- GPCM Daily™ for Intra-Month Stress Testing
- GPCM-PMI™ Power Model Interface
- Gas4Power®
- GPCM Viewpoints® on Natural Gas
- G2M2® Global Gas Market Modeling System™
- NGL-NA® North American Natural Gas Liquids Market Model

Contracts and Administration

For additional information about GPCM® and any other RBAC product, contact James Brooks directly at (281) 506-0588 ext. 126 and visit www.rbac.com.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Gas Company** for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2023	))))))	Case No. U-21064

PROOF OF SERVICE

ESTELLA R. BRANSON states that on December 17, 2021, she served a copy of DTE Gas Company's Application for Gas Cost Recovery Plan and Monthly GCR Factor and Evaluation of Its Five-Year Forecast, Direct Testimony and Exhibits of Witnesses, George H. Chapel, Eric P. Schiffer, Lucian Bratu, Timothy J. Krysinski, Andrea R. Hardy, and Kenneth A. Sosnick in the above-captioned matter, via electronic mail upon the persons listed on the attached service list.

Estella R. Branson Digitally signed by Estella R. Branson Date: 2021.12.17 19:50:13 -05'00'

ESTELLA R. BRANSON

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