# *Gas Demand Response Programs Proposal*

## *For Residential and Non-Residential Programs*

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# ABSTRACT

Gas Demand Response ("DR") programs may offer a flexible, cost-effective approach to managing peak gas demand, mitigating capacity constraints in local gas systems, and reducing peak gas supply costs.

DR programs incentivize customers to voluntarily reduce or shift their gas consumption during critical periods to alleviate gas system pressure drops, improve system reliability, and avoid the purchase of peak gas supply contracts.

Customer participation is voluntary, and success depends on customers perceiving sufficient benefits. While not every customer needs to participate, enough aggregated load reduction must occur during peak hours, typically associated with the coldest times of the year, to be cost-beneficial and defer infrastructure upgrades or avoid peak supply contracts.

The objective is to achieve sufficient demand reduction through behavioral, operational, and technology-driven strategies, such as residential thermostat adjustments and commercial process load curtailment.

DR programs can offer multiple benefits, including enhanced system resilience, reduced infrastructure investment, improved customer engagement, and alignment with state decarbonization goals. These programs can be tailored for both residential and non-residential customers across a system or in targeted areas, leveraging advanced controls and customer choice to deliver measurable peak demand relief.

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# I. INTRODUCTION

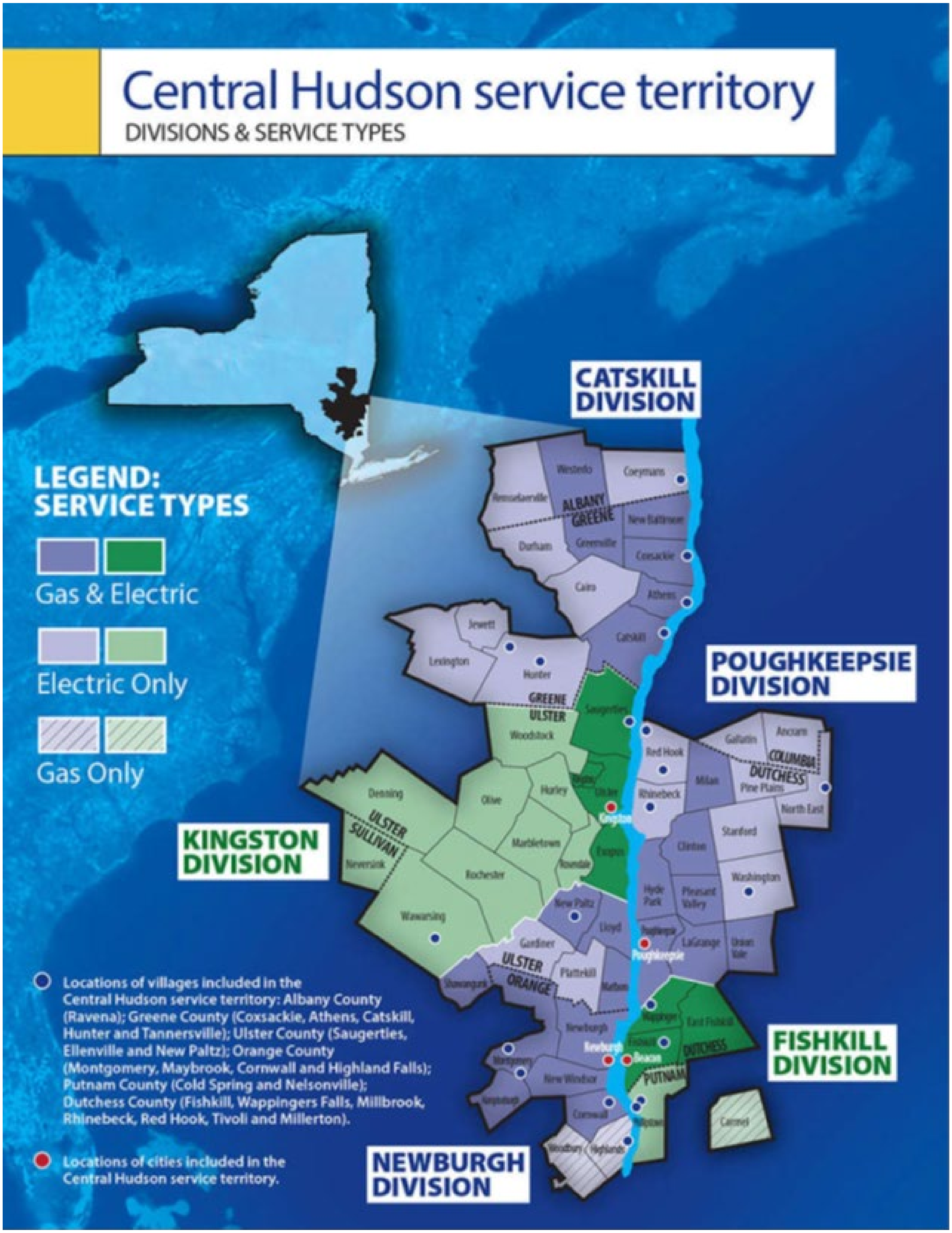
Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company"), incorporated in New York State and headquartered at 284 South Avenue, Poughkeepsie, New York 12601, is a subsidiary of Fortis Inc. As a regulated transmission and distribution utility, Central Hudson serves approximately 315,000 electric customers and 90,000 natural gas customers across eight counties in New York State's Mid-Hudson Valley, serving East and West sides of the Hudson River, extending from the suburbs of metropolitan New York City and as far north as Albany County. The service territory spans approximately 2,600 square miles and is organized into five operating districts: Kingston, Catskill, Poughkeepsie, Fishkill, and Newburgh.

The Central Hudson gas system is comprised of approximately 20,000 miles of services and mains and delivers approximately 13 million MCF of gas annually to residential and non-residential customers.[1] Compared to its electric system, Central Hudson's natural gas service territory is more geographically concentrated along the Hudson River corridor. It consists of 96 local distribution systems (smaller networks) whose gas loads and pressure levels drive infrastructure planning and operational decisions. These areas also heavily overlap with disadvantaged communities, and Central Hudson estimates that approximately 71% of its gas meters are located within such communities.

In alignment with New York state's ambitious climate goals Central Hudson has taken proactive steps towards emissions reduction and clean energy initiatives. The Company is investing in programs that include the advancement of beneficial electrification (e.g. EVs, heat pumps), grid modernization, renewable energy integration, energy efficiency, and demand response initiatives. For more information about Central Hudson, we invite interested parties to our website at: https://www.cenhud.com/about_us.

[1] The value excludes interruptible customers (GS08, G09) and transportation customers (GS11).

**Figure 1: Map of Central Hudson's Gas and Electric Service Territory**



## II. BACKGROUND

In accordance with the New York Public Service Commission's ("Commission") *Order Adopting Gas System Planning Process*[2] ("Gas Planning Order"), Central Hudson developed its Final Gas System Long-Term Plan[3] ("LTP") as part of Case 23-G-0676, to address a 20-year outlook for its gas system reliability, customer needs, and decarbonization efforts. The LTP supports New York State's Climate Leadership and Community Protection Act ("CLCPA" or "Climate Act"), striking a balance between decarbonization goals and maintaining safe, reliable service within its service territory.

The Commission's *Order Regarding Long-Term Natural Gas System Plan and Directing Further Actions*[4] ("July 17, 2025 Order"), issued on July 17, 2025, directs Central Hudson to take specific steps to reduce reliance on traditional infrastructure investments. The July 17, 2025 Order directs Central Hudson to take a number of actions, including filing proposals for demand response programs and identifying segments of its distribution systems that could be addressed with non-pipe alternatives ("NPA").[5]

Specifically, by the July 17, 2025 Order, the Commission directs Central Hudson to file proposals for both a large non-residential customer demand response program and residential customer demand response program targeted to its highly loaded areas with the Secretary to the Commission within 150 days of the Order.[6]

Central Hudson is committed to investing in programs that advance building electrification (e.g., heat pumps), transportation electrification, grid modernization, renewable energy

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[2] Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures ("Gas Planning Proceeding"), Order Adopting Gas System Planning Process (Issued May 12, 2022) ("Gas Planning Order").
[3] Case 23-G-0676, *In the Matter of a Review of the Long-Term Gas System Plans of Central Hudson Gas & Electric Corporation*, Final Gas System: Long Term Plan (filed November 20, 2024) ("LTP").
[4] Case 23-G-0676, *In the Matter of a Review of the Long-Term Gas System Plans of Central Hudson Gas & Electric Corporation*, Order Regarding Long-Term Natural Gas System Plan and Directing Further Actions (Issued July 17, 2025) ("July 17, 2025 Order").
[5] Ibid. p. 2
[6] Ibid. p. 78, Clauses 3 and 4

integration, energy efficiency, and demand response. This document details the proposals for the natural gas demand response programs for non-residential and residential customer sectors.

Together, Central Hudson's Long-Term Plan and the Commission's July 17, 2025 Order establish a proactive framework for advancing innovative solutions such as demand response programs. Through this approach, Central Hudson aims to support the State's clean energy objectives while strategically integrating Distributed Energy Resources ("DERs") into its system in a manner that delivers net benefits to both customers and society.

# III. GAS SUPPLY PLANNING AND DISTRIBUTION PLANNING

As noted earlier, Central Hudson's gas system delivers approximately 13 million MCF of natural gas annually to residential and non-residential customers. As a gas utility, Central Hudson plays a critical role in ensuring reliable gas supply by projecting future demand, securing long-term supply contracts, and reinforcing its distribution networks so that capacity is available to meet growing local needs.

Gas distribution systems are generally sized to maintain adequate pressure under extreme cold conditions, ensuring uninterrupted gas flow. There is an inverse correlation between gas demand and pressure: when demand rises, pressure falls.

The service territory includes four city gate stations, four main gas storage facilities, and 1,300 miles of gas distribution pipelines. City gates reduce pressure from interstate pipelines before gas enters the distribution system. Central Hudson's pipeline network consists of 833 miles of high-pressure lines (60 PSI and above), 174 miles of medium-pressure lines (30–60 PSI), and 315 miles of low-pressure lines. The system also includes 15 transmission regulators and 148 distribution regulators, which create pressure differentials that enable gas to flow from higher to lower pressure points.

Maintaining adequate pressure during extreme cold weather is essential. Gas distribution systems are sized to maintain adequate pressure even under the most extreme cold weather conditions. Pressure drops occur when demand spikes, and low pressure can compromise gas delivery, particularly during peak heating periods. If pressure falls too far, appliances may malfunction, and in severe cases, homes and businesses could lose heat. As weather volatility has intensified with climate change, Central Hudson has updated its planning standards to withstand the increased risk of extreme weather. Central Hudson currently designs its gas system for -8°F (73 HDD) daily average temperature conditions, which occurred in 1994.

At a system-wide level, Central Hudson ensures reliability through long-term supply contracts and continuous monitoring of local systems. Highly loaded systems undergo detailed risk assessments, and when necessary, infrastructure is reinforced through capital investments such as upsizing pipelines or installing additional regulators.

Below, Central Hudson provides additional background on supply planning and distribution planning that is relevant to the development of the gas demand response programs. By implementing a gas demand response program, Central Hudson may limit high peaking prices, delay the need for local distribution upgrades, reduce greenhouse gas emissions, and lessen reliance on the gas system while maintaining reliability during the most challenging conditions.

## A. Territory-wide Supply Planning

Central Hudson's service territory lies next to the Marcellus Shale region, the largest producer of natural gas in the United States. In addition, the Company can access resources from Eastern Canada through the Dawn Hub. Its gas system is supplied by four city gate stations that serve a single contiguous territory, offering both operational flexibility and supply diversification. Central Hudson also maintains contracts with three storage facilities to further strengthen reliability. **Figure 2** lists the entities with which Central Hudson has firm long-term natural gas pipeline transportation contracts and firm long-term natural gas storage capacity with transportation contracts.

**Key Takeaways**

- **Trading Structure**
  Natural gas is traded on daily, not hourly, basis.
- **Cost Avoidance**
  To avoid supply costs, daily gas use must be reduced.
- **Peak Pricing**
  Historical peaking supply prices are **4.8x** the base price and **3.75x** the cost of storage gas.
- **Infrastructure**
  Four city gate stations feed Central Hudson's single contiguous service territory.
- **Procurement Porfolio**
  Gas is typically procured via a diverse portfolio of firm pipeline transportation contracts (5) and firm gas storage (3 facilities).

The configuration provides significant planning and operating flexibility, as well as supply diversity. Central Hudson procures and delivers various supply resources to customers through a combination of owned infrastructure and contracts with third parties. None of the segments of the system are isolated or specifically served by one city gate, which provides for system flexibility and reliability through diversification. If deliverability at one city gate is reduced, for example, Central Hudson can offset the supply loss by procuring and scheduling additional supply through the other three city gates.

**Figure 2: Firm Pipeline and Storage Resources**

| Firm Pipeline Transportation Capacity | Firm Storage Capacity with Transportation Service |
|---|---|
| • Millennium Pipeline (MLP)<br>• Columbia Gas Transmission (TCO)<br>• Tennessee Gas Pipeline (TGP)<br>• Iroquois Gas Transmission (IGT)<br>• Algonquin Gas Transmission (AGT) | • Eastern Gas Transmission and Storage (EGTS)<br>• Columbia Gas Transmission – Columbia Storage<br>• Tennessee Gas Pipeline – Tennessee Storage and National Fuel (NF) Storage |

## GAS SUPPLY PLANNING PROCESS

The annual gas supply planning process begins with sales and peak demand forecasts prepared each spring. A system load duration curve is constructed for the upcoming winter season based on recent historical send-outs, and that curve is adjusted to align with the forecasts. Central Hudson base supply, marketer supplies, storage withdrawal, and peaking supplies are 'stacked' against the load duration curve to ensure adequate supply is available to meet the sales forecast and forecasted design-day peak send-out. Typically, adequate supplies are available at Central Hudson city gates to meet the forecasts. During late Spring, prior to each winter season, the Company develops the Winter Supply Plan. The forecasted gas requirement for each winter season month, November through March, is based on the average of the most recent three-, four-, and five-year average send-outs, adjusted for the forward-looking winter season sales forecast. The estimated send out for each month is then broken down by supply: Central Hudson base supply, marketer supply, storage withdrawal, and peaking supplies.

Based on winter 2023–2024 data, gas peaking contracts were, on average, nearly five times more expensive per $/Dth than gate-delivered base gas and approximately 3.75 times more expensive than gate-delivered storage gas, as illustrated in **Figure 3**. Notably, natural gas is traded on a daily, not hourly, basis. Therefore, reducing daily consumption is essential to lowering supply costs.

Gas supply prices fluctuate with market conditions. When determining the supply portion of the incentive, Central Hudson will rely on the most recent projections of supply prices for the upcoming winter season.

**Figure 3: 2023-2024 Winter Supply Gate Delivered $/Dth Average Costs**

| Base Supply | Storage Supply | Peaking Supply |
|---|---|---|
| $3.2131 | $4.1963 | $15.4566 |

# B. Distribution Planning

Central Hudson's 96 local gas distribution systems are sized to maintain adequate pressure under extreme cold conditions. When demand is high, natural gas pressure drops. If the pressure is too low, it can inhibit the ability to deliver gas to customers precisely when it is coldest, and gas is needed most. If pressure drops too much, the natural gas appliances may not operate properly and, in extreme cases, leave homes and businesses without heat. Due to the critical role of pressure, Central Hudson monitors every local system on a weekly or daily basis and conducts in-depth risk assessments for highly loaded systems.

**Key Takeaways**

- **System Structure**
  Central Hudson has **96** loccal gas systems (smaller gas networks).
- **Design Standards**
  Distribution systems are sized to maintain adequa te pressure under extreme cold conditions (−8°F Daily Average Temperature).
- **Pressure Dynamics**
  When demand is high,natural gas pressre drops.
- **Load Relief Requirements**
  To avoid distribution growth-related capital costs, the right amount of gas load relief is required on the right days and at the right hours. For the gas systems, to alleviate low pressure, the load relief must be positioned downstream from the constraint.
- **Long Term Plan Study**
  As part of the Gas Long Term Plan, Central Hudson's commissioned a study of avoidable gas distribution costs. The study produced a system-wide averag value, and avoided costs by local gas system and year.
- **Avoided Cost Analysis**
  Gas is typically procured via used to calculate the average gas distribution avoided costs for highly loaded local gas systems and update than the **$1,238 per Ccf-year**, in highly loaded areas is **5x** higher than the system-wide average.

At a fundamental level, gas planning and infrastructure planning focuses on maintaining system pressure above a minimum level to ensure normal system functionality. Central Hudson reinforces distribution networks when gas pressure is projected to drop below 50% of the inlet maximum allowable operating pressure under conditions where the average daily temperature reaches -8°F.

## Demand-Side Management

Gas distribution growth-related investments that are shared across multiple customers can be avoided by load relief, including heating electrification, energy efficiency, and demand response, if implemented before the system surpasses its design criteria. However, to avoid the capital costs associated with reinforcing the network, the right amount of gas load relief is required on the right days and at the right hours. For the gas systems, to alleviate low pressure, the load relief must be positioned downstream from the constraint.

In areas with excess capacity, or areas where local, coincident peaks are declining or growing slowly, the value of capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of capacity relief can be substantial, especially if it is possible to delay or defer infrastructure upgrades for an extended period.

## Gas Distribution Avoided Costs

As part of the Gas System Long-Term Plan, Central Hudson commissioned a Location-Specific Gas Distribution Costs Study.[7] The study produced the avoided cost for each local gas system and year, in addition to a territory-wide value. The territory-wide value at the time was $205.38[8] ($2024) per CCF-year (Peak hour load flow). The Study provides a useful starting point for understanding the value of gas demand response in beneficial portions of highly loaded local gas systems.

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[7] Case 23-G-0676, *In the Matter of a Review of the Long-Term Gas System Plans of Central Hudson Gas & Electric Corporation*, Final Gas System: Long Term Plan (filed November 20, 2024). GSLTP - Appendix A: 2024 Central Hudson 20-Year Historical Trend Forecast and Location-Specific Gas Distribution Costs. ("Location-Specific Gas Distribution Costs Study")

[8] Ibid. p.38

To develop an estimate of gas distribution avoided costs for highly loaded areas, Central Hudson:

1. **Identified highly loaded locations in the ten-year period of 2026-2035.** Local systems with a likelihood of exceeding operating limits of 10% or higher were identified.
2. **Scaled the 2024 study values for 2026.** The most recent 2 years of the Gross Domestic Product Implicit Deflator were used for scaling the avoided costs.[9]
3. **Calculated an average avoided cost per year for highly loaded areas** as a load-weighted average across the ten identified systems.
4. **Re-calculated the 10-year levelized value for 2026–2035.**

The update relied on the earlier study developed for the LTP. It did not update load forecasts, capital costs, or reflect more recent reinforcements. To provide more current values, the Location-Specific Gas Distribution Costs Study was utilized with certain simplifications. The approach relied on pro forma or estimated costs rather than a detailed cost analysis. It also did not identify the portion of each local gas system downstream of the constraints. Overall, the avoided distribution value is over five times higher in highly loaded areas than the system-wide value. While we include an estimate of distribution avoided costs in the proposal, the gas distribution avoided cost values and high value load shed areas require periodic updates (e.g., annually) as the gas systems evolve and necessary upgrades are made.

**Table 1** summarizes the updated gas avoided distribution values for load shed areas of highly loaded local gas systems and for local gas systems with headroom. System-wide values have been included as a reference point.

[9] https://fred.stlouisfed.org/series/GDPDEF

**Table 1: Gas Distribution Avoided Costs for 2026-2035 ($2026)**

| Year | Systems with Headroom ($/CCF-year) | Highly Loaded Systems ($/CCF-year) | Territory-wide ($/CCF-year) |
|---|---|---|---|
| 2026 | $10.54 | $1,268.22 | $184.87 |
| 2027 | $11.37 | $1,338.82 | $195.37 |
| 2028 | $14.23 | $1,409.90 | $207.69 |
| 2029 | $17.42 | $1,503.73 | $223.44 |
| 2030 | $26.76 | $1,581.51 | $242.27 |
| 2031 | $51.72 | $1,660.99 | $274.79 |
| 2032 | $61.17 | $1,740.87 | $294.00 |
| 2033 | $92.36 | $1,823.59 | $332.33 |
| 2034 | $121.04 | $320.14 | $148.64 |
| 2035 | $188.26 | $364.44 | $212.68 |
| **Levelized 10-year value (2026-2035)** | **$72.66** | **$1,237.86** | **$234.17** |
| Note: CCF-year refers to the annual peak hour flow (demand) | | | |

# IV. RESIDENTIAL GAS DEMAND RESPONSE PROGRAM

## A. SUMMARY

The following section summarizes Central Hudson's proposed Residential[10] Gas Demand Response Program design. The program is structured as a Bring Your Own Thermostat ("BYOT") initiative built on a pay-for-performance model for aggregators and original equipment manufacturers ("OEMs"), collectively referred to as "vendors." Higher incentives will be offered for residential customers located in load-shed areas of highly loaded local gas systems. While the program is designed for vendors, Central Hudson encourages simple, transparent, and easy-to-understand payment structures for participants (e.g., per device enrollment, event participation, or average performance). To broaden participation and maximize impact, the Company also plans to extend eligibility to small businesses with similar load profiles and compatible connected thermostats.

## B. CUSTOMER ELIGIBILITY

Residential customers may participate by providing their own eligible thermostat control device and enrolling through a vendor. To be eligible to enroll, customers must meet the following qualifications:

1. Be a Central Hudson gas customer;
2. Have gas central heating system controlled by a thermostat; and
3. Have an installed, eligible, and connected Wi-Fi thermostat
4. Customer must have control of their thermostat to participate.
5. If Customer is a tenant, landlord approval is required in writing.

[10] Rate classes including SC1, SC2, SC6 under 50,000 annual CCF. The program will be geared towards connected devices for mass market customers. Most of the sites are anticipated to be residential, but small and medium businesses would not be excluded.

## C. Design Approach

For residential customers, the program is designed to work directly with vendors similar to the model used in the Company's Targeted Demand Management and Dynamic Load Management programs. The proposed approach recognizes that hourly data will be required for settlement, however, Central Hudson has not yet deployed smart meters capable of collecting hourly or sub-hourly data.

Vendors will be required to use connected devices that can:

1. Measure end-use run time or gas flow (CCF/hour) at hourly or sub-hourly intervals;
2. Track operating modes; and
3. Track customer set points.

Vendors must collect this data and provide it to Central Hudson on a regular basis (e.g. following an event and monthly). Connected devices, such as smart thermostats, generally meet these requirements. If run-time data is used, Central Hudson and the vendor will need to agree in advance on the methodology for converting run-time into estimated demand.

The Company will propose an advanced notice schedule for pre-event customer engagement, including provisions for vendors to pre-heat homes and businesses prior to events. Leveraging connected devices, Central Hudson expects to dispatch resources on shorter notice when necessary (i.e. reliability needs) and enable implementers to automate the steps between dispatch instructions and device response.

**Table 2: Proposed Gas Demand Response Program Design (Anticipated Values)**

| Design Component | Residential | |
|---|---|---|
| | Areas with headroom | Highly loaded shed area |
| Program Type | Pay for performance (Aggregator/ OEM) | Pay for performance (Aggregator/ OEM) |
| Incentive $/CCF-hour (Volume on peak) | $2.88 | $28.13 |
| Incentive $ per device enrolled (sign-up) | $25 | $50 |
| Event Duration (hours) | 2-5 | 2-5 |
| Anticipated Minimum Annual Event Hours | 20 | 20 |
| Anticipated Annual Event Hours | 20 - 40 | 20- 40 |
| Availability Months | Nov-Mar | Nov-Mar |

## D. Incentive Levels

All incentive payments will be made to participating vendors, which will be responsible for determining the incentive structure and administering payments to customers. Vendors do not have to use the pay-for-performance structure for individual customers. Again, Central Hudson encourages aggregators to adopt simple, transparent, and easy-to-understand payment structures for residential customers.

The available incentive factors in avoided distribution capacity value, peak day energy supply cost savings, and CO2e emission values. By design, the incentives are designed to deliver net benefits to ratepayers, after accounting for the costs associated with administering programs. The incentives are higher for sites in load-shed areas of the highly loaded local gas systems due to the concentration of avoidable distribution costs in those locations.

By design, the incentives are designed to allow for updates based on changes in peaking day supply prices, co2e valuation, and avoided distribution costs. The incentives and the highly loaded areas may be updated periodically (e.g., annually) to reflect the changes in gas conditions and needs.

**Table 3** summarizes the annual incentives per CCF-year (peak hour flow) of delivered load reduction as a function of annual event hours. **Table 4** illustrates the expected annual incentives for different types of customers using a Central Hudson average customer by building type. The exact annual incentives will vary based on end-uses controlled, load relief performance, and aggregation partner decisions regarding incentives for participants.

**Table 3: Expected Annual Incentives (per CCf-year of Delivered Reduction)**

| | Residential | |
|---|---|---|
| **Event Hours** | **Areas with headroom** | **Highly loaded shed area** |
| 20 | $57.67 | $562.59 |
| 30 | $86.50 | $843.88 |
| 40 | $115.33 | $1,125.17 |
| 50 | $144.17 | $1,406.47 |
| 60 | $173.00 | $1,687.76 |
| 70 | $201.83 | $1,969.05 |
| 80 | $230.67 | $2,250.35 |
| 90 | $259.50 | $2,531.64 |
| 100 | $288.33 | $2,812.93 |

**Table 4: Expected Annual Incentives by Type of Customer**

| | | Whole Building | | | Heating | Annual Incentive | |
|---|---|---|---|---|---|---|---|
| **Building Type** | **Avg Building Sq. ft.** | **Annual CCF (Volume)** | **Peak Day CCF (Volume)** | **Peak Hour CCF (Flow)** | **Peak Hour CCF (Flow)** | **Areas with headroom** | **Highly loaded shed area** |
| Multi-Family | 1,472 | 427 | 5.2 | 0.30 | 0.25 | $7.74 | $74.64 |
| Single-Family Attached | 1,311 | 639 | 8.0 | 0.46 | 0.39 | $11.88 | $114.55 |
| Single-Family Detached | 1,810 | 861 | 10.9 | 0.65 | 0.53 | $16.28 | $156.99 |
| Values are estimated for the average Central Hudson customer. Assumptions: 50% reduction in heating load during event hours, assuming pre-heating of building, a 4-degree thermostat adjustment, 30 hours of dispatch, and that aggregators/OEM pass through 70% of incentives to participants. | | | | | | | |

## E. Event Dispatch

Central Hudson anticipates (but is not limited to) dispatching the gas demand response program for 20–40 hours each winter season, typically during the coldest days of the year. This approach ensures that curtailment events deliver sufficient capacity and supply value, maintain consistent customer engagement, and provide aggregation partners with an annual compensation floor. Dispatch events are expected to last 2–5 hours. The program will be available during the months of November through March.

## F. Budget Proposal

The Order directed Central Hudson to file distinct proposals for large non-residential and residential gas demand response programs. While a program can be implemented for a single sector, many of the overhead costs are shared,[11] and there are spend efficiencies implementing programs for both sectors as a portfolio. In addition, implementing programs for both sectors helps ensure the breakeven volume of participation is more attainable. **Table 5** shows the proposed budget, with the residential program highlighted.

**Table 5: Proposed Budget for Residential Demand Response Gas Program**

| Component | Both Program Options | Residential only | Large Non-Residential only |
|---|---|---|---|
| Annual overhead costs | $250,000 | $200,000 | $200,000 |
| Net benefit per CCF-year (peak hour flow) of reduction[1] | $447.69 | $447.69 | $447.69 |
| CCF-year (peak hour flow) Reduction breakeven | 558.4 | 446.7 | 446.7 |
| Target CCF/hr. | 800 | 700 | 700 |
| Proposed Annual Budget | $650,000 | $550,000 | $550,000 |
| [1] The net benefit assumes 50% of the resources are in load shed areas of highly loaded systems | | | |

[11] Examples include Central Hudson overhead, measurement & evaluations, performance settlement costs, annual aggregator overhead

# V. NON-RESIDENTIAL GAS DEMAND RESPONSE PROGRAM

## A. Summary

The following section summarizes the Company's proposed Non-Residential Gas Demand Response Program design. The foundation of the design is a pay-for-performance program with higher incentives for non-residential[12] customers located in load-shed areas of highly loaded local gas systems.

## B. Customer Eligibility

Non-Residential customers may participate by agreeing to curtail their gas usage when called upon. To be eligible to enroll, customers must meet the following qualifications:

1. Be a Central Hudson gas customer; and
2. Rate Classes SC11, SC2, or SC6 with over 50,000 annual CCF.

## C. Design Approach

For larger non-residential customers, the program is designed to enable direct participation and direct control of devices that manage gas demand is not required. Customers will be encouraged to work with aggregators, but are not required to do so. The proposed approach recognizes that hourly data will be required for settlement. If needed, Central Hudson will install meters capable of collecting hourly or sub-hourly interval gas usage data.

Larger customers are more likely to rely on building management systems and often prefer to manage their loads directly. Thus, the program proposes having a schedule indicating a day-ahead advance notification, for example, 18-hours, meaning that customers receive notice of an event at 6 AM, before noon the day prior. Because of

[12] Rate Classes SC11, SC2, or SC6 with over 50,000 annual CCF.

the longer event lead time, it can be harder to forecast the exact days and hours when the load relief is needed, and can lead to more frequent dispatch.

**Table 6: Proposed Gas Demand Response Program Design**

| Design Component | Non-Residential | |
|---|---|---|
| | **Areas with headroom** | **Highly loaded shed area** |
| Program Type | Pay for performance (Aggregator/ OEM) | Pay for performance (Aggregator/ OEM) |
| Incentive $/CCF-hour (Volume on peak) | $2.88 | $28.13 |
| Event Duration (hours) | 3-5 | 3-5 |
| Anticipated Minimum Annual Event Hours | 20 | 20 |
| Anticipated Annual Event Hours | 20 - 40 | 20- 40 |
| Availability Months | Nov-Mar | Nov-Mar |
| Event Advanced Notice | 18 hours | 18 hours |

## D. Incentive Levels

All incentive payments will be made to direct participants or aggregation partners. The incentive factors in avoided distribution capacity value, peak day energy supply cost savings, and CO2e emission values. By design, the incentives are designed to deliver net benefits to ratepayers, after accounting for the costs associated with administering programs.

**Table 7** summarizes the annual incentives per CCF-year (peak hour flow) of delivered load reduction as a function of annual event hours.

**Table 7: Expected Annual Incentives (per CCf-year of Delivered Reduction)**

| | Large Non-Residential | |
|---|---|---|
| **Event Hours** | **Areas with headroom** | **Highly loaded shed area** |
| 20 | $57.67 | $562.59 |
| 30 | $86.50 | $843.88 |
| 40 | $115.33 | $1,125.17 |
| 50 | $144.17 | $1,406.47 |
| 60 | $173.00 | $1,687.76 |
| 70 | $201.83 | $1,969.05 |
| 80 | $230.67 | $2,250.35 |
| 90 | $259.50 | $2,531.64 |
| 100 | $288.33 | $2,812.93 |

The incentives are higher for sites in load shed areas of the highly loaded local gas systems because avoidable distribution costs are concentrated in those locations. By design, the incentives are designed to allow for updates based on changes in peaking day supply prices, co2e valuation, and avoided distribution costs. The incentives and the highly loaded areas may be updated periodically (e.g., annually) to reflect the changes in gas conditions and needs.

Central Hudson anticipates dispatching the program at least 20 - 40 hours each winter season in order to provide aggregation partners with an annual compensation floor. Event durations are expected to be 3-5hrs. This ensures that load relief resources are used and tested and affords Central Hudson the flexibility to dispatch resources for additional hours in years when it is needed. Without consistent dispatch, customers and aggregators may experience significant fluctuations in revenue/incentives due to year-on-year weather variability, and the performance of gas DR resources may not be adequately tested each year.

## E. Budget Proposal

The July 17, 2025 Order directed Central Hudson to file distinct proposals for a large non-residential and residential gas demand response programs. While a program can be implemented for a single sector, many of the overhead costs are shared,[13] and there are spend efficiencies implementing programs for both sectors as a portfolio. In addition, implementing programs for both sectors helps ensure the breakeven volume of participation is more attainable. **Table 8** shows the proposed budget, with the large non-residential program highlighted.

**Table 8: Proposed Budget for Residential Demand Response Gas Program**

| Component | Both Program Options | Residential only | Large Non-Residential only |
|---|---|---|---|
| Annual overhead costs | $250,000 | $200,000 | $200,000 |
| Net benefit per CCF-year (peak hour flow) of reduction[1] | $447.69 | $447.69 | $447.69 |
| CCF-year (peak hour flow) Reduction breakeven | 558.4 | 446.7 | 446.7 |
| Target CCF/hr | 800 | 700 | 700 |
| Proposed Annual Budget | $650,000 | $550,000 | $550,000 |
| [1] The net benefit assumes 50% of the resources are in load shed areas of highly loaded systems | | | |

For the large non-residential program to achieve cost-effectiveness, Central Hudson estimates that approximately 450 CCf per year of peak-hour load reduction must be realized, assuming that at least half of this relief occurs within load-shed areas of highly loaded systems. To identify these opportunities, the Company will work closely with its engineering team to pinpoint sites located downstream of system constraints.

The success of this program will largely depend on enrolling the largest customers situated in these critical load-shed areas. However, given the limited number of large customers within the service territory, it is challenging to predict in advance whether the targeted level of load relief necessary to cover program overhead costs will be achieved.

[13] Examples include Central Hudson overhead, measurement & evaluations, performance settlement costs, annual aggregator overhead

# VI. PAY-FOR-PERFORMANCE SETTLEMENTS

Methods for settlement are a critical topic in estimating pay-for-performance payments. Demand reductions are not directly metered and must rely on an estimate of what demand would have been absent event dispatch – a baseline or counterfactual. Estimates of demand reduction become more accurate when calculated across multiple event hours, multiple event days, and a broad customer base. Accuracy also improves when the percentage reduction in demand is larger, producing a stronger "signal"[14] and when variability in hourly usage can be more fully explained. However, regardless of the method used, all estimates of demand reduction contain some degree of statistical noise, particularly at the individual site level.

Settlement will be done in aggregate, across all customers and event hours, and the aggregator will be responsible for compensating individual customers. In aggregate, a proposed minimum of 5% gas load reduction during event hours is required for payment eligibility with a number of participating sites (for example, verification that at least 100 customers must participate). The approach is designed to simplify the settlement process and minimize the potential for payments due to statistical variability.

Multiple baseline methods were considered, including day-matching and weather-matching approaches. However, these methods are heuristic in nature. While they are simple and easy to understand, they are not inherently unbiased at the individual site level. For some customers, they may overestimate reductions, while for others they may underestimate them, even if the overall average result appears reasonable on the surface.

Settlement is anticipated to be based on a statistical model known as a linear regression Time-of-Week-and-Temperature model. For example, each hour of the week will have a distinct indicator, variable, and coefficient. A separate model will be estimated for each site. Weather will be modeled as the difference between outside temperature and the device setpoint.

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[14] A clear difference between demand usage on the event day and a typical (adjusted) customer baseline day.

At a high level:

- The model will be estimated using non-event day hourly data and used to produce the counterfactual or baseline for each site.
- The counterfactual and actual loads of participants will be summed up for the participants.
- The estimated load relief will be calculated and the difference between the counterfactual and baseline for each event hour.
- If run time data was provided, the counterfactual, actual load, and load relief values will be scaled using the agreed upon scalar prior to the winter season (Nov-Mar).
- The counterfactual load, actual load, and estimated load relief will be summed across all event hours.
- If the percent reduction (load relief / counterfactual load) exceeds 5%, the Load Relief will be multiplied by the incentive payment.
- At no point will the estimates of load relief be zeroed out. The objective is to avoid payment errors due to asymmetric treatment of statistical noise.

# VII. SHAREHOLDER INCENTIVE

Consistent with Central Hudson's approach for Non-Wires Alternatives ("NWA") and other Non-Pipeline Alternative ("NPA") programs, the Company proposes a shareholder incentive equal to 30% of the net benefits realized through the implementation of Demand Response solutions. Net benefits are calculated based on the Societal Cost Test ("SCT") as outlined in the Company's Benefit-Cost Analysis ("BCA") Handbook. This incentive structure is designed to align shareholder interests with customer and societal benefits by rewarding performance that delivers measurable value beyond traditional infrastructure investments.

The Commission has affirmed its support for innovative demand-side management programs such as NWA and NPA programs, emphasizing their role in promoting distributed energy resource ("DER") adoption and cost-effective alternatives to traditional infrastructure. The Commission underscored that incentives must align financial performance with achievement of public policy goals, allowing utilities to share net benefits from successfully deployed non-traditional solutions.

The calculation of net benefits will follow the same methodology applied in the BCA framework: total benefits, including avoided infrastructure costs, reliability improvements, and environmental benefits, minus total program costs. Once the SCT demonstrates that benefits exceed costs (SCT ≥ 1.0), the shareholder incentive will be applied to the resulting net benefit amount. This approach ensures that incentives are only earned when projects are cost-effective and provide tangible benefits to customers and the system.

By maintaining consistency with existing NWA and NPA incentive mechanisms, this structure promotes transparency, regulatory alignment, and continued innovation in demand-side and non-pipeline solutions. The incentive serves as a critical tool to encourage utilities to pursue alternatives that reduce reliance on traditional capital projects while advancing state policy objectives related to affordability, resiliency, and decarbonization.

# VIII. COST-EFFECTIVENESS

Central Hudson evaluates the cost-effectiveness of its NPA and Demand Response (DR) portfolios using the BCA framework outlined in the Company's BCA Handbook. This framework incorporates three tests, with the SCT serving as the primary metric for determining program viability, consistent with Commission requirements. An SCT score of 1.0 or greater indicates that the benefits of a solution meet or exceed its societal costs, and therefore, the solution is considered cost-effective.

To ensure accuracy and transparency, Central Hudson partners with an independent third-party evaluator to review program performance and cost-effectiveness annually. The Company applies valuation methodologies from the BCA Handbook, tailored to reflect natural gas system characteristics, and incorporates gas-specific benefits and costs where applicable. These protocols are continually refined to capture all relevant impacts, with any material changes made in consultation with Department of Public Service (DPS) Staff.

Because specific costs can be uncertain prior to detailed assessments, initial estimates are based on conservative assumptions. While some projects may begin with preliminary SCT scores below 1.0, the Company may pursue these opportunities if there is a reasonable expectation that the final SCT will meet or exceed the threshold. Central Hudson's overarching goal is to maintain a portfolio-level SCT of 1.0 or greater, ensuring that investments deliver net benefits to customers and society.

# IX. CONCLUSION

Central Hudson's proposed gas demand response programs represent a forward-looking strategy to enhance system reliability, reduce peak supply costs, and defer costly infrastructure investments while supporting New York State's clean energy and decarbonization objectives. By leveraging pay-for-performance structures, advanced technologies, and targeted incentives, these programs aim to deliver measurable benefits to customers and society, including improved resiliency and reduced greenhouse gas emissions.

The proposal provides a comprehensive framework for residential and large non-residential sectors, addressing the unique challenges of highly loaded areas. Success will depend on strong customer and vendor participation, rigorous measurement and verification, and adaptive program design that evolves with system needs.

By pursuing innovative demand-side solutions, the Company reinforces its commitment to affordability, reliability, and sustainability, positioning itself as a proactive partner in achieving the State's climate and energy goals. Through transparent cost-effectiveness evaluations and alignment with regulatory guidance, Central Hudson ensures these programs remain economically sound and beneficial to customers.

This proposal fulfills the requirements set forth in the Commission's July 17, 2025 Order Regarding Long-term Natural Gas System Plan and Directing Further Actions, specifically Clauses 3 and 4, by proposing residential and non-residential gas demand response programs.