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May 7, 2024

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

RE: MPSC Case No. U-21291

Dear Ms. Felice:

Attached please find the following document for e-filing:

- Direct Testimony and Exhibits of Alice Napoleon on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (MEC-17 through MEC-30);
- Proof of Service.

Sincerely,

Digitally signed by Christopher Bzdok
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Christopher Bzdok
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Cc: Parties to Case No. U-21291

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority.	Case No. U-21291

DIRECT TESTIMONY OF ALICE NAPOLEON

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES DEFENSE COUNCIL, AND SIERRA CLUB

May 7, 2024

DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Alice Napoleon. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse Energy Economics") located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources, energy efficiency policies and programs, integrated resource planning, electricity market modeling and assessment, renewable resource technologies and policies, and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse's staff includes over 35 professionals with extensive experience in the electricity and gas industries.

Q Please summarize your work experience and educational background.

A Since joining Synapse in 2005, I have provided economic and policy analysis of electric and gas systems and emissions regulations on behalf of a diverse set of clients throughout the United States and in Canada. I have co-authored several reports and comments on the role of energy efficiency in New York State in meeting its Reforming the Energy Vision ("REV") objectives, as well as two white papers on natural gas regulatory reforms needed if New York is to meet its decarbonization targets. I have also provided policy analysis and technical support on issues related to the future of natural gas utilities in many other states, including Hawaii, Maryland, Rhode Island, Colorado, Massachusetts, Nevada, and California.

I have provided expert advice on demand-side management programs in numerous states and Canadian provinces regarding a range of issues including incentive-setting methodologies, cost-benefit analysis, avoided costs, load forecasting, and locational demand-side management. I also co-authored a manual for regulators on designing performance incentive mechanisms for utilities, which has been highly utilized by many states.

Before joining Synapse, I worked at Resource Insight, Inc., where I supported investigations of electric, gas, steam, and water resource issues, primarily in the context of reviews by state utility regulatory commissions.

I hold a Master's in Public Administration from the University of Massachusetts at Amherst and a Bachelor's in Economics from Rutgers University. My resume is attached as Exhibit MEC-17.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club.

Q **Have you previously testified before the Michigan Public Service Commission ("the Commission")?**

A No.

Q **What is the purpose of your testimony?**

A The purpose of my testimony is to review and critique the proposals of DTE Gas Company (DTE or the Company) regarding the Infrastructure Recovery Mechanism (IRM), the strategies for reducing greenhouse gas (GHG) emissions reductions in its 2024–2033 Gas Delivery Plan (GDP), and the termination of its demand response pilots.

Q **Are you sponsoring any exhibits in this proceeding?**

A Yes, I am sponsoring the following exhibits:

Exhibit MEC-17:	Resume of Alice Napoleon
Exhibit MEC-18:	MNSCDG-5.12 and Attachment
Exhibit MEC-19:	MNSCDG-5.3a
Exhibit MEC-20:	MNSCDG-5.2e and f
Exhibit MEC-21:	DTE 2023 Year-End Earnings Conference Call (Feb. 8, 2024)
Exhibit MEC-22:	MNSCDG-5.10a
Exhibit MEC-23:	MNSCDG-3.16b
Exhibit MEC-24:	MNSCDG-3.13
Exhibit MEC-25:	MNSCDG-2.4f
Exhibit MEC-26:	Case No. U-20839, DTE Gas Company's CleanVision Natural Gas Balance 2023 Annual Impact Report dated March 27, 2024 and DTE Gas Company's CleanVision Natural Gas Balance Annual Report (2022) dated March 29, 2023
Exhibit MEC-27:	MNSCDG-6.3b
Exhibit MEC-28:	MNSCDG-2.6e
Exhibit MEC-29:	ACEEE, "Winter Demand Response Using Baseboard Heaters"

Exhibit MEC-30: MNSCDG-5.5ai, bi, and ci

II. FINDINGS AND RECOMMENDATIONS

Q Please summarize your primary conclusions.

A My findings include the following:

- IRM
  - As implemented, the IRM fails to provide adequate incentives for the utility to minimize costs.
  - The dollars flowing through the IRM have risen dramatically.
  - The IRM process lacks meaningful review and opportunity for contestation.
  - The criteria for what types of projects qualify for the IRM are unclear.
  - Over three-quarters of the proposed IRM expenditure is for replacing old pipes (which may or may not be leak-prone). DTE doesn't consider or pursue non-pipeline alternatives (NPA), which could reduce investments and impacts on rates.
- Gas Delivery Plan
  - Responsibly Sourced Gas (RSG) does not represent a valid GHG-reduction measure. Given the speculative nature of the GHG reductions from RSG, if approved this pilot might incur costs with no associated benefits to DTE customers or to the state.
  - The Carbon Offsets and Renewable Natural Gas program is neither a viable nor cost-effective approach to reducing GHG emissions. Further, the program could work at cross-purposes by giving program participants the

message that it is easy to offset their emissions and could lead to an increase in consumption by participants.

- Demand Response
    - DTE's assessment of gas savings during peak hours does not support its recommendation to discontinue the Smart Savers pilot program.
    - DTE did not conduct a benefit-cost analysis of its demand response pilots.
    - Demand response is an option for DTE to seek alternatives to pipeline investments.

Q **Please summarize your recommendations.**

A Based on my findings, I offer the following recommendations:

- IRM
    - Given the high likelihood of cost recovery for approved IRM programs, there should be more stringent guidelines for IRM program eligibility.
    - The Commission should reconsider and revise the purpose, requirements, process, and structure of the IRM.
    - At a minimum, the Commission should not approve expanding the scope or increasing the dollars in the IRM.
- Gas Delivery Plan
    - Michigan utilities' decarbonization approach should be considered in a holistic way in which stakeholders (including gas and electric) consider the challenges and opportunities with different pathways for achieving policy goals, i.e., a future of heat proceeding.
- Demand Response

- DTE should continue offering the Smart Savers pilot program.

III. THE DESIGN AND STRUCTURE OF THE IRM PROPOSAL IS PROBLEMATIC

A. Background and overview of current proposal

Q What is the IRM?

A The IRM is a cost recovery mechanism that allows DTE to seek pre-approval of costs for select programs. DTE submits a five-year plan for capital expenditure and project activity to be recovered through customer surcharges. Total IRM costs are approved at the start of the five-year expenditure period; however, surcharges are calculated annually in a reconciliation filing. In testimony, Witness Janness states that the purpose of IRM programs is "to ensure the safety of DTE Gas's customers and the public and to allow the Company to provide reliable utility service."[1]

Q How are IRM costs recovered from customers?

A IRM costs are recovered by charging customers a surcharge that is determined annually based on approved investment plans, minus any budget underruns from the previous year. The IRM surcharge is calculated each calendar year of the five-year investment period and is based on the predetermined cumulative incremental revenue requirement associated with the incremental capital investment. The Company files an annual reconciliation in the first quarter of the year for the capital invested in the prior year for the Commission to review. IRM investments incur pre-tax rate of return, while regular rate-based investments

[1] Direct Testimony of Eric D. Janness, p. EDJ-5.

earn an after-tax rate of return. The current pre-tax rate of return on IRM investments is 8.78 percent.[2]

Q Please describe the original IRM that the Commission approved for Mich Con, the predecessor of DTE Gas.

A The Commission approved Mich Con's IRM in 2013 in Case No. U-16999.[3] The original IRM funded the 10-year Main Removal Program (MRP) (now called the Gas Renewal Plan, or GRP) and Meter Move Out (MMO) programs that the Commission had already approved in other dockets in 2011.[4] The Commission also approved IRM spending on the Pipeline Integrity (PI) program, based on a finding that the program was "required under federal and state safety standards and is an integral part of the company's overall effort to improve the safety and reliability of its system."[5]

The initial IRM was approved at spending levels of $77.4 million per year, including $46.9 million per year for the MRP, $22.7 million per year for the MMO program, and $7.8 million per year for the PI program.[6]

Q Please describe the Company's current IRM.

A The Commission approved DTE Gas's current IRM in Case No. U-20940. The approved IRM allowed DTE to recover the predetermined incremental revenue requirement for

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[2] Response to Discovery MNSCDG-7.1ai & MNSCDG-7.1aii, K. Vangilder, April 9, 2024.

[3] Case No. U-16999, Order, April 16, 2013.

[4] Case No. U-16999, Order, April 16, 2013, p. 2, citing Case No. U-16451, Orders dated September 13, 2011, and November 10, 2011, and Case No. U-16407, Order, September 13, 2011.

[5] Case No. U-16999, Order, April 16, 2013, p. 22.

[6] Case No. U-16999, Order, April 16, 2013, pp. 24-25.

annual infrastructure capital expenditures in certain programs for each year from 2022 to 2026.[7] The current, approved IRM includes four programs: MRP, MMO, Meter Assembly Check/Meter Move Out (MAC/MMO), and PI.

Q How does DTE decide eligibility for inclusion in the IRM?

A It is unclear how DTE determines which programs are appropriate for inclusion in the IRM. DTE claims that all of the programs currently included within the IRM are essential to ensure safety and reliability. However, there are many other programs that DTE determines to be essential for safety and reliability that are *not* included in the IRM.[8]

DTE states that cost recovery through the IRM "ensures spending included in rates for strategic capital improvements is spent for those purposes and provides greater long-term certainty on recovery of reasonable and prudent costs related to those improvements."[9]

Q How have IRM budgets changed over time?

A As noted above, the initial IRM was approved for an annual budget of about $77 million. In contrast, the 2022 annual budget is $287 million, which is about 370 percent of the initial IRM annual budget. Much of the increase in IRM budgets occurred over the past seven years, during which time the annual budget for IRM programs has more than tripled, as shown in Table 1.

[7] Direct Testimony of Rajan M. Telang, p. RMT-23.

[8] Response to Discovery, MNSCDG-5.11d.

[9] MNSCDG-5.4.

Table 1. IRM Total Costs 2016–2022 ($M)

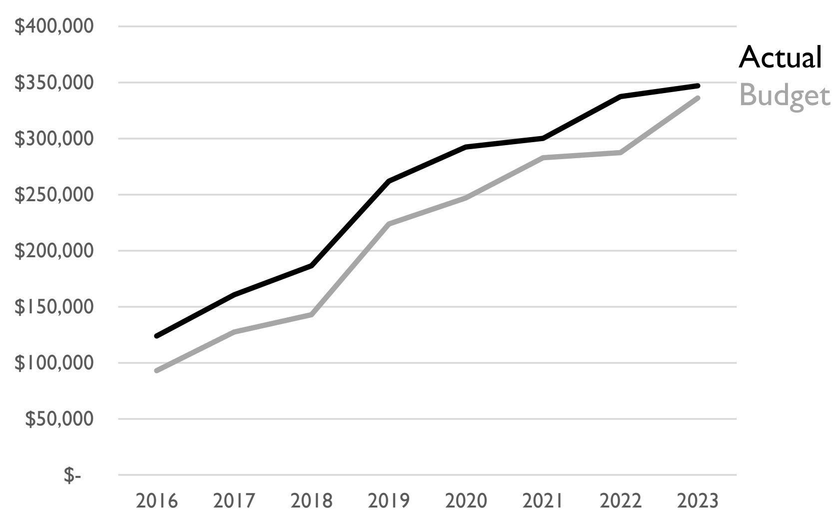
	2016	2017	2018	2019	2020	2021	2022	2023
Budget	$93	$128	$143	$224	$247	$283	$287	$336
Actual	$124	$161	$187	$262	$292	$300	$338	$347
Cost Variance	$31	$33	$44	$38	$45	$17	$50	$10

*As reported in Discovery Response MNSCDG-5.8 Exhibit A-12 B6.1; 2023 expenditure from U-21291 Exhibit A-12 Schedule B6.5 E.D. Janness. Values are rounded to the nearest million.

Q How have actual IRM expenditures compared to budget historically?

A DTE has overspent its IRM annual budget by as much as $50 million per year. As shown in Figure 1, DTE spent more than its budget every year from 2016 to 2022.[10]

Figure 1. IRM Expenditure, 2016–2023 ($M)



Source: 2016–2022 expenditure from Response to Discovery MNSCDG-5.8 B6.1, 2023 expenditure from U-21291 Exhibit A-12 Schedule B6.5 E.D. Janness.

[10] Response to Discovery MNSCDG-5.8, Exhibit A-12 B6.1, E.D. Janness, March 15, 2024.

Q What happens to expenditures on IRM programs that exceed the authorized IRM spending amounts?

A They are included in rate base in the next rate case. [11]

Q Which programs are proposed for inclusion in the IRM in this rate case?

A The Company is proposing to continue the IRM for the five-year period 2025–2029 with two adjustments.[12] DTE is proposing to (1) include Cathodic Protection as part of the IRM, and (2) consolidate the MRP and MMO programs into the GRP. The Company is phasing out the MAC/MMO program because the Company is caught up on its MAC backlog.[13] If Cathodic Protection capital expenditures are not included in the final IRM surcharge calculation in this rate case, those costs must be included in Routine Distribution capital expenditures.[14]

If the Commission approves DTE's proposal in the immediate rate case, the IRM will include the following three programs:

1. GRP: MRP and MMO
2. Cathodic Protection Program
3. PI

[11] Janness Direct, p. EDJ-8.

[12] Telang Direct, p. RMT-24, lines 8-13.

[13] Telang Direct, p. RMT-25 to 25.

[14] Telang Direct, p. RMT-26.

Q **Is the Company proposing other changes to the IRM?**

A Yes. DTE is proposing to increase the pre-tax rate of return from the current rate, 8.78 percent, to 9.31 percent in this docket.[15]

Q **What is the Company's budget forecast for the IRM proposals?**

A DTE is asking for increased funding for the IRM, which will result in higher IRM surcharges.[16] The Company's proposed budget is almost $1.7 billion over seven years (through 2029), with an annual spending of $310–355 million.[17] As proposed, DTE's budgets for the IRM programs would increase to $349.1 million in 2024 and $354.2 million in 2025, followed by a modest decrease from the 2025 peak spending to $344.5 million in 2026 and 2027, and $311.4 million in 2028 and 2029.[18]

Table 2. Proposed IRM Budget, 2024–2029 ($000)

	2024	**2025**	**2026**	**2027**	**2028**	**2029**
Total IRM	$349,135	$354,205	$344,545	$344,545	$311,425	$311,425

Source: Response to Discovery MNSCDG-5.12 attachment.

Q **How does this compare with previous IRM annual budgets?**

A The proposed annual program budgets exceed annual budgeted expenditures for each of the past seven years, 2016 through 2022.

Q **Please describe the proposed budget for IRM programs.**

A See Table 3, below. The vast majority of IRM spending is in the GRP.

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[15] Response to Discovery MNSCDG-7.1ai & MNSCDG-7.1aii, K. Vangilder, April 9, 2024.

[16] Janness Direct, p. EDJ-6.

[17] Case No. U-21291, Exhibit A-12 part 2, Schedule B6.5, E.D. Janness.

[18] Ex MEC-18, discovery response MNSCDG-5.12 and attachment; see also, Janness Direct, p. 9, Table 1.

Table 3. IRM Proposed Project Costs ($000)

Program		2025	2026	2027	2028	2029
GRP	MRP	$274,000	$274,000	$274,000	$274,000	$274,000
	MMO	$47,545	$47,545	$47,545	$16,705	$16,705
PI		$23,060	$13,400	$13,400	$11,120	$11,120
Cathodic Protection		$9,600	$9,600	$9,600	$9,600	$9,600
Total		$354,205	$344,545	$344,545	$311,425	$311,425

*Data from Discovery Response MNSCDG-5.12 Exhibit A-12 B6.5 and Janness Direct Testimony.

Q What are DTE's proposed targets for the IRM programs?

A The Company proposes the following targets for the IRM programs.

Table 4. IRM Proposed Project Targets

Program		Units	2025	2026	2027	2028	2029
GRP	MRP	Miles of Main	206	206	206	206	206
	MMO	Number of Meters	18,500	18,500	18,500	6,500	6,500
PI		*none reported	-	-	-	-	-
Cathodic Protection		Corrosion Work Orders	1,695	1,695	1,695	1,695	1,695
		CP Engineering	12	12	12	12	12

*Data from Discovery Response MNSCDG-5.12 Exhibit A-12 B6.5 and Janness Direct Testimony (Cathodic Protection unit targets page EDJ-47). Unit targets are not reported for PI program.

B. Concerns with the IRM

Q Please summarize your concerns with the IRM.

A The IRM is a channel for DTE to make infrastructure investments in a way that is low risk to the utility, because spending on the IRM is pre-approved. The IRM poses several issues:

1. As implemented, the IRM fails to provide adequate incentives for the utility to minimize costs.
2. Budget and actual spending on IRM programs has increased substantially since the IRM was first approved, and DTE's IRM expenditures have consistently exceeded budget.
3. The IRM process lacks meaningful external review and opportunity for contestation.
4. The criteria for what types of projects qualify for the IRM are unclear, and the utility has incentives to include routine projects in the IRM. The IRM includes minimal guardrails.
5. Over three-quarters of the proposed IRM expenditure is for replacing old pipes (which may or may not be leak-prone). DTE doesn't pursue alternatives to conventional delivery system investments (NPAs), which could reduce investments and impacts on rates. The IRM provides no oversight over decisions to replace old pipes rather than evaluate and pursue NPAs.

Q With respect to your first concern, how does the IRM provide a reduced incentive to minimize costs?

A IRM surcharges are set based on the previous year's expenditure. This disincentivizes DTE from minimizing annual costs, because reducing annual costs could limit future IRM budgets.

Additionally, DTE has not conducted a benefit-cost analysis to determine the cost-effectiveness of the Gas Renewal Program, the Meter Move Out Program, or the Pipeline

Integrity program.[19] To the extent there are alternatives to these programs, such as emissions monitoring and pipe repair, an assessment of the cost-effectiveness of these programs relative to the alternatives is a necessary step to understanding and minimizing costs. However, this step is not incorporated into the IRM process.

Q Please describe your second concern.

A As discussed earlier, DTE's IRM budget has increased dramatically over the past seven years. At the same time, DTE's IRM expenditures have consistently exceeded budget.

Q Do you have concerns with past IRM performance and associated expenditures?

A Yes. As shown in Table 1 above, DTE's IRM spending has consistently exceeded its budget. Furthermore, as shown in Table 5, below, DTE's actual cost per unit has been higher than projected most years from 2016 to 2022.

Table 5. IRM Project Cost per Unit ($/mile of main or $/meter)

		2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Avg.**
MRP	Planned	762,195	762,602	858,943	1,379,675	936,893	1,128,157	1,128,157	993,803
	Actual	926,991	925,149	911,522	1,090,960	1,106,683	1,121,831	1,185,158	1,038,328
	Difference	164,796	162,548	52,579	(288,715)	169,790	(6,326)	57,001	44,525
MMO	Planned	1,775	1,775	1,535	1,535	1,535	1,535	1,535	1,603
	Actual	3,459	1,737	1,759	1,979	2,254	1,664	2,108	2,137
	Difference	1,684	(38)	224	444	719	129	573	534
MAC/ MMO	Planned	-	-	-	2,538	2,538	2,063	2,630	1,954
	Actual	-	-	2,044	2,001	2,190	2,708	2,777	2,344
	Difference				(536)	(347)	645	147	(98)

*Values from Response to Discovery MNSCDG-5.8 Exhibit A-12 B6.1.

[19] Ex MEC-30, Responses to Discovery MNSCDG-5.5ai, MNSCDG-5.5bi, and MNSCDG-5.5ci, E. D. Janness, March 15, 2024.

Q **Does this indicate that DTE's IRM expenditures are not being adequately scrutinized?**

A Not necessarily. There may be reasonable explanations for each exceedance. However, the overall pattern gives rise to concerns that DTE's spending on investments not subject to normal rate case review has been high and that there is a lack of oversight of its spending.

Q **Please describe your third concern regarding the IRM process.**

A The IRM surcharge approval process lacks opportunity for external stakeholder review of cost prudency and project completion. DTE is required to file an annual report (reconciliation filing) of IRM expenditures, completed main/meter units, and adjusted surcharges for Commission review.[20] However, there is no opportunity for stakeholders to participate in review of the reconciliation filing such as through a hearing or other processes.[21] Further, there is little threat that the Commission will disallow IRM expenditures.

Q **Has the Commission ever disallowed IRM expenditures based on the annual reconciliation filing?**

A No.[22]

[20] Janness Direct, p. EDJ-49.

[21] Case No. U-16999 Order, March 20, 2013, p. 10.

[22] Ex MEC-19, Response to Discovery, MNSCDG-5.3a, R. M. Telang, March 15, 2024.

Q Regarding your fourth concern, how does DTE determine what types of projects qualify for the IRM?

A DTE has provided no clear set of specific parameters for projects to qualify for the IRM. DTE states that the projects included in the IRM are "strategic capital improvements" essential for the safety and reliability of the system and are required "under federal or state safety standards."[23] Moreover, DTE's description of investments that align with the IRM's purpose leaves substantial room for interpretation. DTE acknowledges that the IRM is not intended to cover all safety and reliability investments.[24]

Q Why are vague criteria for qualifying projects for the IRM problematic?

A DTE may be applying these parameters liberally to proposed investments that are part-and-parcel of a gas utility's business and do not reasonably warrant special treatment. Qualifying projects for the IRM reduces the Company's risk that the project could be found imprudent in the future. Safety and reliability investments are supposed to be the core duties of the utility and are required by law. Nothing is stopping DTE from applying these parameters liberally to proposed investments.

Q Do utilities have incentives to make capital investments without the special treatment provided by the IRM?

A Yes. Regulated utilities have an existing and powerful incentive to spend on capital projects because they can earn a return for shareholders on capital expenditures. Even without the reduced risk from IRM investments, DTE has an incentive to favor capital

[23] Ex MEC-20, Response to Discovery MNSCDG-5.2e, E.D. Janness, March 15, 2024.

[24] Ex MEC-20, MNSCDG-5.2f.

expenditures over operating expenses (which typically do not earn a return) in order to increase earnings and profit to investors. The IRM enhances and magnifies an incentive that the utility already has.

In addition, I note that there may also be cost recovery advantages of passing investments through the IRM. IRM investments incur a pre-tax rate of return, while the overall rate of return on rate-based investments are after-tax. I have not analyzed the impacts of the difference but note that the currently-approved pre-tax rate of return used to calculate the IRM tariff rates is 8.78 percent,[25] while DTE Gas' currently approved overall required rate of return (for investments recovered through base rates) is 5.41 after taxes.[26] For this case, the Company proposes a pre-tax rate of return of 9.31 percent to calculate the IRM revenue requirement, while the proposed overall after-tax rate of return for non-IRM investments is 6.04 percent.[27]

Q How does DTE describe returns on the IRM to investors?

A In materials to shareholders, DTE indicated that it is "[d]elivering premium shareholder returns" through "[i]ncreased 5-year utility capital investment."[28] To this end, DTE Gas highlights the "[s]ignificant investment recovered through Infrastructure Recovery Mechanism (IRM) to support main renewal."[29]

[25] MNSCDG-7.1ai.

[26] MNSCDG-7.1bi.

[27] MNSCDG-7.1aii and MNSCDG-7.1bii.

[28] Ex MEC-21, DTE 2023 Year-end Earnings Conference Call (February 8, 2024), p. 4.

[29] *Id*., p. 6.

Q With respect to your fifth issue, what are your concerns with long-term IRM pipeline replacement?

A Over three-quarters of the proposed IRM expenditure is for replacing old pipes.[30]

As discussed above, the utility has incentives (lower risk) to pursue IRM projects, as compared to other projects that go through prudency review in rate cases. Investments are approved without any meaningful review, as IRM projects are approved in normal course. Including pipe replacement in the IRM effectively increases DTE's incentives to replace pipes, even when that action might not be the most prudent course of action. As I discussed, utilities already have strong incentives to make capital investments, due to the return on investment over a long period of time. In contrast, utilities have far less incentive to invest in NPAs that would avoid spending on pipeline replacements and allow for pipe retirement, even if NPAs would save ratepayers money.

Q Could the IRM be reoriented to support initiatives that are more consistent with policy priorities?

A Yes. DTE currently replaces 15 miles of high-risk legacy main annually, selected using a risk-ranking at the segment level.[31] The Company is proposing switching to a grid-level risk-ranking that considers population density and building occupancy in addition to other risk factors.[32] Assessing pipe replacement at the grid-level would be a good opportunity

[30] Calculated using values from Response to Discovery MNSCDG-5.12 Exhibit A-12 B6.5.

[31] Janness Direct, p. EDJ-21.

[32] Janness Direct, p. EDJ-25.

for DTE to consider the cost-effectiveness of implementing NPAs instead of replacing pipe.

Q Has DTE done analysis on whether it would be cheaper for ratepayers to remove pipe from service without replacing it, rather than replace it?

A No. DTE doesn't evaluate, let alone pursue, NPAs, which could minimize investments and impacts on rates. DTE "has not conducted any studies or analysis of NPAs as a potential source of emissions reductions"[33] and states that "[n]o specific guidelines have been developed to consider NPAs at this time"[34] and "[t]here are currently no processes for broader implementation of NPAs."[35] DTE has not identified assets or types of assets on its gas system that may be most or least likely to remain used and useful in the event of widespread electrification of gas end uses.[36] This is contrary to ratepayer interests; NPAs such as electrification or demand response are more consistent with state and federal policies to curb GHG emissions and can prevent stranded assets as gas demand declines with decarbonization. (Stranded costs are discussed in the testimony of Dr. Hopkins.) Notably, DTE is proposing to end its existing demand response programs.

Q Do other jurisdictions require consideration of NPAs in gas utility planning or investment decisions?

A Yes. As mentioned in the testimony of Dr. Hopkins, several other states have implemented regulatory processes to examine and reform how gas utilities conduct their business. Some

[33] MNSCDG-7.3b.

[34] MNSCDG-7.3ci.

[35] MNSCDG-7.3cii.

[36] Ex MEC-22, Discovery response MNSCDG-5.10a.

of these states, such as New York and Massachusetts, have or are exploring requirements for utilities to consider NPAs.

Q Please describe developments related to NPA requirements in New York.

A The New York Public Service Commission instituted a gas planning proceeding (Case 20-G-0131) in 2020 to "establish planning and operational practices that best support customer needs and emissions objectives while minimizing infrastructure investments and ensuring the continuation of reliable, safe, and adequate service to existing customers."[37] In 2022, the Commission issued a Gas Planning Order in this docket which, among other things, requires each gas utility to file comprehensive, long-term plans analyzing gas system supply and demand over a 20-year planning horizon.[38] In these long-term plans, utilities must explicitly consider energy efficiency and NPAs, including analysis of an "NPA-only" scenario. Furthermore, the Gas Planning Order required utilities to propose NPA screening and suitability criteria to inform consideration of potential NPAs; the Commission is currently reviewing proposed NPA screening and suitability criteria.

Some New York utilities have begun implementing NPAs. For example, Con Edison has developed a "Whole Building Electrification Service" NPA program. Con Edison initially identified for NPA consideration more than 45 segments of leak-prone mains that would

[37] State of New York Public Service Commission. Order Instituting Proceeding. March 19, 2020. Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures. Page 4. Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2BE6F1CE-5F37-4A1A-A2C0-C01740962B3C}.

[38] State of New York Public Service Commission. Order Adopting Gas System Planning Process. May 12, 2022. Case 20-G-0131 and Case 12-G-0297. Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={130B05B5-00B4-44CE-BBDF-B206A4528EE1}.

otherwise be replaced over the next decade.[39] Under this program, customers currently connected to an identified pipeline segment could be incentivized to fully electrify, allowing the utility to avoid replacing the pipe and retire it instead. As another example, New York State Electric and Gas Corporation has issued a request for proposals for NPAs to defer or avoid a planned pipeline reinforcement project in the Lansing, New York area.[40] This NPA portfolio includes installing efficient heat pumps and other energy efficiency measures.

Q What is the current state of NPA consideration as a part of gas utility planning in Massachusetts?

A The Massachusetts Department of Public Utilities (DPU) opened Case No. 20-80 to examine the role of gas utilities in achieving the state's climate goals and to "to develop a regulatory and policy framework to guide the evolution of the gas distribution industry in the context of a clean energy transition."[41] In 2023, the DPU issued an Order on Regulatory Principles and Framework in that docket ("Order 20-80"). Order 20-80 requires gas distribution companies to prove that they adequately considered NPAs for any new gas system investments. In this case, NPAs are broadly defined to include electrification, networked geothermal, and targeted energy efficiency. Gas utilities must prove that replacement was the best alternative (and NPAs were found to be "non-viable

[39] Consolidated Edison Company of New York, Non-Pipeline Alternatives Implementation Plan, NY PSC Case No. 19-G-0066 (Nov. 17, 2022), p. 20; NY PSC Case No. 19-G-0066.

[40] NYSEG. 2022. "Lansing Non-Pipes Alternatives (NPA) Portfolio." Available at: https://www.nyseg.com/documents/40132/5899449/22-5069+NYSEG+Lansing+Non-Pipes+Alternatives_12.30.22.pdf.

[41] See Exhibit 8, Order on Regulatory Principles and Framework, DPU-20-80-B (December 6, 2023) ("Order 20-80").

or cost prohibitive") before they can receive full cost recovery for additional investment in natural gas infrastructure.[42]

Q Beyond immediate affordability issues, are there other concerns with the increases in rates caused by IRM investments?

A Yes. Gas system assets, including those in the IRM, have very long physical engineering lifetimes. In light of the market and policy developments that will put downward pressure on gas sales, as discussed in Dr. Hopkins's testimony, utilities will seek to recover the costs of gas system assets over fewer sales, pushing up gas prices. In turn, reductions in load and customer defection from the gas system would escalate costs for remaining customers. This process may cause some gas assets to become underutilized or no longer serve customers and become stranded.

This process is particularly concerning for disproportionately vulnerable or disadvantaged customers, who generally face greater challenges with switching off of gas to more affordable options. Existing affordability problems for these customers are likely to compound.

Q What do you recommend?

A Given the high likelihood of cost recovery for IRM-approved programs, there should be more stringent guidelines for IRM program eligibility. I recommend that the Commission not approve the proposed IRM. Instead, the Commission should initiate an open, collaborative proceeding to consider and revise the purpose, requirements, process, and structure of the IRM. Through the IRM or otherwise, any investment in pipeline

[42] See Exhibit 8, Order 20-80 at 97-98.

replacements should be evaluated against gas demand projections as well as NPAs. In addition, the Commission should not approve increases in IRM spending or expansion of its scope in this rate case.

IV. DTE'S GAS DELIVERY PLAN INCLUDES QUESTIONABLE STRATEGIES FOR ACHIEVING EMISSIONS REDUCTIONS

Q Does DTE have internal emissions reduction targets?

A Yes. The Company has committed to achieving net-zero emissions by 2050 for its internal gas utility operations and for all the natural gas DTE Gas purchases. It has also committed to a 35 percent reduction in emissions by 2040 from the natural gas used by its customers.[43]

Q What strategies has DTE identified for achieving emissions reductions to meet its internal climate targets and state policies?

A The Company's GDP (Exhibit A-12 Schedule B5.6) is a ten-year overview of DTE's natural gas infrastructure investment plans and how the Company plans to meet the needs for natural gas supply and demand.[44] DTE's GDP outlines several actions by which it will reduce emissions from its customers and utility operations. These include investments in RSG, renewable natural gas (RNG), carbon offsets, and other "advanced technologies" such as hydrogen, gas heat pumps, and carbon capture.[45]

[43] Exhibit A-12 Schedule B5.6 p. 10.

[44] Testimony of K.M. Fedele, p. KMF-15, lines 1-5.

[45] MNSCDG-2.2a

Q Do you have concerns with these strategies?

A Yes. As I will describe, these strategies are unlikely to provide actual emissions reductions, and any potential emissions reductions from them are small compared to alternatives such as electrification. They also entrench reliance on the gas system and continued fossil fuel emissions from its use.

A. Responsibly Sourced Gas

Q What is RSG?

According to the Company, RSG (also called "certified" or "differentiated" gas) is "natural gas that has been verified by a third party to have met specified environmental targets during production."[46] These environmental targets typically are focused on mitigating methane emissions, with an emphasis on measurement and monitoring.[47] Methane, a potent GHG, is a primary component of fossil gas, and methane leakage is a significant source of GHG emissions throughout the gas supply chain.[48] RSG provides a construct for compensating producers for actions that may reduce GHG emissions associated with fossil gas production. RSG certification schemes allow producers to voluntarily differentiate all or a portion of their gas supply (e.g., for some or all of their wells), which purchasers (such as DTE) can then purchase for a premium. Some such programs require the gas to meet criteria for methane intensity, i.e., the amount of methane

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[46] Testimony of Henry J. Decker, p. HJD-35, lines 17-18.

[47] Sankalp Garg et al. "A critical review of natural gas emissions certification in the United States" 2023. Environ. Res. Lett 18 023002. Available at: https://iopscience.iop.org/article/10.1088/1748-9326/acb4af

[48] Alvarez et. al. 2018. "Assessment of methane emissions from the U.S. oil and gas supply chain." Science. DOI: 10.1126/science.aar7204. Available at: https://science.sciencemag.org/content/361/6398/186.

emissions released relative to the amount of gas produced, typically expressed as a percent.

Q Please describe the Company's proposals in this rate case related to RSG.

A The Company is proposing to procure up to 4,000,000 Dth of RSG in the projected test year, with an expected premium of $180,000, or $0.045 per Dth.[49] The Company estimates this would reduce approximately 4,000 to 8,000 metric tons of carbon dioxide equivalent ("CO2e") emissions, "depending on the methane intensity of RSG purchased."[50]

Q Has DTE committed to any particular certification standard for RSG purchases?

A No. DTE has not committed to a specific certification standard or process, only stating that "at a minimum, third party verification is a criterion that will be used when procuring RSG."[51]

Q Has DTE purchased RSG previously?

A Yes. DTE has made two RSG purchases, in 2022 and 2023 respectively. The Company issued a Request for Information (RFI) to understand the market dynamics for RSG.[52] In 2022, DTE purchased 1,134,200 Dth of RSG from two different suppliers at a total cost of $7,858,562, which includes the commodity cost of $7,821,754 and premium cost of $36,808, based on premium prices of $0.02 and $0.04 per Dth.[53] DTE calculates that this

[49] Decker Direct, p. HJD-49, lines 1-6, Q125.

[50] Decker Direct, p. HJD-49, lines 6-8.

[51] Decker Direct, p. HJD-41, Q98, lines 2-3.

[52] Decker Direct, p. HJD-41, Q99, lines 8-9.

[53] Exhibit A-22, Schedule L3.

premium would be approximately $0.03 annually per customer. [54] In 2023, DTE purchased 1,990,200 Dth of RSG, with a commodity cost of $4,388,391 and a premium cost of $29,853, based on a premium price of $0.015 per Dth.[55]

Q How is the Company seeking to recover the costs of RSG purchases?

A DTE is seeking recovery for both the commodity cost and the RSG premiums for RSG purchased in 2022 and 2023 as part of DTE's annual GCR reconciliation cases.[56]

Also, DTE seeks Commission guidance on "the integration of RSG into the portfolio as the Company continues to develop a robust RSG procurement strategy." Further, DTE indicates that it "believes that as the industry has evolved, premiums paid for RSG attributes are reasonable and prudent similar to other environmental costs, which are recoverable."[57]

Q Do you have concerns with this proposal?

A Yes. DTE is relying on RSG as a decarbonization strategy without any indication that it reduces emissions. In the GDP, DTE highlights that acquiring RSG is a part of its long-term approach to support decarbonization goals.[58]

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[54] MNSCDG-3.11a.

[55] Exhibit A-22, Schedule L3.

[56] Decker Direct, p. HJD-46, lines 15-19 Q118.

[57] Decker Direct, p. HJD-48.

[58] Exhibit A-12, Schedule B5.6, p. 34.

Q What are the issues with relying on RSG as a long-term decarbonization strategy?

A There are many issues with relying on RSG as a long-term decarbonization strategy, which are being increasingly raised in the literature.[59] These include the following:

1. RSG is not regulated, and private standards for RSG lack uniformity. Further, DTE has not set specific requirements for emissions reductions from RSG.
2. Federal emissions standards have likely reduced the benefits of RSG.
3. The potential for emissions reductions from RSG is limited.
4. DTE has not justified the cost-effectiveness of RSG compared to other GHG emissions reduction strategies.
5. Significant dependence on RSG may prolong dependence on the gas system.

Q Please describe your first point regarding regulation and uniformity of standards for RSG.

A There are no regulations or official standards for RSG. As it currently stands, certification standards are developed by private entities. These standards are inconsistent, lack transparency, and do not provide assurance that RSG provides incremental benefits above what is already occurring in the industry (that is, they do not address whether emission reductions are *additional,* i.e., an incremental improvement compared to counterfactual scenarios). DTE claims that RSG "is becoming a new industry standard for lower methane gas requirements."[60] However, in DTE's review of certification standards, the Company

[59] Environmental Defense Fund. Certification of Natural Gas with Low Methane Emissions: Criteria for Credible Certification Programs. 2022. Available at: https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2022/05/EDF_Certification_White-Paper.pdf.

[60] Decker Direct, p. HJD-47.

stated that the RSG certification process currently lacks uniformity.[61] Furthermore, DTE acknowledges that there is no standard calculation of methane emissions intensity for natural gas: "the method of calculating and reporting intensity is not consistent across the natural gas industry."[62]

Without uniform standards, it is difficult to know whether the emissions reductions from RSG are additional, i.e., if they would not occur without the certification. Furthermore, standards do not require all suppliers to participate, or even individual suppliers to certify all of their wells. An individual supplier can opt to, and has a financial incentive to, certify its already low-emitting wells and not certify its high-emitting wells; thus, this supplier could earn incremental revenues from RSG certification without making any changes to its operations or investments in technology that would reduce emissions.[63] If suppliers select only their currently low-emitting wells to include in RSG programs, RSG certification will produce no reductions in emissions, just higher costs to DTE ratepayers.

Q Given the lack of uniformity of standards, has DTE set a limit on the methane intensity of RSG purchases?

A No, DTE has not set a specific methane intensity level or limit for its RSG purchases.[64] Of the three RSG purchases the Company procured in 2022 and 2023, each supplier had a different certification standard and methane intensity: MiQ Grade A, with a methane

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[61] Decker Direct, p. HJD-40, Q97, lines 2-4.

[62] Decker Direct, p. HJD-42, Q102, lines 6-8.

[63] Letter to the Chair of the Federal Trade Commission from Senators Markey, Merkley, Whitehouse, Warren, Blumenthal, Sanders, and Booker. February 12, 2024. Available at: https://www.markey.senate.gov/imo/media/doc/certified_gas_letter_21224.pdf.

[64] Ex MEC-23, discovery response MNSCDG-3.16b.

intensity of less than 0.01, Project Canary Trustwell Platinum, with a methane intensity of less than 0.063, and EO Trustwell Platinum, with a methane intensity of less than 0.05.[65] Since DTE has not committed to any specific methane intensity requirements for the program, there is no assurance that the program will produce any GHG emission reductions.

Q With respect to your second point, please describe how federal emissions standards relate to RSG.

A In late 2023, the U.S. Environmental Protection Agency released new regulations for the oil and gas industry. These regulations require reductions in fugitive emissions from wells and transmission and distribution systems.[66] To provide *additional* emissions reductions, RSG providers would have to reduce emissions beyond what is mandated by law. It is currently unclear whether individual RSG standards, such as those DTE has used previously, offer any environmental benefits beyond the new federal regulations. These regulations may reduce or eliminate the environmental benefits that DTE can claim from procuring RSG.

Q Regarding your third point, can purchase of RSG substantially reduce emissions?

A The potential for emissions reductions from RSG is very limited; by itself, it cannot meet federal or state GHG reduction targets. RSG will still release GHGs during combustion, and RSG will leak from the distribution system and from customer end-use equipment

[65] MNSCDG-3.14c.

[66] U.S. Environmental Protection Agency. 2023. "EPA's Final Rule for Oil and Natural Gas Operations Will Sharply Reduce Methane and Other Harmful Pollution." December 2. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/epas-final-rule-oil-and-natural-gas.

just the same as traditional "uncertified" fossil gas. Furthermore, RSG will emit criteria pollutants such as nitrogen oxides when burned, thus causing the same indoor and outdoor air quality public health impacts problems when combusted as conventional fossil gas.

Q Turning to your fourth point, has DTE compared the cost of emissions reductions from RSG to other alternatives for reducing emissions?

A No.[67] Considering that RSG may provide very little or no real reductions in emissions, the cost per avoided ton of GHG is very high.

Q With respect to your fifth point, do you have other concerns with RSG?

A Yes. RSG sends a message to customers implying that natural gas is an environmentally preferred solution. Customers may be more likely to continue to stay on the gas system if they believe RSG is a viable decarbonization pathway, and as a result they may make investments in gas-fired equipment that will last for decades.

Q What do you conclude about the proposed RSG pilot?

A I find that RSG does not represent a valid GHG reduction measure. Given the speculative nature of the GHG reductions from RSG, if approved this pilot might incur costs with no associated benefits to DTE customers or to the state.

Q What do you recommend?

A The Commission should reject the RSG pilot.

[67] Ex MEC-24, discovery response MNSCDG-3.13

B. Carbon Offsets and Renewable Natural Gas

Q Please describe the Company's voluntary carbon emissions offset program.

A According to the Company's filing, the Company's CleanVision Natural Gas Balance Program is a fee-based voluntary carbon emissions offset program that customers may opt into to reduce some or all of their emissions from gas usage through RNG attributes and carbon offsets. The product mix includes 5 percent RNG attributes and 95 percent carbon offsets.

The program was launched in January 2021 as a three-year pilot.[68] Currently there are 10,352 DTE Gas residential and small business customers enrolled in the program. DTE claims that the program resulted in 11,792 metric tons of CO_2e emissions negated using carbon offsets in 2022.[69] In 2022, the program also acquired 11,264 mcf of RNG; DTE claims that this negated 621 metric tons of CO_2e emissions.[70]

Q What are carbon offsets?

A Offsets are credits produced by projects intended to reduce GHG emissions, increase carbon storage, or remove GHG from the atmosphere. Offsets are purchasable; one offset represents one metric ton of CO_2e emissions reduced. Offset programs are designed to allow purchasers to credit offsets against their emissions, with the intention of negating or reducing those emissions on net. However, as I describe further below, many offsets on the market today do not actually lead to GHG emissions

[68] MNSCDG-3.2a

[69]MNSCDG-2.4c, 2022 NGB Annual Report.

[70]MNSCDG-2.4c, 2022 NGB Annual Report.

reductions.[71,72] The purchase of an offset that is not associated with a real emission reduction will not achieve the buyer's objective, which is to decrease net GHG emissions.

Q What is renewable natural gas?

A RNG is pipeline-quality gas derived from biomass or other renewable resources which has been processed or upgraded to be fully interchangeable with conventional natural gas.[73]

Q Is DTE providing RNG to participants in the program?

A DTE does not appear to be providing physical RNG to all participants. The environmental attributes of RNG (or hydrogen or other alternative fuel) can be purchased separately from the physical gas. DTE purchases RNG environmental attributes that are bundled or unbundled with physical gas. DTE retires the environmental attributes.[74] Of the four sources of RNG procured for the Natural Gas Balance program, two include the physical gas commodity while the other two sources are only the environmental attribute of the RNG.[75] DTE states that "[w]hen DTE is purchasing just the environmental attribute, DTE does not track the final end use of the specific molecule and therefore does not identify

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[71] Song, Lisa. 2019. "An Even More Inconvenient Truth - Why Carbon Credits For Forest Preservation May Be Worse Than Nothing." *ProPublica*. May 22. Available at: https://features.propublica.org/brazil-carbon-offsets/inconvenient-truth-carbon-credits-dont-work-deforestation-redd-acre-cambodia/

[72] Haya, Barbara. 2019. *Policy Brief: The California Air Resources Board's U.S. Forest offset protocol underestimates leakage*. Center for Environmental Public Policy, Univ. of Calif. Berkeley. May 7. Available at: https://gspp.berkeley.edu/assets/uploads/research/pdf/Policy_Brief-US_Forest_Projects-Leakage-Haya_4.pdf.

[73] Michigan Public Acts of 2021, Act No.87, https://www.legislature.mi.gov/documents/2021-2022/publicact/htm/2021-PA-0087.htm.

[74] MNSCDG-3.8di.

[75] MNSCDG-3.8c.

the end use of the RNG."[76] RNG environmental attributes on their own do not represent gas that is physically delivered to customers purchasing the attributes; this means that these customers are not actually reducing their own emissions on-site.

It is important to note that the GHG emissions associated with RNG vary considerably based on the feedstock and process used to make it. Many RNG sources should not be considered zero-emissions or even low emissions, compared with fossil gas. DTE indicates that its sources of RNG are either from animal manure or landfill gas feedstocks.[77] While RNG from animal manure is likely to reduce GHG emissions, RNG from landfill gas will likely result in GHG emissions that are lower than fossil gas but still positive.[78]

Q **Do you have concerns with carbon offsets as a decarbonization strategy?**

A Yes. While the CleanVision Natural Gas Balance (NGB) program costs are not considered in this proceeding, the inclusion of this program in DTE's long-term decarbonization strategies in its GDP is concerning. Carbon offset programs and projects have been widely discredited upon evaluation. In light of the concerns I raise herein, it is critical that the Commission investigate whether the NGB provides net benefits to any ratepayers,

[76] MNSCDG-3.8dvi.

[77] MNSCDG-3.8c.

[78] According to ICF's September 2022 study on RNG, the carbon intensity associated with extraction and processing of fossil gas is 8.27, while RNG from landfill gas is higher, 10.91. How RNG is transported will impact the overall carbon intensity. If RNG is blended with fossil gas in the distribution system, RNG leakage will occur at the same rates as fossil gas. (ICF. September 23, 2022. *Michigan Renewable Natural Gas Study: Final Report.* Prepared for the Michigan Public Service Commission. Accessed at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf).

whether they participate or not. While I have not conducted a thorough investigation of NGB benefits and costs, it appears that their main benefit is for DTE's marketing purposes i.e., to broadcast the likely false claim that the Company is reducing emissions from its gas portfolio through this program.

Q Please explain.

A To ensure credibility and environmental integrity, carbon offsets should meet five criteria:

1. Permanent: Emissions reductions or removals should not be reversible, meaning that a reduction in emissions now will not be followed by an equivalent increase in emissions later.
2. Additional: The offset project should represent new emissions reductions. Offsets are additional if they enable carbon reduction to occur that would not otherwise occur without the offset funding.
3. Verifiable: Emissions reductions from offsets should be monitored and regularly verified by an independent third party.
4. Enforceable: To avoid double-counting, the ownership of an offset should be enforceable to ensure that only one credit can be claimed for the offset.
5. Real: Offsets should represent one ton of carbon emissions reduced as the result of the offset project without carbon displacement occurring, which occurs when the offset results in the same emissions occurring elsewhere rather than actually

reducing overall emissions. This criterion involves ensuring that the quantity of emissions reductions are not inflated and that accurate accounting takes place.[79]

DTE uses the American Carbon Registry for its carbon offsets in the NGB program.[80] Verified carbon offset registries, including DTE's chosen registry, lack transparency regarding the actual impacts of their carbon offset projects. For example, a satellite analysis released in December 2022 detected no real climate benefit from 10 years of forest carbon offsets administered by the American Carbon Registry and the Climate Action Reserve in California.[81] Another analysis of the global Joint Implementation offset program in 2015 found that roughly 75 percent of offset credits issued were unlikely to represent additional emissions reductions.[82]

Q Has DTE analyzed the costs of these decarbonization strategies to customers?

A No. DTE "has not done an evaluation of the costs to customers" for any of the initiatives to reduce customer emissions, including the voluntary carbon offset program and RNG.[83]

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[79] World Resources Institute. 2010, The Bottom Line on Offsets. Available at: https://www.wri.org/research/bottom-line-offsets.

[80] MNSCDG-3.5b.

[81] Coffield, Shane and James Randerson. 2022. "Satellites detect no real climate benefit from 10 years of forest carbon offsets in California." *The Conversation*. December 1. Available at: https://theconversation.com/satellites-detect-no-real-climate-benefit-from-10-years-of-forest-carbonoffsets-in-california-193943; Coffield, S.R., Vo, C.D., Wang, J.A, Badgley, G. Goulden, M.L., Cullenward, D., Anderegg, W.R.L, & Randerson, J.T. 2022. "Using remote sensing to quantify the additional climate benefits of California forest carbon offset projects." Global Change Biology (Vol. 28, Issue 22). Available at: https://onlinelibrary.wiley.com/doi/10.1111/gcb.16380.

[82] Kollmuss, A., L. Schneider, V. Zhezherin. 2015. *Has Joint Implementation reduced GHG emissions? Lessons learned for the design of carbon market mechanisms.* Stockholm Environment Institute, Working Paper 2015-07. Available at: https://mediamanager.sei.org/documents/Publications/Climate/SEI-WP-2015-07-JI-lessons-for-carbon-mechs.pdf.

[83] Ex MEC-25, MNSCDG-2.4f.

This program is likely not a least-cost way to achieve GHG emission reductions. DTE found that the NGB program offers customers emission reductions at approximately $37 per mt, for "Level 4" customers balancing 100 percent of their gas usage.[84] However this value only reflects the customer program fee and does not reflect DTE's program administration costs. While not included in base rates, the total expenses for the NGB program in 2022 and 2023 were over twice the revenues, with a program net loss of over $1 million each year.[85] This is not a cost-effective model for significant long-term emissions reductions.

Q Do you have other concerns with this strategy?

Yes. As with RSG, pursuing a customer-facing carbon offset program could work against the state's efforts to reduce GHG emissions. Participants in particular, and customers in general, receive the message that it is easy to offset their emissions, or they delay switching off of gas. Such misinformation can have negative consequences: participants may increase their gas consumption, resulting in even higher GHG emissions. According to research, carbon offsets might be perceived as a moral license to behave in environmentally harmful ways.[86] Assuming this is true of consumption that leads to GHG

[84] Ex MEC-24, MNSCDG-3.13.

[85] Ex MEC-26, Case No. U-20839, DTE Gas Company's CleanVision Natural Gas Balance 2023 Annual Impact Report dated March 27, 2024 and DTE Gas Company's CleanVision Natural Gas Balance Annual Report (2022) dated March 29, 2023.

[86] Warburg, Johan, Britta Frommeyer, Julia Koch, Sven-Olaf Gerdt, and Gerhard Schewe. "Voluntary carbon off setting and consumer choices for environmentally critical products—An experimental study." Business Strategy and the Environment. Volume 30, Issue 7. p. 3009-3024.

emissions, the availability of offsets may lead to an increase in gas consumption by NGB participants.

Q What are your recommendations?

A As discussed in Dr. Hopkins's testimony, Michigan utilities' decarbonization approach should be considered in a holistic setting in which stakeholders (including gas and electric utilities) consider the challenges and opportunities of different pathways for achieving climate policy goals while reducing the risk of stranded assets, i.e., in a future of heat proceeding. Until then, and until there has been a full assessment of the net benefits of the NGB, the Commission should not approve the NGB or any similar programs, in this docket or in any other docket. If DTE wishes to pursue the NGB program, it should funded by shareholders exclusively.

V. <u>DTE FAILED TO PROVIDE ADEQUATE SUPPORT FOR ITS PROPOSAL TO DISCONTINUE ALL EXISTING DEMAND RESPONSE PROGRAMS</u>

Q Please summarize briefly DTE's demand response pilot program.

A Pursuant to the settlement in Case U-20642 and the Commission's recommendation on demand response in the Statewide Energy Assessment report in the same case, DTE implemented two residential gas demand response pilot programs and one commercial demand response pilot program. Details of these pilots are as follows:

- The Smart Savers Gas pilot: this pilot targeted residential customers who already had a Wi-Fi enabled smart thermostat installed. In the program, DTE remotely adjusted the set point of participants' thermostats by up to 4 degrees to achieve peak load reduction. Program participants received a $50 up-front gift card upon enrollment and another $50 gift card if they remained enrolled at the end of the pilot program. The program enrolled approximately 6,140 devices during the 2022–2023 winter period.

- The Energy Action Days pilot: through this behavior-based demand response program, DTE provided customers a variety of educational resources to encourage customers to save gas usage during winter peak periods. DTE did not provide any financial incentives to customers. The pilot targeted two DTE regions (Southeast Michigan and Northeast Michigan) and used an opt-out approach where all customers were automatically enrolled in the pilot.
- The Small and Large Commercial pilot: this pilot targeted large customers (e.g., customers who are under rate GS-1, GS-2, or the S-rate). This program did not provide any financial incentives to participants, but instead installed telemetry equipment at the participants' premises at no cost in order to measure peak load gas usage during peak load events. DTE asked the participants to voluntarily reduce gas usage during the peak load events.[87]

DTE implemented these pilots for two years from 2022 to 2023. Per the settlement, DTE would defer up to $4 million for the cost of the programs as a regulatory asset. To date, DTE has incurred approximately $2.5 million on the demand response pilot programs.[88]

[87] Decker Direct, pp. HJD-79 to HJD-80.

[88] Exhibit A-26. Schedule P1.

Q What is DTE's proposal regarding its demand response pilots?

A DTE witnesses conclude that DTE's demand response program was not effective and mentions DTE does not request an extension of the program. More specifically, Witness Telang mentions as follows: "At the conclusion of the second year of the demand response pilot, DTE Gas reviewed the results and determined the demand response program was not effective and determined not to request to extend the pilot or make the program permanent. DTE Gas believes that this pilot fulfilled the purpose set forth by the Commission and the costs were incurred reasonably and prudently."[89] In addition, Witness Decker states as follows:

> "the Company conducted multiple pilots, gathered and analyzed results and ultimately made the decisions not to continue with any gas [demand response] pilots or programs at this time. The Company was able to gather valuable information with total costs of the pilots being less than the total amount allowed for in the deferral. The total cost was reasonable and prudent because it achieved the goal of obtaining information at the request of the Commission. At the conclusion of the pilots, it was clear that [demand response] programs were not effective and DTE Gas determined that it would not be reasonable or prudent to propose additional [demand response] programs and therefore further costs were not incurred."[90]

Q Did any of DTE witnesses define the "effectiveness" of the demand response pilot program?

A DTE witnesses do not clearly define what effectiveness means with respect to the demand response pilot programs. However, it appears that effectiveness refers to gas savings during the peak gas events based on Witness Decker's discussion of the three demand

[89] Telang Direct, p. RMT-28: 20-23.

[90] Decker Direct, p. HJD-84: 6-14.

response pilot programs in his direct testimony.[91] Also, DTE's response to data request MMSCDG-2.6f clearly makes a connection between gas consumption reductions during events and effectiveness, as follows: "Overall, based on the results of the three pilots, the Company did not observe gas reductions across the various events which would lead the Company to determine the pilots were effective, thus driving our determination not to request extension of the pilot or to make the program permanent."

Q Do you have any concerns about DTE witnesses' conclusions about the demand response pilot programs?

A Yes. I have two concerns about DTE witnesses' conclusions about the demand response pilot programs. First of all, I found that DTE's own assessment of gas savings during peak hours does not support its recommendation to discontinue the Smart Savers pilot program. In fact, this pilot program led to a 36 percent to 72 percent reduction in gas use during the past five gas events, as shown in Table 5 below (see the "% Reduction" column). [92] While it is notable that the overall gas consumption for the participants during one of the five peak day events (January 28) increased slightly, that event was an outlier caused by snapback effects.[93] For all other days, the pilot saved considerable amounts of gas during the peak events, as shown in Table 6 under "Cumulative Event Usage (therms)." The results of the Smart Savers Program illustrate its effectiveness as a peak load reduction program.

[91] Decker Direct, p. HJD-80 to HJD-83.

[92] Ex MEC-27, produced by DTE gas in response to MNSCDG-6.3b.

[93] One of the files DTE provided in response to MNSCDG-2.6, titled "U-21291 MNSCDG-2.6d Gas DR Pilot Results Season 2," slide 7 through 9, clearly shows snapback effects that occurred right after the peak gas reduction periods.

Table 6. Performance of the Smart Savers Pilot Program

Date	Event Time	Devices Targeted	Gas Reduction (therms)	Gas Reduction per Device (therms)	Cumulative Event Usage (therms)	Event Avg. Temp	Opt-Out (%)	% Reduction
1/20/2022	5pm-7pm	1,309	509	0.386	(349)	18°	11.2	72%
1/28/2022	6am-8am	1,278	387	0.295	66	13°	10.6	41%
1/30/2023	5pm-7pm	6,138	1,850	0.301	(241)	21°	13.0	50%
1/31/2023	6am-8am	6,138	2,184	0.356	(1,354)	5°	16.4	36%
2/3/2023	6am-8am	6,058	2,120	0.350	(1,983)	8°	15.3	36%

Source: Ex MEC-27, DTE's response to MNSCDG-6.3b.

Second, DTE did not assess the cost-effectiveness of any of the demand response pilot programs. In response to MNSCDG-2.6e, DTE states that "The Company did not evaluate any avoided commodity or gas infrastructure costs" for the demand response pilot programs. [94]

Q Are there any demand response pilots that DTE should continue offering?

A Yes. DTE should continue offering the Smart Savers pilot program. DTE's evaluation showed that its pilot reduced large amounts of gas usage during gas demand events. Demand response is an opportunity for DTE to seek alternatives to pipeline investments.

Q Do you have any recommendations regarding the evaluation of the Smart Savers pilot program?

A Yes. DTE's evaluation shows a small increase in gas consumption among the participants in one out of five peak day events. To increase the success rate, DTE should explore and evaluate ways to reduce snapback effects. One approach DTE could explore is pre-heating

[94] Ex MEC-28, discovery response MNSCDG-2.6e.

participants' buildings by remotely increasing thermostat temperatures slightly prior to peak gas events.[95]

Second, I recommend that the Commission require DTE to evaluate the cost-effectiveness of demand response as an alternative to conventional gas pipeline investments, as discussed in Section III. Witness Telang's direct testimony notes, "DTE pursued these pilots to determine the effectiveness of gas demand response as a requirement of the Commission in its State Energy Assessment report and the settlement agreement in Case U-20642."[96] The Commission's order in U-20642 recommends that the gas utilities work with Staff and stakeholders to evaluate the potential for natural gas demand response programs. It is the industry-standard practice to evaluate cost-effectiveness of any demand-side resources including demand response when they are promoted or examined as a ratepayer-funded program, as DTE did when it evaluated the cost-effectiveness of its Energy Waste Reduction program.[97]

Q Does this complete your direct testimony?

A Yes, it does.

[95] See, Ex MEC-29, ACEEE. "Winter Demand Response Using Baseboard Heaters: Achieving Substantial Demand Reduction Without Sacrificing Comfort." 2016. Available at: https://www.aceee.org/files/proceedings/2016/data/papers/1_88.pdf.

[96] Telang Direct, p. RMT-28: 9-11.

[97] DTE. 2020. 2020 Annual Report – Energy Waste Reduction. Available at: https://newlook.dteenergy.com/wps/wcm/connect/24f9b27e-6ffd-4a2f-905e-5360dc331f28/2020EWRAnnualReport.pdf?MOD=AJPERES.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Principal Associate*, June 2021 – Present; *Senior Associate*, June 2013 – June 2021; *Associate*, July 2008 – June 2013; *Research Associate*, April 2005 – July 2008.

- Provides expert analysis, ongoing stakeholder support, and consulting services in regulatory proceedings regarding energy efficiency program design and performance, funding and incentive mechanisms, cost-effectiveness screening, potential studies, and plans. Develops and sponsors testimony on electric and natural gas energy efficiency plans, advanced metering infrastructure (AMI) proposals, innovative programs, and regulatory structures.
- Researches policies and practices regarding ratemaking for energy efficiency, power procurement, risk management, and fuel diversity.
- Managed efforts by Synapse and subcontractors to conduct a sweeping study of the disparate impacts of electric and natural gas infrastructure on economic, social, and health outcomes, and options for improving energy equity. Conducted interviews and oversaw research, including a literature review, web meetings, and several case studies.
- Conducted extensive research on low-income energy efficiency efforts in U.S. states. Analyzed energy burden differences by income level and across factors that can impact participation in and efficacy of energy efficiency programs in order to inform program design and targeting efforts. Provided consulting services and testimony on low-income energy efficiency programs and proposals.
- Led development of a cost-effectiveness tool, program designs, and case studies to facilitate incorporating strategic energy management programs into energy efficiency program portfolios for commercial and industrial customers.
- Designed research approach and managed team that conducted a sweeping analysis of energy efficiency potential studies from utilities, states, and regions across the U.S.
- Conducted research and co-authored reports on efforts to increase resilience of the electric system, including emerging regulatory mechanisms. Designed survey instrument and oversaw interviews.
- Facilitated residential, commercial, and industrial policy working groups and managed technical analysis of working group recommendations to reduce greenhouse gas (GHG) emissions in Colorado, South Carolina, and Maryland.

Resource Insight, Inc., Arlington, MA. *Research Assistant*, 2003-2005.

Responsible for conducting research and analysis of electric, gas, steam, and water resource issues. Conducted discounted cash flow analysis for asset valuation. Developed market-price benchmarks for analysis of power-supply bids including energy, capacity, ancillary services, transmission, ISO services, losses, and adjustment for load shape. Prepared discovery responses, formal objections, comments, and testimony; collaboratively wrote and edited reports; created and formatted exhibits. Participated in drafting an Energy Plan for New York City. Edited solicitation for competitive power supply to serve aggregated municipal load.

University of Massachusetts, Amherst, MA. *Teaching Assistant*, 2001-2002.

Developed and taught lessons on applied math to a diverse group of incoming graduates; tutored students in microeconomic theory and cost benefit analysis; graded problem sets and memoranda.

International Council for Local Environmental Initiatives, Berkeley, CA. *Cities for Climate Protection Intern for the City of Northampton, MA*, 2001.

Compiled primary and secondary source data on energy consumption and solid waste generation by the municipal government, city residents, and businesses; applied emissions coefficients to calculate total GHG emissions; identified current and planned municipal policies that impact GHG emissions; researched the predicted local effects of global warming; gathered public feedback to provide acceptable and proactive policy alternatives. Composed a GHG emissions inventory describing research findings; wrote and distributed a policy report and press releases; gave newspaper and radio interviews; addressed public officials and the public during a televised meeting.

University of Massachusetts, Amherst, MA. *Research Assistant*, 2000-2001.

Located federal data sources, identified changes, and updated a research database to evaluate the Habitat Conservation Program; proofread articles and white papers; composed a literature review on land use modelling. Collaboratively administered, tested, and proposed interface enhancements for a web-based data warehouse of regional habitat change research; formally presented the system to an independent research group.

Court Square Data Group, Inc., Springfield, MA. *Administration Manager*, 1998-2000; *Project Administrator*, 1996-1998.

As Administration Manager, analysed profitability and diversity of income sources; managed cash flow, expense, and income data; created budgets; devised and implemented procedures to increase administrative efficiency; implemented new accounting system with minimal disruption to workflow.

As Project Administrator, coordinated implementation of software features; identified opportunities for future development; monitored problem resolution; wrote and coordinated production of a user's manual and questionnaires; edited technical proposals and a business plan.

EDUCATION

University of Massachusetts, Amherst, MA
Master of Public Administration, 2002

Rutgers University, New Brunswick, NJ
Bachelor of Arts in Economics, 1995

Syracuse University, Syracuse, NY, 1994

PUBLICATIONS

Forthcoming. Woolf, T., A. Napoleon, D. Goldberg, E. Carlson, C. Mattioda. 2023. *Distributed Equity Analysis for Energy Efficiency and Other Distributed Energy Resources.* Synapse Energy Economics for Lawrence Berkley National Lab and E4TheFuture.

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New York Public Service Commission (Case 23-G-0225 and Case 23-G-0226): Direct Testimony of Alice Napoleon proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service and The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service. On behalf of Natural Resources Defense Council. September 1, 2023.

Nova Scotia Utility and Review Board (NSUARB M11003): Evidence of Alice Napoleon in the Matter of The Public Utilities Act, R.S.N.S 1989, c.380, as amended, and the application of Nova Scotia Power Inc. for Authorization to Overspend on Capital Work Order CI47124- Advanced Metering Infrastructure. On behalf of Counsel to Nova Scotia Utility and Review Board. June 22, 2023.

New York Public Utilities Commission (Case No. 22-E-0064 and 22-G-0065): Direct and Rebuttal Testimony of Alice Napoleon and Asa Hopkins regarding Con Edison's proposed gas-side investments as greenhouse gas mitigation strategies and gas extension allowance rule changes and the need for long-term planning for the gas system and adequacy of the company's non-pipe alternatives framework. On behalf of Natural Resources Defense Council, May 2022.

Nova Scotia Utility and Review Board (M10473): Evidence of Alice Napoleon and Kenji Takahashi regarding EfficiencyOne's 2023-2025 DSM Resource Plan, with a focus on the Settlement Plan. On behalf of Counsel to Nova Scotia Utility and Review Board, May 2022.

Pennsylvania Public Utility Commission (Docket No. M-2020-3020824): Revised Direct Testimony of Alice Napoleon and Kenji Takahashi regarding PPL Electric Utilities' proposed Act 129 Phase IV Energy Efficiency and Conservation. On behalf of the Natural Resources Defense Council. January 19, 2021.

Pennsylvania Public Utility Commission (Docket No. M-2020-3020830): Direct testimony of Alice Napoleon and Courtney Lane regarding PECO Energy Company's proposed Act 129 Phase IV Energy Efficiency and Conservation Plan. On behalf of the natural Resources Defense Council. January 14, 2021.

Nova Scotia Utility and Review Board (Matter No. M09519): Evidence of Alice Napoleon regarding Nova Scotia Power's Smart Grid Nova Scotia Project proposal. On behalf of Counsel to the Nova Scotia Utility and Review Board. February 19, 2020.

New York Public Service Commission (Cases 20-E-0380 and 20-G-0381): Direct testimony of Alice Napoleon and Kenji Takahashi regarding proposed earnings adjustment mechanisms in a proceeding on Rates, Charges, Rules, and Regulations related to Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service and National Grid for Gas Service. On behalf of the Natural Resources Defense Council. November 25, 2020.

California Public Utilities Commission (Application Nos. 19-11-003, 19-11-004, 19-11-005, 19-11-006): Prepared Testimony of Alice Napoleon addressing proposals of Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company related to the Energy Savings Assistance (ESA) Program and Budgets for Program Years 2021-2026. On behalf of The Utility Reform Network. September 4, 2020.

California Public Utilities Commission (Application Nos. 19-11-003, 19-11-004, 19-11-005, 19-11-006, 19-11-007): Comments of The Utility Reform Network on the Energy Division Staff Proposal and Utility Applications. On behalf of The Utility Reform Network. July 24, 2020.

Nova Scotia Utility and Review Board (Matter No. M09096): Evidence of Alice Napoleon regarding EfficiencyOne's 2020-2022 DSM Plan. On behalf of Counsel to the Nova Scotia Utility and Review Board. May 28, 2019.

New York Public Service Commission (Cases 19-E-0065 and 19-G-0066): Direct testimony of Tim Woolf and Alice Napoleon regarding energy efficiency targets and incentives in Con Edison rate case. On behalf of the Natural Resources Defense Council. May 24, 2019.

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TESTIMONY ASSISTANCE

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State of New Jersey Board of Public Utilities (Docket No. EO14080897): Direct testimony of Kenji Takahashi regarding the Petition of Public Service Electric & Gas Company to continue its Energy Efficiency Economic Extension Program on a Regulated Basis (EEE Extension II). On behalf of New Jersey Division of the Ratepayer Advocate. November 7, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony of Tim Woof regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

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State of New Jersey Board of Public Utilities (Docket No. GO12070640): Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

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Virginia State Corporation Commission (Case No. PUE-2009-00097): Direct testimony of William Steinhurst regarding Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq. On behalf of the Southern Environmental Law Center, Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of The Sierra Club. March 23, 2010.

Delaware Public Service Commission (Docket No. 07-20): Jointly authored an expert report, with Robert Fagan, William Steinhurst, David White, and Kenji Takahashi, In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d). On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

State of New Jersey Board of Public Utilities (BPU Docket EM05020106): Direct and surrebuttal testimony of Bruce Biewald, Robert Fagan, and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005 and December 27, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): Direct testimony of William Steinhurst regarding Ameren's proposed competitive procurement auction (CPA). On behalf of Illinois Citizens Utility Board. June 15, 2005 and August 10, 2005.

Illinois Commerce Commission (Docket 05-0159): Direct testimony of William Steinhurst regarding Commonwealth Edison's Proposal to implement a competitive procurement process. On behalf of Illinois Citizens Utility Board and Cook County State's Attorney's Office. June 8, 2005 and August 3, 2005.

Resume updated April 2024

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.12	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 12. Provide the information included in Exhibit A-12, Schedule B6.5 going back to the initiation of the IRM.

Answer: See attached.

Attachment: U-21291 MNSCDG-5.12 Exhibits A-12 B6.5

Michigan Public Service Commission
DTE Gas Company
Investment Recovery Mechanism Expenditures History and Projections
For 2020-2029

Case No.: U-21291
Exhibit: A-12
Schedule: B6.5
Witness: E. D. Janness
Page: 1 of 1

	(a)									(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	**Description**	**Actual**												**Projected Calendar Year (1)**					
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023 (2)**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
	MAIN RENEWAL																		
1	Legacy Main Renewal - SEMI (Miles)	33	51	66	59	76	111	125	145	151	158	164	166	150	150	150	150	150	150
2	Legacy Main Renewal - GRMI (Miles)	9	23	17	15	18	23	33	39	55	56	57	62	56	56	56	56	56	56
3	Legacy Main Renewal - Total (Miles)	**42**	**74**	**83**	**75**	**93**	**134**	**157**	**183**	**206**	**214**	**222**	**228**	**206**	**206**	**206**	**206**	**206**	**206**
4	Main Renewal Costs - SEMI ($K)	$ 23,038	$ 32,618	$ 39,751	$ 44,389	$ 79,169	$ 113,910	$ 122,132	$ 173,677	$ 179,870	$ 191,223	$ 212,328	$ 204,213	$ 213,545	$ 210,000	$ 210,000	$ 210,000	$ 210,000	$ 210,000
5	Main Renewal Costs GRMI ($K)	$ 4,323	$ 11,543	$ 6,825	$ 8,359	$ 7,041	$ 10,060	$ 20,422	$ 25,969	$ 48,106	$ 48,849	$ 50,777	$ 55,588	$ 64,000	$ 64,000	$ 64,000	$ 64,000	$ 64,000	$ 64,000
6	**Main Renewal Costs - Total ($K)**	**$ 27,361**	**$ 44,161**	**$ 46,576**	**$ 52,748**	**$ 86,210**	**$ 123,970**	**$ 142,554**	**$ 199,646**	**$ 227,977**	**$ 240,072**	**$ 263,105**	**$ 259,801**	**$ 277,545**	**$ 274,000**	**$ 274,000**	**$ 274,000**	**$ 274,000**	**$ 274,000**
7	$/Legacy Mile Retired - SEMI ($K)	$ 695	$ 637	$ 602	$ 747	$ 1,047	$ 1,026	$ 980	$ 1,200	$ 1,191	$ 1,211	$ 1,293	$ 1,229	$ 1,423	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400
8	$/Legacy Mile Retired - GRMI ($K)	$ 493	$ 508	$ 407	$ 550	$ 395	$ 446	$ 622	$ 672	$ 879	$ 878	$ 885	$ 899	$ 1,143	$ 1,143	$ 1,143	$ 1,143	$ 1,143	$ 1,143
9	**$/Legacy Mile Retired - Total ($K)**	**$ 653**	**$ 598**	**$ 562**	**$ 707**	**$ 923**	**$ 928**	**$ 905**	**$ 1,088**	**$ 1,108**	**$ 1,124**	**$ 1,187**	**$ 1,139**	**$ 1,347**	**$ 1,330**	**$ 1,330**	**$ 1,330**	**$ 1,330**	**$ 1,330**
	METER MOVE OUT																		
10	Inside Meter Move Outs - MMO *(1)*	10,279	10,940	10,171	9,013	6,699	12,038	12,126	12,753	11,980	12,671	11,973	11,133	20,790	18,500	18,500	18,500	6,500	6,500
11	Inside Meter Move Outs - MAC MMO	0	0	0	0	0	0	2,543	8,042	8,016	8,138	8,353	8,631	-	-	-	-	-	-
12	**Inside Meter Move Outs - Total**	**10,279**	**10,940**	**10,171**	**9,013**	**6,699**	**12,038**	**14,669**	**20,795**	**19,996**	**20,809**	**20,326**	**19,764**	**20,790**	**18,500**	**18,500**	**18,500**	**6,500**	**6,500**
13	MMO Costs ($K)	$ 20,200	$ 23,300	$ 26,189	$ 24,735	$ 26,688	$ 23,172	$ 24,151	$ 29,308	$ 35,294	$ 26,194	$ 30,889	$ 34,343	$ 51,600	$ 47,545	$ 47,545	$ 47,545	$ 16,705	$ 16,705
14	MAC MMO Costs ($K)	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,106	$ 16,092	$ 17,559	$ 22,037	$ 23,195	$ 27,068						
15	**Meter Move Out Costs ($K)**	**$ 20,200**	**$ 23,300**	**$ 26,189**	**$ 24,735**	**$ 26,688**	**$ 23,172**	**$ 29,257**	**$ 45,401**	**$ 52,853**	**$ 48,230**	**$ 54,085**	**$ 61,411**	**$ 51,600**	**$ 47,545**	**$ 47,545**	**$ 47,545**	**$ 16,705**	**$ 16,705**
16	$/GRP MMO ($K)	$ 1.97	$ 2.13	$ 2.57	$ 2.74	$ 3.98	$ 1.92	$ 1.99	$ 2.30	$ 2.95	$ 2.07	$ 2.58	$ 3.08	$ 2.48	$ 2.57	$ 2.57	$ 2.57	$ 2.57	$ 2.57
17	$/MAC MMO ($K)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.01	$ 2.00	$ 2.19	$ 2.71	$ 2.78	$ 3.14						
18	$/MMO - Total ($K)	**$ 1.97**	**$ 2.13**	**$ 2.57**	**$ 2.74**	**$ 3.98**	**$ 1.92**	**$ 1.99**	**$ 2.18**	**$ 2.64**	**$ 2.32**	**$ 2.66**	**$ 3.11**	**$ 2.48**	**$ 2.57**	**$ 2.57**	**$ 2.57**	**$ 2.57**	**$ 2.57**
19	**Total GRP ($M)**	**$ 47,561**	**$ 67,461**	**$ 72,765**	**$ 77,483**	**$ 112,898**	**$ 147,142**	**$ 171,811**	**$ 245,046**	**$ 280,830**	**$ 288,302**	**$ 317,189**	**$ 321,213**	**$ 329,145**	**$ 321,545**	**$ 321,545**	**$ 321,545**	**$ 290,705**	**$ 290,705**
20	Pipeline Integrity		$ 7,840	$ 8,110	$ 9,030	$ 11,111	$ 13,379	$ 13,750	$ 17,139	$ 11,659	$ 11,726	$ 20,437	$ 25,730	$ 19,990	$ 23,060	$ 13,400	$ 13,400	$ 11,120	$ 11,120
21	Cathodic Protection														$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600
22	**Grand Total IRM ($M)**	**$ 47,561**	**$ 75,301**	**$ 80,875**	**$ 86,513**	**$ 124,009**	**$ 160,521**	**$ 185,561**	**$ 262,185**	**$ 292,488**	**$ 300,028**	**$ 337,626**	**$ 346,943**	**$ 349,135**	**$ 354,205**	**$ 344,545**	**$ 344,545**	**$ 311,425**	**$ 311,425**

(1) Line 10: projection excludes 2,000 yearly inside meter moveouts and costs associated with Main Renewal to align with historical actuals
(2) 2023 actuals are still being finalized in preparation for the IRM filing due March 31st, 2024

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.3a	
Respondent: R. M. Telang	
Page: 1 of 1	

Question: 3. Identify each and every instance in which the MPSC has disapproved, disallowed, or adjusted a request by DTE Gas or its predecessor related to the IRM or any IRM program or expenditure – whether projected or actual. Include in your answer a citation to the orders in which the Commission took the actions you identified including electronic files. Please refer to Case No. U-21291 on page RMT-26 where Witness Telang states, “These IRM surcharges will terminate in conjunction with a final rate order superseding the IRM established and approved by the Commission in this general rate case. If no such order is issued, the IRM will continue indefinitely at the December 2029 level, adjusted for any reductions from the last reconciliation filing.”

a. Telang’s statement asserts that DTE can continue charging surcharges ‘indefinitely’ for costs that have not been approved. Please cite the relevant order where the Commission approves this, including date, page numbers or quotes.

Answer: The Commission has not disapproved, disallowed or adjusted the IRM surcharges approved in its Rate Case orders Case Nos. U-16999, U-17999, U-18999, U-20642, and U-20940. The parties reached a settlement agreement in the 2014 IRM reconciliation in Case No. U-16999 (document number U-16999-00200) adjusting the IRM surcharges.

Mr. Telang does not assert that there is any surcharge for costs that have not been approved. The statement that the IRM will continue indefinitely at the December 2029 level, adjusted for any reductions from the last reconciliation filing refers to only costs that have been approved by the Commission through this rate case and then reviewed as part of the IRM reconciliation. See case No. U-20940, the Commission’s December 9, 2021, order, Paragraph B approving the tariff sheets in Attachment B. See Attachment B to that order, page 5 of 14 noting “2026-beyond”. Also, see language “The IRM will not expire until a final rate order superseding the IRM is issued in a general rate proceeding, however the rate may be lowered as a result of the annual reconciliation.” This language has been included in every IRM tariff sheet since the inception of the IRM surcharge in U-16999.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.2e	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 2. Please refer to Case No. U-21291 on page EDJ-5 where Witness Janness states, "IRM programs are necessary to ensure the safety of DTE Gas's customers and the public and to allow the Company to provide reliable utility service."

e. How does DTE determine which investments (or types of investments) should be recovered through the IRM?

Answer: Investments included in the IRM are strategic capital improvements. Additionally, the IRM ensures spending on these items is made a priority. (Commission's order U-20836, page 77) IRM projects have recurrent investment and are long term. IRM investments are required under federal or state safety standards and are an integral part of the Company's overall effort to improve the safety and reliability of its system. (Commission's orders U-16407, U-16451, U-16999, U-17701, U-17999, and U-18999)

Attachment: None.

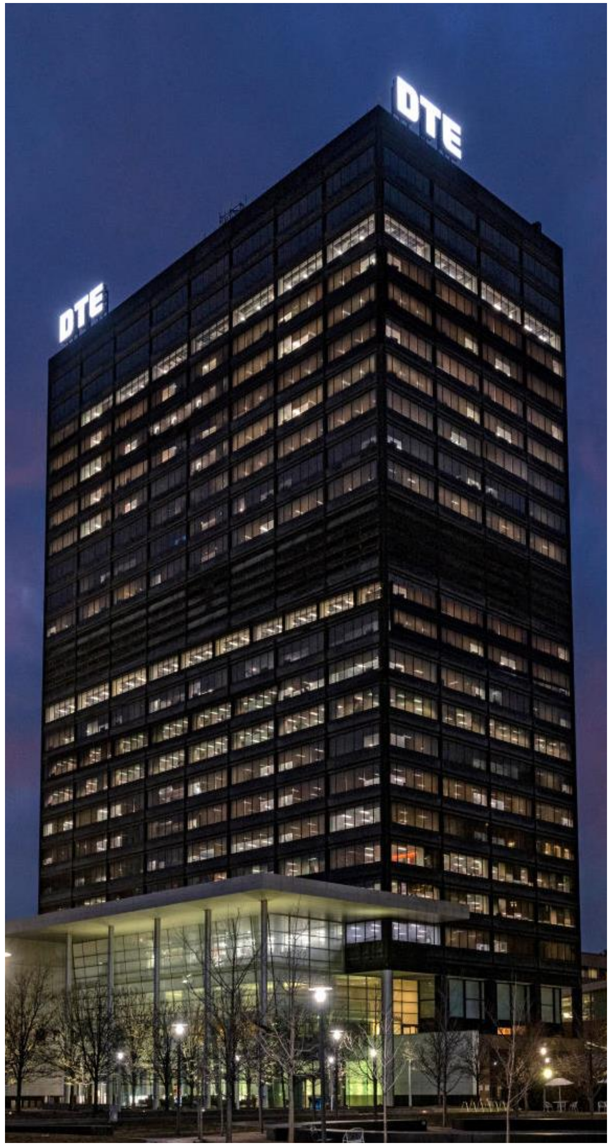
MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.2f	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 2. Please refer to Case No. U-21291 on page EDJ-5 where Witness Janness states, "IRM programs are necessary to ensure the safety of DTE Gas's customers and the public and to allow the Company to provide reliable utility service."

f. Does DTE maintain that the IRM is intended to cover all safety and reliability investments? Please explain, and cite any MPSC orders you rely on for your position.

Answer: No.

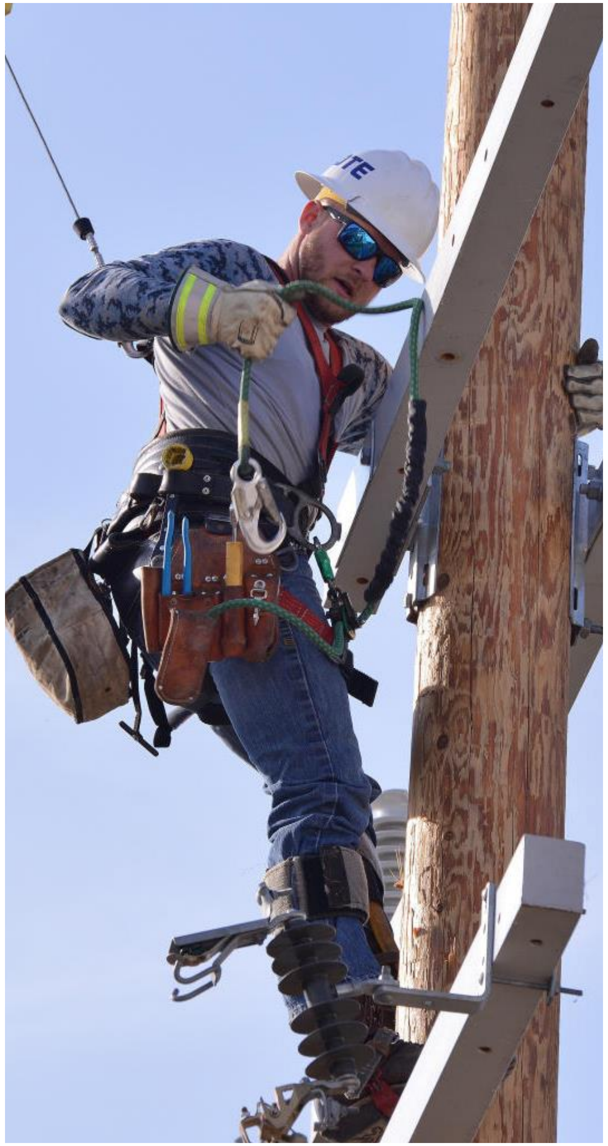
Attachment: None



DTE

2023 Year-end Earnings Conference Call

February 8, 2024



Safe harbor statement

The information contained herein is as of the date of this document. DTE Energy expressly disclaims any current intention to update any forward-looking statements contained in this document as a result of new information or future events or developments. Words such as “anticipate,” “believe,” “expect,” “may,” “could,” “projected,” “aspiration,” “plans” and “goals” signify forward-looking statements. Forward-looking statements are not guarantees of future results and conditions but rather are subject to various assumptions, risks and uncertainties that may cause actual future results to be materially different from those contemplated, projected, estimated or budgeted. Many factors may impact forward-looking statements including, but not limited to, the following: the impact of regulation by the EPA, EGLE, the FERC, the MPSC, the NRC, and for DTE Energy, the CFTC and CARB, as well as other applicable governmental proceedings and regulations, including any associated impact on rate structures; the amount and timing of cost recovery allowed as a result of regulatory proceedings, related appeals, or new legislation, including legislative amendments and retail access programs; economic conditions and population changes in our geographic area resulting in changes in demand, customer conservation, and thefts of electricity and, for DTE Energy, natural gas; the operational failure of electric or gas distribution systems or infrastructure; impact of volatility in prices in international steel markets and in prices of environmental attributes generated from renewable natural gas investments on the operations of DTE Vantage; the risk of a major safety incident; environmental issues, laws, regulations, and the increasing costs of remediation and compliance, including actual and potential new federal and state requirements; the cost of protecting assets and customer data against, or damage due to, cyber incidents and terrorism; health, safety, financial, environmental, and regulatory risks associated with ownership and operation of nuclear facilities; volatility in commodity markets, deviations in weather and related risks impacting the results of DTE Energy’s energy trading operations; changes in the cost and availability of coal and other raw materials, purchased power, and natural gas; advances in technology that produce power, store power or reduce power consumption; changes in the financial condition of significant customers and strategic partners; the potential for losses on investments, including nuclear decommissioning trust and benefit plan assets and the related increases in future expense and contributions; access to capital markets and the results of other financing efforts which can be affected by credit agency ratings; instability in capital markets which could impact availability of short and long-term financing; impacts of inflation and the timing and extent of changes in interest rates; the level of borrowings; the potential for increased costs or delays in completion of significant capital projects; changes in, and application of, federal, state, and local tax laws and their interpretations, including the Internal Revenue Code, regulations, rulings, court proceedings, and audits; the effects of weather and other natural phenomena, including climate change, on operations and sales to customers, and purchases from suppliers; unplanned outages at our generation plants; employee relations and the impact of collective bargaining agreements; the availability, cost, coverage, and terms of insurance and stability of insurance providers; cost reduction efforts and the maximization of plant and distribution system performance; the effects of competition; changes in and application of accounting standards and financial reporting regulations; changes in federal or state laws and their interpretation with respect to regulation, energy policy, and other business issues; successful execution of new business development and future growth plans; contract disputes, binding arbitration, litigation, and related appeals; the ability of the electric and gas utilities to achieve net zero emissions goals; and the risks discussed in DTE Energy’s public filings with the Securities and Exchange Commission. New factors emerge from time to time. We cannot predict what factors may arise or how such factors may cause results to differ materially from those contained in any forward-looking statement. Any forward-looking statements speak only as of the date on which such statements are made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. This document should also be read in conjunction with the Forward-Looking Statements section in DTE Energy’s public filings with the Securities and Exchange Commission.

Participants

Jerry Norcia – Chairman and CEO

Dave Ruud – Executive Vice President and CFO

Barbara Tuckfield – Director of Investor Relations

Highly engaged team committed to delivering best-in-class results for our customers, communities and investors

Continuing best-in-class engagement, health and safety of our employees

- ✓ *Received Gallup Great Workplace Award for 11th consecutive year*
- ✓ *Named one of Metro Detroit's Best and Brightest Companies to Work For*

Addressing our customers' most vital needs

- ✓ *Distribution Grid Plan (DGP) provides roadmap to improved reliability and accelerated automation; improved reliability by 33% in 2023 on upgraded circuits*
- ✓ *Integrated Resource Plan (IRP) supports transition to cleaner energy future while providing $2.5 billion in reduced future costs to customers*
- ✓ *Energy policy drives Michigan's clean energy future; consistent with IRP*
- ✓ *Historic investments in utility infrastructure exceed strong cash generated by our businesses, as supported by regulatory construct*

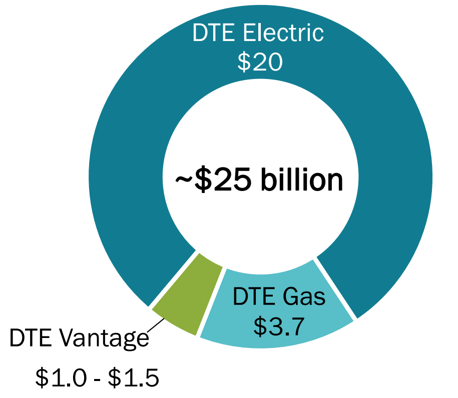
Supporting our communities

- ✓ *Named one of the most community-minded companies in the U.S. with Points of Light's Civic 50 award for the 6th consecutive year*

Delivering premium shareholder returns

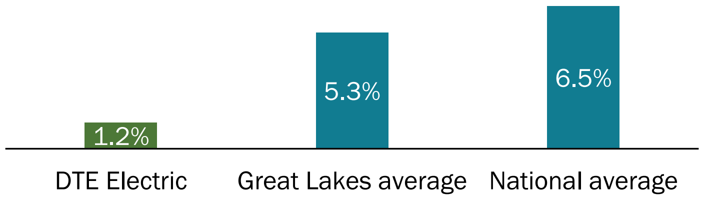
- ✓ *Increased 5-year utility capital investment by $2 billion over previous plan*
- ✓ *2024 operating EPS[1] guidance provides 7% growth from 2023 original guidance midpoint; long-term operating EPS growth rate target of 6% - 8% through 2028*

95% of 5-year investment plan in utilities 2024 - 2028
(billions)



10-year investment plan of over $50 billion

Electric bill increase well below national average
Average annual residential bill growth since 2020[2]



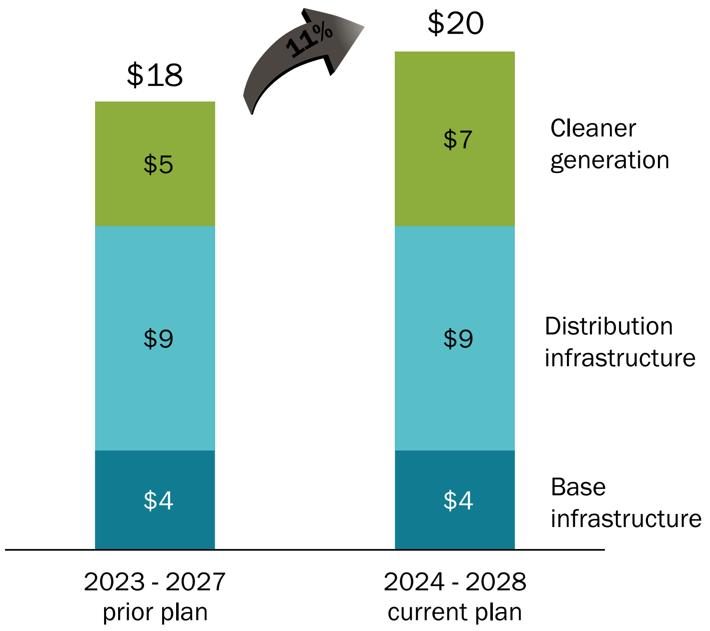
1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix
2. Source: Energy Information Administration (EIA)

DTE Electric: transformational investments in distribution and generation

Capital investment plan focused on building the grid of the future and transitioning to cleaner generation

- DGP outlines detailed roadmap to increase reliability by over 60% over the next 5 years
  - Continuing accelerated tree trimming; over 5,000 miles of trees trimmed in 2023
  - Continuing preventative maintenance by upgrading more than 10,000 miles of infrastructure; upgraded more than 1,300 miles in 2023
  - Advancing infrastructure rebuild by accelerating the replacement of 4.8kV system and pursuing undergrounding
  - Enhancing grid automation by accelerating installation of 10,000 smart grid devices to greatly reduce outage duration
- Transforming generation by targeting carbon emission reductions of 85% in 2032, 90% by 2040 and net zero[1] by 2050
  - Cleaner generation investment driven by expanded renewables and utility-scale energy storage; provides more affordable energy for customers over the long term
  - Renewable investment supports continued success of MIGreenPower voluntary program which allows customers to attribute up to 100% of electric use to renewable sources

DTE Electric investment
(billions)

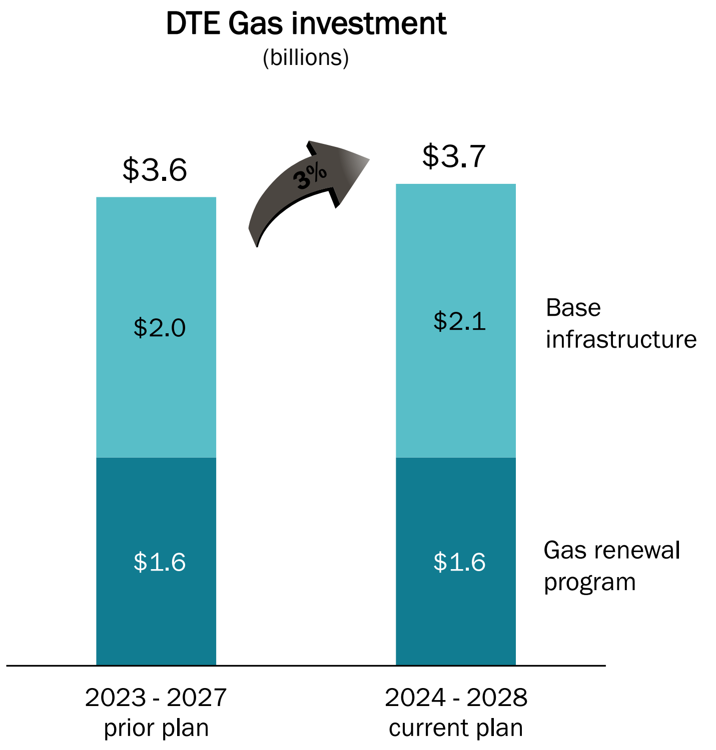


1. Definition of net zero included in the appendix

DTE Gas: replacing aging infrastructure to ensure reliability and transition to net zero emissions

Capital investment focused on infrastructure improvements and decarbonization

- Significant investment recovered through Infrastructure Recovery Mechanism (IRM) to support main renewal
  - Renewed over 1,700 miles since program inception
  - Gas renewal investments minimize leaks and reduce costs
- Base infrastructure investments enhance transmission, compression, distribution and storage
- Targeting to reduce GHG emissions by 65% by 2030, 80% by 2040 and net zero by 2050
  - Natural Gas Balance program empowers customers to manage their carbon footprint using both carbon offsets and RNG



DTE Vantage: strategic focus on decarbonization solutions for customers

Capitalizing on a growing preference for cleaner, more efficient energy

- Strong development pipeline in RNG, large custom energy solutions and carbon capture and sequestration projects
  - Expanded long-term, fixed fee custom energy solutions agreement with Ford Motor Company in Tennessee to build, own, operate and maintain its central utility plant and distribution infrastructure
  - Inflation Reduction Act (IRA) improves opportunities in decarbonization as enhanced tax credits allow carbon capture, RNG and combined heat and power to be more economic
  - Strong RNG market growth supported by the federal RFS and California's LCFS

Long-term growth driven by a combination of custom energy solutions, RNG/renewables[1] and new decarbonization opportunities

- Targeting operating earnings[2] growth of over $15 million annually
  - 2024 guidance of $125 - $135 million
  - 2028 operating earnings projection of $200 - $210 million
- $1.0 - $1.5 billion capital investment 2024 - 2028

1. Renewables includes wood and landfill gas facilities
2. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

2023 operating earnings[1] variance

(millions, except EPS)

	2022	2023	Variance	Primary drivers
DTE Electric	$961	$791	($170)	Warmer winter weather, cooler summer weather, higher storm expenses, higher rate base costs, lower sales and 2022 accelerated deferred tax amortization offset by one-time O&M cost reductions
DTE Gas	272	294	22	One-time O&M cost reductions and IRM revenue offset by warmer weather and higher rate base costs
DTE Vantage	93	153	60	RNG and steel related earnings
Energy Trading	14	105	91	Physical power portfolio performance
Corporate & Other	(144)	(159)	(15)	Interest expense
DTE Energy	**$1,196**	**$1,184**	**($12)**	
Operating EPS	**$6.10**	**$5.73**	**($0.37)**	
Avg. Shares Outstanding	196	206		

Overcame majority of unprecedented headwinds in 2023 without sacrificing reliability or commitment to customer service

1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

2024 operating EPS[1] guidance midpoint provides 7% growth over 2023 original guidance midpoint

(millions, except EPS)

	2023 original guidance	2024 guidance
DTE Electric	$1,010 - $1,030	$1,100 - $1,120
DTE Gas	262 - 272	295 - 305
DTE Vantage	115 - 125	125 - 135
Energy Trading	20 - 30	30 - 40
Corporate & Other	(150) - (136)	(195) - (185)
DTE Energy	**$1,257 - $1,321**	**$1,355 - $1,415**
Operating EPS	**$6.09 - $6.40**	**$6.54 - $6.83**

1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

Maintaining strong cash flows, balance sheet and credit profile

Strong balance sheet supports robust customer-focused investment agenda

- Investment is primarily funded with consistent, healthy cash flows
- Targeting minimal equity issuances of $0 - $100 million annually through 2026
- Effectively managing near-term debt maturities to support long-term plan
- Maintaining solid investment-grade credit ratings; targeting 15% - 16% FFO / Debt[1]

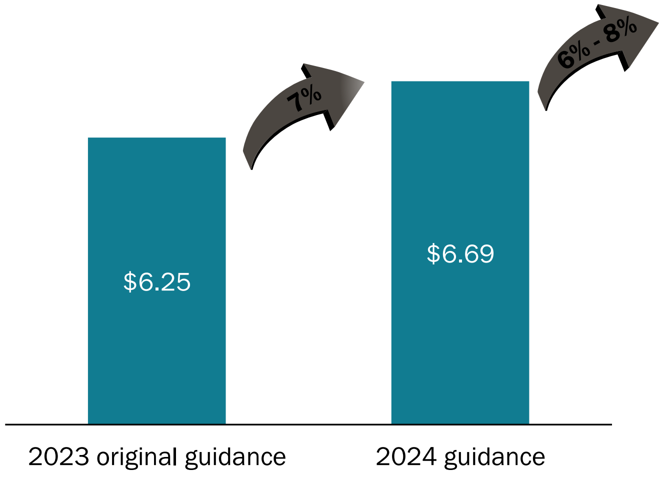
Credit ratings	S&P	Moody's	Fitch
DTE Energy (unsecured)	BBB	Baa2	BBB
DTE Electric (secured)	A	Aa3	A+
DTE Gas (secured)	A	A1	A

1. Funds from Operations (FFO) is calculated using operating earnings, debt excludes a portion of DTE Gas' short-term debt and considers 50% of the junior subordinated notes as equity

Increased utility investment focused on improved reliability and cleaner generation; well-positioned for long-term growth

- ✓ Highly engaged team committed to delivering best-in-class results for our customers, communities and investors
- ✓ Customer-focused capital investments support building the grid of the future and cleaner energy transition
- ✓ Utility investment and affordability commitment support long-term growth
- ✓ 2024 operating EPS[1] guidance provides 7% growth from 2023 original guidance midpoint
- ✓ Long-term operating EPS growth rate target of 6% - 8% through 2028, with 2023 original guidance midpoint as the base
- ✓ 2024 annualized dividend of $4.08 per share is in line with operating EPS growth
- ✓ Strong balance sheet and solid investment-grade credit profile support capital investment plan

Operating EPS guidance midpoint



1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

Appendix

Cash flow and capital expenditures

Cash flow

(billions)	2023 actuals	2024 guidance
Cash from operations[1]	$3.2	$3.3
Capital expenditures	(4.0)	(4.7)
Free cash flow	**($0.8)**	**($1.4)**
Dividends	(0.8)	(0.8)
Other	(0.1)	-
Net cash	**($1.7)**	**($2.2)**
Debt financing		
Issuances	$3.3	$4.3
Redemptions	(1.6)	(2.1)
Total debt financing	**$1.7**	**$2.2**

Capital expenditures

(millions)	2023 actuals	2024 guidance
DTE Electric		
Base infrastructure	$943	$630
New generation	591	1,200
Distribution infrastructure	1,593	1,550
	$3,127	**$3,380**
DTE Gas		
Base infrastructure	$398	$380
Gas renewal program	347	335
	$745	**$715**
Non-utility	**$167**	**$550 - $650**
Total	**$4,039**	**$4,645 - $4,745**

1. Includes equity issued for employee benefit programs

Weather impact on sales

DTE Electric

Cooling degree days[1]

	2022	2023	% Change
Actuals	980	703	(28%)
Normal	899	913	2%
Deviation from normal	9%	(23%)	

Operating earnings[2] impact of weather

	(millions)		(per share)	
	4Q	YTD	4Q	YTD
2022	($3)	$25	($0.02)	$0.13
2023	($11)	($106)	($0.05)	($0.52)

Weather normal sales[1]

(GWh)	2022	2023	% Change
Residential	15,647	15,313	(2.1%)
Commercial	19,011	18,923	(0.5%)
Industrial	10,213	10,273	0.6%
Other	210	204	(2.9%)
	45,081	44,713	(0.8%)

DTE Gas

Heating degree days[3]

	4Q 2022	4Q 2023	% Change	2022	2023	% Change
Actuals	2,108	1,924	(9%)	6,422	5,564	(13%)
Normal	2,177	2,179	0%	6,314	6,319	0%
Deviation from normal	(3%)	(12%)		2%	(12%)	

Operating earnings[2] impact of weather

	(millions)		(per share)	
	4Q	YTD	4Q	YTD
2022	($4)	$11	($0.02)	$0.06
2023	($20)	($52)	($0.10)	($0.25)

1. DTE Electric 2022 weather normalized data based on 2006 – 2020 weather and 2023 weather normalized data based on 2007 – 2021 weather
2. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix
3. DTE Gas 2022 weather normalized data based on 2007 – 2021 weather and 2023 weather normalized data based on 2008 – 2022 weather

Overcame a significant portion of the ~$400 million of unprecedented operating earnings[1] headwinds in 2023

~$400 million of unprecedented headwinds faced throughout the year

Headwinds

4Q 2022	1H 2023	3Q 2023	4Q 2023
• Lower-than-expected rate order received in 2022 driven by difference in sales forecast: $100 million	• Historical winter storms: $92 million • 4th warmest 1Q winter in over 60 years and cooler spring weather: $73 million	• Additional storms: $53 million • One of the coolest summers in over 20 years: $53 million	• One of the warmest 4Q winters in over 60 years: $31 million

Overcame ~$300 million of headwinds with significant response

Actions

- Implemented significant one-time O&M actions and created opportunities throughout the portfolio
- Through 1H, identified offsets to headwinds to achieve midpoint of original guidance while remaining focused on customer service excellence
- Continued earnings pressure drove a revision to operating EPS guidance in 3Q
- Overcame majority of additional headwinds from warmer than normal weather in 4Q

1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

IRP supports transition to cleaner energy future while focusing on reliability and affordability

Accelerating path to cleaner generation…

- Transforming generation by targeting carbon emission reductions of 85% in 2032, 90% by 2040 and net zero by 2050
- Ceasing coal use at Belle River by 2026; converting to 1,300 MW natural gas peaking resource
- Retiring two coal units at Monroe in 2028; accelerating retirement of remaining two units from 2035 to 2032; studying a range of replacement technology solutions
- Accelerating the development of energy storage, targeting 780 MW through 2030 and 1,830 MW by 2042
- Developing 6,500 MW of solar and 8,900 MW of wind by 2042

…while continuing to focus on customer affordability and economic development

- Investing over $11 billion in the next 10 years in the cleaner energy transition, supporting more than 32,000 Michigan jobs
- Developing more than 15,000 MW of Michigan-generated renewable energy by 2042, the equivalent of powering approximately 4 million homes
- Directing an additional $110 million to support most vulnerable customers
  - $70 million over the next four years for energy efficiency programs, $30 million over 15 years for bill assistance and $8 million over the next four years for home repairs to facilitate cleaner energy
- Reducing future costs to customers by up to $2.5 billion

Energy policy drives Michigan's clean energy future and supports our cleaner energy journey

- Accelerates the pace of decarbonization and deployment of renewables
  - Renewable compliance standard of 50% by 2030 and 60% by 2035
  - Clean energy standard of 80% by 2035 and 100% by 2040
  - Allows MPSC to approve emerging low and zero carbon technologies, including carbon capture and sequestration
  - Sets 2,500 MW statewide energy storage target
  - Raises energy efficiency targets and increases incentives
  - Provides flexibility in meeting targets and off-ramps for resource adequacy, excessive cost and feasibility
  - Allows financial compensation mechanism on power purchase agreements for renewable energy and energy storage
- Supportive of IRP plan and clean energy goals

2022 and 2023 reconciliation of reported to operating earnings (non-GAAP) and operating EPS (non-GAAP)

	Twelve Months Ended December 31,							
	2023				2022			
	Reported Earnings	Pre-tax Adjustments	Income Taxes[1]	Operating Earnings	Reported Earnings	Pre-tax Adjustments	Income Taxes[1]	Operating Earnings
	(In millions)							
DTE Electric	$ 772	$ 25 A	$ (6)	$ 791	$ 956	$ 8 A	$ (3)	$ 961
DTE Gas	294	—	—	294	272	—	—	272
Non-utility operations								
DTE Vantage	153	—	—	153	92	1 E	—	93
Energy Trading	336	(308) B	77	105	(92)	140 B	(35)	14
						2 E	(1)	
Non-utility operations	489	(308)	77	258	—	143	(36)	107
Corporate and Other	(158)	—	(7) C	(159)	(145)	(10) E	3	(144)
			6 D			11 F	(3)	
Net Income Attributable to DTE Energy Company	$ 1,397	$ (283)	$ 70	$ 1,184	$ 1,083	$ 152	$ (39)	$ 1,196

	Twelve Months Ended December 31,							
	2023				2022			
	Reported Earnings	Pre-tax Adjustments	Income Taxes[1]	Operating Earnings	Reported Earnings	Pre-tax Adjustments	Income Taxes[1]	Operating Earnings
	(Earnings per share[2])							
DTE Electric	$ 3.74	$ 0.12 A	$ (0.03)	$ 3.83	$ 4.88	$ 0.04 A	$ (0.02)	$ 4.90
DTE Gas	1.43	—	—	1.43	1.39	—	—	1.39
Non-utility operations								
DTE Vantage	0.74	—	—	0.74	0.47	0.01 E	—	0.48
Energy Trading	1.63	(1.49) B	0.37	0.51	(0.47)	0.72 B	(0.18)	0.07
						0.01 E	(0.01)	
Non-utility operations	2.37	(1.49)	0.37	1.25	—	0.74	(0.19)	0.55
Corporate and Other	(0.78)	—	(0.03) C	(0.78)	(0.75)	(0.05) E	0.02	(0.74)
			0.03 D			0.06 F	(0.02)	
Net Income Attributable to DTE Energy Company	$ 6.76	$ (1.37)	$ 0.34	$ 5.73	$ 5.52	$ 0.79	$ (0.21)	$ 6.10

Adjustments key
A) MPSC disallowance of certain capital project costs previously recorded — recorded in Operating Expenses — Asset (gains) losses and impairments, net
B) Certain adjustments resulting from derivatives being marked-to-market without revaluing the underlying non-derivative contracts and assets — recorded in Operating Expenses — Fuel, purchased power, gas, and other — non-utility
C) Adjustment to Income Tax Expense due to a tax law change in West Virginia
D) Adjustment to Income Tax Expense due to a tax law change in Massachusetts
E) (Gain) loss on sale of assets — recorded in Operating Expenses — Asset (gains) losses and impairments, net
F) One-time benefit expenses — recorded in Other (Income) and Deductions — Non-operating retirement benefits, net

1. Excluding tax related adjustments, the amount of income taxes was calculated based on a combined federal and state income tax rate, considering the applicable jurisdictions of the respective segments and deductibility of specific operating adjustments
2. Per share amounts are divided by Weighted Average Common Shares Outstanding – Diluted, as noted on the Consolidated Statements of Operations

Reconciliation of reported to operating earnings (non-GAAP)

Use of Operating Earnings Information – Operating earnings exclude non-recurring items, certain mark-to-market adjustments and discontinued operations. DTE Energy management believes that operating earnings provide a meaningful representation of the company's earnings from ongoing operations and uses operating earnings as the primary performance measurement for external communications with analysts and investors. Internally, DTE Energy uses operating earnings to measure performance against budget and to report to the Board of Directors. Operating earnings is a non-GAAP measure and should be viewed as a supplement and not a substitute for reported earnings, which represents the company's net income and the most comparable GAAP measure.

In this presentation, DTE Energy provides guidance for future period operating earnings. It is likely that certain items that impact the company's future period reported results will be excluded from operating results. A reconciliation to the comparable future period reported earnings is not provided because it is not possible to provide a reliable forecast of specific line items (i.e., future non-recurring items, certain mark-to-market adjustments and discontinued operations). These items may fluctuate significantly from period to period and may have a significant impact on reported earnings.

Definition of net zero

Goal for DTE Energy's utility operations and gas suppliers at DTE Gas that any carbon emissions put into the atmosphere will be balanced by those taken out of the atmosphere. Achieving this goal will include collective efforts to reduce carbon emissions and actions to offset any remaining emissions. Progress towards net zero goals is estimated and methodologies and calculations may vary from those of other utility businesses with similar targets. Carbon emissions is defined as emissions of carbon containing compounds, including carbon dioxide and methane, that are identified as greenhouse gases.

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.10a	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 10. Has DTE identified which assets (or types of assets) on its gas system are most likely or least likely to remain used and useful in the event of widespread electrification of gas- fueled end uses (such as space and water heating)?

a. If so, please describe the assets (or types of assets) identified.

Answer: No.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-3.16b	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 16. Please refer to the following statement on page HJD-49 of Witness Decker Direct Testimony: "We estimate this would prevent approximately 4,000 to 8,000 metric tons CO2e from being released to the atmosphere, depending on the methane intensity of the RSG purchased."

b. What range of methane intensities of RSG will the company consider?

Answer: The Company has determined that, at a mimimum, third party verification is a criterion that will be used when procuring RSG, i.e. the gas must be certified. A specific methane intensity level has not been defined at this time.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-3.13	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 13. Has DTE performed or commissioned any analysis of the cost of emissions reductions (in $/MT CO2e) achieved through use of RSG compared to an alternative such as electrification? If so, please provide the analysis, including all supporting documentation and workpapers with formulas intact and with sources, units, and assumptions clearly identified. If not, please explain why not.

Answer: DTE has not evaluated RSG vs. electrification in cost to reduce emissions. We have compared RSG to the Natural Gas Balance program. Exact costs can vary based on the specific project, but we've found RSG is in the range of $30/mt while the natural gas balance (NGB) program offers customers emission reductions at approximately $37/mt.

Calculation for RSG Costs: Per witness H.J. Decker's testimony, a premium of $180,000 is expected to reduce emissions by 4,000 to 8,000 mt CO2-e. Assuming the midpoint in emission reductions, $180,000/6,000mt CO2-e is $30/mt CO2-e

Calculations for NGB reduction costs: Average residential gas usage is ~92 mcf, which equates to ~5.1 mt CO2-e per year. For Level 4 customers balancing 100% of their usage, it costs customers $192/year. $192/5.1 mt CO2-e is about $37/mt CO2-e.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-2.4f	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 4. Please refer to page 34 in Exhibit A-12 Schedule B5.6 DTE Gas Delivery Plan, where it says “Internally DTE Gas will reduce greenhouse gas emissions to net zero by 2050 through operational improvements, renewal of existing infrastructure, investments in renewable natural gas and carbon offsets, and implementation of advanced technologies.” And “Downstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e g, RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).” When responding to the following requests, please include all supporting workpapers with formulas intact and sources and assumptions clearly stated.

f. Please identify any anticipated impact on customers of each of the initiatives identified in response to prior sub-parts of this question, individually and in the aggregate, including bill impacts. Provide all supporting workpapers with formulas intact and sources, methodologies, and assumptions clearly stated.

Answer: DTE has not done an evaluation of the costs to customers.

Attachment: None

Michigan's cleaner energy future

It's been more than three years since DTE Energy launched the CleanVision Natural Gas Balance program – and there is a lot to celebrate! More than 13,000 DTE Gas residential and small business customers are enrolled in the program, joining us in our commitment to achieve net zero carbon emissions by 2050.

Thank you for remaining a valued member of this community. Together, we are pioneering the use and development of renewable natural gas in Michigan, protecting our state's mature trees that act as natural carbon scrubbers and addressing emissions from natural gas usage in heating, cooking, water heating and other home uses – without adjusting your energy usage.

How it works

Natural Gas Balance offers DTE Gas customers an affordable, effective way to help the environment by addressing their carbon footprint. For a small monthly fee, participants can balance between 25% to 100% of greenhouse gas emissions from an average home's natural gas use.

Natural Gas Balance 2023 Impact

13,212
Customers enrolled

18,472 metric tons
Natural gas-related CO2-e emissions negated

4,396
Equivalent number of cars off the road

Carbon offsets

Trees are one of the world's most important tools against climate change. They naturally absorb greenhouse gases, helping to offset emissions produced by natural gas usage.

Through a partnership that began in 2021 with Anew, formerly Bluesource, North America's leading carbon offset developer, Natural Gas Balance is purchasing carbon offset credits to limit aggressive tree harvesting in parts of the Upper Peninsula. Greenleaf Improved Forest Management is protecting 24,000 acres of forest across 13 Michigan counties and one in Wisconsin through our partnership. These trees will scrub greenhouse gases from the atmosphere for generations to come.

BREAKING DOWN THE NUMBERS

2023 carbon offset impact

17,548 metric tons

Natural gas-related CO2-e emissions negated

Renewable natural gas

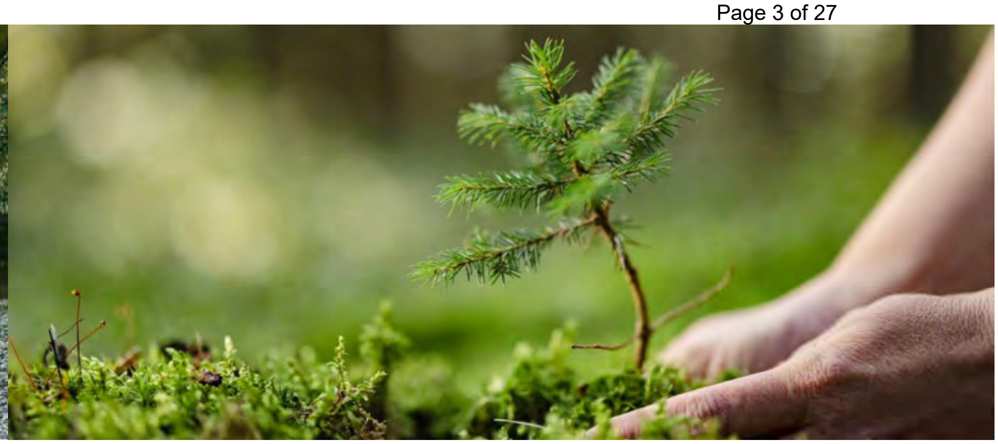
Renewable natural gas, or RNG, is derived by capturing methane gas emitted by organic waste materials in landfills, wastewater treatment plants and dairy farms. The gas is trapped, and impurities are removed, creating a renewable source of pipeline-quality gas. Natural Gas Balance sources RNG from multiple Michigan producers, including the Sauk Trail Hills landfill in Canton and a wastewater treatment facility in Grand Rapids.

BREAKING DOWN THE NUMBERS

2023 RNG impact

16,946 mcf

Renewable natural gas acquired on behalf of participating customers, negating **923.6 metric tons** of natural gas-related CO2-e emissions



"Our City Commission approved a target date of 2040 this past February for carbon neutrality.

By enrolling in CleanVision Natural Gas Balance we will be balancing 100% of the associated natural gas emissions for all our municipal buildings – and it's a natural partnership to work with DTE Energy as we took this next step in delivering on our goals."

– Doug La Fave
Deputy City Manager for East Grand Rapids

2023 Rewind – East Grand Rapids enrolls in Natural Gas Balance

East Grand Rapids joined Natural Gas Balance Custom, the companion program to Natural Gas Balance designed for DTE's large commercial and industrial customers, in July 2023. The town is the first in the state to balance their usage through the program.

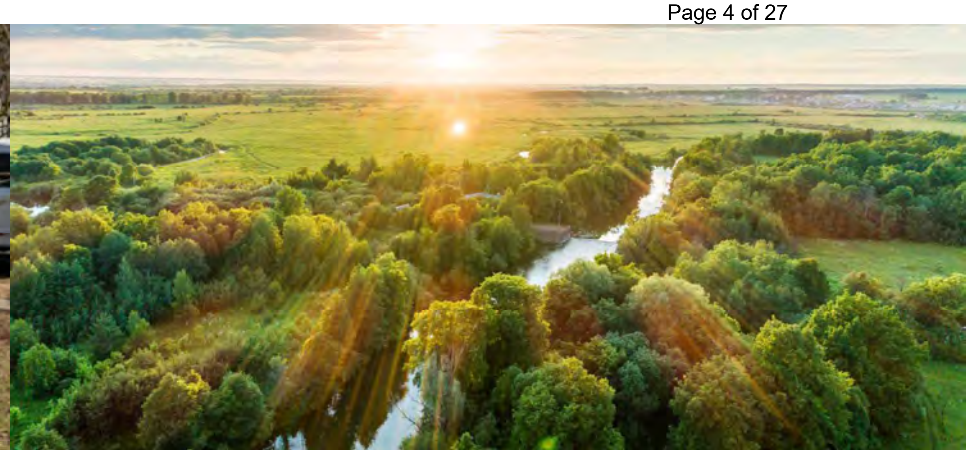
Many East Grand Rapids residents were excited to follow their municipality's lead – more than 200 households enrolled after the municipality committed to the program.

2023 Rewind – West Michigan residents embrace cleaner energy

Kent and Muskegon County residents have spoken – they're ready to embrace cleaner energy!

More than 100 Kent and Muskegon County residents enrolled in Natural Gas Balance when DTE rolled out a challenge to encourage customers to sign up in August. If more than 100 residents between the two counties enrolled in Natural Gas Balance by the end of August, DTE promised to plant 10 trees in each county. Residents easily exceeded the goal – bravo!

Natural Gas Balance team members and crews from DTE's Wealthy and Muskegon service centers were on hand to plant the trees on Oct. 13. Ten trees were planted in Kent County's Wahlfield Park and the other 10 were planted in Muskegon County's Moore Park.



We're proud of what we've accomplished together so far and are excited about what's ahead.

What's next

In 2024, projects will include:

- Receive approval from the Michigan Public Service Commission to extend the pilot period as we continue to learn and grow in our knowledge of how this program fits into our customers' sustainability goals.
- Purchase additional Michigan-made carbon offsets and renewable natural gas to support the growth of this program.
- Continue educating customers on the role balancing emissions can have to grow enrollment levels in Natural Gas Balance's Level 2-4 program offerings.

DTE's commitment to sustainability

In 2020, DTE Gas was one of the first natural gas companies to announce carbon reduction goals across the natural gas industry, with net zero by 2050 goals for our own operations and gas supply, and a 35% reduction in our downstream or customer emissions by 2040. Achieving this goal could reduce annual greenhouse gas emissions by more than six million metric tons by 2050 – and we're on track to meet this goal.

- **We will reduce our own internal greenhouse gas emissions** – not just methane emissions – from utility operations and achieve carbon neutrality by continuing to replace aging pipelines, new operational improvements and the use of carbon offsets.
- **We are committed to purchasing the cleanest natural gas available from producers**, which means we expect our suppliers to be eliminating their own emissions as they produce natural gas.

Natural Gas Balance is a key component of DTE Energy's CleanVision initiative, a portfolio of bold environmental programs designed to achieve our ambitious climate action goals. It encompasses programs that support wind and solar energy, energy waste reduction, electric vehicles, appliance recycling and more.

Take your impact to the next level

Already enrolled? You can increase your impact on climate change by increasing your commitment. Consider moving up to the next level to make an even bigger difference in mitigating carbon emissions. Go to dteenergy.com/NaturalGasBalance.

CARBON EMISSIONS MITIGATED

25%	Level 1
50%	Level 2
75%	Level 3
100%	Level 4

Let's connect!

We'd like to hear from you. Send your comments, questions and suggestions to us at **NaturalGasBalance@dteenergy.com**.

DTE
CleanVision
Natural Gas Balance

DTE Gas Natural Gas Balance (NGB) U-20839

Program Update and 2023 Annual Report

Preliminary – Subject to revision

March 2024

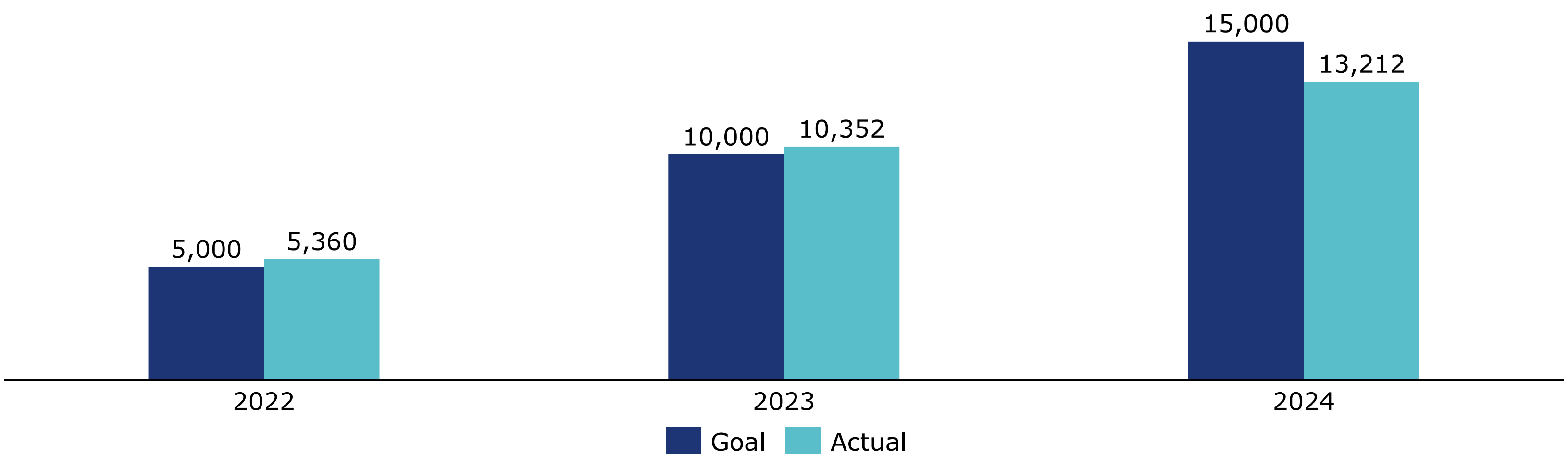
Based off our filing, below is the set of criteria to be share with you and our customers regarding our 2023 Natural Gas Balance program performance

Required Criteria	Location in Document(s)
1. Customer enrollment levels and selected block levels	See slide 4
2. Information about projects utilized by the company to source the carbon reduction supply	See Annual Report, "Carbon offset" section
3. The quantity of total emissions negated	See Annual Report, "Natural Gas Balance 2023 Impact" section
4. Marketing and administration costs with marketing methods explained, including copies of marketing materials used and links to digital media	See slides 5 – 6
5. Quantity, source, and cost of renewable gas and carbon offsets purchased	See Annual Report "Carbon offset" and "Renewable natural gas" for supply source, slide 5 for quantity and cost
6. Customer participation forecasts	See slide 4 for annual enrollment targets
7. Marketing studies	N/A; No marketing studies have been performed
8. DTE Gas will also meet annually with the Staff to review the report and results of the program, as well as discuss the company's future plans	See Annual Report, "What's next" section
9. The company will offer a place for customers to submit questions or concerns related to the program	See website: www.dteenergy.com/naturalgasbalance

2023 Annual Report

Customer Enrollment Levels

Total Enrolled Customers and Forecast



Year-end Enrollments by Level

2021

Level	# of enrollments
Legacy	1,678
Level 1	2,947
Level 2	384
Level 3	55
Level 4	296
TOTAL	**5,360**

2022

Level	# of enrollments
Legacy	1,550
Level 1	7,426
Level 2	648
Level 3	84
Level 4	644
TOTAL	**10,352**

2023

Level	# of enrollments
Legacy	1,357
Level 1	10,259
Level 2	760
Level 3	105
Level 4	731
TOTAL	**13,212**

DTE

The 2024 enrollment goal is 17,000 enrollments by year-end

NGB Income Statement and Supply Totals 2023

Natural Gas Balance Income Statement

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
Revenue													
Total Program Revenue	$50,394	$46,034	$72,564	$48,643	$49,078	$47,144	$53,275	$58,707	$59,805	$61,679	$63,032	$63,465	$673,820
Total Revenue	$50,394	$46,034	$72,564	$48,643	$49,078	$47,144	$53,275	$58,707	$59,805	$61,679	$63,032	$63,465	$673,820
Expenses													
ST Labor	($9,093)	($10,247)	($9,851)	($9,834)	($10,934)	($10,037)	($7,577)	($4,599)	($12,773)	($13,382)	($13,382)	($12,773)	($124,481)
RNG			($123,480)			($52,632)			($53,160)			($58,584)	($287,856)
Carbon Offsets			($32,408)			($34,576)			($34,912)			($38,480)	($140,376)
Contract Labor	($733)	($734)	($809)	($806)	($4,678)	($811)	($891)	($5,502)	($815)	($818)	($821)	($821)	($18,238)
Outside Services	($41,174)	($67,004)	($67,261)	($53,968)	($52,201)	($78,971)	($51,294)	($65,250)	($272,510)	($96,210)	($112,800)	($37,490)	($996,133)
Dues & Assessments	($4,660)				($3,200)		($5,000)		($7,000)	($7,000)		($5,000)	($31,860)
Other		($2,500)	($1,707)	($99,459)	$544	($1,708)	($6,320)		($7,240)	($19,100)	($77,493)	($6,950)	($221,933)
Burdern	($206)	($335)	($338)	($317)	($294)	($395)	($314)	($350)	($1,369)	($481)	($564)	($193)	($5,154)
Total Expenses	($55,865)	($80,820)	($235,854)	($164,384)	($70,764)	($179,130)	($71,395)	($75,700)	($389,778)	($136,991)	($205,059)	($160,292)	($1,826,031)
Program Net Income (Loss)	($5,471)	($34,786)	($163,289)	($115,741)	($21,686)	($131,986)	($18,120)	($16,993)	($329,973)	($75,312)	($142,027)	($96,827)	($1,152,211)

	2023 Total Supply Retirements
Carbon Offsets	17,548 (measured in metric tons per CO2-e)
Renewable Natural Gas	16,946 mcf

DTE

Natural Gas Balance continues to use marketing funds to grow enrollments, which are not included in base rates

Customer Outreach - $300,550

- Digital social campaign - $90,000
- Video creation - $5,500
- Emails, bill inserts, direct mail - $205,050

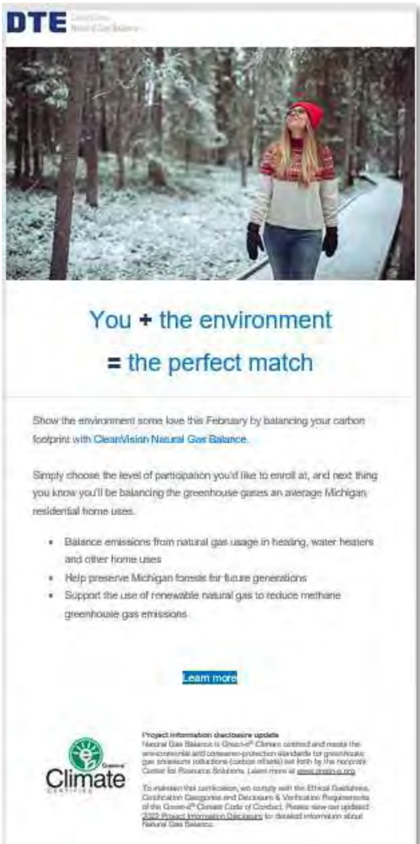
Direct Marketing & Support - $704,990

- Direct Outbound Calling Campaigns
  - Direct sales calling - $674,990
  - Inbound call center support - $30,000

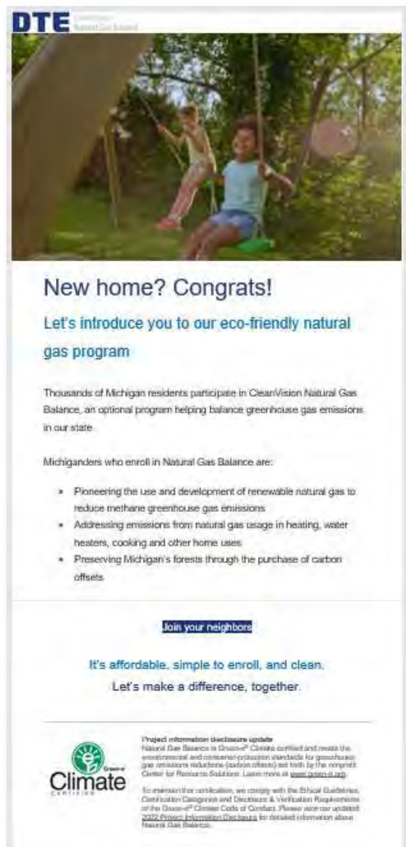
Misc. Marketing - $38,400

- Events - $17,500
- Legal - $8,800
- Community Incentive - $12,100

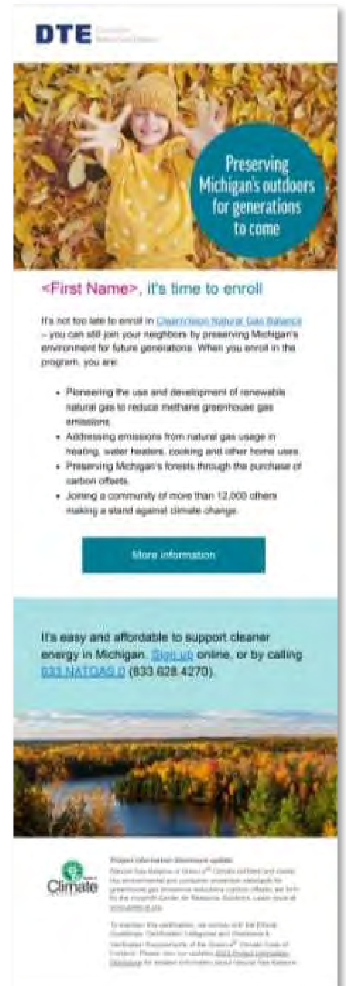
A variety of channels are used to reach our customer base



2/22 Targeted acquisition email



6/22 Targeted email to new DTE customers



October retargeted email

A variety of channels are used to reach our customer base

7/1-7/8
Traverse City
Cherry Festival

5/23 Huron
River Day
Event

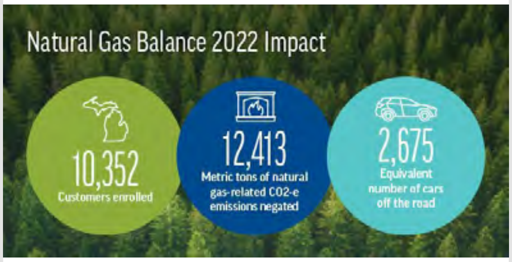
7/20-7/22
Ann Arbor Art
Festival

DTE CleanVision Natural Gas Balance

THANK YOU for being a CleanVision Natural Gas Balance program customer.

We're thrilled to share more than 10,000 DTE Gas residential and small business customers enrolled in the program, joining us in our commitment to achieve net zero carbon emissions by 2050.

Thank you for being part of this incredible effort throughout our state. Together, we're protecting state forests, supporting renewable energy development, and building a cleaner, brighter energy future for Michigan.



Carbon offset credits

Trees are one of the world's most important tools when it comes to preserving the Earth's climate. They naturally absorb greenhouse gases, helping to balance emissions produced by natural gas usage. Through a partnership that began in 2021 with Anew, North America's leading carbon offset developer, Natural Gas Balance is purchasing carbon offset credits to limit aggressive tree harvesting throughout Michigan. With our support, Greenleaf Improved Forest Management is protecting 24,000 acres of forest across 13 Michigan counties and one in Wisconsin, which ensures thousands of trees remain to continue scrubbing greenhouse gases from the atmosphere.

Last year, we also added a second forestry project preserving 100,000 acres of the Pigeon River County State Forest for 10 years. This land, also known as The Big Wild, is considered one of Michigan's greatest treasures. The project is the first of its kind to use state land to generate forestry carbon offsets. The project will also provide more than $10 million to the state's Forest Development and Fish and Game funds for natural resource management.

2022 Carbon Offset Credit Impact	**11,792** metric tons Natural gas-related CO_2-e emissions negated

Renewable natural gas

Renewable natural gas, or RNG, is derived by capturing methane gas emitted by organic waste materials in landfills, wastewater treatment plants and dairy farms. The gas is trapped, and impurities removed, creating a renewable source of pipeline-quality natural gas. Natural Gas Balance sources RNG from multiple local producers, including the Sauk Trail Hills landfill in Canton and a wastewater recovery facility in Grand Rapids.

2022 RNG Impact	**11,264** mcf Renewable natural gas acquired on behalf of participating customers, negating **621** metric tons of natural gas-related CO_2-e emission

What’s next

We’re proud of what we’ve accomplished together so far and are excited for what’s next. In 2023, we will:

- Receive Green-e Certification for the Pigeon River County State Forest; an additional certification for the carbon offset credits we purchase.
- Purchase additional Michigan-made supply to support the growth of this program.

2022 Highlights

Grand Rapids Water Resource Recovery Facility supplies RNG

Earlier this year, we contracted with the Grand Rapids Water Resource Recovery Facility to produce RNG. Methane and other greenhouse gases are naturally produced during the WRRF’s typical recovery processes, and are harmful greenhouse gases (GHG). RNG projects capture this methane and redirect it away from the environment, where it can be used as pipeline-quality natural gas delivered to your home.

Planting Trees in Washtenaw County

In April last year, DTE challenged Washtenaw County residents to enroll in CleanVision Natural Gas Balance AND MIGreenPower – if more than 100 residents enrolled in April, the company promised to plant 20 trees in the county.

Washtenaw County residents were up to the challenge!

On Sept. 30 the company planted 10 trees in Ann Arbor’s Arbor Oaks Park to meet our end of the bargain. Later in November, we planted 10 trees in Washtenaw County’s Nature Preserves in Superior Township.

BlueSource Changes Name to Anew

Anew is the new BlueSource! You may see Anew crop up in more messages and communications from our program, so we wanted to let you know BlueSource rebranded to Anew.

All of our carbon offset credits are provided through Anew, which works with Michigan forest landowners and experts to provide the credits. We work in partnership with Anew to participate in Improved Forest Management (IFM) projects that protect Michigan’s natural forests from being over-harvested by commercial loggers. IFM project developers follow the methodology and protocol established by the nonprofit and independent American Carbon Registry.

Take your impact to the next level

You can increase your impact on climate change by increasing your commitment. Consider moving up to the next level to make an even bigger difference in mitigating carbon emissions.

See how

Let's connect!

We'd like to hear from you. Send your comments, questions and suggestions to us at **naturalgasbalance@dteenergy.com**.

Climate

Project information disclosure update

Natural Gas Balance is Green-e® Climate certified and meets the environmental and consumer-protection standards for greenhouse gas emissions reductions (carbon offsets) set forth by the nonprofit Center for Resource Solutions. Learn more at www.green-e.org.

To maintain this certification, we comply with the Ethical Guidelines, Certification Categories and Disclosure & Verification Requirements of the Green-e® Climate Code of Conduct. Please view our updated 2022 Project Information Disclosure for detailed information about Natural Gas Balance.

DTE Gas Natural Gas Balance (NGB) U-20839

Program Update and
2022 Annual Report

Preliminary – Subject to revision

March 2023

Based off our filing, below is the set of criteria to share with you and our customers regarding our 2022 Natural Gas Balance program performance

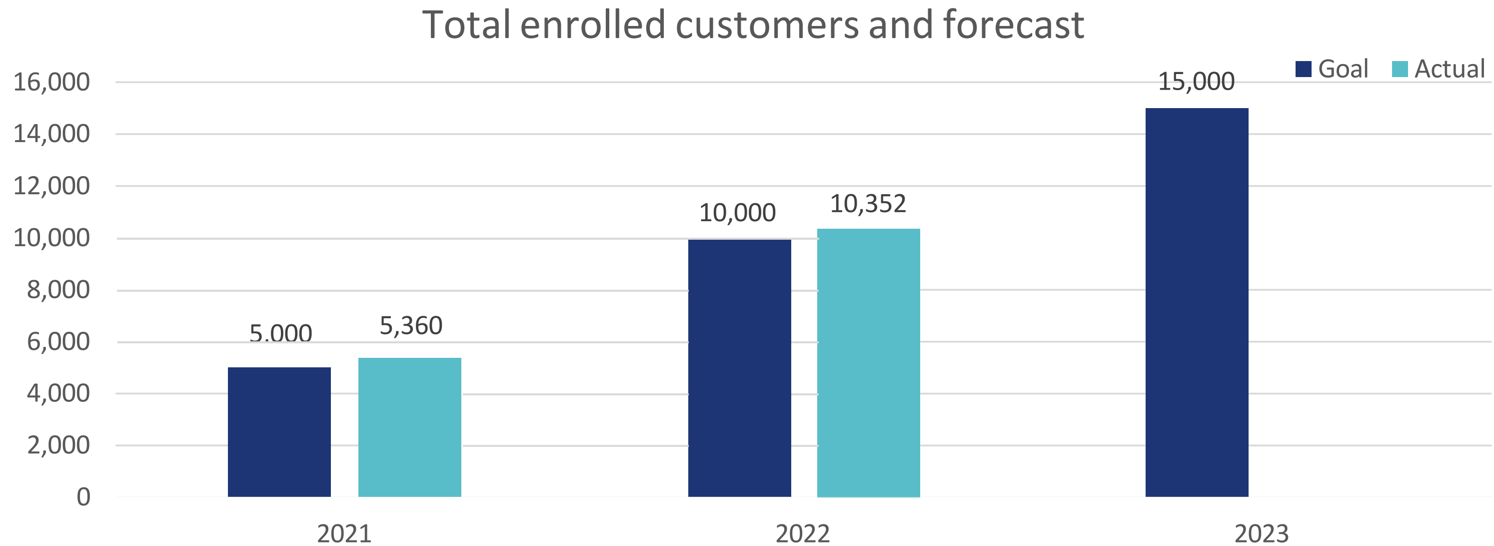
- **1.Customer enrollment levels and selected block levels**
- –See slide 5
- **2.Information about projects utilized by the company to source the carbon reduction supply**
- –See Annual report, “Carbon offset credits” section
- **3.The quantity of total emissions negated**
- –See Annual report, “Natural Gas Balance 2022 Impact” section
- **4.Marketing and administration costs with marketing methods explained, including copies of marketing materials used and links to digital media**
- –See slides 6-10
- **5.Quantity, source, and cost of renewable gas and carbon offsets purchased**
- –See Annual report “Carbon offset credits” and “Renewable natural gas” for supply source, slide 6 for quantity and cost
- **6.Customer participation forecasts**
- –See slide 5 for annual enrollment targets
- **7.Marketing studies.**
- –N/A, No marketing studies have been performed
- **8.DTE Gas will also meet annually with the Staff to review the report and results of the program, as well as discuss the company’s future plans**
- –See annual report, “What’s next” section
- **9.The company will offer a place for customers to submit questions or concerns related to the program**
- –See website

Agenda

- Discuss overall program achievements
  - Review Annual Report
- Discuss enrollment levels and forecast
- Review NBG Income Statement
  - Marketing expenses and details
- Review program extension proposal

2022 Annual Report

Customer Enrollment Levels



YE Enrollments by Level

2021

Level	# of enrollments
Legacy	1,678
Level 1	2,947
Level 2	384
Level 3	55
Level 4	296
TOTAL	5,360

2022

Level	# of enrollments
Legacy	1,550
Level 1	7,426
Level 2	648
Level 3	84
Level 4	644
TOTAL	10,352

NGB Income Statement and Supply Totals 2022

Natural Gas Balance Income Statement

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
Revenue													
Total Program Revenue	$ 24,488	$ 23,045	$ 35,423	$ 28,668	$ 32,354	$ 50,112	$ 35,615	$ 40,299	$ 39,276	$ 42,513	$ 44,112	$ 44,112	$ 440,017
Total Revenue	$ 24,488	$ 23,045	$ 35,423	$ 28,668	$ 32,354	$ 50,112	$ 35,615	$ 40,299	$ 39,276	$ 42,513	$ 44,112	$ 44,112	$ 440,017
Expenses													
ST Labor	$ (7,428)	$ (9,355)	$ (7,507)	$ (10,475)	$ (9,822)	$ (7,249)	$ (9,524)	$ (11,920)	$ (11,079)	$ (9,997)	$ (9,948)	$ (12,171)	$ (116,475)
RNG			$ (67,689)			$ (82,919)			$ (38,688)			$ (45,194)	$ (234,490)
Carbon Offsets			$ (19,022)			$ (22,000)			$ (25,672)			$ (29,856)	$ (96,550)
Contract Labor	$ -	$ -	$ (4,351)	$ (126)	$ (2,200)	$ -	$ (55)	$ -	$ -	$ (7,083)	$ -	$ -	$ (13,815)
Outside Services	$ (16,250)	$ (59,063)	$ (32,725)	$ (79,572)	$ (72,907)	$ (74,130)	$ (75,059)	$ (70,202)	$ (79,805)	$ (55,915)	$ (169,637)	$ (134,300)	$ (919,563)
Dues & Assessments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other	$ 3,000	$ -	$ -	$ -	$ (17,700)	$ (2,245)	$ (2,634)	$ -	$ (55,947)	$ (62,370)	$ 24,491	$ (93,110)	$ (206,515)
Burden	$ (66)	$ (295)	$ (164)	$ (291)	$ (1,438)	$ (371)	$ (376)	$ (351)	$ (399)	$ (2,583)	$ (1,179)	$ (678)	$ (8,189)
Total Expenses	$ (20,744)	$ (68,713)	$ (131,456)	$ (90,463)	$ (104,067)	$ (188,913)	$ (87,648)	$ (82,472)	$ (211,590)	$ (137,948)	$ (156,273)	$ (315,309)	$ (1,595,596)
Program Net Income (Loss)	**$ 3,744**	**$ (45,669)**	**$ (96,033)**	**$ (61,795)**	**$ (71,713)**	**$ (138,801)**	**$ (52,033)**	**$ (42,173)**	**$ (172,314)**	**$ (95,435)**	**$ (112,161)**	**$ (271,197)**	**$ (1,155,579)**

	2022 Total Supply Retirements
Carbon Offsets	11,792 (measured in metric tons per CO2-e)
Renewable Natural Gas	11,264 mcf

DTE

2021 supply retirements: 4,211 mt CO2-e of Carbon Offsets, 4,044 mcf of RNG

Natural Gas Balance met its enrollment target by utilizing marketing funds which are not included in base rates

Customer Outreach - $302,100

- Digital social campaign - $93,000
- Ad creation - $6,000
- Video creation - $58,200
- Emails, bill inserts, direct mail - $144,900

Direct Marketing - $658,500

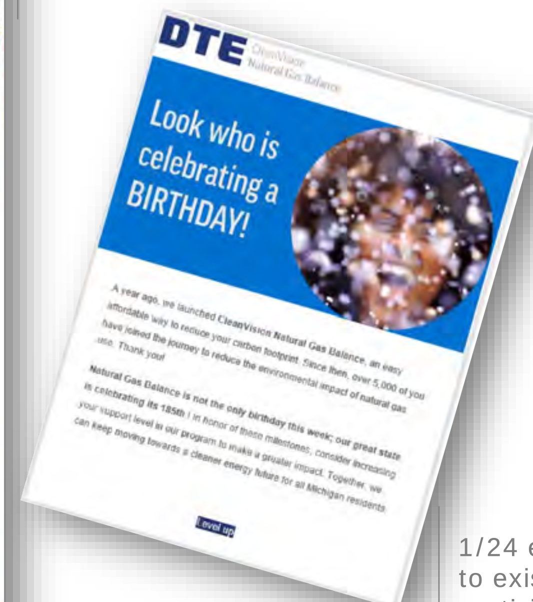
- Direct Outbound Calling Campaigns
  - Direct sales calling - $624,000
  - Inbound call center support -$34,500

Misc. Marketing - $38,400

- Events - $14,800
- Legal - $13,800
- Door knocking - $2,600
- Community Incentive - $7,200

A variety of channels are used to reach our customer base

4/26 Dual promotional email with MIGreenPower/ NGB



1/24 email to existing participants

10/21 Targeted email to Grand Rapids area

A variety of channels are used to reach our customer base

10/29 U of M Tailgate - Dual promotional event with MIGreenPower/ NGB

Print advertisement used for varies sponsorships including Burns Park Players production and X

A variety of channels are used to reach our customer base

Grand Rapids Water Resource Recovery Facility - Renewable Natural Gas Supply Source

Sauk Trail Hills Landfill in Canton – Renewable Natural Gas Supply Source

Greenleaf Project – Carbon Offset Supply Source

Water - [Developing Renewable Natural Gas with Natural Gas Balance | DTE Energy – YouTube]
Landfill - [Turning Methane Into Renewable Natural Gas | DTE Energy – YouTube]
Forest - [Protecting Michigan's Forests With Natural Gas Balance | DTE Energy - YouTube]

While total enrollments were as expected, the average participation level was lower than modeled causing us to seek additional time in the pilot phase

- Plan to file for extension of program pilot (3 years)
- Continue experimenting with marketing and sales tactics
- Evaluate program performance and customer's sentiment, drivers


THANK
YOU!

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-6.3b	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 3. Please refer to Table 10 on page 81 of Witness Decker's direct testimony regarding Smart Savers pilot program and DTE's response to MNSCDG-2.6e.

b. Please provide the gas reduction estimates during the peak hours for each of the five gas events as a percentage of the total gas usage by the program participants during the peak hours. Please recreate Table 10 by adding these percentage peak savings.

Answer: See table below. Percent reduction is based on comparison to calculated baseline.

Date	Event Time	Devices Targeted	Gas Reduction (therms)	Gas Reduction per Device (therms)	Cumulative Event Usage (therms)	Event Avg. Temp	Opt-Out (%)	% Reduction
1/20/2022	5pm-7pm	1,309	509	0.386	(349)	18°	11.2	72%
1/28/2022	6am-8am	1,278	387	0.295	66	13°	10.6	41%
1/30/2023	5pm-7pm	6,138	1,850	0.301	(241)	21°	13.0	50%
1/31/2023	6am-8am	6,138	2,184	0.356	(1,354)	5°	16.4	36%
2/3/2023	6am-8am	6,058	2,120	0.350	(1,983)	8°	15.3	36%

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-2.6e	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 6. Please refer to the following statement regarding DTE Gas's demand response pilot on page 28 of Direct Testimony of Telang, line 20-23: "At the conclusion of the second year of the demand response pilot, DTE Gas reviewed the results and determined the Demand Response program was not effective and determined not to request to extend the pilot or make the program permanent."

e. Please provide all analyses (in Excel format with formulas intact) conducted by DTE Gas or DTE Gas's consultants to assess the effectiveness of the demand response pilot, including the costs of the demand response pilot and the avoided costs of gas commodity and gas infrastructure used for the analysis.

Answer: Please see the attachments referenced below. The Company did not evaluate any avoided commodity or gas infrastructure costs. Additionally, the pilot cost a total of $2.500,658 as detailed in exhibit A-26 of the filing.

Attachment: U-21291 MNSCDG-2.6e 2022-04-08 DTE Gas BDR Season Summary
U-21291 MNSCDG-2.6e 2023-04-18 DTE 2022-2023 Gas BDR Season Summary
U-21291 MNSCDG-2.6e Energy Action Day Calculator 2-4-2022
U-21291 MNSCDG-2.6e Energy Action Day Calculator 1-31-2023
U-21291 MNSCDG-2.6e Energy Action Day Calculation _02.03.2023
U-21291 MNSCDG-2.6e Energyhub Gas DR Event Report – DTE Event 10340 + 10341
U-21291 MNSCDG-2.6e Energyhub Gas DR Event Report – DTE Event 10346 + 10347
U-21291 MNSCDG-2.6e Energyhub Gas DR Event Report – DTE Event 10353 + 10354
U-21291 MNSCDG-2.6e Location 1 and 2 Event Data
U-21291 MNSCDG-2.6e Location 1 Data
U-21291 MNSCDG-2.6e Location 2 Data
U-21291 MNSCDG-2.6e Energy Action Day Calculation 3-3-2022

Winter Demand Response Using Baseboard Heaters: Achieving Substantial Demand Reduction Without Sacrificing Comfort

Michaël Fournier, Marie-Andrée Leduc,
Institut de Recherche d'Hydro-Québec (IREQ-LTE)
Guillaume Nadrault

ABSTRACT

While smart thermostats have been around for a few years for HVAC central systems, their equivalent for the control of electric baseboard heaters have just hit the market and have yet to demonstrate their benefit for winter demand response (DR). This paper describes the use of such thermostats in fully instrumented research houses to study DR strategies for preserving occupants' comfort while providing substantial load reduction.

The first study focusses on the advantage of preheating and setpoint ramping to create an advanced setpoint modulation strategy. This strategy is compared to a simpler step up/down strategy. The advanced setpoint modulation of ±1°C (1.8°F) resulted in significant demand reductions during the morning and afternoon events, though slightly lower than for the simpler 2°C (3.6°F) step down strategy. Based on the ASHRAE Standard 55-2013 local thermal discomfort requirements, the advanced strategy also resulted in more comfortable conditions.

The second study consists of controlling only a fraction of the installed baseboards. The load reductions achieved for several fraction levels are given and insights on the selection of the most appropriate baseboards to control are discussed.

Introduction

Programmable communicating thermostats and smart thermostats for the control of HVAC central systems, in cooling and heating conditions, have been around for a few years. Such thermostats can deliver significant energy savings and allow automated setpoint adjustments to reduce peak demand (York et al. 2015).

Line-Voltage Communicating Thermostats (LVCTs) for electric baseboard heaters, have only recently hit the market (Sinopé 2016, Stelpro 2016). Some, incorporating an energy meter, provide valuable feedback on heating energy use on a per room basis. During winter, they can also contribute to reduce peak demand where baseboard heating is prevalent. They offer an alternative to load control modules which could be used to cycle baseboard heaters. That latter option, used by Puget Sound Energy, proved disappointing since cycled baseboards were found to contribute relatively little to demand reduction (PSE 2012). LVCTs, in replacement of existing wall thermostats, make possible the use of setpoint modulation strategies for baseboard heaters, hopefully leading to more consistent load sheds.

Modern digital line-voltage thermostats make use of proportional control and power electronics allowing multiple switching per minute, resulting in a quasi-continuous modulation of the heating output. Moreover, when in accordance to the energy performance standard CAN/CSA-C828 (CSA 2013), room temperature fluctuations for steady setpoint are less than 0.5°C (0.9°F), which goes unnoticed. Conversely, forced air systems are either on or off over longer periods, commonly controlled according to a temperature deadband to limit the number of on-off cycles and decrease the wear of their mechanical components. Starts and stops can be felt either because of air drafts, sudden temperature change or sound level. Comfort expectations for occupants of baseboard heaters equipped dwellings are thus likely higher than those with forced air systems. Hence, thermal comfort should be a prime concern when implementing DR strategies in homes heated with baseboards.

This paper describes two studies making use of LVCTs in fully instrumented research houses to assess occupants' comfort and demand reduction under setpoint modulation strategies. To our knowledge, no field study of such strategies for load shedding of baseboard heaters has been publicly released.

The first study assesses the advantages of preheating and setpoint ramping to create an advanced setpoint modulation strategy and is discussed in terms of load shed and local thermal discomfort. While step up/down simple strategies could be used, they would not take advantage of the finer control made possible by digital line voltage thermostats. Through simulation, the use of ramps, in place of step increases of setpoint, was previously found to reduce the maximum heating demand (Fournier and Leduc 2014).

The second study investigates the shedding potential occurring when only a fraction of the thermostats are contributive, hence possibly limiting the number of existing thermostats to be replaced with more costly LVCTs. This is made possible since the heating of each room is controlled individually by its own thermostat in a baseboard heater equipped dwelling. For dwellings equipped with HVAC systems, no more than a few thermal zones, hence thermostats, are typically found.

The following section describes the experimental test bench, the methodology as well as the criteria used for comparison. The results are presented and discussed for each study.

Methodology

Description of the test bench

The studies were performed in the "Maisons d'Expérimentation en Énergétique du Bâtiment" (MEEB 2016), located in Shawinigan, Quebec. They consist of twin two-storey detached homes (Figure 1, House #1-H1, House #2-H2) with excavated basements, each with a 60 m^2 (646 ft^2) footprint. The single attached garage is excluded from the tests and analysis. The houses are typical light wood framed constructions with insulation levels that were corresponding to applicable regulation at the time of construction (2011), i.e. wall insulation 3.52 RSI (R-20) and roof insulation 5.28 RSI (R-30). The basements' poured-in-place concrete walls are partly insulated while the exposed slabs are not, which was also common in the marketplace at that time.

Each room is equipped with its own LVCT to control its electric baseboard heater, including rooms in the basement. The thermostats are CAN/CSA-C828 compliant and allow the setpoint to be remotely adjusted by 0.1°C (0.2°F) increments. Heating demand, air temperature and mean radiant temperature for each individual room are measured over 15 minute intervals. Local meteorological data are also gathered at the same sampling rate.

During the tests, there was no occupancy, no mechanical ventilation or other internal loads; only the heating system was active. South and east facing windows were blocked with an aluminum foil to reduce solar gains. The houses are also unfurnished. The care taken in ensuring a high degree of similarity during construction enables simultaneous comparative testing between the two houses; i.e. one house can operate under reference conditions while the other performs the test alternative. As shown on Figure 2, inner doors were closed for both studies, except for those on the main floor between the Kitchen (K), Dining (DR) and Living Room (LR).

Figure 1. MEEB test bench (H1 on left, H2 on right)

The emulated winter DR events correspond to peak periods occurring twice daily between 6 and 9 am and from 4 to 8 pm. This is typical when the outside air temperature (OAT) is low (i.e. below -20°C (-4°F) in the province of Quebec).

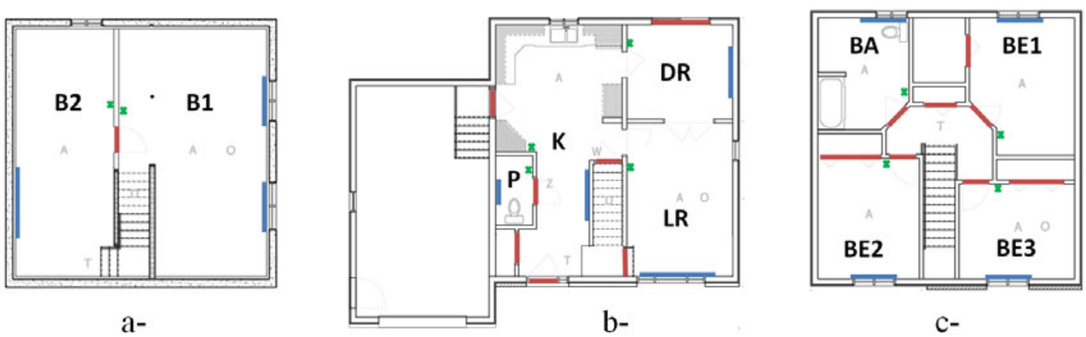


Figure 2. Room layout for a- basement, b- main and c- top floors. Closed doors are shown in red, baseboards heaters in blue and LVCTs locations in green.

Methodology for Study 1

The tested DR strategies consist of lowering the thermostat setpoints from the value that would normally prevail in the targeted rooms (set here at 21°C (69.8°F) for the main and top floor and 19°C (66.2°F) for the basement). In real-life conditions, the original setpoints are chosen by the occupant and therefore are assumed to result in acceptable reference comfort conditions.

For the first study, a simple setpoint reduction strategy is applied to one house while an advanced one is applied to the other. Figure 3 shows the applied setpoint modulation profiles for the main and top floors. The setpoint profiles applied to the basement have the same shape but are offset by 2°C (3.6°F).

In the simple strategy, the setpoint is instantaneously lowered by 2°C (3.6°F) at the beginning of the peak period and brought back to its initial value at the end of the peak period. In the advanced strategy, the setpoint follows a linear ramp starting two hours prior to the peak period to reach 22°C (71.6°F), i.e. 1°C (1.8°F) above the reference. It then remains unchanged for an hour. At the beginning of the peak period, the setpoint is progressively lowered using a linear ramp until halfway through the peak period, to reach 20°C (68°F), i.e. 1°C (1.8°F) below the reference value. At the end of the peak period, the setpoint value is raised over a one-hour period, still using a ramp, up to the reference value. The same strategy is applied for the afternoon event, with the difference that the peak period spans over four hours.

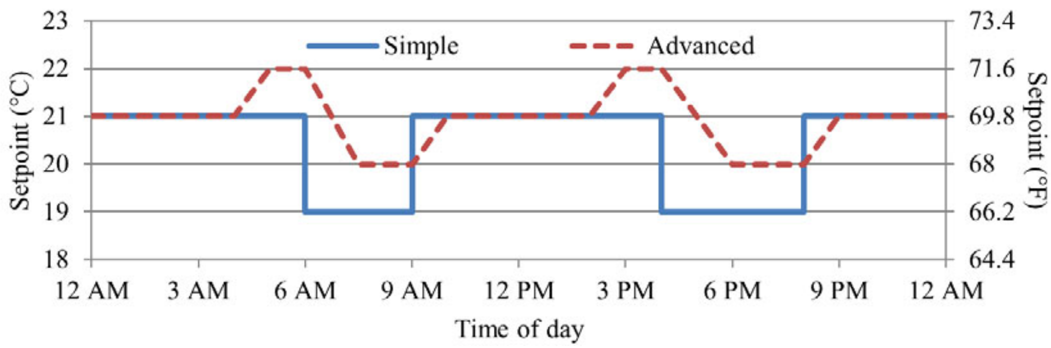


Figure 3. Simple and advanced setpoint modulation profiles for the main and top floors.

Following a stabilisation period for both houses where the reference setpoints are applied, the tests were run over a three day period while alternating which house uses which strategy.

Load shed evaluation. The results are discussed in terms of demand profile impact. The average load sheds during the peak periods are computed from the average demand of each setpoint modulation strategy and the average demand that would have occurred if the reference scenario had been applied. The reference scenario's demand profile is estimated from past measurements.

Comfort evaluation. Thermal comfort is known to be affected by six factors: metabolic rate, clothing insulation, air temperature, radiant temperature, air speed and humidity. ASHRAE Standard 55-2013 (ASHRAE 2013) was used to evaluate the effect of the setpoint modulation on thermal comfort. The Standard is applicable to occupants of residential as well as commercial buildings (ASHRAE 2014) but not to occupants who are sleeping, reclining in contact with bedding or able to adjust blankets or bedding, as might be the case in the early hours of the morning DR event. As previously mentioned, the reference conditions were assumed to be comfortable to the occupants and therefore were not evaluated according to the Standard. Local thermal discomfort requirements that assess differential conditions were evaluated, i.e. vertical air temperature difference and operative temperature drifts and ramps. ASHRAE 55 limits on temperature cycles, ramps and drifts were also used by Zhang, de Dear and Candido (2016) to study the thermal environment resulting from the cycling of an HVAC cooling system in a commercial building, as could occur under a direct load control scheme. These limits were found to be overly conservative in the context of their study.

Based on available measured temperature data points, vertical air temperature difference is computed from measured air temperatures at the center of each room at heights of 0.05 m (2 in.) and 1.8 m (72 in.), which are the nearest measurement points available to the values of 0.1 m (4 in.) and 1.7 m (67 in.) suggested by the Standard for standing occupants. According to the Standard, the difference must not exceed 3°C (5.4°F).

Operative temperature was approximated using the following equation:

$$t_o = \frac{t_a + \overline{t_r}}{2},$$

where t_o is the operative temperature, t_a the average air temperature and $\overline{t_r}$ the mean radiant temperature (from ASHRAE 55-2013, Appendix A Case 3). This approximation is valid because air speed (drafts) is less than 0.2 m/s (40 fpm, no mechanical ventilation), metabolic rates of typical occupants are likely between 1.0 and 1.3 (corresponding to quiet activities like seating), there is no direct sunlight and the difference between mean radiant temperature and the average air temperature (t_a) is less than 4°C (7°F).[1] The average air temperature and the mean radiant temperature ($\overline{t_r}$), measured using a black sphere, are both taken at the center of the rooms at 1.2 m (48 in) from the floor. Requirements for drifts and ramps are qualified for various timeframes; these are explicitly identified in Figure 9.

Methodology for Study 2

The second study looks at the demand impact of partial control within the house. Table 1 lists the controlled rooms for each tested scenario.

Table 1. Scenarios, Study 2

		Scenarios						Area
Rooms		2	3	4*ag*	4*ib*	6	10	[m²(ft²)]
BE1	Bedroom #1			•		•	•	13.3 (143)
BE2	Bedroom #2					•	•	12.3 (132)
BE3	Bedroom #3					•	•	11.1 (119)
K	Kitchen	•	•	•	•	•	•	21.0 (226)
LR	Living room	•	•	•	•	•	•	17.7 (191)
DR	Dining room		•	•	•	•	•	11.1 (119)
BA	Bathroom						•	9.8 (105)
P	Powder room						•	3.1 (33)
B1	Basement #1				•		•	35.9 (386)
B2	Basement #2						•	25.7 (277)
	Total							161 (1 731)

The name of the scenario corresponds to the number of controlled rooms.

The setpoint profile used for controlled rooms is shown in Figure 4; unlike Study 1, it does not include progressive ramps. There are two scenarios controlling four rooms, one including only above ground rooms (4*ag*) and one that includes a portion of the basement (4*ib*). The unmarked rooms operate with a constant setpoint. The morning DR event includes a two hour preheating period while the afternoon does not. On a particular day, one scenario (for example two rooms) is applied to one of the houses while another scenario (for example three rooms) is applied to the other.

[1] This difference was calculated for each room during the test; the maximum difference was found to be 2.8°C (5°F).

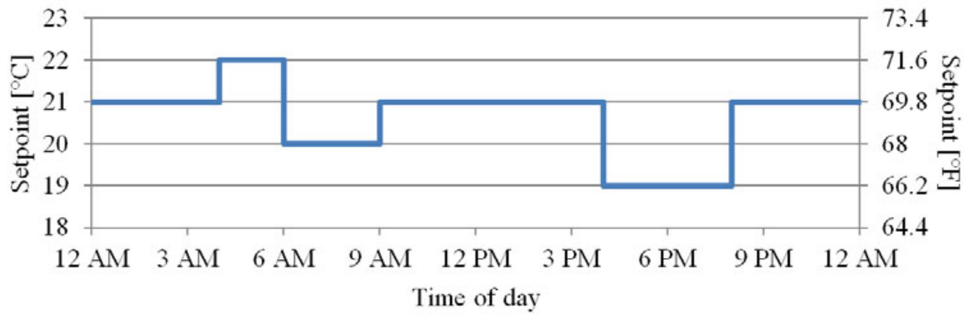


Figure 4. Setpoint modulation profiles used on the main and top floor, Study 2.

Results

Study 1

Load shed results. Similar results were observed for all tests; only the results for January 31st 2015 are presented for brevity. This was the coldest day of the three with OAT ranging from -23.8 to -13°C (-9.4 to 8.6°F). Figure 5 shows the demand profile of each house for that day and the adjusted reference demand profile (constant setpoint) from a day with similar solar radiation. One can see that the simple strategy results in sudden changes in demand. The heating demand vanishes for almost an hour at the beginning of each peak period. The heating demand then progressively resumes in the different rooms as the lowered setpoint is reached. After the peak period, the heating demand rebounds (11.6 vs 4 kW). This could be managed at the distribution level in order to avoid creating a new grid peak, for example by spreading the end time of peak periods across the population (randomization). Periods of high heating demand, however, correspond to undesirable local thermal discomfort conditions as will be discussed below.

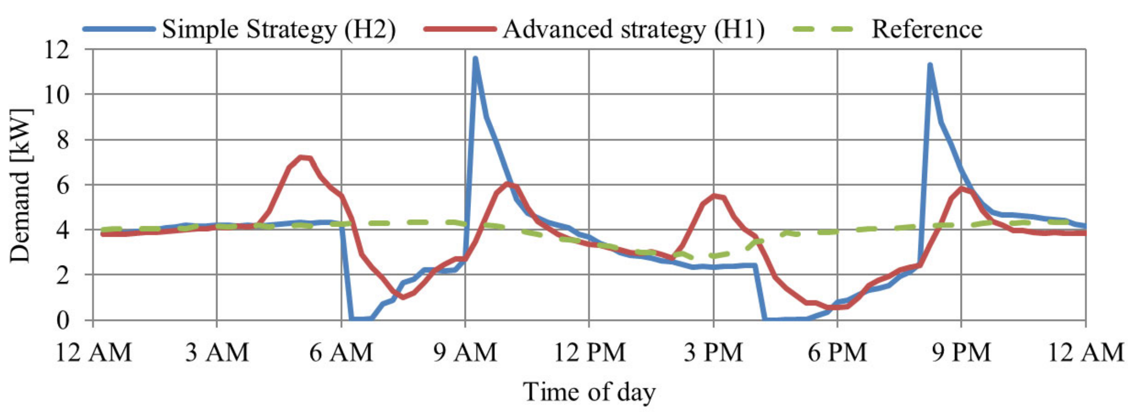


Figure 5. Houses demand profiles on January 31st, Study 1.

The advanced strategy shows a much smoother demand profile. The demand increase caused by the preheating is clearly visible but peaks about an hour ahead of the peak periods. The demand then decreases progressively to reach a minimum midway through the peak period, where the chances of occurrence of the grid fine peak are the highest. From that moment and until the end of the peak period, the demand level is comparable to the simple strategy. The demand then progressively rises until an hour after the end of the peak period.

Table 2 gives the average load shed over the peak periods for each strategy in comparison to the reference demand profile. The advanced strategy has a smaller average load shed, by 20 to 27%. This comes from the instantaneous drop in demand in the simple strategy at the beginning of the peak period. Shifting the setpoint profile of the advanced strategy by 15 minutes earlier would increase its average load shed but it would still not equal that of the simple strategy.

Table 2. Average load shed, Study 1

	AM peak period [kW]	PM peak period [kW]
H1 - Advanced	2.1	2.4
H2 - Simple	2.9	3.0
Difference	0.8 (27 %)	0.6 (20 %)

Comfort results. First, vertical air temperature differences were evaluated. For most rooms, the advanced strategy shows values well below the requirement, even during the preheating period. This is observed in Figure 6 which illustrates the conditions in Bedroom#1. Stratification closely follows the evolution of setpoint modulation trajectory. The sudden heating demand generated by the instantaneous setpoint increase creates a high vertical air temperature differential due to the convection air jet from the electric baseboard. The ramping of setpoints lowers this differential because the effective heat output is reduced resulting in an altered convection pattern.

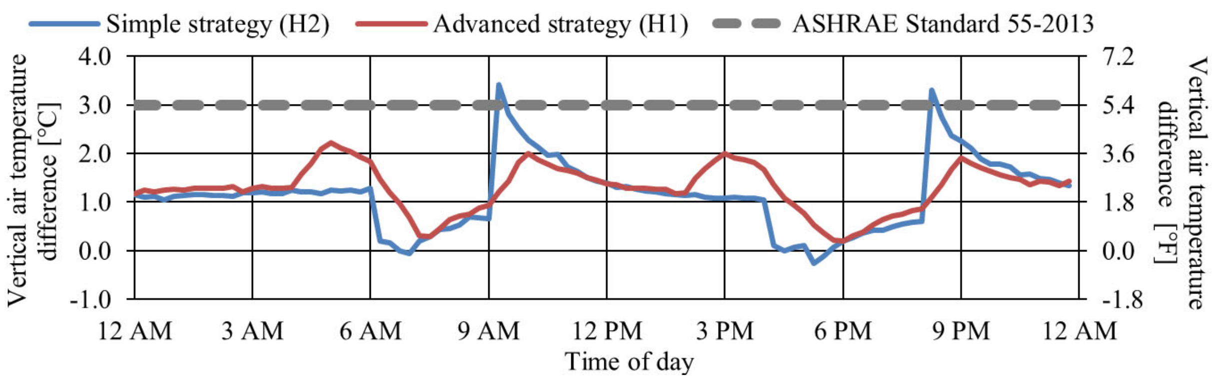


Figure 6: Vertical air temperature difference for advanced and simple strategies, Bedroom#1, Study 1.

Figure 7 illustrates the impact of the advanced strategy in Basement#1. The benefits are not as obvious for this room, which has thermal characteristics differing from the rooms above ground. Its surface area is also greater than that of the other rooms.

Based on these observations, the application of the simple strategy leads to a greater vertical air temperature gradient in above ground rooms, especially following the peak periods. This gradient is a potential source of discomfort for occupants.

Temperature drifts and ramps were also studied for the following periods: preheating, peak periods and two hours after the peak periods. Figure 8 shows operative temperature changes of Bedroom #1, for the various timeframes considered by the Standard (0.25 h, 0.5 h, 1 h, 2 h and 4 h). The simple strategy exceeds the 0.25 h and 0.5 h requirement limits almost systematically. This conclusion holds for all rooms, though it is not as important in the Kitchen where the requirement is exceeded only during the two hour period following the afternoon peak.

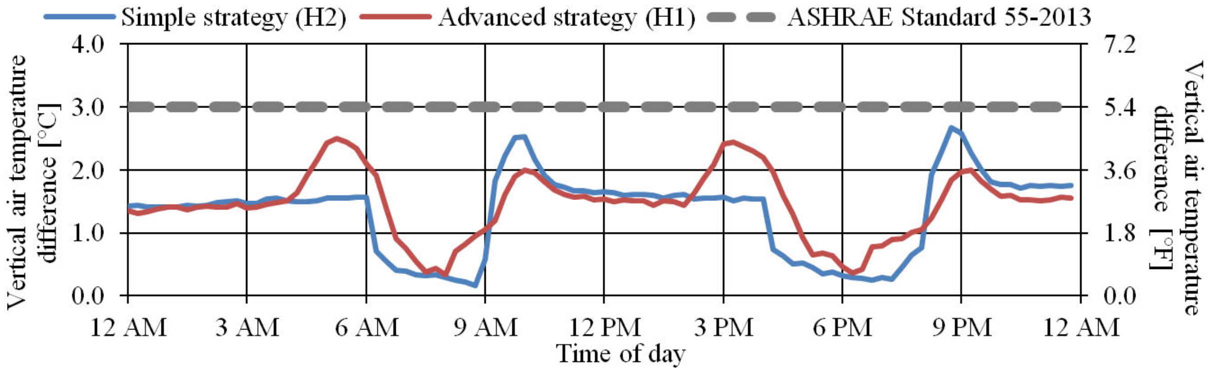


Figure 7. Vertical air temperature difference for advanced and simple strategies, Basement#1, Study 1.

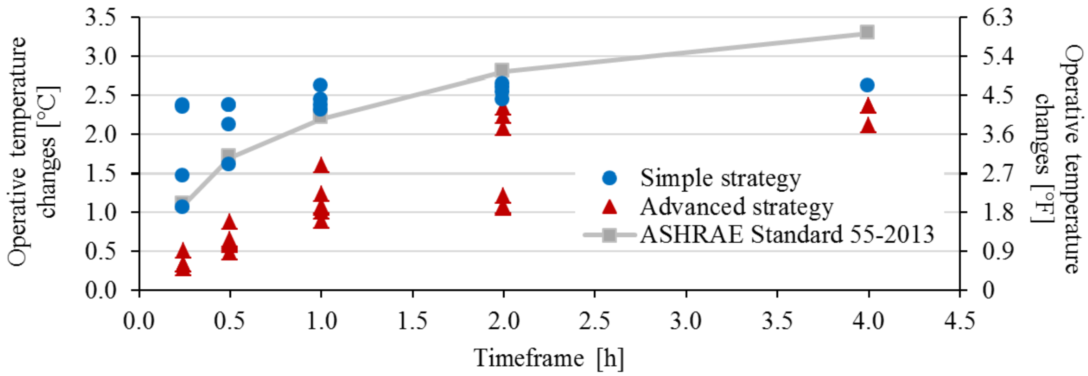


Figure 8. Operative temperature drifts and ramps, Bedroom#1, Study 1.

Overall, it appears that the simple strategy often fails to respect the Standard for both requirements. Therefore, in terms of local thermal discomfort, it seems clear that the advanced strategy would most likely generate less discomfort before, during and after DR events. Furthermore, the air temperature varies by only 1°C (1.8°F) relative to the original setpoint compared to 2°C (3.6°F) for the simple strategy. The smaller excursion from the user-selected reference setpoint would inevitably be more comfortable to the occupants.

Study 2

When comparing the impact of controlling two or three rooms, it was found to differ according to which house operated which scenario. Upon closer inspection, we found that when the main floor interior doors are open, the Kitchen baseboard of H2 often delivered more heat than H1, even if the differences in air temperatures, measured at the center of each rooms of the main floor are within measurement error. Under such conditions, the daily main floor total heating energies are still the same for both houses. This difference in the distribution of the heating source across the main floor rooms is not observed when the interior doors are closed. This suggests a convective heat flow from the Kitchen (master) to the Dining room and Living room (slaves) when the doors are left open.

In a relatively open floor plan, the impact of controlling or not a specific room depends heavily on its status (master or slave) when involved in such a dependency relationship. The control of a master room would result in a larger than expected demand impact if preheating is performed as it would also store energy in adjacent rooms. In the case of a slave room, the heating load is partially satisfied by a master room, and thus has a lower heating demand. Its control would therefore result in a lesser load shed than expected for a self-relying room. The presence of a master-slave relationship and the status held by each room, are hardly predictable as illustrated by the case of the MEEB which were built identical but still show different behaviors on the main floor. When deploying LCVTs for DR, it is therefore advisable to install and control all the thermostats of an open area space in order to eliminate the chance of relying on the control of a slave room.

The results of controlling three or more rooms are not biased from the discrepancies observed on the main floor because the interior doors of the other floors were closed and all thermostats from the main floor open area space were always controlled for these scenarios. Table 3 gives the observed load shed for the morning peak period according to the number of controlled rooms. Only the morning events are presented as those for the afternoon are highly influenced by solar radiation variations, which are difficult to rule out from one day to another. OAT ranged from -30 to -12°C (-22 to 10°F) during the morning peak periods. Up to 61% of the house total heating demand was shed over the three hour morning peak period using only ±1°C modulation around the comfort setpoint.

Table 3. Morning load shed according to the number of controlled rooms

Dates	Scenarios	Fraction of controlled area	Load shed [kW]	Reference heating demand [kW]	Heating demand shed
2015-02-03 2015-01-02 & 06	3	0.31	0.5- 0.8	3.2-4.7	13-17%
2014-12-31 2015-01-06	4ag	0.39	0.8-0.9	4.3-4.8	20%
2015-02-02	4ib	0.53	1.6	4.7	34%
2015-02-03 & 04 2015-01-02 & 03	6	0.54	1.1-1.7	3.1-4.7	23-39%
2015-01-03 2015-02-04	10	1.00	2.6	4.3-4.5	57-61%

Figure 9 suggests a linear relationship between the house total heating demand shed, expressed as a proportion of the reference heating demand, and the fraction of controlled area. No sign of saturation is visible with this independent variable.

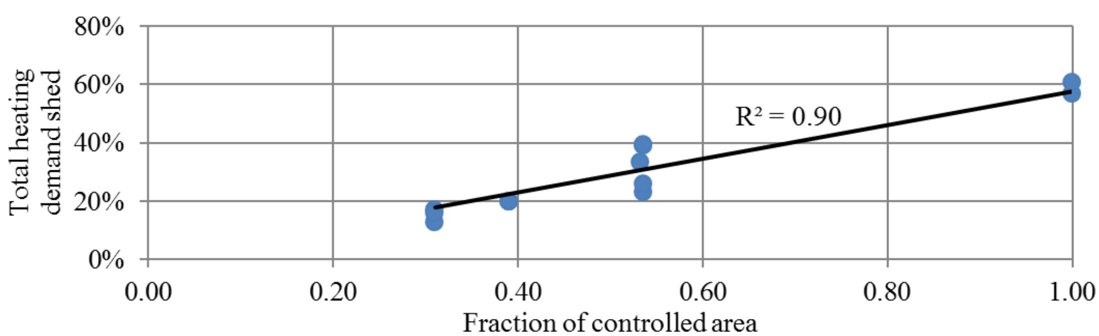


Figure 9. Total heating demand shed according to the fraction of area under control, Study 2

From the available test results, it was also possible to directly compare load sheds resulting from the control of a basement thermostat versus one on the top floor. Figure 10 shows the heating demand profiles of Bedroom#1 and Basement#1 for January 1st 2015. On that day, scenario 4*ig* was run on H1 while scenario 4*ag* was run on H2. The setpoint modulation was applied to the main floor of both houses and to an additional zone (Basement #1 for H1 or Bedroom #1 for H2). OAT was warmer on that day, averaging -7.5°C (18.5°F) which is why it was not included in Table 4. The heating demand of Bedroom #1 is slightly more than half that of Basement #1. The heating dynamic is also quite different during peak periods. While the heating resumes at 7:15 am and 5:45 pm for Bedroom#1, it delays until 8 am and the end of the afternoon peak period. This tends to show that in-ground rooms could sustain longer without heating during setback periods than those above ground. The higher thermal mass, and possibly lesser air infiltration compared to the upper floor, are likely explanations for this dissimilarity.

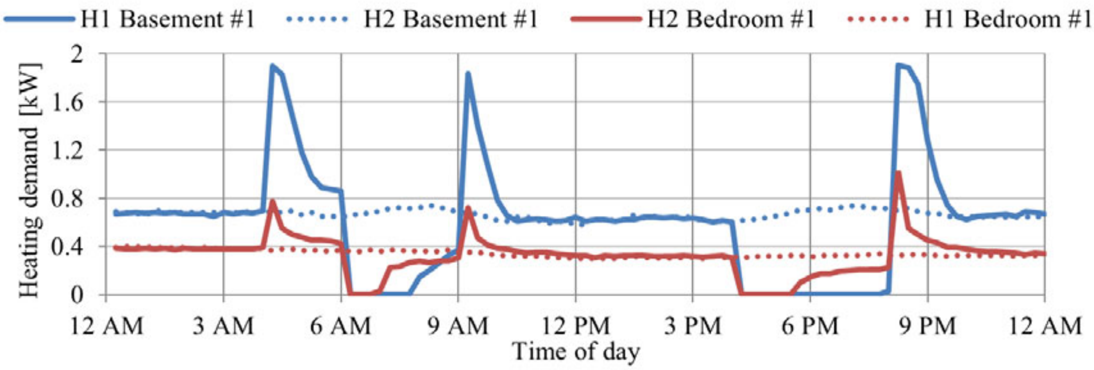


Figure 10. Heating demand profile for Bedroom #1 and Basement #1, January 1st 2015, Study 2

Table 4 presents the load sheds of both rooms during peak periods for both events of January 1st 2015. As shown in Figure 4, setpoint modulation strategies differed for the morning and afternoon events. As expected, load sheds are higher for Basement #1 than for Bedroom #1, even when expressed in terms of specific load shed. The relative basement advantage ranges from 18 to 21%. At the whole-house level, the basement advantage could be less as it is presumed that the main floor heating demand should increase to compensate the reduced incoming heat flow from the basement.

Table 4. Load shed comparison between a top floor room and a basement room

Event	Load shed		Specific load shed		Basement advantage
	Basement #1	Bedroom #1	Basement #1	Bedroom #1	
AM	0.6 kW	0.2 kW	17 W/m²	14 W/m²	21 %
PM	0.7 kW	0.2 kW	19 W/m²	16 W/m²	18 %

This second study has shown a direct relationship between the load shed and the area under control. This suggests that when deploying LVCTs for DR and only a fraction of the thermostats are to be replaced, prioritizing the rooms with the largest area should yield the most load shed. More shedding may also be expected by controlling an equivalent area of basement space to upper floor space, at least for the tested construction type, and if the basement is kept at or near comfort temperatures.

Conclusion

Setpoint modulation strategies of electric baseboard heating were applied in research experimentation houses to study their impact for winter demand response. These houses were unfurnished and unoccupied, solar gains were reduced and there were no other loads than space heating. The basement was partially finished. Generalisation of the results should therefore be performed with care. For example, the presence of internal heat gain could lower the absolute load shed as the overall heating demand would be reduced. The experimental setup allowed the detailed comparison of DR strategies but a real life pilot would better estimate shedding levels achievable upon DR program deployment.

Nonetheless, an advanced strategy, making use of ramps and preheating, resulted in average load shed of more than 2 kW per house using only a ±1°C (1.8°F) setpoint modulation. This was about 25% less than with a simple strategy (2°C (3.6°F) step down). The advanced strategy, however, resulted in increased comfort as demonstrated by the analysis of the local thermal discomfort requirements of the ASHRAE Standard 55-2013. It was shown to reduce the vertical air temperature gradients compared to the simple strategy because of lower effective heat output from the electric baseboards. The setpoint modulation of the advanced strategy also reduces operative temperature changes (drifts and ramps) hence lowering discomfort perceived by occupants as a result of the DR strategy. It should be noted that the simple strategy often exceeded limits of the Standard for both requirements. In this study, the advanced strategy was applied to rooms originally operating at constant setpoints. Alternate versions of the advanced strategy could be developed for thermostats operating nighttime setbacks or both daytime and nighttime setbacks, as was presented in Fournier and Leduc (2014).

The second study showed evidence of a convective heat transfer between rooms of the main floor when interior doors are open. This is hardly predictable and could significantly impact the load shed when only a fraction of the rooms are under control. It was also found that the total load shedding level versus the fraction of the house area under control showed no sign of saturation. Up to 61% of the house total heating demand was shed for a three hour morning event using only ±1°C (1.8°F) step changes around the reference temperature setpoint. Finally, the control of basement rooms resulted in higher specific load shed (per unit area) than the control of a top floor room.

If only part of the house thermostats were to be controlled for DR, the selection of the rooms with the largest heating demand should result in the best shedding level per thermostat. However, individual room heating demand is not typically known before the installation of LVCT. In such a case, and based on the above results, it seems advisable to:

- install and control LVCT in all rooms of an open area space in order to eliminate the chance of relying on the control of a slave room;
- prioritize the rooms with the largest area first;
- favour basement space over equivalent top floor space if the basement is kept at or near comfort setpoint, i.e. is used as a living space.

Other factors, such as convective heat flow between floors (through staircases, for example), may also modify the load shed when a fraction of the rooms are under control but these aspects were not investigated.

Though derived from observations made in specific conditions, taking into account these recommendations in the design of a real life pilot should improve chances of recording substantial DR load sheds. Such a pilot could also bring insights on occupant satisfaction with the use of LVCTs for DR. Perceived comfort and ease of installation and use could be evaluated. Finally, LVCTs could be adapted to natively perform ramps to alleviate discomfort associated with setpoint changes, during both application of DR events and normal operation.

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MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.5ai	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 5. Has DTE conducted a cost-benefit analysis to determine the cost-effectiveness of:

a. The Gas Renewal Program (GRP)?

i. If so, please provide all workpapers with formulas intact and sources, methodologies, and assumptions clearly stated.

Answer: No.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.5bi	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 5. Has DTE conducted a cost-benefit analysis to determine the cost-effectiveness of:

b. The Meter-Move-Out program (MMO)?

i. If so, please provide all workpapers with formulas intact and sources, methodologies, and assumptions clearly stated.

Answer: No.

Attachment: None.

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.5ci	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 5. Has DTE conducted a cost-benefit analysis to determine the cost-effectiveness of:

c. The Pipeline Integrity (PI) program?

i. If so, please provide all workpapers with formulas intact and sources, methodologies, and assumptions clearly stated.

Answer: No.

Attachment: None.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority.	U-21291

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony and Exhibits of Alice Napoleon on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club** was served on the following:

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The statements above are true to the best of my knowledge, information, and belief.

TROPOSPHERE LEGAL, PLC
Counsel for MEC, NRDC, & SC

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