BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Electric Power Company and Wisconsin as LLC for a Certificate of Authority under Wis. Stat. § 196.49 and Wis. Admin. Code § PSC 133.03 to Construct a System of New Liquified Natural Gas Facilities and Associated Natural Gas Pipelines near Ixonia and Bluff Creek, Wisconsin	Docket No. 5-CG-106

DIRECT TESTIMONY OF ASA S. HOPKINS
ON BEHALF OF
SIERRA CLUB

I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address, and position.

A My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139. I am a Vice President at Synapse Energy Economics, Inc.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q **Please describe your education and professional experience before beginning your current position at Synapse Energy Economics.**

A Before joining Synapse Energy Economics in 2017, I was the Director of Energy Policy and Planning at the Vermont Public Service Department from 2011 to 2016. In that role, I was the director of regulated utility planning for the state's public advocate office, and the director of the state energy office. I served on the Board of Directors of the National Association of State Energy Officials. Prior to my work in Vermont, I was an AAAS Science and Technology Policy Fellow at the U.S. Department of Energy, where I worked in the Office of the Undersecretary for Science to develop the first DOE Quadrennial Technology Review. Prior to my time at the U.S. DOE, I was a postdoctoral fellow at Lawrence Berkeley National Laboratory, working on appliance energy efficiency standards. I earned my PhD and Master's degrees in Physics from the California Institute of Technology and my Bachelor of Science degree in physics from Haverford College. My resume is attached as Ex.-SC-Hopkins-1.

Q **On whose behalf are you testifying in this case?**

A I am testifying on behalf of the Sierra Club.

Q **Have you testified previously before the Public Service Commission of Wisconsin?**

A No, I have not.

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

A The purpose of my testimony is to evaluate whether the proposed facilities are needed, (1) relative to the needed fossil fuel reductions required to meet state and federal goals for mitigating global climate change; and (2) in light of more reasonable load projections and the potential for cost-effective demand-side alternatives.

Q How is your testimony organized?

A I begin with a summary of my conclusions and recommendations in Section II. In Section III, I address the need for the proposed facilities in light of necessary reductions in natural gas use in order to meet state and federal policy objectives regarding climate change. In Section IV, I critique the load forecast provided by Wisconsin Electric Power Company and Wisconsin Gas (together "the Utilities"). In Section V, I demonstrate that a set of demand-side actions that could avoid or defer the need to build the proposed facilities at a lower cost and that the Utilities should have seriously considered such an alternative. In Section VI, I address the risk that the proposed facilities will become stranded before the end of their useful lives. In Section VII, I address physical limits to the proposed facilities that limit their value compared to demand-side approaches.

Q Are you sponsoring any exhibits to your testimony?

A Yes. I am sponsoring 31 exhibits:

- Ex.-SC-Hopkins-1 is my resume.
- Ex.-SC-Hopkins-2 is two web pages from the United States Climate Alliance, describing that organization and showing Governor Evers's membership.
- Ex.-SC-Hopkins-3 is Governor Evers's Executive Order #38.
- Ex.-SC-Hopkins-4 is an excerpt of the Paris Agreement, of the United Nations Framework on Climate Change containing the preamble and Articles 1 through 3. The full text is available at https://unfccc.int/sites/default/files/english_paris_agreement.pdf.
- Ex.-SC-Hopkins-5 is an excerpt of the Intergovernmental Panel on Climate Change special report on *Global Warming of 1.5ºC*. The full text

is available at https://www.ipcc.ch/site/assets/uploads/sites/2/2019/06/SR15_Full_Report_High_Res.pdf.

- Ex.-SC-Hopkins-6 is the White House fact sheet on the current United States commitments under the Paris Agreement.

- Ex.-SC-Hopkins-7 is the press release from the White House in 2015 with the initial United States commitments under the Paris Agreement.

- Ex.-SC-Hopkins-8 is a paper published by the University of Maryland School of Public Policy entitled *Charting an Ambitious U.S. NDC of 51% Reductions by 2030*.

- Ex.-SC-Hopkins-9 is a report published by Princeton University entitled *Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report*.

- Ex.-SC-Hopkins-10 contains the data plotted in Figure 1, which are sourced from the supporting material for Ex.-SC-Hopkins-9.

- Ex.-SC-Hopkins-11 is a report by the International Energy Agency entitled *Net Zero by 2050: A Roadmap for the Global Energy Sector*.

- Ex.-SC-Hopkins-12 is an excerpt from data Annex A to the IEA report in Ex.-SC-Hopkins-11. The full spreadsheet is available at https://iea.blob.core.windows.net/assets/6c7ed6ac-a71d-4de1-88ee-2549441d07c5/NZE2021_AnnexA.xlsx.

- Ex.-SC-Hopkins-13 contains a pair of news articles about Foxconn.

- Ex.-SC-Hopkins-14p and Ex.-SC-Hopkins-14c contain analysis of commercial and industrial loads.

- Ex.-SC-Hopkins-15 is a petition by Consolidated Edison Company of New York ("ConEd") to the New York Public Service Commission regarding the Smart Solutions for Natural Gas Customers Program.

- Ex.-SC-Hopkins-16 is WEC Energy Group's *Pathway to a Cleaner Energy Future 2021 Climate Report*.

- Ex.-SC-Hopkins-17 is a press release from the State of New York regarding the Westchester Clean Energy Action Plan.

- Ex.-SC-Hopkins-18 is the *Focus on Energy 2016 Energy Efficiency Potential Study* and its Appendix D.

- Ex.-SC-Hopkins-19 is a presentation entitled *Energy Efficiency Potential Study: Draft Results Meeting* of April 29, 2021, related to the ongoing energy efficiency potential study for Focus on Energy.

- Ex.-SC-Hopkins-20 is a report published by the Rocky Mountain Institute entitled *The Economics of Electrifying Buildings: How Electric Space and Water Heating Supports Decarbonization of Residential Buildings*.

- Ex.-SC-Hopkins-21 contains data from a National Grid (Brooklyn Gas) rate filing regarding sales to different rate classes, including "temperature-controlled" rates.

- Ex.-SC-Hopkins-22p and Ex.-SC-Hopkins-22c contain analyses of the illustrative temperature-controlled rate I discuss in my testimony.

- Ex.-SC-Hopkins-23 is a report from ConEd entitled *Updated Gas Demand Response Report on Pilot Performance – 2019/2020*.

- Ex.-SC-Hopkins-24 is a report from the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government entitled

Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990.

- Ex.-SC-Hopkins-25 is an article by Averch and Johnson entitled "Behavior of the Firm Under Regulatory Constraint." which was published in *The American Economic Review*, vol. 52, no. 5, 1962, pp. 1052–1069.

- Ex.-SC-Hopkins-26c and Ex.-SC-Hopkins-26p are the attachment to the Utilities' response to data request 2-Sierra Club-9.

- Ex.-SC-Hopkins-27 is the Utilities' response to data request 2-Sierra Club-13 (without its attachments).

- Ex.-SC-Hopkins-28 is the Utilities' response to data request 2-Sierra Club-6.

- Ex.-SC-Hopkins-29c and Ex.-SC-Hopkins-29p are one sheet from the attachment to the Utilities' response to 2-Sierra Club-4.

- Ex.-SC-Hopkins-30 is the Utilities' response to data request 2-WIEG-7.

- Ex.SC-Hopkins-31 is the U.S. Environmental Protection Agency's May 26, 2021, comments to the Federal Energy Regulatory Commission in Docket No. PL18-1-000.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your primary conclusions.

A My primary conclusions are summarized as follows:

1) The claim by the Utilities that the new liquified natural gas ("LNG") facilities and associated natural gas pipelines near Ixonia and Bluff Creek, Wisconsin (the "Proposed Facilities") are well suited to meet the Utilities' capacity needs is inconsistent with Wisconsin and federal policy regarding greenhouse gas ("GHG") emission mitigation.

2) The Utilities overstate the near-term peak load growth due to overcounting commercial and industrial ("C&I") load. This is particularly acute for Wisconsin Electric Power Company – Gas Operations ("WEGO").

3) The Utilities failed to meaningfully consider demand-side alternatives. The Utilities' "low growth" case is not a sufficient analogue to a case where demand-side resources are actually designed and implemented to defer or avoid the need for capital investment. A demand-side approach provides a lower cost alternative to achieve reliable service, while also providing additional benefits that the Proposed Facilities do not: reducing energy burden, reducing emissions, advancing state and federal climate and energy policy, and improving health and comfort.

   Demand-side action to defer the construction of the Proposed Facilities also preserves the valuable option, referred to here as "optionality," to change or cancel the project as events, customer characteristics, technology, and policy changes occur. These conclusions are especially strong for WEGO, which has a smaller capacity gap than Wisconsin Gas and for which the illustrative demand-side alternative could meet the capacity need within just a few years.

4) The Proposed Facilities will likely become stranded assets before the end of their useful engineering or accounting lives, especially if Wisconsin and the United States take actions consistent with a lower carbon future.

5) The Proposed Facilities have physical limitations due to their limited storage capacity that reduce their value compared with demand-side alternatives.

Q Please summarize your primary recommendations.

A I recommend that the Commission:

1) Require the Utilities to revise the planning for winter peak capacity to be consistent with emission reductions aligned with state and federal GHG emission reduction policy;

2) Require the Utilities to revise near-term commercial and industrial load forecasts to reflect the best available current knowledge regarding load growth and to eliminate double-counting;

3) Require the Utilities to demonstrate that a portfolio of demand-side alternatives sufficient to delay or avoid the Proposed Facilities is not technically feasible or cost-effective, as required by Wis. Stats. §196.025(1) and Wis. Stats. §1.12(4);

4) Require the Utilities to include the value of optionality in the comparison of different alternatives to meet the potential capacity gap;

5) Deny a Certificate of Authority for the Proposed Facilities unless and until the Utilities demonstrate that the Proposed Facilities are preferable to the demand-side alternatives; and

6) Require the Utilities to evaluate the risk that the Proposed Facilities become stranded and take appropriate actions to mitigate risk to Wisconsin ratepayers and the Utilities' shareholders that the facilities might become standard assets, such as shorter book lives (depreciation schedules) and a condition on any Certificate of Authority precluding the Utilities from recovering or earning a return on any costs of the Facilities that become stranded.

III. NEED FOR THE PROPOSED FACILITIES

Q Please summarize the Utilities' case that the Proposed Facilities are needed.

A The Utilities claim that they require more firm capacity and deliverability within the next 10 years than they currently have under contract or can reasonably expect to secure on existing pipelines. As Mr. Gerlikowski testifies, the Utilities' analysis shows a shortfall in winter peak day capacity of "approximately [redacted] in the winter of 2023-24 up to approximately [redacted] in the winter of 2028-29 under the base growth scenario" (Direct-WEGO WG-Gerlikowski-4c). Mr. Gerlikowski further states that the Proposed Facilities would meet this need and be a better solution than the [redacted] alternatives they examined (Direct-WEGO WG-Gerlikowski-10c).

Q Did the Utilities consider alternatives?

A Yes. But only [redacted] alternatives.

Q Do you agree with the Utilities' characterization of the need for the Proposed Facilities?

A No. I disagree with the Utilities on two points. First, the claimed need is predicated on the idea that load will continue to grow steadily into the future; this is inconsistent with greenhouse gas reductions Wisconsin and the federal government have committed to. Second, the methodology for projecting additional commercial and industrial loads double-counts those loads and includes direct and induced growth from facilities that are unlikely to materialize as assumed. (I address this second point in Section IV.)

Q Why do you say that the Utilities' case for the Proposed Facilities is based on the idea that load will continue to grow steadily into the future?

A The Utilities' peak load forecast assumes that the future is a continuation of the past, without change in trends or disruption. Simply speaking, they project that there will be customer growth, and that new customers will increase peak demand. The rate of increase is moderated somewhat by assumed increases in efficiency that lower the use by existing and new customers and thereby the level of peak load growth relative to the rate of customer growth. However, even with that small moderation, gas use increases indefinitely in the Utilities' projections.

The Utilities' projections assume no substantial policy changes occur over the next decade to address climate change, and not substantial changes in the technology used by customers. According to Mr. Gerlikowski, "there are not any structural changes that would warrant a meaningful reduction in future forecasts versus the historical growth trends" (Direct-WEGO WG-Gerlikowski-5p). In response to a data request, he further elaborates that there is a "lack of evidence that the trend in end users' preference for natural gas would reasonably be subject to a material disruption" (Ex.-SC-Hopkins-28). He allows for only small potential downside risk on load growth by pointing to the "low growth" scenario, which projects [redacted] percent per year growth instead of the [redacted] percent per year growth used in the base case. Even in the "low growth" scenario, load continues to grow continuously into the future.

Q How do greenhouse gas constraints impact the need for these Proposed Facilities?

A Continued growth in gas demand, even at a reduced level (i.e., the "low growth" scenario), is inconsistent with meeting state and national GHG emission reduction targets. The Utilities' load forecast assumes increasing, rather than decreasing emissions from the gas sector. That is inconsistent with all reasonable estimates of the action required to meet state and federal emission reduction targets. The baseline load projections used to evaluate the need for the Proposed Facilities should be consistent with a trajectory that meets state and federal policy.

Q Please describe the greenhouse gas emission reduction targets you refer to.

A The United States is a party to the Paris Agreement, which sets specific goals for climate change mitigation. Additionally, Governor Evers separately committed the State of Wisconsin to the Paris Agreement: the state is a member of the U.S. Climate Alliance (a bipartisan coalition of 25 governors committed to implementing policies that advance the goals of the Paris Agreement (Ex.-SC-Hopkins-2)) and he issued Executive Order #38 on August 16, 2019, which charges the Wisconsin Office of Sustainability and Clean Energy with ensuring Wisconsin is reducing emissions in line with the Paris Agreement. (Ex.-SC-Hopkins-3)

The Paris Agreement commits its signatories to strive to keep global warming well below 2 degrees Celsius above pre-industrial levels, and preferably to 1.5 degrees. (Ex.-SC-Hopkins-4) The Intergovernmental Panel on Climate Change ("IPCC") studied the emission reductions necessary to meet the 1.5-degree goal and concluded that global net anthropogenic CO_2 emissions reductions of about 45 percent below 2010 levels by 2030 and net zero by around 2050 are required. (Ex.-SC-Hopkins-5) President Biden subsequently established the formal goal of the United States to reduce emissions 50 to 52 percent below 2005 levels by 2030 as part of the country's Paris Agreement commitment. (Ex.-SC-Hopkins-6) The current goal represents a substantially more ambitious commitment than the United States' previous commitment of a 26 to 28 percent reduction by 2025. (Ex.-SC-Hopkins-7)

Q Have the Utilities or their affiliated companies acknowledged the need to plan for meeting climate policy commitments?

A Yes. WEC Energy Group's "Pathways to a Cleaner Energy Future 2021 Climate Report" (Ex.-SC-Hopkins-16) states that "Our intermediate- and longer-term GHG emissions reduction goals are consistent with national and international climate policy commitments to date, while recognizing uncertainties inherent in long-term planning." (page 24) This report also states that "We see the potential for economywide emissions reduction through electrification, which our electric companies could help facilitate." (page 3) Regarding buildings in particular, WEC Energy Group states that "Continued electrification of space and water heating may also play a role in reducing the emissions from natural gas use." (page 17)

They further identify as a corporate risk that “End-use efficiency, decarbonizing supply and electrification could impact the economics of our natural gas distribution and storage businesses.” (page 20) One of the insights that this report cites from an earlier scenario analysis is that “Strategic electrification could also play a role in reducing emissions from space- and water-heating in buildings.” (page 21) WEC Energy Group’s senior leaders are aware of and claim to be tracking policy action on decarbonization and electrification at the state and federal level. (page 23)

Q Would structural changes that reduce future load forecasts be required to meet the state and national GHG targets?

A Yes. The Utilities’ contention that there are no foreseeable structural changes warranting a meaningful reduction in gas use is irreconcilable with the reductions required to meet the Paris Agreement and, by extension, Governor Evers’s policies. The projected need for the Project advanced in this case means the Utilities are either ignoring the emission reductions required or are disregarding the Governor’s commitment.

Q What reduction in natural gas use in buildings is required to meet the Paris Agreement and Governor Evers’s emission reduction targets?

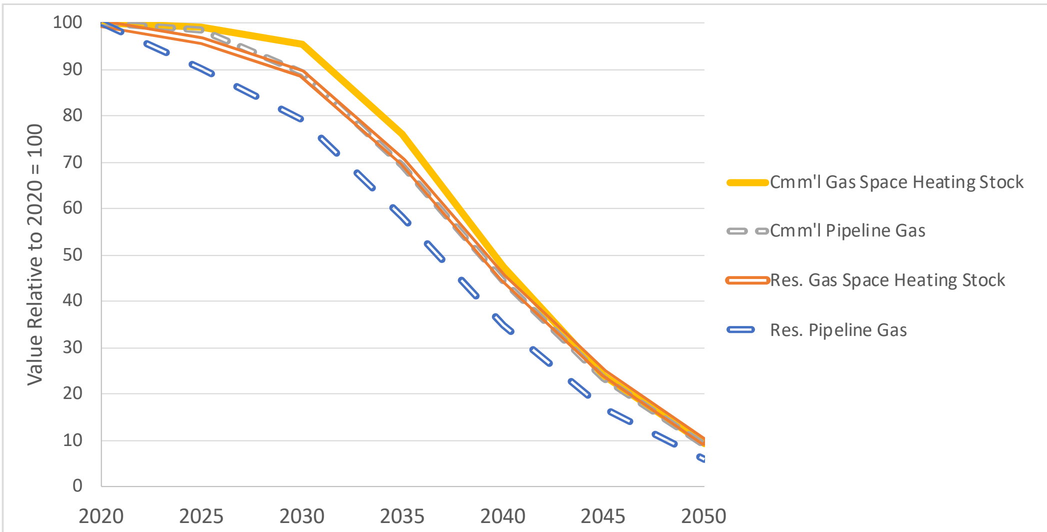
A If Wisconsin is to meet the emission reductions necessary to track the Paris Agreement, natural gas use in buildings must decline consistently and dramatically. Three separate independent analyses support this conclusion: from the University of Maryland, from Princeton University, and from the International Energy Agency (“IEA”).

1. A recent analysis by Center for Global Sustainability at the University of Maryland concludes that to achieve a 51 percent reduction by 2030 across the United States, as part of a comprehensive set of actions across all sectors, carbon dioxide emissions from buildings must decline by more than 17 percent from 2019 levels. (Ex.-SC-Hopkins-8.) While that analysis projects

lower emission reductions by 2030 from buildings than from other sectors, this sectoral difference reflects the long timescale of change in building systems while putting emission reductions on track for more ambitious targets in 2050. In this analysis, the initial reduction by 2030 occurs from a combination of electrification (for new equipment) and building envelope energy efficiency; this approach avoids the lock-in of emitting systems with long lifetimes that would make 2050 goals more difficult and expensive to achieve.

2. The Net-Zero America study from Princeton University describes five technology pathways for achieving net zero GHG emissions from the United States by 2050. (See Ex.-SC-Hopkins-9.) Four of the pathways include nearly full electrification of transport and buildings, while one pathway ("Less High Electrification") has, as its name implies, less electrification. The case with less electrification shows distinctly higher energy system cost (Ex.-SC-Hopkins-9:Page 36) than the high-electrification case. (The other three scenarios primarily differ in their treatment of the electric sector and industrial production and are thus less relevant for our purpose.) In the interest of lower energy system cost, I focus on the high electrification pathway from this study. I note that the study does not attempt to meet the nation's 2030 GHG target, which was set after the study was complete. As a result, all 2030 values from the study should be considered conservative, because additional actions beyond those envisioned here will be required. The study is helpful here because the authors provide state-specific outputs for the pathways in each modeled case, so we can look specifically at the model for Wisconsin. (I provide the relevant data excerpted in Ex.-SC-Hopkins-10.) Figure 1 shows the Wisconsin trajectories for total pipeline gas use by the residential and commercial building sectors, and most appropriate for winter peak demand, the stock of gas space heating systems in each sector. The study shows noticeable declines in all four metrics by 2030, and 90 percent or more reduction by 2050.

Figure 1. Wisconsin trajectories, relative to 2020, for residential and commercial pipeline gas use and gas space heating stock in the High Electrification case of the Net-Zero America study.



3. The IEA published its Net Zero by 2050 analysis in May of this year. (See Ex.-SC-Hopkins-11.) The IEA builds from the IPCC's conclusion that net zero by 2050 is required to meet the Paris Agreement's 1.5 degree warming target and models a worldwide path to that level of emissions from the energy sector. The analysis shows global use of heat pumps for heating almost tripling as a share of heat by 2030 (from 7 to 20 percent) on the way to 55 percent by 2050. On the production side, the report states that "Beyond projects already committed as of 2021, there are no new oil and gas fields approved for development in our pathway, and no new coal mines or mine extensions are required. The unwavering policy focus on climate change in the net zero pathway results in a sharp decline in fossil fuel demand." Use of gaseous fuels[1] in buildings falls from 28 exajoules (EJ) in 2020 (consisting entirely of fossil natural gas) to 6 EJ in 2050; the share for fossil natural gas is just 1 EJ in 2050. (See Ex.-SC-Hopkins-12.) Gaseous fuel use in buildings falls at a compound rate of 2.1 percent per year between 2020 and 2030, but

[1] Combining fossil natural gas, biomethane, and hydrogen.

intensifies after 2030 so that between 2020 and 2050 the use falls at a compound rate of minus 4.9 percent per year.

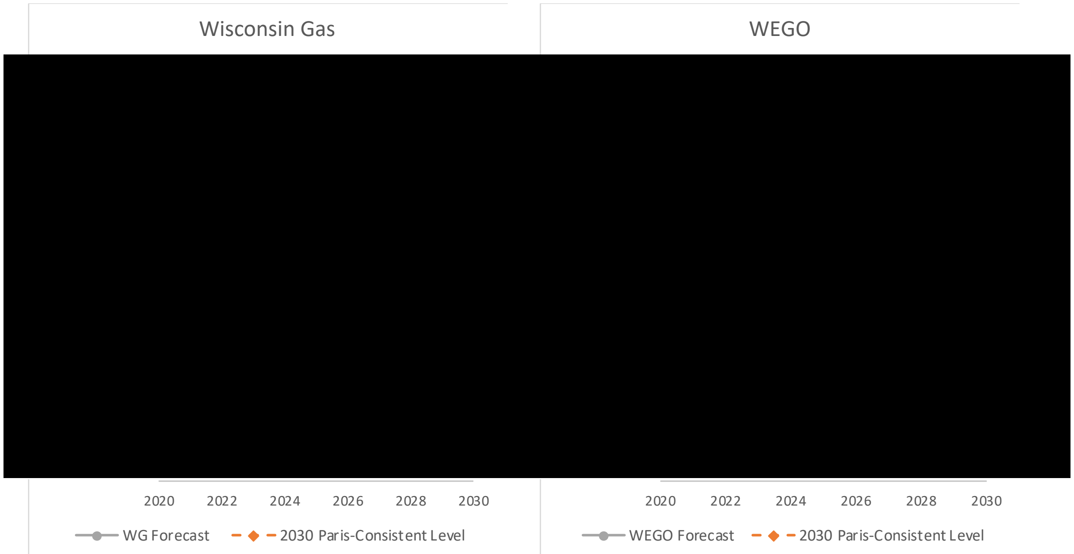
The most appropriate benchmark for necessary changes in Wisconsin's natural gas use to meet the commitments in the Paris Agreement is the Maryland study, which is designed specifically to achieve emissions aligned with the U.S. commitment. (Emissions in the Princeton are higher than the country's 2030 target, while the IEA study is global in scope.) Nonetheless, all three analyses also provide useful insights that inform my conclusions. For example, the Princeton study provides state-specific data and analyses, confirming that electrification and efficiency are key components of the lowest-cost scenario for 2050 (including in Wisconsin). Similarly, the IEA analysis shows that a global net zero emissions energy system is consistent with the approach taken by the Maryland researchers for analysis of the United States, including near elimination of natural gas use in the building sector worldwide.

Across all three studies, one conclusion is clear: the Utilities' assumption that "there are not any structural changes that would warrant a meaningful reduction in future forecasts versus the historical growth trends" is clearly incorrect if Wisconsin and the United States are to reach their stated commitments.

Q How do the Utilities' load growth projections compare to the necessary reductions in natural gas use required by Governor Evers's and federal commitments to meet the Paris Agreement?

A Figure 2 below compares the Utilities' growth assumptions underlying their application with the 17 percent reductions required to meet the federal and state emission reduction targets. The two potential futures are incompatible.

Figure 2. Utility projections of peak load growth compared with the 17 percent reduction in peak load by 2030 that would be consistent with the Paris Agreement

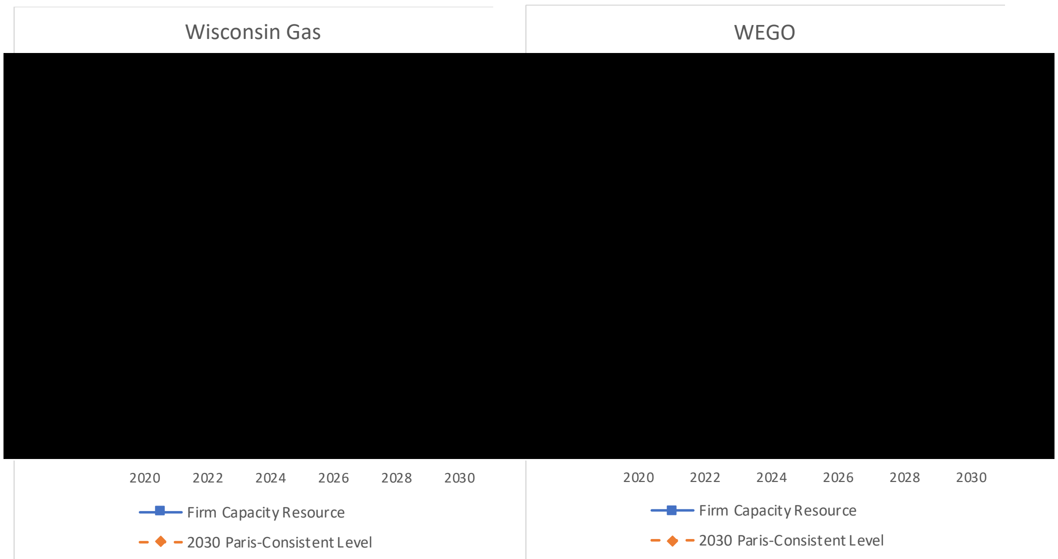


Q How would a 17 percent reduction in natural gas use in buildings by 2030 to meet emission reductions targets affect the Utilities' purported need for the Proposed Facilities?

A Assuming linear gas use reductions for Wisconsin Gas between 2019 and 2030 to meet the 17 percent reduction target, the corresponding peak gas demand requirement (including the 5 percent margin) would fall by more than [redacted] per year, and after [redacted] the capacity gap used to justify the proposed WG facility would no longer exist. The impact is even stronger for WEGO: a linear reduction in peak demand toward 17 percent below 2019 in 2030 would mean there are [redacted] in which the demand exceeds the capacity WEGO has already secured or for which it has right of first refusal. Figure 3 shows the linear decrease trajectories toward a 17 percent reduction by 2030 alongside each utility's secured capacity.

Note that this obsolescence of the Proposed Facilities due to reductions to meet climate policies is independent of the critiques I lay out below regarding the Utilities' load forecast.

Figure 3. Utility secured firm winter capacity resource compared with a linear trajectory to the 17 percent reduction in peak load by 2030 that would be consistent with the Paris Agreement



[redacted]

IV. LOAD FORECASTS

Q You mentioned a second concern with the Utilities' peak day load forecast. How have the Utilities overstated the expected new commercial and industrial (C&I) load?

A The Utilities double-count new C&I loads because their load projections add individual new C&I loads to a long-term trend that also includes new load additions. Adding individual new loads to a trend line implies that the trend line excludes new C&I loads and reflects only increased use by existing customers. However, the Utilities' historical trends used in this case do not exclude growth due to new C&I load additions. Adding particular new loads to the trend that also includes growth due to new load additions double-counts the impact of new loads.

Q To the extent that the Utilities attempt to justify adding new load to the historic trend that also includes new load by the "lumpy" nature of C&I additions which may create large increases in short periods outside the long-term trend, is there a way to account for that possibility without double-counting?

A Yes. There are several accepted methods to account for the short-term divergence from long-term averages in load forecasting. One reasonable option is to reflect specific new load additions in particular years but return the overall growth to the long-term trend within a few years. Added loads in this method "decay" to the long-term trend. The decay period for new load additions is informed by the difference between the additions and the long-term trend (in effect, the smaller the individual load addition relative to the historical trend, the faster it decays into the historical trend). Another credible way would be to remove the growth trend from the C&I portion of the peak load regression and account for specific added C&I loads and energy efficiency separately.

Q Other than the double-counting problem, have the Utilities accurately accounted for the specific new C&I loads?

A No. In particular, the Utilities have not updated their load forecast for the changes [redacted] In the attachment to 2-Sierra Club-4 (Ex.-SC-Hopkins-29c), the Utilities show an analysis for the net peak load caused by the growth of [redacted] This analysis is predicated on [redacted] and the assumption that [redacted] However, there is no [redacted]. There is no current evidence of any such single employer in the service territory. The largest new job statement by any employer in the service territory appears to be Foxconn's current plan to create up to 1,454 jobs (See Ex.-SC-Hopkins-13). That is [redacted] lower than WEGO's assumed single employer addition and the associated indirect and induced jobs.

Q How would correcting the peak load to eliminate double-counting and new C&I loads impact the need for the Proposed Facilities?

A I conducted a simple calculation to downscale [redacted] and added a decay term to avoid double-counting. See Ex.-SC-Hopkins-14c. Making these simple corrections indicates that [redacted]. This represents [redacted]- [redacted] the projected capacity shortfall for WEGO in 2028-29, before accounting for any impact from changes in energy policy to meet GHG targets. The adjustment for Wisconsin Gas is [redacted]. The correction for double-counting removes about [redacted] from the capacity need in 2028-29. Figure 4 later in my testimony shows these reductions visually.

V. EVALUATION OF DEMAND-SIDE ALTERNATIVES

Q Did the Utilities evaluate demand-side alternatives to the Proposed Facilities?

A No.

Q Should the Utilities have considered demand-side alternatives?

A Yes. Demand-side alternative analysis is part of basic utility best practice. It is my understanding that Wisconsin law also requires consideration of cost-effective, technologically feasible, and environmentally sound demand-side options before deciding to build gas supply resources.

Q What is the Utilities' purported basis for failing to evaluate demand-side alternatives?

A The Utilities' Application states that the "low growth" case is an adequate proxy for increased energy efficiency, and that "[g]iven the magnitude of the need for additional capacity and supply, the increased energy efficiency assumed in the low demand forecast does not materially change the overall need for the Project.

Additional conservation activities, renewable resources, or any other energy priorities listed in Wis. Stats. §1.12(4) cannot provide a means to provide additional capacity and supply in the area." (Ex.-WEGO WG-Application: Page 59) This appears to reflect two contentions: (1) the Utilities assume the difference between the "base" case load growth and the "low growth" scenarios reflects all of the potential for energy efficiency and demand response; and (2) by framing the goal as adding "capacity and supply" the Utilities assume they can preclude consideration of demand-side options.

Q Do you agree that additional demand-side approaches are unable to provide an alternative to the Proposed Facilities?

A No. I am not offering a legal opinion of whether the Utilities correctly construe and apply Wisconsin's Energy Priorities Law. My expert opinion is that as a matter of prudent utility planning, engineering, and economics, demand-side options like efficiency and demand response are alternatives to supply capacity additions. This is the fundamental premise underlying integrated resource planning, as practiced across the country for many years.

Q How would efficiency and demand response provide an alternative to the Proposed Facilities?

A The need for the Proposed Facilities is premised on the purported gap between the Utilities' projected peak day load and the firm capacity that the Utilities have secured. The Utilities' supply side proposals (LNG facility and pipeline) increase the supply to meet or exceed the peak day load forecast. But the gap can also be closed by lowering the peak day load, or a combination of reducing peak day load and a smaller increase in supply. Ultimately, what matters is whether the firm capacity exceeds the peak day load—not whether the load comes down, the firm capacity increases, or some combination. Demand-side solutions reduce peak day load and thereby meet customer needs just as reliably as actions that increase the firm capacity.

Q Do utilities have an incentive to downplay or ignore demand-side alternatives?

A Yes. Under cost-of-service ratemaking, utilities earn a return for their shareholders by investing in capital projects. Growth in ratebase results in growth in allowed return. The tendency of cost-of-service regulated utilities to favor capital expenditures has been well known for more than 50 years. It is known as the Averch-Johnson effect, named for the authors of a 1962 paper (Ex.-SC-Hopkins-25). Energy efficiency and demand response programs are commonly treated as expenses (as they are in Wisconsin) rather than capital investments. Therefore, they produce no return for shareholders. In fact, by reducing load they reduce the need for capital investment and thereby hurt financial growth projections. WEC Energy Group's 2021 Climate Report (Ex-SC-Hopkins-16) explicitly cites the risk from energy efficiency and electrification to the traditional gas utility business.

Q Have you evaluated demand-side alternatives?

A Yes, I conducted a high-level review and assessment to demonstrate that demand-side alternatives can reasonably be expected to reduce or eliminate any need for the Proposed Facilities. As is nearly always true in any utility planning case, intervenors (and commission staff) suffer information asymmetry with the utility and often lack access to all necessary and relevant information. As a result, intervenors cannot develop a full utility efficiency and demand response program of the sort that utilities are able to do with their resources and information. The point of my analysis is to demonstrate that load-side alternatives are feasible and cost effective, not to design a fully implementable program at this step.

Q Please summarize what you found.

A My analysis indicates that there is enough likelihood of low-cost (and even negative-cost) demand-side solutions to delay or defer the Proposed Facilities and, therefore, that the Utilities were wrong to reject these options out of hand. A combination of reasonable demand-side approaches, if well-planned and executed, could reduce peak day gas demand to below the level of the Utilities' committed long-term capacity resources at lower cost than the Proposed Facilities. The illustrative demand-side alternative that I developed would save Wisconsin Gas ratepayers a present value of more than $24 million and WEGO ratepayers a present value of more than $160 million, compared to the Proposed Facilities. These approaches would also be consistent with Governor Evers's stated public policy on GHG emissions and could reduce emissions between now and 2030 by more than 2.8 million metric tons. Perhaps even more importantly, demand-side alternatives would be more equitable by reducing bills, improving comfort and health, and reducing long-term financial risk for ratepayers and the Utilities compared to a large capital expenditure that increases the rate base and costs to ratepayers with few associated co-benefits.

Q What demand-side actions did you consider?

A I looked at a combination of two approaches: energy efficiency and demand response. For energy efficiency, I considered weatherization (improvements in building envelopes) as well as more efficient heating systems (including electric heat pumps). For demand response, I considered interruptible rate designs triggered by cold temperatures.

Q Can demand-side solutions meet the need within the same timeframe that the Proposed Facilities could be built?

A That depends on how quickly they are implemented. Energy efficiency tends to be slower to implement than demand response. Energy efficiency reduces the load incrementally and is well suited to long-term solutions. It has the advantage of delivering long-term savings and, in many cases, has a negative net present value (NPV) of ratepayer cost as it is less expensive than supply-side solutions to meet customers' energy needs. In this case, efficiency can bend the demand curve below the Utilities' firm capacity after a few years, and avoid the need for ongoing expenditures for demand response or expensive supply-side solutions after it bends the curve sufficiently. Demand response, in contrast, can be quicker to implement (because it commonly involves either behavior change or smaller changes in infrastructure) than energy efficiency.

Q Could the Utilities have made demand-side options more viable by acting on the capacity gap sooner?

A Yes. Demand-side programs acquire capacity steadily over time, whereas capital investments or contracts can acquire capacity quickly. This means that careful planning and early identification of capacity gaps is necessary in order to give demand-side approaches the necessary time to perform. The Utilities were aware of the risk that they would not be able to easily renew all of their firm capacity when they signed the contracts with those terms. By waiting until just before the loss of capacity to pursue solutions, the Utilities prejudice analyses of alternatives toward capital investments. This produces an uneven playing field that favors the resource that the Utilities are already incentivized to pursue while increasing cost and reliability risk to ratepayers.

Q Could demand-side solutions form part of a hybrid solution with supply-side options?

A Yes. Even if energy efficiency and demand response do not completely displace the need for a supply-side solution, they often delay and reduce the needed supply-side resource. Adding some smaller supply-side options to demand-side actions to ensure the performance of the overall portfolio by covering a remaining gap is often less expensive (on a present value basis) than building large and long-lived supply-side-only facilities. If the remaining gap is limited in duration, customers can see present value lifetime savings even if the annual cost of limited-term supply-side options is higher than the Proposed Facilities (because the total investment life is shorter).

Q How do you compare the cost and benefits of a demand-side alternative, which involves investment in a customer's building or other facility, to the cost and benefits of the Proposed Facilities?

A The appropriate metric is the net present value of total costs, including both upfront costs for programs or capital investment and ongoing savings, such as from efficiency, as well as policy-related costs and benefits such as a value of carbon emission reductions.

Traditional energy efficiency cost-effectiveness analysis, for purposes of program approval, typically defines efficiency as "cost effective" if it produces a net negative cost from an NPV standpoint. However, the Proposed Facilities have a positive NPV cost. This means that to compare a demand-side alternative to the Proposed Facilities, the demand-side alternative is cost effective even if it does not produce net negative costs (under the typical program approval metric), as long as it produces net costs that are still below the positive NPV of the Proposed Facilities. Thus, even if new energy efficiency or other demand-side actions would not be deemed "cost effective" under traditional energy efficiency program planning metrics (i.e., according to the existing benefit-cost test) they can still be cost-effective compared to the Proposed Facilities.

Q Have demand-side solutions been adopted in other situations to avoid or defer infrastructure investments?

A Yes, demand-side solutions have avoided or deferred infrastructure investments in both the electric and natural gas industries. So-called "no-wires alternatives" and "non-pipes alternatives" have become more common over the last several years.

Q Is there a particularly relevant example from the gas industry that has instructive parallels with the present docket?

A Yes, one relevant example is from the New York City area. Natural gas use in the area grew rapidly over the last decade, primarily to replace heating oil. Pipeline capacity into the area became constrained. In Westchester, NY (north of New York City), Consolidated Edison ("Con Edison") proposed a suite of demand-side programs in 2017 to mitigate a situation similar to that faced by the Utilities in this case: reliance on short-term purchase of delivered supply from third-party shippers to bridge the gap between the utility's committed firm capacity and its projected winter peak load.[2] (Ex.-SC-Hopkins-15) Con Edison proposed four "non-traditional solutions": (1) doubling the gas energy efficiency program, (2) starting a demand response program, (3) developing renewable alternatives to natural gas heating (most particularly electric heat-pump based systems), and (4) issuing a market solicitation for additional non-pipeline solutions. Con Edison also asked regulators to allow cost recovery of costs associated with pursuing supply-side solutions such as expanded pipeline capacity, while explicitly noting that the demand-side actions taken in the immediate term would allow the utility to pursue reduced-size pipeline-based solutions. The New York Public Service Commission approved, with modifications, each of the demand-side approaches that Con Edison proposed.[3] It also declined to support Con Edison's request for recovery of costs associated with exploring supply-side solutions, stating that the development risk for new pipeline resources was appropriately born by the unregulated pipeline developers and not by New York ratepayers. When Con Edison announced a moratorium on new natural gas customer connections in the Westchester area in 2019,[4] the NYPSC and other state agencies focused their

[2] Notably, unlike the Utilities in this docket, Con Edison does not attempt to retain firm capacity equal to 105 percent of its entire winter peak load—it was concerned about the portion covered falling from 83 percent to 78 percent. The filing states that "an appropriate amount of Delivered Services can play an important role in a utility's pipeline capacity portfolio" (Ex.-SC-Hopkins-15, p. 2). This indicates that the Utilities may be overly conservative regarding their need for long-term secure access to their entire peak winter capacity, plus a 5 percent margin.

[3] Three orders from the New York Public Service Commission in Case No. 17-G-0606: July 12, 2018: *Order Approving in Part, with Modification, and Denying in Part Smart Solutions Program*. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={DD7A45AB-9B98-4EF7-898A-268F4162CDAB}; August 9, 2018: *Order Approving with Modification Gas Demand Response Pilot*. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4AA81E30-D21E-4F34-BA06-9E909EB1143C}; and February 7, 2019: *Order Approving with Modification the Non-Pipeline Solutions Portfolio*. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={64CE307C-4FD6-4043-8BE2-A5F04C5080E8}.

[4] Consolidated Edison Company of New York. January 17, 2019. *Re: Cases 16-G-0061 & 17-G-0606: Notice of Temporary Moratorium for Gas Service.* Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C52FF33C-24A7-4DB1-A6B4-6B8779DC3F0A}

efforts on enhancing demand-side solutions such as heat pumps and energy efficiency. (See Ex.-SC-Hopkins-17)

Q What particular lessons does the Con Edison experience provide for this case?

A First, the Con Edison example shows that demand-side alternatives like energy efficiency, demand response, and electrification are a credible and accepted solution to gas capacity constraints. Second, this example shows that demand-side approaches can defer or reduce the size of eventual supply-side solutions, even if some supply side elements are still required. Third, it shows that state regulatory leadership can protect ratepayers from unnecessary costs and risk of supply-side investments when unregulated entities can develop those investments and take the risks instead of ratepayers. And fourth, it shows that state policy commitment to clean energy options can rightfully inform the regulatory response to gas system challenges.

Demand-Side Resource Potential

Q Is there enough cost-effective energy efficiency potential to defer the need for the Proposed Facilities?

A Yes, when combined with other demand-side resources such as demand response. The *Focus on Energy 2016 Energy Efficiency Potential Study* ("Potential Study", Ex.-SC-Hopkins-18), published in June 2017 by the Cadmus Group, shows that the achievable economic potential, with high upfront incentives, could reduce load by 17.3 percent over 12 years (annualized rate of about 1.57 percent per year).[5] The space heating portion of this (which provides a reasonable proxy for measures that would address winter peak demand issues) amounts to 0.98 percent per year, primarily in the commercial and residential sectors. Using the same

[5] While Focus on Energy has acquired some of this potential in the years since the study was conducted, I am assuming that the state can continue to capture efficiency beyond the timeframe of the 2016 Potential Study at a comparable rate. Focus on Energy has not been able to scale programs to capture the full cost-effective potential, and the 2021 draft potential study (discussed below) indicates that further savings are available.

space heating portion of each sector (from the Potential Study) and applying to the gross savings achieved by Focus on Energy in 2019 (from Attachment to the Response to Data Request 2-Sierra Club-9, reproduced in Ex.-SC-Hopkins-26c) indicates that current energy efficiency programs reduce peak demand by about [redacted] percent per year, which is about a factor of seven below the cost-effective potential for energy efficiency identified by the Cadmus Group. This indicates that the current Focus on Energy budget cap is a limiting factor and that there are additional cost-effective savings, on the order of [redacted] percent per year on winter peak, achievable over a 12-year period.

Q What is "achievable economic potential"?

A For purposes of the Potential Study, economic potential is the amount of energy efficiency that can be acquired during the study period and for which the measure is cost-effective under Focus on Energy's Modified Total Resource Cost test, as approved by the PSC. The economic potential threshold is conservative with respect to portfolio construction because it includes only individual measures that are cost-effective, while Focus on Energy only has a requirement to be cost-effective at the portfolio level. That is, Focus on Energy could include measures that are not individually cost-effective as long as they are balanced out by measures that are more cost-effective.

The achievable potential is a subset of the economic potential that reflects the impact of market barriers on adoption, including limits on the incentives that Focus on Energy can provide. My analysis here primarily uses the "high incentive" version of the achievable potential, which has higher budgets than current programs in order to offer larger incentives. These budgets are used to return funds to ratepayers in the form of incentives, so they do not affect the benefit-cost test.

Q Does the economic potential reflect the cost of the Proposed Facilities?

A No. The Potential Study is based only on the cost of avoided fuel. It does not include the addition capacity costs avoided like the proposed LNG storage facilities. Therefore, if a measure is cost-effective under the standard state test, it will definitely be cost-effective to avoid or defer the Proposed Facilities. Moreover, some measures that are not cost-effective when using the generic values (i.e., based only on fuel cost) will be cost-effective when the additional cost of the Proposed Facilities can also be deferred or avoided.

Q How does the Potential Study relate to the scope of demand-side alternatives for meeting the winter capacity gap?

A The Potential Study understates the gas energy efficiency potential for winter peak reduction because (1) it screens for cost-effectiveness at the measure level, rather than the wider portfolio level; and (2) does not account for the significant benefits associated with avoiding the Proposed Facilities when evaluating measures for cost-effectiveness. Thus, I am being conservative when I use the Potential Study as the basis for my illustrative demand-side alternative.

Q How does the amount of untapped, but cost-effective, energy efficiency available but untapped compare to the Utilities' claim that the "low growth" case reflects the impact from all possible demand-side alternatives?

A The untapped potential of cost-effective energy efficiency, in just the space heating sector alone, is many times the difference between the Utilities' base and "low growth" cases (peak savings of [redacted] percent per year compared to only [redacted] percent per year).

Combined with the load forecasts corrected for better treatment of C&I loads, the available cost-effective energy efficiency would reduce peak load very close to the critical load for need (that is, 5 percent above the projected peak load) in 2029 for WEGO. The largest gap between demand and secured capacity for WEGO occurs in 2023–24, at just less than [redacted] Dth/day.

For Wisconsin Gas, energy efficiency provides one part of an overall demand-side alternative. Unlike WEGO, where available cost-effective energy efficiency identified in the Potential Study *alone* closes the capacity gap, the Potential Study's energy efficiency alone does not close all of Wisconsin Gas's capacity gap before the 2040s. However, near-term cost-effective energy efficiency reduces Wisconsin Gas's capacity gap to a maximum of about [redacted] Dth/day in 2023–24 and the gap shrinks slowly as long as efficiency programs continue to balance customer growth. This remaining gap can be covered by the demand response rate option I discuss below, or by electrification of space heating.

Q Would the level of cost-effective efficiency you identify above from the Focus on Energy studies be enough on its own to put the state on a natural gas consumption trajectory consistent with the state's commitment to the Paris Agreement?

A No. Based on the Potential Study, achievable efficiency could reduce gas consumption (including non-peak measures) by about 15 percent from 2019 through 2030 (counting achieved 2019 and 2020 savings). This is not sufficient to both balance customer growth and meet the 17 percent reduction level. Additional actions beyond traditional cost-effective energy efficiency would still be required to meet the 2030 emissions goal. Further, net zero by 2050 cannot be achieved by incremental efficiency alone.

Q Does the 2021 potential study, in process, have any relevant insights that would change your conclusions?

A The consultants conducting the 2021 potential study released draft results in April 2021. I have attached these draft results as Ex.-SC-Hopkins-19. The draft study results do not include same the measure-specific information as the 2016 Potential Study that allowed me to separate energy savings from peak-day savings, which prevents me from replicating the full analysis I presented above using the updated analysis. To the extent those additional data become available later, I can update my analysis to include them at that time.

However, overall, the cost-effective potential is 2021 appears to be about 20 percent smaller in the new study than in the 2016 Potential Study. The updated potential is higher in single family homes, but smaller in other sectors. This is primarily because the projected cost of natural gas is lower now than was assumed in the 2016 Potential Study. Some measures that could produce substantial savings and were cost-effective (using the traditional cost-effectiveness test, not reflecting the cost of the Proposed Facilities) in the 2016 Potential Study are not cost-effective in the 2021 study but barely miss the threshold for being deemed cost-effective. (That is, they have a benefit-cost ratio of more than 0.75 but less than 1.) Many of these measures are related to space heating and weatherization (Ex.-SC-Hopkins-19: Slide 20).

It is important to note, again, the difference between the measure specific cost-benefit ratio applied in the potential studies and a cost-effective portfolio compared to the cost of the Proposed Facilities in this case. An overall portfolio containing less cost-effective measures can still be cost-effective as a whole even if certain measures, alone, are not. Focus on Energy is, appropriately, able to screen the cost-effectiveness of its actions at the portfolio level rather than the measure level. The draft 2021 results show that adding measures with benefit-cost ratios over 0.75 to the portfolio returns the overall potential to about the same level as was observed in the 2016 Potential Study (Ex.-SC-Hopkins-19: Slide 46).

Additionally, like the 2016 Potential Study, the draft 2021 potential study only compares efficiency measures to the value of avoided fuel costs. That is, it does not compare measures to the cost of the Proposed Facilities. Building and operating the Proposed Facilities would cost ratepayers $460 million (NPV), whereas the energy efficiency reflected in the potential analysis provides net negative costs by avoiding the purchase of natural gas. Measures like heat pumps that do not produce a benefit-cost ratio above 1.0 using only avoided fuel costs can still be part of a portfolio solution that costs less than the Proposed Facilities, and would also reduce emissions and help achieve state GHG targets.

The draft 2021 results show that including additional space heating and weatherization measures that have a benefit-cost ratio between 0.75 and 1 would increase the 12-year economic potential by about 25 percent, to about 21 percent of projected sales (Ex.-SC-Hopkins-19: Slide 46). A program that included measures down to a benefit-cost ratio of 0.5, which would offer savings 36 percent above the baseline results, might have a small net cost to ratepayers when considered on its own but would, again, remain below the net cost of the Proposed Facilities. I discuss cost in more detail later in my testimony.

Q Please explain what you mean by electrification and how it impacts the need for the Proposed Facilities.

By electrification, I mean the recent trend towards efficient electric technologies for space heating, water heating, cooking, and laundry. Many of the products whose market shares are growing are based on heat pump technologies which deliver efficiency greater than 100 percent because they work by moving heat, rather than generating it. These technologies can both reduce GHG emissions and save customers money. Recent advances in cold climate air source heat pumps, for example, have made it possible to reliably heat homes and other buildings cost-effectively with electric heat pumps even in cold climates. Electrification is the dominant strategy used for decarbonizing the buildings sector in the vast majority of deep decarbonization or net zero studies I am aware of, including those I highlighted earlier in my testimony.

Notably, electrification of space heat is a key cost-effective component for both new and retrofit applications as part of portfolios of actions that achieve international, federal, and state GHG reduction goals. Installing new gas heating systems today risks creating extra costs when early replacement becomes necessary to meet emissions requirements or mitigate rising gas rates driven by changes in consumption and/or climate policy.

Electrification, and specifically of space heating, will reduce peak gas demands in the Utilities’ service territory. At present costs for electricity, natural gas, and current technology, heat pumps for space heating are typically not cost-effective under traditional cost-benefit analysis for retrofit applications. However, they can be cost-effective in new construction where they can avoid gas infrastructure costs and avoid the need to purchase separate heating and cooling systems. See, for example, the analysis for Chicago presented in Ex.-SC-Hopkins-20. Additionally, when avoiding the cost of LNG storage is included in the cost-effectiveness calculation, additional measures and programs are cost-effective beyond those that meet a fuel-only cost-effectiveness test.

Electrification of space heating can be cost-effective, alongside steps like weatherization, as part of an overall alternative to the $460 million cost of the Proposed Facilities.

Q Could adding electrification of space heating as part of an overall cost-effective portfolio help close the capacity gap sooner?

A Yes. By eliminating some of the current space heating demand during winter peaks by moving it to electricity, the peak demand reduction per participant can be much higher. This would allow peak reduction at a rate much greater than the [redacted] percent per year additional reduction from cost-effective energy efficiency. In the Princeton Net Zero America study, for example, the lowest-cost "high electrification" scenario models a 10 percent reduction in the number of gas-heated homes in Wisconsin over the 10 years between 2020 and 2030, and a 5 percent reduction in commercial space heating with gas. In this case, heat pump share increases by a factor of 2.4 (commercial) and 2.5 (residential) from 2020 to 2030, and use of electric resistance heat also increases.

That level of gas heating system stock reductions more than counters population growth and are in addition to building shell energy efficiency, so the electrification effect is substantially larger than the [redacted] percent per year estimate of the potential from cost-effective efficiency. (Recall that the Princeton study does not reduce CO_2 emissions by 50–52 percent by 2030 to align with the national Paris Agreement target, so the overall GHG reductions by 2030 would need to be larger. If these additional reductions were properly accounted for, the electrification measures used to replace the Proposed Facilities would be even more cost-effective.)

Q You mentioned a role for demand response in a portfolio of demand-side solutions that could be an alternative to the Proposed Facilities. What types of demand response did you examine?

A I looked at temperature-controlled rates, although other kinds of demand response might also be applied. By temperature-controlled rates, I mean a rate structure that offers a discount on per-unit gas costs in exchange for an agreement to reduce gas use when temperatures fall below a set level. Typically, customers would use the savings from the reduced gas costs to cover the costs of using alternate heating systems, such as electric, propane, wood, fuel oil, or (where the system is available) district steam.

Q The Utilities offer interruptible rates now. Could you describe those rates?

A The Utilities currently offer interruptible rates for C&I customers who use more than 100,000 therms per year. In 2019, customers who use this much gas consumed 5 percent of the gas that the Utilities sold (not counting transportation service). In 2019, 14 percent of the use from these large customers (and 0.7 percent of all gas sold by the Utilities, not counting transportation service) was covered by interruptible rates. The Utilities' current rates offer a discount of 7 (WEGO) and 9 (WG) cents per therm, which corresponds to about a 15 percent savings.

Q Why do you think that temperature-controlled rates could further reduce peak winter demand?

A Those current interruptible rates are designed to allow the Utilities to manage gas costs and address unexpected contingencies. They are not designed to induce a price response to avoid a cost of new peaking capacity on the scale of the Proposed Facilities. For Wisconsin Gas, for example, the annual carrying cost of the new facility peaks at over $27 million per year to meet a short-duration peak day capacity deficiency of about [redacted] (or [redacted] after cost-effective energy efficiency programs). This deficiency is projected to occur on only the coldest of days (and secondary use for the purpose of managing costs would be available no more than the equivalent of 10 full days per year).

If markets were driving that investment decision, customers would decide if all of their peak day use was worth that cost. However, if the Commission approves the Proposed Facilities and spreads the cost among all customer usage, customers are forced to pay for that additional capacity, even those who value their peak day use less than the cost of that additional capacity. That represents a market failure due to regulation. An alternative, market-based option would provide customers a price signal to reduce use during those peak days for a cost less than $27 million per year.

I developed a simple temperature-controlled rate example to demonstrate the scale of the Proposed Facilities' costs when put in rate terms and offered to customers as a rate savings opportunity, rather than utility cost addition. In effect, the utility is buying-down the capacity requirement from customers on the coldest days rather than buying more physical capacity for those days. As a result, overall cost to all customers is lower. I believe a tariff like this would elicit a noticeably different level of customer response than WG's existing rate.

Q Has participation in the Utilities' interruptible rates been higher in the past?

A Yes. In 2019, just 3 percent of Wisconsin Gas's sales to C&I customers was sold to customers on interruptible rates. The average participation between 2002 and 2004 was 7 percent, with a maximum of 7.7 percent in 2002. This indicates that there are some large customers on firm service for whom the existing incentive of the Utilities' interruptible rates is insufficient to induce response, but for whom a more focused and higher incentive of a temperature-controlled rate could be attractive.

Q Have temperature-controlled rates been used elsewhere?

A Yes. National Grid offered a temperature-controlled rate for its New York City territory (also known as Keystone Gas New York and Brooklyn Gas) until the rate was merged with another interruptible rate tariff. In 2017, for example, about 10 percent of the utility's total sales were to customers enrolled in the temperature-controlled rates. (See Ex.-SC-Hopkins-21.) National Grid's temperature-controlled and interruptible rates offered a bill discount of about 20 percent.[6] The level of participation required to completely close the Wisconsin Gas capacity gap would correspond to [redacted] of sales. For WEGO, the smaller gap means that participation from only [redacted] of sales would eliminate the gap. While I recognize than the customer mix and historical conditions are different between Wisconsin and New York City, the National Grid example indicates that these levels of participation are possible in cold climate regions when the rate offers comparable or larger customer savings.

Q Please describe the temperature-controlled rate example you developed for WG and WEGO.

A The Utilities could offer a rate with a discount of 25 cents per therm to all C&I customers with substantial space heating loads in exchange for not using gas when temperatures are below a fixed level. Non-space-heating customers could have a different, smaller rate discount that reflects their smaller relative contribution to winter peak capacity needs. Similarly, a smaller per-therm rate discount would apply for customers who reduce, rather than cease, their use (proportional to the amount of their reduction on peak). Alternatively, the Utilities could offer a monthly fixed bill credit proportional to the customer's demand reduction on winter peak days.

[6] State of New York Public Service Commission. December 16, 2016. *Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans* in Case No. 16-G-0059 and others. Page 48. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA75F304F-604B-4ECA-A3B8-596DCAE1F72D%7D

In contrast to the current interruptible rate, which can be called on one hour's notice, this rate would be called with day-ahead notice and would be triggered by the weather forecast (so that all customers could look ahead and plan for it). Interruptions would be triggered when the average daily temperature is projected to be below some trigger value, such as 0 degrees. The trigger level should be based on each utility's firm capacity resources and peak demand expectations, but would likely be a level that would be triggered fewer than 10 days per winter on average. (The number of days per year could decrease as more efficiency is acquired.) For reference, the 25 cent rate discount is more than 2.5 times the current interruptible rate discount that WG offers, more than triple the discount that WEGO offers, and more than 40 percent of the average rate paid by C&I customers who use more than 4,000 therms per year. (This would be twice the average bill discount, in percentage terms, offered by National Grid for its similar rate.) Given the predictable nature of the interruptions, the greater advance notice, the wider ability to participate (including commercial customers currently excluded from the interruptible rate program because their usage is too low), the history of higher interruptible rate participation in Wisconsin, and the substantial increase in the discount for participation, I expect that this rate would increase participation in interruptible rates and thereby lower firm capacity requirements.

Q What would be the potential cost and impact of such a rate program?

A Let me take the two utilities separately, because the size of their capacity gaps is so different. For Wisconsin Gas, which would have a gap of at most [redacted] Dth/day when coupled with enhanced energy efficiency, the total rate program cost would be [redacted] per year if the C&I customers solved the entire gap. This would be a savings of more than [redacted] when compared to the average carrying cost of the Proposed Facilities from 2024 through 2028. To meet this level would take participation by the equivalent of about [redacted] of the load-weighted share of C&I customers who use more than 4,000 therms per year (equivalent to about 8.3 percent of firm sales).

For WEGO, which would have a gap of, at most, [redacted] Dth/day when coupled with energy efficiency, the program could be commensurately smaller. Filling the gap would require participation from less than [redacted] of firm C&I customers who use more than 4,000 therms/year or more (equivalent to about [redacted] of firm sales), and the rate program cost would be less than [redacted]. This would save WEGO ratepayers more than [redacted] per year on average.

Ex.-SC-Hopkins-22c shows the derivation of these costs and performance.

Q What if participation at your example rate were not high enough to bridge the capacity gap that remains after enhanced energy efficiency programs?

A For both utilities, if participation were low, the cost would be lower and the rate incentive for participation could be made larger until an optimum level is found. This kind of responsive rate approach would better reflect the dynamics of the market for winter peak capacity and reflect the extent to which customers value this aspect of service from the Utilities. In the event that participation, even after optimization, was not high enough to bridge the full gap between peak demand and long-term firm capacity, short-term gas delivery purchases or other lower-commitment supply-side options such as LNG or CNG trucking could be used to bridge the remaining gap.

In all cases, the winter peak capacity need would be reduced at a cost per Dth/day that is below that of the Proposed Facilities. As important, doing so avoids irreversible multi-decade infrastructure commitments that run counter to the trajectory needed to meet climate commitments. A tariff design like this can scaled back each year if it exceeds the remaining capacity gap (which would be shrinking due to energy efficiency and electrification).

Q Are other kinds of demand response also possible?

A Yes. Con Edison has been piloting a performance-based demand response program for large customers and a smart thermostat-based program in its New

York gas territory. (See Ex.-SC-Hopkins-23.) The performance-based program pays customers for participation as well as for delivering measured reductions in consumption during event days. The smart thermostat program pays customers to allow the utility to set their thermostat to a lower setpoint during events. (Both Madison Gas & Electric and Xcel (Northern States Power Company) offer similar programs for summer electric savings.) These approaches have the advantage of not requiring complete cessation of gas use during an event, but they are more complex to operate and verify and they require a greater number of participants to deliver a given amount of peak day load reduction than do interruptible rate approaches.

Performance of Demand-Side Alternative

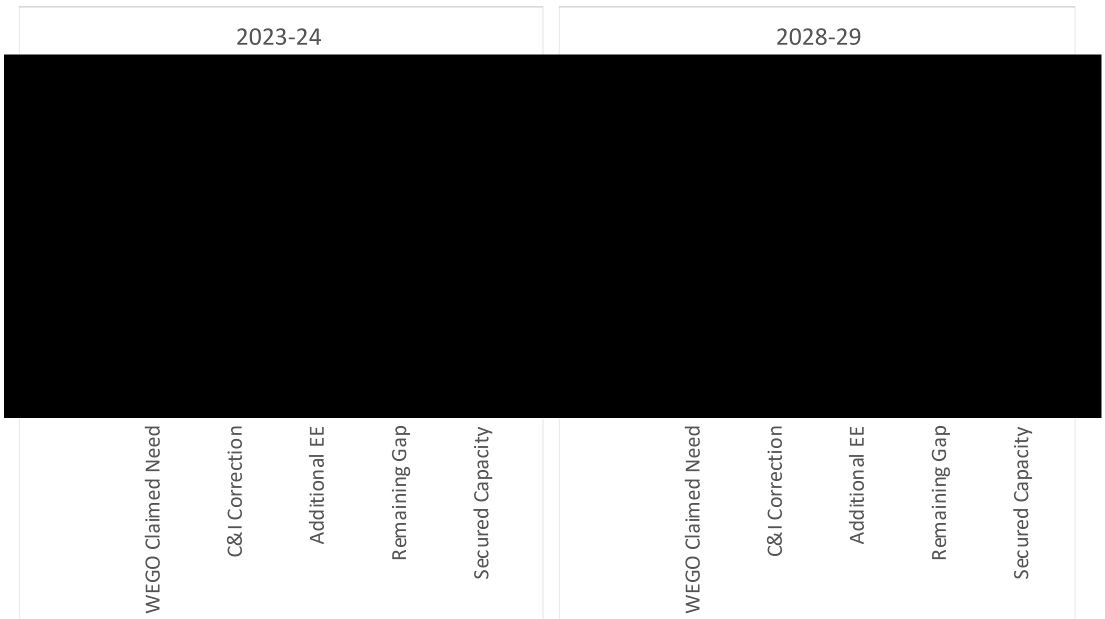
Q How would the demand-side alternatives you discuss perform at closing the capacity gap, when viewed as a portfolio?

A Energy efficiency reduces the size of the capacity gap substantially for both Utilities, and demand response can bridge some or all of the remaining gap. In both cases, the capacity gap after demand-side interventions is much smaller than the capacity of the Proposed Facilities.

Let us take the two utilities in turn, beginning with WEGO. Figure 4 shows the capacity gap for the WEGO as a whole, as documented in the Application (the difference between the two orange bars), for the years 2023-24 and 2028-29. I plot a "waterfall" of three bars showing how the gap can be bridged. The first, grey bar reflects corrections to the C&I load forecast. The second, yellow bar reflects enhanced energy efficiency to meet the "high incentive" potential from the Potential Study, and the third, blue bar shows the remaining gap to be bridged by demand response.

The illustrative energy efficiency investments would produce ongoing and accumulating peak day savings about [redacted] (WEGO) for each year the programs are implemented. This leaves a gap of just less than [redacted] between WEGO's committed capacity and the remaining load in 2023-24, shrinking to less than [redacted] in 2028-29 and then [redacted] in future years. If the demand-side approach used electrification, rather than gas heating system efficiency, this gap could be smaller or completely eliminated sooner.

Figure 4. WEGO peak day claimed capacity need, adjustments, and remaining gap for 2023-34 and 2028-29



The story is similar for Wisconsin Gas, although the gap is wider, as shown in Figure 5. The illustrative energy efficiency investments would produce ongoing and accumulating peak day savings about [redacted] (WEGO) for each year the programs are implemented. Because of the larger gap, Wisconsin Gas might find it necessary to make some use of supply-side solutions if participation in the temperature-controlled rate program is not sufficient to bridge the larger gap. However, those supply-side solutions could be ones that are much smaller in scale, duration, and lifetime cost than the Proposed Facilities, such as truck-based LNG or CNG, or smaller storage-based approaches, or simply contracting for additional firm capacity even if the prices per unit are high.

Figure 5. Wisconsin Gas peak day claimed capacity need, adjustments, and remaining gap for 2023-34 and 2028-29

Q **Is peak day capacity the only kind of performance the Commission should consider?**

A No. Each alternative also provides other kinds of performance and net benefits. For example, steps like efficiency, weatherization, and electrification provide health and comfort benefits year-round to customers by making their homes and workplaces more comfortable and less costly to heat and cool, reducing energy cost burden for low-income customers, improving air quality, and starting to put the state on the path to its GHG targets. The efficiency program expansions discussed above would reduce GHG emissions by more than 2.8 million metric tons through 2030 (not counting the continuing savings after 2030 resulting from the measures).

As the U.S. Environmental Protection Agency (EPA) noted in recent comments to the Federal Energy Regulatory Commission (FERC), “when a [benefit cost analysis or] BCA is conducted, it is appropriate to use estimates of the [Social Cost of Greenhouse Gases or] SC-GHG that reflect the best available science and methodologies to incorporate the value to society of net changes in direct and indirect GHG emissions resulting from a proposed project (i.e., relative to a no action alternative). Where it is possible to develop a reasonable estimate of the net change in emissions due to the proposed project (e.g., that reflects how carbon-based energy production and demand from competing markets might change), then SC-GHG estimates will be useful for assessing the value to society of GHG changes in the BCA." (Ex.-SC-Hopkins-31: Page 2)

Using the interim federal value for the social cost of carbon dioxide emissions from Ex.-SC-Hopkins-24, the GHG reduction from efficiency programs as part of the demand-side alternative has a societal value of more than $140 million through 2030. Reductions in methane leakage could add further to this value. Counting lifetime savings beyond 2030, incremental energy efficiency implemented through 2030 would reduce emissions more than 8 million metric tons, with a societal value of more than $400 million.

Cost of Demand-Side Alternatives

Q How do you compare the costs of the Proposed Facilities and the illustrative demand-side alternative you have sketched out?

A There are two ways of looking at cost, and I understand that both matter. One is the immediate-term rate impact; the other is the lifetime NPV.

Q How would you characterize the Proposed Facilities on these metrics?

A The Proposed Facilities have an NPV cost of $460 million, and the rate impact is greatest in 2024 (the first full year of operation) at just over [redacted]. This translates to about a [redacted] rate impact for WEGO and [redacted] impact for Wisconsin Gas (relative to total gas sales revenue in 2019). The annual revenue requirement impact falls slowly over the subsequent 40 years, to about [redacted] per year just before the facilities are paid off. (Ex.-WEGO WG-Application: Volume I, Appendix F, Attachment 3)

Q **What about the illustrative demand-side alternative?**

A Let's look at the costs by program component, starting with energy efficiency and proceeding to demand response. The 2016 Potential Study estimates that pursuing the "high incentive" achievable potential scenario (which I used as the basis for my analysis) would have a statewide average annual budget of about $323 million, across both gas and electric, of which about $116 million would be for gas. This compares with the "business as usual" (BAU) case statewide budget of about $90 million, of which $32.4 million is for gas efficiency. I estimate the WG and WEGO share of those statewide totals by scaling based on current ratepayer spending for WG and WEGO of about [redacted] the statewide BAU natural gas spending. The 2016 "high incentive case" implies a [redacted] budget for WG and WEGO (half of [redacted]). This reflects a [redacted] increase over today's energy efficiency spending (the BAU case). Note that this increase in efficiency spending is lower in gross dollars than the annual cost of the Proposed Facilities. However, because the portfolio is cost-effective comparing spending to benefits, the net cost (NPV) for these programs is zero or less even before accounting for savings that occur by avoiding the Proposed Facilities.

Q **What about demand response measures?**

A Demand response via temperature-controlled rates would have a net cost, for as long as the program was necessary. As discussed above, at its maximum extent in 2024, a WG program that filled the entire gap left after energy efficiency would cost about [redacted] per year; the WEGO program would cost less than [redacted] per year at peak if the programs produced a peak response equal to the maximum capacity gap: [redacted] for WG and [redacted] for WEGO.

Q **Can you compare the annual and NPV costs across the next 10 years of the demand-side alternatives to the costs of the Proposed Facilities?**

A Yes. Let me start with WEGO. For the purposes of these tables, I am continuing to make the conservative assumption that the additional energy efficiency, taken as a whole, has a benefit-cost ratio of 1.0 or better. (This is conservative because the portfolio of measures in the Potential Study includes many measures with a benefit-cost ratio of greater than one.) The first table shows the NPV of the energy efficiency programs implemented in each year, alongside the annual net costs of the Bluff Creek facility. The illustrative demand-side alternative would save $197 million, present value, during the next ten years.

Table 1. Net present value of costs to WEGO ratepayers from the illustrative demand-side alternative (and sub-components) and the Proposed Facilities ($ in nominal millions)

	EE NPV @ BCR 1.0	Temp-Controlled Rates	Combined Illustrative Demand-Side	Proposed Bluff Creek	Savings from Demand-
2021	[redacted]				
2022	[redacted]				
2023	[redacted]				
2024	[redacted]				
2025	[redacted]				
2026	[redacted]				
2027	[redacted]				
2028	[redacted]				
2029	[redacted]				
2030	[redacted]				
10-Year NPV	[redacted]				

The next table shows the annual flows on customer bills, including (1) the cost of energy efficiency programs, (2) the reductions in bills because of the savings from the installed energy efficiency measures, (3) the cost of demand response programs, (4) the combined bill effect of the illustrative demand-side alternative, and (5) the bill effect of the Bluff Creek facility.

Table 2. Annual net bill costs for WEGO ratepayers for the illustrative demand-side alternative (and sub-components) and for the Proposed Facilities ($ in nominal millions)

	EE Program Costs	EE Savings @ BCR	Temp-Controlled Rates	Combined Illustrative Demand-Side	Proposed Bluff Creek	Savings from Demand-
2021	[redacted]					
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						

As shown in these tables, for WEGO the demand-side alternative has lower present value cost for the next decade, and lower direct bill impact for all years after the Proposed Facilities are built. That is, customers would pay less overall, and less on each year's bills after a limited startup cost, under the demand-side alternative. The combined bill impact of the demand-side alternatives declines faster than does the annual cost of the Proposed Facilities, so savings would continue past 2030 as well.

In the case of Wisconsin Gas, the NPV comparison for the next 10 years is shown in Table 3. The illustrative demand-side alternative would save $69 million, present value, during the next ten years.

Table 3. Net present value of costs to Wisconsin Gas ratepayers from the illustrative demand-side alternative (and sub-component) and the proposed facilities ($ in nominal millions)

	EE NPV @ BCR 1.0	Temp-Controlled Rates	Combined Illustrative Demand-Side	Proposed Ixonia Facility	Savings from Demand-
2021	[redacted]				
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
10-Year NPV					

The annual bill impacts are shown in Table 4.

Table 4. Annual net bill costs for Wisconsin Gas ratepayers for the illustrative demand-side alternative (and sub-components) and for the Proposed Facilities ($ in nominal millions)

	EE Program Costs	EE Savings @ BCR	Temp-Controlled Rates	Combined Illustrative Demand-Side	Proposed Ixonia Facility	Savings from Demand-
2021	[redacted]					
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						

Table 3 shows that the present value of costs is clearly in favor of the demand-side alternative, while Table 4 shows that the annual bill impact of the demand-side approach is higher in the first 6 years. As in the WEGO case, the bill impact is falling faster than the carrying costs of the Proposed Facilities, so the trend is in favor of the illustrative demand-side alternative after 2030. Note that for the first two years in which the demand-side alternative is more expensive (2021 and 2022), its cost is higher in part because it procures the peak capacity for those winters that would not be provided by the Proposed Facilities. Without demand response in those two years (that is, providing the same level of reliability as the Proposed Facilities), the ten-year NPV cost of the illustrative demand-side alternative would be [redacted] lower, increasing the savings to at least [redacted].

Q Do these costs include the cost of carbon emissions or other societal costs and benefits?

A No. The savings from the illustrative demand-side approach only include utility-system costs and benefits. Reduced gas consumption throughout the year would reduce GHG emissions, which would reduce the societal cost imposed by the combustion of fossil fuels in Wisconsin. As I discussed above, the value of emission reductions from efficiency programs would add more than $140 million in societal value between now and 2030 and more than $400 million over the lifetime of measures implemented through 2030.

Optionality

Q Does making a capital investment in utility LNG infrastructure have an opportunity cost in terms of lost optionality?

A Yes. Until the Utilities make a capital investment, they retain the option to choose to delay or change the investment. However, once it is made, the decision is sunk for the life of the project (in this case, 40 years). Meanwhile, the energy sector is rapidly changing. This change is driven by advancing technology and changing public policy to address the imperative to mitigate global climate change. Selecting and proceeding with the proposed long-lived LNG facilities means taking the risk that the winter peak demand for methane delivered by pipeline will not be there and will not justify the investment for some or all of its 40-year life. In the event that the asset is no longer used and useful before the end of its planned life, it becomes a stranded asset.

As EPA stated in its recent comments to FERC regarding natural gas pipeline determinations, "[t]he determination of need should consider how the … increased penetration of alternative energy sources due to current policies (e.g., drilling limitations, building electrification) will affect natural gas demand in the area. The high up-front costs, including the exercise of eminent domain, may be wasted, or worse, incentivize further gas use when the true social cost of gas (including the climate change impacts) exceeds the cost of available substitute energy sources. The value of not locking in gas use should be included in the assessment going forward, under a variety of scenarios, before eminent domain, the potential for stranded assets, and other costs are realized." (Ex.-SC-Hopkins-31: Page 1.)

Incremental investments that meet customer reliability needs through smaller, shorter-lived, or reversible investments would allow the Utilities to retain the option to not build any facility, to build something else, or otherwise pivot in a quickly changing energy system and market. This option has financial value, and if that value could be quantified it should be included in the assessment of investment choices. At a minimum, this value should be recognized as an important benefit of the demand-side alternatives in that it can help reduce risks to customers.

Q Have you quantified this option value?

A In part. Developing a universal value for the option would require quantifying the uncertainty of the future load growth (or decline) for each of the Utilities. I consider this future load to be highly uncertain, because of the technological and policy risks I discussed above. However, I have explored the value of the option for an example deferral situation assuming simplified characterization of the uncertainty.

Q What is the situation you examined?

A I quantified the value of deferring the decision to build the Proposed Facilities for seven years, such that whatever is built would enter service in 2030. (Similar analyses could be conducted with different durations of deferral.) Deferring construction provides two sources of value: (1) the time value of money, and (2) risk value. Making the irreversible choice to construct today eliminates both of these sources of value. The question for the Utilities and the PSC is whether the costs of actions to create that deferral cost more or less than that value.

The first source of value is the simple time value of money: due to discounting, building facilities later instead of today costs less on a present value basis. Simply deferring either of the two Proposed Facilities by seven years would have a present value of about [redacted] (or [redacted] for both), using the Utilities' suggested discount rate ([redacted]) and assuming 2 percent cost inflation for the projects.

The second source of value results from the chance that, in seven years, it will be clear that the facilities are not needed or that smaller (less expensive) facilities could be constructed instead. As noted above, meeting Governor Evers's and federal climate policy will make the Proposed Facilities unneeded well before the end of their investment life. Even if there is some uncertainty about whether the Governor and federal government will achieve their commitments, there is a cost of simply assuming they will not (as the Utilities' proposal implicitly does).

Even just a 20 percent chance that Governor Evers's and federal climate policy will put Wisconsin on the trajectory to 2030 emission reductions that I discussed earlier in my testimony (which would clearly make the Proposed Facilities unneeded after 2030), would reduce the value of those facilities, as seen from today, by 20 percent. This implies that it would be better for ratepayers to spend up to 20 percent of the present value of the cost of the facilities in actions that would retain the option to not build, in addition to the time value of the deferral. Alternatively, if cost-effective energy efficiency investments could reduce the size of the needed investment by 20 percent over the next decade, ratepayers would benefit if up to 20 percent of the present value cost of the facilities were spent on actions that would result in that cost reduction. Of course, if the likelihood that Governor Evers and the United States' emission reduction commitments are met is higher than 20 percent, even greater expenditure to avoid building the Proposed Facilities is justified.

Q Could you provide a concrete example?

A Yes. Let us look at the case of Wisconsin Gas. If there is a 20 percent chance of climate policy success (that is, an 80 percent chance the project would be needed, at its full cost, in 2030) it would be worth spending up to [redacted] (present value) to create the deferral to 2030. And this is with only a 20 percent chance of climate policy success. If we grant the Governor and federal government a 50 percent chance of success, then it would be worth spending almost [redacted] (present value) in order to avoid the risk of stranding the cost of the facility when demand declines. Recall that all of the efficiency required to cut the peak capacity gap to about [redacted] has no net present value cost (or could provide a benefit), so this spending could be entirely allocated to demand response or limited-term supply-side solutions. And if the capacity gap can be closed for less than these threshold values, then ratepayers save.

If project cost can be reduced by requiring a smaller peak day capacity (e.g., 50,000 Dth/day instead of 100,000), then energy efficiency, demand response, and short-lived supply-side options to achieve this smaller project size could also be less costly than building the full-size project. (A 20 percent reduction in project cost is mathematically equivalent to a 20 percent potential for climate policy success.)

In the event that incremental energy efficiency returns more than one dollar for each dollar invested (that is, the benefit-cost ratio is more than 1.0), those savings can also help to fund further short-term actions to create the option to avoid or reduce the cost of the project.

Q Does a similar story hold for WEGO?

A Yes, but the choice is even more stark. The remaining capacity gap for WEGO is much smaller, after correcting the load forecast and implementing cost-effective energy efficiency. It would save ratepayers money to spend as much as [redacted] (present value) simply to defer this project, even if it were certain that it would still be needed at full size in 2030. If there is a 20 percent chance of climate policy success (or a certainty that the project budget could be reduced by 20 percent) it would be worth spending up to a present value of [redacted]. Even if incremental energy efficiency returned only 50 cents for every dollar invested, if there is a 20 percent chance of climate policy success it would still be worth spending [redacted] the cost of the illustrative temperature-controlled rates example in order to defer the project until 2030. In short, the large size and expense of the Bluff Creek facility, relative to the need for WEGO's winter peaks, is such that it is worth going to great lengths to avoid or defer the cost.

Q Does the deferral to achieve this value have to come exclusively from the demand-side alternatives you have identified in your testimony?

A No, although the options that I have presented are cost-effective, particularly in the case of energy efficiency. Even expensive but short-lived spending on peak capacity through pipelines, fuel trucking, or other supply-side options could be lower cost than making the irreversible decision to build.

Q What would be the implication of approving the Proposed Facilities without accounting for the option value?

A If the Commission approves the financial modeling presented by the Utilities and the resulting irreversible investment in the Proposed Facilities today, the

Commission would be fully discounting any value from deferral and any value associated with addressing Governor Evers's and federal climate change mitigation policies.

Conclusions on Demand-Side Alternatives

Q Please summarize your conclusions regarding demand-side alternatives.

A By developing a demand-side alternative, I illustrate how the Utilities erred by dismissing the demand-side alternatives without giving them full consideration. The "low growth" case is not a sufficient analogue to a case where demand-side resources are actually considered to defer or avoid the need for capital investment. A demand-side approach can bridge the capacity gap and retain reliable service while being lower cost to customers, reducing emissions, advancing state policy, and improving health and comfort relative to the option of constructing the Proposed Facility. Incremental investment in demand-side action to defer the construction of the Proposed Facilities also preserves the valuable option to change or cancel the project. These conclusions are especially strong for WEGO, which has a smaller capacity gap than Wisconsin Gas (both before and after accounting for overestimates of C&I load) and for which the demand-side alternative could meet the capacity need within just a few years.

VI. STRANDED ASSET RISK

Q For how many years did the Utilities project the peak day load?

A Eight years, until the winter of 2028–2029.

Q What is the lifetime of the asset?

A It is unclear. The Utilities' filings contain conflicting numbers. The Utilities claim the expected life of the asset is 30 years from an engineering standpoint, but 40.7 years from an accounting standpoint. (See Ex.-SC-Hopkins-30.)

Q Is there a risk that the asset would become stranded and no longer "used and useful" well before 30 to 40 years of operation?

A Yes. As I discussed earlier in my testimony, to meet the national commitment to reduce emissions 50 to 52 percent from 2005 levels by 2030, substantial reduction in natural gas use in buildings is very likely. Governor Evers has already committed Wisconsin to do its part to meet this target, as well as the broader objective of the Paris Agreement, to keep warming well below 2 degrees Celsius (which is consistent with net zero emissions). As a cold climate state, space heating will be a larger part of its contribution in Wisconsin than it would be in warmer climates. These reductions would directly impact the winter peak load and thus the need for the Proposed Facilities. In other words, it is not possible for Wisconsin to meet its climate commitment and for the Utilities' gas use assumptions used to justify the Proposed Facilities to occur.

Q Could changes in public policy impact the long-term need for the Proposed Facilities?

A Yes. In fact, such changes should be expected. To create the emissions reductions required to meet stated objectives, both federal and state policies will require significant reductions in natural gas use—below the level at which these facilities would be required.

Q Could reductions in demand make the asset no longer used and useful within the first half of its lifetime?

A Absolutely. As discussed earlier, reductions in gas use consistent with the 2030 level set by the Biden administration for the Paris Agreement and in Governor Evers's goals for Wisconsin would be enough to make the facilities unnecessary. To make this concrete, if just [redacted] of WEGO's residential and commercial customers fully electrified their space heating (or one-third weatherized their buildings substantially) and the utilities retained the rest of their firm capacity, the WEGO Facility would be un-needed in 2028–29 (without any other efficiency or demand response programs). For Wisconsin Gas, the project would be unneeded if about [redacted] of residential and commercial customers fully electrified their space heating (or about 60 percent weatherized their buildings substantially), again without any other load management programs. These adoption levels for electric space heating are aligned with the Wisconsin-specific projection for the lowest-cost scenario to net zero in 2050 in the Princeton Net Zero America study.

Q Have the Utilities considered these policy risks?

A Not in any demonstrable way. In response to 2-Sierra Club-13 (reproduced in Ex.-SC-Hopkins-27), the Mr. Kuse states that "The peak forecast methodology does not include an analysis of greenhouse gas emission reductions regarding the 2015 Paris Climate Accord and Wisconsin Executive Order #38, section 2(b)." and also that "The peak day forecast methodology does not include an analysis of the recommendations in the Governor's Task Force on Climate Change Recommendation 07 that the PSC set a utility energy use reduction goal or standard of one percent for natural gas." As I mentioned earlier, Mr. Gerlikowski states that "there are not any structural changes that would warrant a meaningful reduction in future forecasts versus the historical growth trends" (Direct-WEGO WG-Gerlikowski-5p). None of these statements is consistent with a serious consideration of the stranded cost risk associated with this proposed investment.

Q How could the Commission limit stranded cost risk?

A There are two primary methods. The first is to accelerate the depreciation schedule of any approved facilities. This would limit the risk that there is still substantial book value at the time that the facilities cease to be used and useful. While we do not know the exact timeframe for this transition, the calculations above indicate that the Paris Accord level reductions would occur to the point of obviating the Proposed Facilities by 2030 or before. Using a 20-year depreciation schedule would extend beyond that time period but reduce the stranded asset risk and better align the ratepayers benefitting from the capacity to those who pay for it. It would also substantially increase the annual cost of the Proposed Facilities during that 20-year period. The second method would be to condition any approval on not allowing the Utilities to recover or earn a return on any costs of the Facilities that become stranded. This also has the benefit of testing the veracity of the Utilities' case for the investment. Utility managers and planners have an incentive for more rigorous planning, risk analysis, and comparison of alternatives when they know that their shareholders, rather than their captive ratepayers, will take the risk for capital investments.

VII. FLEXIBILITY OF THE PROPOSED FACILITIES

Q Would the Proposed Facilities be able to deliver both price arbitrage and displace firm capacity from other resources on demand throughout the winter?

A No, they have limited storage and liquification capacity. They would have the capacity to provide 100,000 Dth/day for 10 days each before needing to be refilled. (Ex.-WEGO WG-Application: Volume I, Appendix F, Attachment 2: Page 2) For every day of full utilization as a supply-side resource, they require 20 days to refill. (Ex.-WEGO WG-Application: Volume I, Appendix F, Attachment 2: Page 2) They would have to run at full capacity for liquification for 200 days to fill completely for a coming winter.

Q What impact does this limited capacity have on the Proposed Facilities' ability to deliver value?

A If a winter were to have more than 10 days in which the facilities were used at their full capacity (for reliability or economic purposes), the value of the facilities for the rest of the winter would be zero. If used for even one or two days (i.e., for fuel cost savings), their ability to serve as a capacity resource for a later peak 10-day period is also reduced. In fact, prudent operation might require that the Utilities be conservative in deploying the stored gas in order to retain a reserve for any further cold snap or supply constraint.

Therefore, if the Utilities used stored liquefied gas in the event of a high-cost period like the 4-day period during the Texas cold snap this past winter, the facility would use 40 percent of its annual capability over just a few days if it were fully utilized for economic purposes. The period of high prices for Wisconsin that coincided with the Texas cold snap came at the end of a string of cold days that began on the 5th of February and followed a January with several cold days as well. However, none of those days were as cold as the Utilities' design days. If the Utilities elected to dispatch stored gas for price arbitrage, they would not have known how long they would need to wait for prices to drop again and to refill at normal prices. And it would have taken 80 days to refile for those four days of use. Between waiting for prices to drop and then the long refill period, the storage units would sit partially empty for an extended and probably unknown period, even though temperatures had not yet dropped to the design values. The units would then not have been available for their intended reserve capacity.

In short, price arbitrage is a very different use case than the reserve capacity case used to justify the Proposed Facilities in the Application. Because of their long refill period and the unknowable length and frequency of price spikes, using the Proposed Facilities for price arbitrage diminishes or precludes their use and value as capacity reserves. Stored gas can be used to avoid market purchases, or reserved for capacity, but not both at the same time.

Q Would alternative resources have faced these same challenges in delivering over many days?

A Demand-side solutions do not have these kinds of limits and do not need to be recharged. Efficiency delivers a reduction in demand every day the equipment is running, and interruptible loads are available each time the conditions of the tariff are met. Their supply is not exhausted like the gas in storage facilities, and they have no long recharge times like the Proposed Facilities.

Q **Does this conclude your direct testimony?**

A Yes, it does.