UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Federal and State Current Issues Collaborative Docket No. AD24-7-000

COMMENTS OF NRG ENERGY

NRG Energy, Inc. submits the following comments to the Federal Energy Regulatory Commission (the "Commission") in response to the Dec. 4, 2024 notice[1] inviting post-meeting comments based on the discussion at the meeting of the Federal and State Current Issues Collaborative (the "Collaborative") on November 12, 2024.

These comments pertain to a single topic, natural gas demand response, which Commissioner Rosner raised in his opening remarks at the in-person Collaborative.[2] This topic has dimensions of both state and federal jurisdiction and has been generally underexplored in the electric-gas coordination discussions to date. NRG submits that it is accordingly a deserving topic of the Collaborative's attention, as well as that of the Commission and State Commissions.

I. INTRODUCTION

NRG is one of the largest competitive retailers of electricity and natural gas supply in the United States by both customer count and volume, participating in Commission-regulated wholesale markets to buy the energy, transmission services, and other products necessary to serve retail customers. Through its state-approved operating licenses, NRG provides retail natural gas service in the service territories of utilities located in California, Connecticut, District of Columbia, Georgia, Illinois, Kentucky, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Virginia, as well as certain Canadian provinces. We serve about 8 million energy and energy services customers throughout North America. In addition, NRG sells natural gas to large industrial users and electric generators that are directly connected to interstate and intrastate pipelines. Through one of our senior executives, NRG has been an active participant in the Gas Electric Alignment for Reliability ("GEAR") task force, including with regard to the topics we comment upon here.

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[1] *Notice Inviting Post-Meeting Comments* (Dec. 4, 2024), Docket No. AD24-7.
[2] *See* the Transcript of the Nov. 12, 2024 meeting of the Federal and State Current Issues Collaborative. Docket No. AD24-7, at 46:9-17.

NRG broadly supports demand-side management as a valuable tool that can enhance reliability, lower overall energy costs, and limit the need for additional new infrastructure. Specifically, natural gas demand response can:

- Ameliorate distribution system pressure concerns behind the city gate of gas utilities ("local distribution companies" or "LDCs") for which State Commissions have responsibility;
- Lower design day requirements and thus reduce capacity costs on the part of LDCs and others who buy capacity from pipelines in the restructured market that the Commission has created;
- Enable peak-shaving that, on a forward-looking basis, delays or avoids the need to upsize gas infrastructure by pipeline companies; and
- Allow, in limited situations, for parties to make commercial decisions that enable supplies of natural gas to be consumed by other entities that value the natural gas more highly at that time.

NRG is a substantial provider of demand-side solutions in the electric-power markets, both as an aggregator of "demand response" into the wholesale energy and capacity markets that the Commission regulates, and also, more organically, through its actions as a state-licensed competitive retailer in restructured states. NRG acts as a load-serving entity and, in some states, actively manages our retail customers' demand with their consent, with plans to grow our existing "Virtual Power Plant" to over one gigawatt of capacity using smart thermostats.[3] Unfortunately, demand response strategies for electricity do not always transfer neatly to demand response for natural gas. Unlike electricity, natural gas is compressible, which means if natural gas consumption is reduced, that natural gas is sometimes stored in pipelines instead of being reallocated across a grid.[4] Gas also does not redispatch in real-time, at the speed of light, in response to 5- or 15-minute locational marginal prices, as happens in the competitive power markets. However, even taking the physical properties of natural gas into account, properly structured economic incentives for customers to alter consumption patterns will still yield reliability and pecuniary benefits.

[3] For example, NRG plans to create a 1 gigawatt "Virtual Power Plant" in the ERCOT market, building on our previous successes, which is predicated on our ability to remotely dispatch customers' smart thermostats in exchange for an incentive payment. "NRG, Renew Home and Google Cloud Announce Partnership" (Nov. 7, 2024). https://www.nrg.com/about/newsroom/2024/43921.html

[4] Natural gas cannot flow from a lower-pressure system onto a higher-pressure system without the use of compression.

NRG believes that the benefits of natural gas demand-side management ultimately fall into three broad categories: (1) reductions in LDC aggregate demand that can ameliorate real-time pressure crises; (2) peak-shaving and load shifting that reduce the quantity and cost of capacity that LDCs or others who take on firm retail service obligations must procure for the so-called design day, usually the coldest day of a span of modeled weather years; and (3) the ability to use existing infrastructure to transport more natural gas to where it is needed most, through optimization of pipeline capacity contracts and through financially incentivizing large-volume customers to voluntarily sell their gas back into the market when it is needed most.

II. COMMENTS

A. Existing Gas-Utility Demand Response Programs Should Incorporate Advanced Metering Infrastructure ("AMI") and Third-Party Supplier Activities

Robust demand response programs can only work if customers' meters are "smart" enough to enable economic incentives to be tailored and applied to customer behavior that reduces consumption in a manner that provides those customers benefits that outweigh, in customers' judgment, the value of that avoided energy's usage.[5] Customers have indicated a willingness to engage in demand response and to automate their participation if it can lower their bills, but AMI and data-sharing protocols are needed in order for this opportunity to exist in the first instance.[6] NRG believes that AMI is essential in fostering meaningful natural gas system demand response that can address distribution system pressure crises and allow LDCs to adjust their forecasts and capacity holdings.

There are only a handful of LDC demand response programs in the United States, putting aside traditional interruptible retail tariff offerings that have long existed for larger customers who happen to locate behind the city gate. Most State Commission-regulated gas LDCs have no demand response programs whatsoever. Those that do exist have significant room for improvement.

In NRG's experience, programs have tended to rely on estimates of impacts to demand, rather than meter readings sourced from AMI. Incentives were often "front-loaded" to drive enrollment in a program, but with no financial consequences for customer non-performance.[7]

[5] As noted in the Commission's annual reports on demand response and advanced metering, as required by Section 1252(e)(3) of the Energy Policy Act of 2005.
[6] Smart Energy Consumer Collaborative, "Smart Home and Energy Data: What Do Consumers Want?" (June 28, 2021).
[7] ConEdison Gas Demand Response Report on Pilot Performance – 2021/2022 Case 17-G-0606 & Case 14-E-0423 (July 15, 2022).

Meanwhile, with a traditional natural gas meter, it was often not possible to verify if a customer has complied with an LDC's curtailment rules, let alone engaged in voluntary demand response. Absent real data on customer usage, it was unreasonable to expect an LDC to modify its design-day methodology or adjust its estimates of necessary transportation and storage entitlements. These considerations have all made the few state-level gas demand response programs that do exist more of a "Hail Mary" when emergencies strike than a workable and consistent programmatic approach for an active demand side.

Ironically, to the degree that the customer is being paid to curtail by an LDC, but is supplied by the retail commodity supplier in the restructured gas markets, Energy Service Companies ("ESCOs"),[8] the latter often has no visibility into that arrangement and will therefore continue to buy and arrange delivery for gas supply as if demand response is not being called. This misalignment of incentives between the LDC, the ESCO, and the customer means that, while this type of demand response may (or may not) function as a real-time, "break-glass" emergency tool, there is no real connection to a particular customer's degree of demand-response activity and also no connection to the real economic value of avoiding the use of the commodity or capacity that the customer or the customer's retail supplier has paid for.[9] The technological remedy to both of these problems is AMI. The policy remedy is LDC program design that integrates the retail supplier's relationship with the customer as a lever that can be used to obtain deeper and more reliable levels of willing demand response.

Through AMI, a consumer's true impact on the system can be measured, both in real-time when responding to an immediate pressure emergency and in the longer-term, when considering aggregate usage to determine peak demand and design day. Through appropriate LDC demand-response program design, consumers (either directly or, where applicable, through their suppliers) should be rewarded for consumption behavior that (1) reduces the need to hold additional capacity entitlements and (2) reduces the need to build new or additional infrastructure. Without AMI, it is not clear how the policy design can be accomplished.

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[8] A significant number of jurisdictions allow for gas customer choice, indeed a larger number than permit retail electric choice. In these comments, we use "retail supplier" interchangeably with the term "Energy Service Company/ESCO" and "marketer" and "third-party supplier." Not all marketers are ESCOs and not all ESCOs are marketers, but there is significant overlap.

[9] To the extent an ESCO had financially hedged its anticipated sales and then had those sales reduced due to its end-use customers' participation in demand response programs, the ESCO would suffer, and not benefit, from participation in demand response.

Finally, the use of AMI to facilitate better program design for gas LDC demand response programs is a complement to retail demand-response activity occurring on the electric side. Typically, one smart thermostat controls both the heating and air-conditioning in a single-family home. NRG estimates that in the eastern restructured states alone, there are nearly half a million smart thermostats already enrolled in direct-load-control programs that allow and compensate for residential customers' automatic reductions in air-conditioning loads during summer peaks or summer emergency situations. If NRG or other retailers had access to such metering and payments for performance on the gas side, then the most commonplace residential demand-response program on the electric side—smart thermostats—also could be built out to achieve heating demand response when the LDC (or market forces) signaled the value of doing so, adding value to sunk investments in smart devices that already exist in many consumers' homes and which are becoming more ubiquitous each year.

B. Regulators Should Promote and Expand Current Natural Gas Demand Side Management Approaches

i. Asset Management Arrangements

Under a qualifying Asset Management Arrangement ("AMA") as contemplated by FERC Order No. 712,[10] holders of interstate pipeline capacity may release that capacity to third parties without the use of the Commission's mandated competitive bidding requirements. While the previous section of these comments dealt with the underdeveloped retail programs jurisdictional to State Commissions, the market upstream of this has seen a greater level of commercialization of economic demand response but remains underutilized due to the incentives of utility regulation that both State Commissions and FERC can remedy.

NRG's subsidiary, NRG Business Marketing LLC, is a large natural gas marketer that routinely enters into AMAs as an asset manager. When released capacity is not needed to fulfill contractual obligations to the releasing shipper, the asset manager can release it or use it to make sales to third parties. This allows the asset manager to optimize pipeline capacity, effectively making more efficient use of existing natural gas transportation and storage assets.

Many LDCs employ AMAs for the majority, if not all, of their qualifying interstate pipeline

[10] *Promotion of a More Efficient Capacity Release Market*, Order No. 712, FERC Stats. & Regs. ¶ 31,271, at P 165, *order on reh'g*, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *order on reh'g*, Order No. 712-B, 127 FERC ¶ 61,051 (2009).

capacity contracts.[11] Some states provide incentives to LDCs to release capacity, but others do not.[12] NRG believes it is in the interests of LDCs, their customers, and ESCOs for utility capacity to be released to avoid stranded costs and to fully utilize the country's natural-gas infrastructure, including for power-generation purposes. Substantial capacity is purchased by LDCs for design-day purposes that seldom occur, even during times when stress exists on the electric-power grid.

State Commission ratemaking practices typically allow LDCs to recoup 100 percent of the costs of capacity contracts that are needed to serve their customers, usually through adjustment clauses that true-up retail charges to the actual costs of the commodity and the capacity paid for by the LDC. In the aftermath of Winter Storm Uri, a comprehensive study NRG commissioned found that these utility adjustment clauses, or alternatives to such clauses such as securitization, caused $14.8 billion in both gas and power costs to flow through to retail customers' bills.[13] Utilities should have at least some "skin in the game" to manage the costs that flow through these adjustment clauses.

The Commission's AMA rules allow LDCs broad latitude to bargain and contract for delivery protections that they need when releasing capacity to asset managers.[14] To the extent that a marketer is willing to pay to optimize that capacity, both consumers and the LDC should share in that credit against capacity contract costs. One way of doing this, which some State Commissions have authorized, is by establishing sharing mechanisms and other incentives within ratemaking that encourage LDCs to more fully utilize the capacity they have bought by its release through AMAs. To these comments, NRG is appending as Attachment A one example of a retail tariff, that of NIPSCO approved by the Indiana Utility Regulatory Commission, that provides for cost-sharing within an adjustment clause.[15] Establishing these incentives up front would ensure state regulators that the utilities they regulate had some "skin in the game" to reduce costs when

[11] As evinced on the indices of customers publicly posted on interstate pipelines' electronic bulletin boards.
[12] ISO New England, MISO, PJM, and SPP, "Strategies for Enhanced Gas-Electric Coordination: A Blueprint for National Progress" (Feb. 20, 2024).
[13] This figure understates or does not include carrying or financing costs for these amounts, where recouped over time. Guy Sharfman and Jeff Merola, *Beyond Texas. Evaluating Customer Exposure to Energy Price Spikes: A Case Study of Winter Storm Uri, February 2021* (Apr. 2022 update). https://nrg.com/assets/documents/energy-policy/_2022/beyond-texas-evaluating-customer-exposure-to-energy-price-spikes.pdf
[14] *See supra*, note 10.
[15] NRG has reviewed other examples of such tariffs as well, which include Kentucky, Missouri, New York, and Tennessee. Value sharing can be as straightforward as "75% to the customer/25% to the LDC" or more complicated as part of a holistic calculation attempting to net out all gas cost expenses and savings. What is important is that in all of these examples, the LDC is incentivized to release unneeded capacity, most likely to a non-LDC third party that will optimize it.

possible, giving added comfort to state regulators when it came time to review the annual (or more frequent) filings their LDCs make in adjustment-clause proceedings.

AMAs may have natural advantages to in-house approaches by LDCs. An LDC gas supply department may only have underlying base contracts and credit arrangements with a handful of suppliers. While this is sufficient for normal operations, it is less than ideal for a Winter Storm Uri or Winter Storm Elliott situation where it may be necessary to purchase gas from a new counterparty for the first time or acquire supplies from non-traditional sources. Contrast this with a natural gas marketer, who would typically have enabling agreements in place with far more counterparties than an LDC and is more accustomed to buying and reselling gas at wholesale. An LDC may have limited to no incentive to use its capacity to facilitate selling gas to a generator in a critical weather event, when it may be simultaneously dealing with operational issues on its own system. Having pipeline capacity released to an asset manager may be preferrable to having that capacity managed by an LDC during a critical weather event.

Many states already have incentives in place to induce LDCs to release capacity portfolios to marketers for optimization. NRG believes that the increased use of AMAs benefits end-use customers, LDCs, and marketers alike. The Commission should encourage states to support the release of LDCs' capacity entitlements through AMAs.[16]

ii. "Direct Connect" Industrial Customers

Large users of natural gas, particularly industrial customers, often bypass LDCs when feasible to directly connect to interstate pipelines. They often also hold their own capacity entitlements and contract with natural gas marketers for needed gas supply. Unlike LDCs, when these users reduce their natural gas consumption, more of that unused gas can be expected to stay on the interstate pipeline.[17] Marketers are uniquely positioned to bargain with these types of customers during critical events. The marketer already has a contractual relationship with that customer, likely has credit arrangements in place with that customer, and knows how much natural gas its customer is using and the price the customer is paying for it. Further, the marketer likely already has capacity entitlements on the pipeline that is supplying that customer. This process does not require any additional regulation to occur, it already happens when conditions permit.

[16] *See* recommendation #5 from the North American Energy Standards Board, "Gas Electric Harmonization Forum Report" (July 28, 2023).

[17] Unlike an LDC, industrial users don't typically operate sizeable lower-pressure systems that can store meaningful amounts of unused gas as line pack.

Accordingly, it is easy to see how a customer that baseloaded its normal anticipated industrial usage at first-of-the-month pricing could be able to benefit if daily prices spiked.

A marketer can bargain with its industrial customers to reduce natural gas usage in real time. Residential gas usage in a cold weather event is not typically thought of as a financial consideration, and can be a matter of life-and-death. However, for an industrial customer, energy usage may be strictly an economic bargain. An industrial customer may have dual-fuel capability that allows it to avoid using natural gas for a period of time. Alternatively, they may be able to pay liquidated damages for non-performance of a contract that are less than the value it can receive for selling its natural gas entitlements. Residential consumers do not have these options or incentives.

While reducing residential customer demand through demand response can help a distribution system avoid a catastrophic depressurization event, due to physical constraints, it is unlikely to "create" additional natural gas that can be consumed by an electric generator. An industrial customer that is directly served off an interstate pipeline can take actions that result in more gas being left on the pipeline—and its marketer is well positioned to facilitate that natural gas being put to its highest value use. Again, this process already occurs, but if more LDCs released capacity to asset managers through AMAs, it could potentially occur more often. If a natural gas LDC released capacity directly to an industrial customer, that LDC has no financial incentive to bargain with that industrial customer to free up natural gas for electric generation, nor is it likely to have contracts in place with that industrial customer to do so.

C. Regulators Should Consider Adopting New Natural Gas Demand Side Management Approaches

i. Redesign the Design Day

Currently, a natural gas design day is a proxy for the maximum forecast level of all firm sales customers' gas requirements during a Gas Day. Some LDCs calculate their design days considering the coldest day observed in the last X[18] years, others fit a distribution to temperatures and choose the temperature based on probabilistic statistical analysis of prior periods.[19] There are other methods, but fundamentally, the purpose of the design day calculation is to determine what transportation and storage entitlements the LDC needs to have in order to meet its projected

[18] "X" is usually a lengthy period, 20-40 years is common.
[19] Kaftan, David Joseph, "Design Day Analysis - Forecasting Extreme Daily Natural Gas Demand" (2018). Master's Thesis (2009). 482.

possible greatest need.

Design day calculations have traditionally been a "highest common denominator" exercise, and with good reason. The consequences of underestimating demand are far too devastating for any LDC to simply impute a demand reduction and hope that it materializes. The continued implementation of AMI, coupled with financial incentives for ESCOs and consumers to implement and sign-up for demand response service offerings will create real, meaningful data about how a distribution system's needs change when residential customers' thermostats can be automatically adjusted to a lower temperature setting. It should be possible, over time, to create new data points that result in lower design day calculations through peak shaving/demand reductions.

ii. Time of Use Rates

Natural gas is typically priced and measured by the Gas Day. Accordingly, there is no direct financial benefit to shifting natural gas usage within the Gas Day. Most natural gas production is produced ratably and most pipeline tariffs require shippers to try to take gas on a ratable basis.[20] However, for residential end-users, there is no expectation that usage is ratable. Most distribution systems see intraday peaks when consumers wake up in the morning and return home from work. What this means is that LDCs are required to try to balance ratable pipeline services with non-ratable customer usage.

Customers typically pay a fixed per-unit price for natural gas, regardless of the fluctuating market price or their actual consumption pattern. With traditional meters, this is the only feasible rate design methodology. This leaves LDCs with limited options to financially incentivize their customers to, in the aggregate, use natural gas more ratably throughout the Gas Day. Some LDCs offer interruptible services to industrial and commercial customers, or customers with dual fuel options, at a lower price than firm service, which enables the pipeline to interrupt those customers when conditions require them to do so for reliability purposes. Alternatively, storage services, if available, may be used to smooth out load and supply throughout the day. Ultimately, LDCs need to have enough capacity to transport sufficient natural gas to their systems to meet a design day and they need to have sufficient capacity to meet their load peaks.[21]

With the data available from AMI, there is no reason that customers cannot be incentivized

[20] Some pipelines offer non-ratable services and/or no-notice services, typically priced at a premium.

[21] For example, if a system used 24 units in a design day but used 3 units at its hourly peak, the infrastructure would need to be sized and the utility may need to hold **72 units** of capacity entitlements per day in order to ensure that it could provide reliable service.

to smooth system usage throughout the day. ESCOs should be able to tailor natural gas offerings to customers offering higher prices during morning and evening ramp times with lower off-peak prices, just as they do for electric services. If customers adopt time of use services, there should be systemwide benefits in the form of reduced peaks, with concomitant benefits in the form of reduced capacity portfolio costs and reduced need for infrastructure upgrades to meet load growth.

III. CONCLUSION

NRG supports gas demand response, which can best be enabled through the continued deployment of AMI. NRG views AMI as a necessary step on the path to more efficient overall use of our existing energy infrastructure. Consumers need to be rewarded for making consumption choices that lower overall costs. Under traditional ratemaking and gas cost recovery principles, the benefits of demand response would inure to the entire system—even to the customers that did not contribute to it. Regulators should be mindful that in the absence of a mechanism to reward the consumers that choose to participate in programs, customers will have far less inducement to do so. Likewise, ratemaking for LDCs that features adjustment clauses that do not have cost-sharing or similar incentives will lead to an underutilization of the capacity LDC customers have pay for. The positive impacts of natural gas demand response will not all come quickly, but through proper incentives, regulators can accelerate moving toward a more efficient and reliable future.

In order to move towards a future in which natural gas infrastructure is used more efficiently and in a manner that improves reliability, NRG urges this Commission and State Commissions to consider the following recommendations:

- Continue to deploy modern natural gas meters that allow for time of use measurement;
- Encourage LDCs to release unneeded pipeline capacity to natural gas marketers;
- Offer end-use customer incentives aligned with desired outcomes to smooth out natural gas usage throughout the gas day and/or reduce usage at critical times;
- Allow ESCOs to play a role in offering innovative products that reward customers that permit demand response at the expense of customers who do not.

NRG would be pleased to participate in any future discussions that the Federal and State Current Issues Collaborative has on these topics, and we are at the disposal of members of the Collaborative for any discussions they wish to have on these comments.

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Respectfully Submitted,

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GENERAL RULES AND REGULATIONS
Applicable to Gas Service

15. GAS COST INCENTIVE MECHANISM

The Company will adjust the Gas Cost Adjustment factors for billing purposes by the effect of the application of the Gas Cost Incentive Mechanism most recently approved in Cause No. 44081.

The Gas Cost Incentive Mechanism rewards and/or penalizes the Company for its performance of gas supply acquisition when compared to a market standard ("Benchmark").

The Benchmark shall incorporate a "Benchmark Price," which (1) for daily purchases will be the mid-point average of the "Daily Pricing" as published in Gas Daily "Daily Price Survey, Daily Midpoint" and NGI's "Daily Gas Price Index" natural gas commodity price applicable as of the date of purchase, and (2) for purchases designated as monthly will be the mid-point average of the month "FOM Pricing" as published Inside FERC and NGI Bidweek. These gas prices shall reflect the gas prices for the geographic locations representative of the supply basin/location where the gas was purchased and delivered to the primary and secondary receipt points of the Company's transportation capacity. The "Benchmark Price" will be determined for each month ("FOM Pricing") and each day ("Daily Pricing") of the year.

The Benchmark Dollars are calculated by applying the Benchmark Prices from the indices to the actual units purchased within the geographic supply zones. The aggregated dollars are the Benchmark Dollars which will be compared to the Company's actual gas commodity purchases on a monthly basis in order to determine the Company's performance under the Gas Cost Incentive Mechanism. If the Company's actual gas commodity purchase dollars are less than the Benchmark Dollars, a Positive Performance exists. If the Company's actual gas commodity purchase dollars are greater than the Benchmark Dollars plus the Tolerance Band, a Negative Performance exists. Sharing of the dollar differences between the Company and the Customers will be as follows:

Negative Differential (Actual cost > Benchmark Price)

% of Benchmark Price above Benchmark Price	% of Sharing Customer	% of Sharing Company
>0%	50	50

Positive Differential (Actual cost < Benchmark Price)

% of Benchmark Price above Benchmark Price	% of Sharing Customer	% of Sharing Company
>0%	50	50

The Customers' share of dollars as determined on a monthly basis will be included in the Gas Cost Adjustment calculations for Sales Customers.

GENERAL RULES AND REGULATIONS
Applicable to Gas Service

16. CAPACITY RELEASE SHARING MECHANISM

Revenues generated by releasing interstate pipeline capacity not assigned to Choice Suppliers on a recallable or non-recallable basis in the interstate market on a monthly basis shall be shared with 75% of such revenues credited to GCA customers through the GCA mechanism and 25% retained by NIPSCO. Revenues generated by releasing upstream capacity assigned to Choice Suppliers, but mitigated by Choice Suppliers, shall be shared with 85% of revenues generated by such releases being donated to a NIPSCO Care Plan-Universal Service Plan, and 15% retained by NIPSCO.