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A Hitchhiker's Guide to Gas Demand Response

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Abstract

Providing energy consumers with more information about the cost of when and how much energy they use is a hot topic in this era of climate change. All utilities use energy efficiency measures to help consumers reduce energy usage, but thus far, only electric utilities have utilized "demand response" programs on a large scale. Such programs provide incentives for not using electricity during certain times of the day. The Energy Infrastructure Demand Response Act of 2018 seeks to apply demand response to natural gas utilities, for whom seasonal consumption of gas for heating purposes drives infrastructure investment. Wind and temperature, two drivers of gas consumption patterns, are not within the control of utilities. But with prices that better reflect the forward-looking costs of investing in infrastructure that meets the winter peak, gas utilities can incentivize customers to reduce peak consumption, infrastructure investment, and fossil fuel use.

Introduction

Interest in promoting gas demand response programs gained national attention with a bill sponsored by Senator Sheldon Whitehouse (D-RI) to "establish a natural gas demand response pilot program to use the latest demand response technology from the energy sector for natural gas."[1] While the bill is still in committee, part of it was included in the 2019 Energy and Water appropriations bill and requires the Department of Energy (DOE) to study the potential for natural gas demand response. The study will address "the costs and benefits associated with those savings, including avoided energy costs, reduced market price volatility, improved electric and gas system reliability, deferred or avoided pipeline or utility capital investment, and air emissions reductions."[2]

Demand response programs promote pricing signals to consumers that better reflect the resource cost of their consumption. Such signals permit consumers to change their consumption behavior during peak usage times. For electricity markets, demand response programs represent mechanisms that allow customers to adjust consumption according to real-time wholesale prices. With advanced metering infrastructure capable of transmitting such prices, consumers can choose to reduce demand during peak periods (when electricity prices are higher) and consume during off-peak periods (when prices are lower).[3]

Implementing demand response programs in gas requires acknowledgement of a different supply infrastructure for a different type of commodity. The goals of reducing energy usage and reducing infrastructure investment—goals of electric demand response programs—also apply to gas. Gas demand response programs have the potential to reduce peak consumption such that infrastructure investment decisions can be delayed. Prices that better reflect the forward-looking costs of investing in infrastructure to meet the winter peak—an application of marginal cost pricing—can achieve this goal.[4] Coupled with traditional energy efficiency programs to reduce overall gas usage, gas utilities and state regulators—who have the planning and public interest responsibilities—can modify the rate structure such that it incentivizes customers to reduce peak consumption leading to less infrastructure investment and fossil fuel use.

The next section describes two subjects that often complicate discussions of gas demand response programs: 1) New England's unique pipeline capacity issues and 2) traditional energy efficiency measures. The following section contrasts the differing peak and off-peak time horizons relevant to demand response actions in electricity and gas. Next is a description of how utilities can use a novel form of marginal cost pricing to modify rate design and incentivize consumer behavior, possibly resulting in delayed infrastructure investment. The final section concludes.

Isolating Demand Response from Other Subjects

Gas demand response is a potentially useful initiative, but one that has tended to be caught up in discussions of other unrelated problems and initiatives. One such problem is related to the "polar vortex" in New England. Another is the longstanding application of simple energy efficiency programs aimed at gas use.

New England Is a Special Case Study in Missing Regulation

The gas demand response bill was motivated in part by New England's extreme polar vortex weather events over the last five years, which twice caused very high energy prices due to heavy reliance on gas-fired power generation in the region and a lack of interstate pipeline capacity to serve both home heating requirements and electric generation during the coldest winter days.[5] These two polar vortex events represent times when two energy markets visibly failed to intersect successfully with one another.

A frequent assumption of competitive energy markets holds that everything, other than the regulation of the local distribution network facilities, can and should be left to the market. Elsewhere I have called this an "economic folk theorem."[6] Unlike the situation in restructured electricity markets, where legislation bars state regulators and electric distributors from wholesale power generation, state regulatory action for gas utilities reaches far upstream from the boundaries of regulated local distributors who support investment in interstate pipelines with regulatory review and approval. As it stands today, however, New England's wholesale power market cannot support such capital investments. Efforts in the region have so far been unable to overcome opposition in the courts and from power producers who look to cold-weather-induced price surges as a source of earnings. The gas pipeline capacity constraints facing New England illustrate a failure to recognize that certain types of energy infrastructure investments—interstate gas pipelines in particular—require the institution of public interest regulation to assess need and harness the credit of the region's millions of gas consumers. Gas demand response programs cannot target the primary issue for New England—that the region's gas-fired power generators tend not to sign long-term contracts with interstate pipelines.

Energy Efficiency Programs Are Not Demand Response

Energy efficiency programs emerged during the energy crises of the 1970s to encourage consumers to mitigate home energy usage and for states to meet emission reduction goals. Energy efficiency employs technologies or products to help consumers use less energy to do the same or a better job than before. For gas, this means better home insulation, more efficient heating systems, and appliances that help consumers reduce overall energy usage and spending.[7] States and utilities all around the country use financial incentives (e.g., price discounts, rebates, low-cost financing) to encourage consumer participation.[8] In 2016, the states that spent more than $10 per residential and commercial customer saved enough energy to heat more than 600,000 average US households for one year.[9]

While it is easy to confuse energy efficiency and demand response because both can be characterized as forms of managing consumption, there is an important distinction: demand response specifically aims to reduce energy usage during peak times.[10] In other words, energy efficiency seeks to incentivize consumers to adopt technologies that make electric or gas usage more efficient during both peak and off-peak periods. Demand response, on the other hand, seeks to incentivize consumers to use less electricity or gas during the peak. Energy efficiency initiatives cannot target the primary issue that gas demand response seeks to alleviate—that usage during peak winter months drives costly infrastructure investment.

Gas Utilities' Yearly Planning Cycle

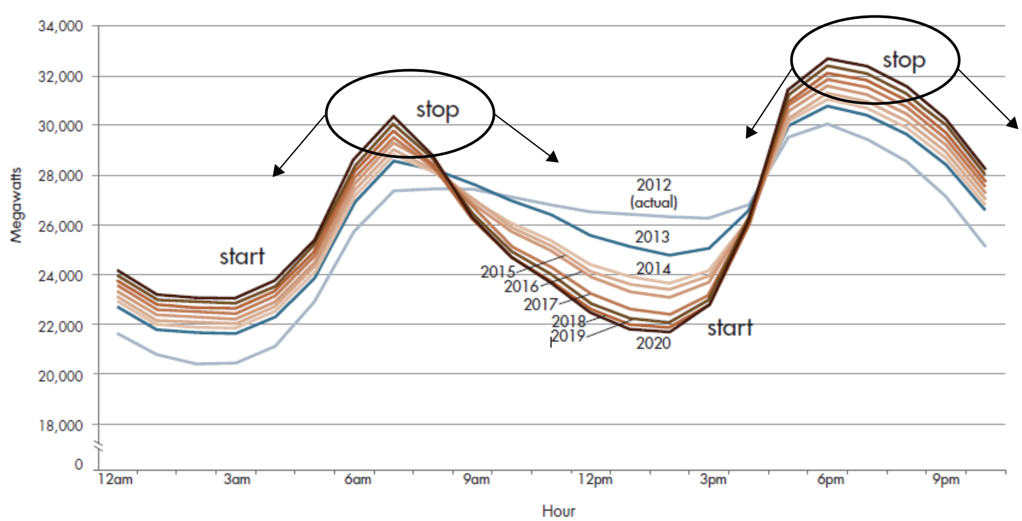
In the United States, natural gas is predominantly a space-heating fuel, and peak gas consumption occurs during the winter months. Gas utilities plan for gas demand over the course of the year based on the relationship between historical "sendout" (quantity of gas delivered) and weather. The planning process works well—but how do we get consumers to use less gas overall and how can we reduce need for more infrastructure to serve the peak? Changing the relationship between sendout and weather by modifying rate design to recognize the costs of serving the peak can potentially achieve the goals of demand response—to reduce gas usage and infrastructure investment.

Demand response in electricity focuses on providing customers with price signals, often in real-time with advanced metering, to incentivize reduced consumption to off-peak hours within the day. The planning period for gas targets the peak months in a year. Hourly changes in consumption are not relevant for gas utility planning purposes.

Many retail and wholesale electricity market actors participate in demand response programs. In its thirteenth assessment of electric demand response and advanced metering infrastructure, the Federal Energy Regulatory Commission (FERC) shows demand resource participation in regional transmission organizations/independent system operators (RTOs/ISOs) grew more than 3% between 2016 and 2017.[11] The potential for peak demand savings from retail demand response programs grew more than 9% and customer enrollment in retail demand response programs grew more than 8% between 2015 and 2016.[12]

Figure 1 below shows the now infamous California duck curve, where increased solar generation over the years lowers the belly of the duck and usage increases at the peak once the sun sets. As illustrated, load-shifting demand response encourages usage during off-peak hours.[13] Demand response can incentivize consumers to change consumption from peak periods—those periods that drive electricity markets and infrastructure investment.[14] The success of price signals to consumers of the costs of consuming electricity during peak hours can be measured by lower peaks.

Figure 1. Demand Response Encourages Consumers to Reduce Hourly Peak Demand

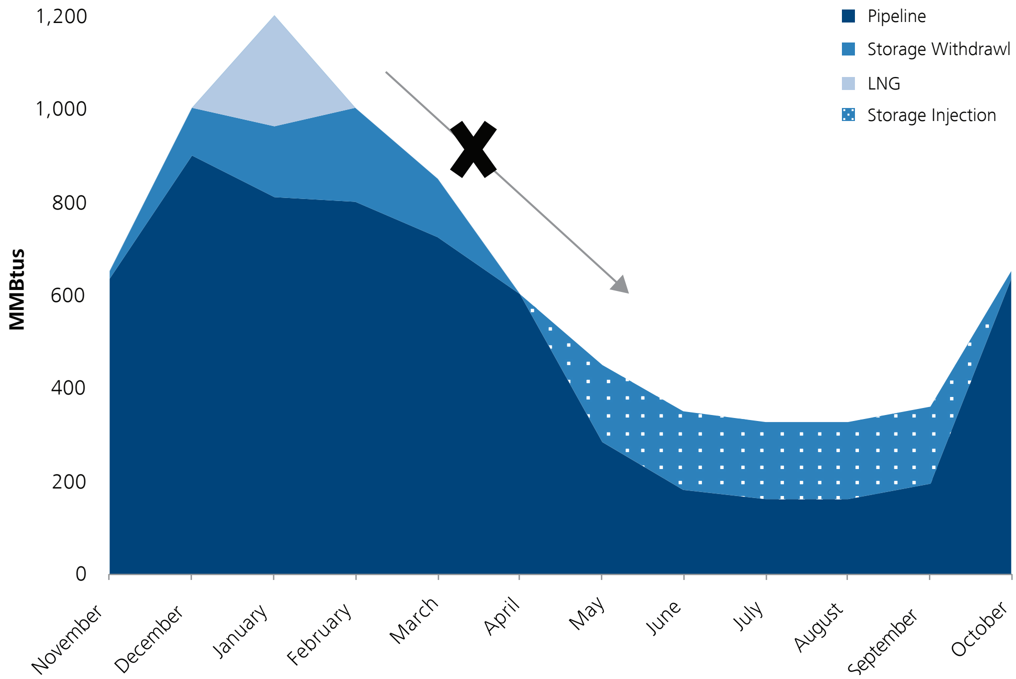


Source: California Independent System Operator with illustration by author.

Electric demand response concerns both 1) the energy costs of generating enough electricity to meet peak consumption and 2) capacity costs of generation, transmission, and distribution, to serve the peak. Electric demand response programs can reduce power plant investment and, by mitigating network congestion, reduce transmission and distribution investment.[15] Gas demand response concerns only transport and storage infrastructure.

The time horizon that drives infrastructure investment for gas is annual (see Figure 2). The focus of gas demand response programs will need to encourage a change in behavior to more accurately reflect the relevant peak periods: the winter months.

Figure 2. Consumers Cannot Shift Home Heating Gas Usage to Off-Peak Months



The gas distribution utility can use its off-peak capacity during the summer months to supplement pipeline throughput capacity during the peak months from November to March. That is, during off-peak months (April through October, depending on the location), utilities serve customers' needs (largely water heating, cooking, and gas clothes dryers) using ample pipeline throughput capacity and injecting some gas into storage to save for the winter. During the winter months, distributors use all the resources available (pipeline, stored gas, and liquefied natural gas (LNG)) to serve consumers heating demands.

Because gas distribution utilities use various forms of storage to meet their winter peaks, even though peak day capacity may not be exceeded on any one day, gas distribution utilities must guard against the possibility of running out of gas over the course of the year. Utilities use stored gas (or other supplemental supplies, such as LNG) to serve large portions of their peak winter loads in addition to pipeline capacity. It is theoretically possible, during a very cold winter, for a gas utility to use up its stored and supplemental supplies and run out of gas.

This scenario is conceivable—even if none of the daily loads come close to the daily capacity of the gas distribution system. The utility's system must be designed with enough storage to meet the winter heating requirements, regardless of the date or duration of the peak load. This is what is meant by "annual capacity." It is a capacity measure for gas utilities that is independent of peak capacity and is just as important from the perspective of providing service to customers.

The gas demand response program piloted by Southern California Gas (SoCalGas) during the winter of 2017–2018 illustrates the distinction between reducing energy usage during peak hours and peak months.[16] Originally approved in late 2016 as part of several natural gas conservation efforts and demand response programs, the program became more important after several pipeline outages and the 2015 leak at the Aliso Canyon gas storage facility, resulting in the SoCalGas system operating at less than full capacity.[17] In an effort to mitigate constraints, SoCalGas gave a thermostat rebate to consumers who agreed to allow the utility to turn down their thermostats by three or four degrees during morning and evening hours on certain days. The program was successful in meeting the objective of reducing gas usage during those hours of system stress identified by the utility. However, it did not reduce overall gas usage, as savings largely disappeared as soon as thermostats returned to preferred temperatures after the event (called "snapback").[18] The SoCalGas program provides an example of an effective gas demand response program addressing unique circumstances—where certain hours of certain winter days are particularly difficult for the system and advanced metering infrastructure and thermostat control allow the utility to alter home heating demand.[19]

As illustrated by Figure 2 and the SoCalGas example, it is not possible to force consumers to consume gas that primarily heats homes during the summer, and targeting certain hours may alleviate some system constraints but is unlikely to result in overall gas savings. But it is possible to change consumer consumption during the peak winter months by changing rate design to better reveal the costs of serving winter peak demand, which may encourage consumers to reduce usage during those months and, therefore, delay or prevent new infrastructure investment.

Gas Demand Response Can Change Consumer Behavior

Demand response programs can utilize a novel form of marginal cost pricing. For electricity, this means communicating wholesale spot market prices to consumers through advanced metering infrastructure and time-of-use pricing to encourage those consumers to reduce usage during peak hours.[20] For gas, it means communicating the costs of serving the winter peak months by altering rate design to better reflect the costs that are driving the investment during those months. This does not necessarily require advanced metering infrastructure to signal prices to gas consumers, because hourly demand does not drive investment. Rather, all it requires is modifying rate design to collect a greater proportion of the costs during peak months.

The Costs to Serve Gas Consumers

Gas utility costs generally fall into four major categories: gas supply, transmission, storage, and distribution. Gas supply depends on contracts signed between producers and local distribution companies who have a portfolio of long- and short-term gas supply contracts and some spot market, storage, and LNG purchases.[21] Those local gas distributors also sign contracts with pipelines and storage facilities. Distribution includes the cost of infrastructure to transport gas to homes and businesses. Local distribution companies file gas supply plans with state regulators, who approve those plans and uphold the public interest by ensuring the company procures sufficient gas supply and pipeline and storage capacity for ratepayers.[22]

As gas utilities go through the planning process, any changes in demand (for instance, due to newly created demand response programs) travel a longer path to revealing changes. The impact of a change in consumer behavior due to a gas demand response program takes longer to observe than in the electricity market. However, the longer path does not need to be a deterrent for demand response initiatives. Programs to encourage consumer awareness of gas usage can serve to avoid or delay investment in new infrastructure. By building demand response into the gas infrastructure planning process, it is possible to reduce peak consumption and, therefore, infrastructure spending.

There exists a straightforward way to implement a gas demand response program—which requires a simple change to rate design—that has the ability to change consumer behavior and achieve the goals of reduced infrastructure investment, peak usage, and emissions. Solving the problem of how to reveal the costs of serving peak winter months is the first step to implementing gas demand response. The next step is to see how that price signal, and ensuing changes in behavior, may affect utility gas supply and infrastructure needs.

Marginal Cost Pricing

Marginal cost pricing recognizes that, for consumers to make efficient choices, they must know the cost of the product they plan to purchase so they can make a decision about whether the satisfaction they gain from consuming that product is worth the cost.[23] Off-peak usage does not impose capacity constraints on the system. By creating a rate design that signals to consumers the costs of consuming gas during the peak winter months, utilities can reduce gas usage, which reduces infrastructure investment going forward.

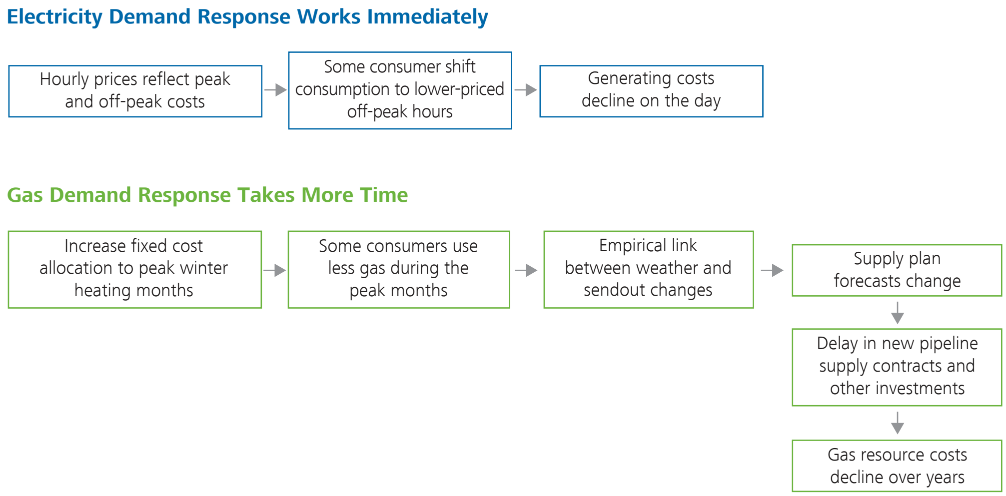
Marginal cost pricing looks to the future by examining what additional consumption or production caused the firm to incur additional costs.[24] In the context of a gas demand response program, additional consumption refers to the consumption that caused the utility to incur additional costs of gas supply procurement and investment in interstate pipeline and distribution infrastructure. A gas demand response program that adjusts rate design to recognize the additional costs of gas supply and infrastructure during peak usage months—the winter months that drive incremental investment—can be called "latter-day marginal cost pricing."[25]

The approach is not new. Some state regulators have used marginal cost pricing for their gas and electric utilities since the 1970s when inflation, high energy prices, and the seeming exhaustion of scale economies in the electric utility industry drove real prices up. Led by New York and Wisconsin, regulators and state legislators implemented marginal cost pricing to encourage more efficient utility ratemaking by separating and allocating regulated costs toward those customer classes more responsible for the costs needed to serve the peak.

Figure 3 shows the steps through which demand response programs must travel to impact electricity and gas resource costs (fuel and infrastructure). For electricity, the path has fewer steps and the impact can be seen within a day. Time-of-use pricing and advanced metering infrastructure reveal the price of consuming electricity during peak usage times to consumers. They will react to those prices by changing the time of day in which they use electricity-intensive appliances. Immediately, the electric system will require fewer resources at the peak and electric costs will decline.

For gas, the relevant peak to consider comes in the winter months, when consumers use gas to heat homes. Allocating fixed costs to those peak winter months that drive infrastructure investment will better reflect actual costs to serve consumers. Consumers may react to this price and change behavior by reducing gas usage. The ultimate effect of this change may be a reduction in gas resource costs, but changes in gas supply and infrastructure investment can only be measured by looking at how a change in consumer behavior affects the gas distribution utility planning process.

Figure 3. How Demand Response Programs Impact Energy Resource Costs



Changed consumer behavior will alter the relationship between weather and sendout. Consumers will have a better idea of the costs of using gas during peak (and off-peak) periods. Distributors can take this changed relationship into account when developing supply plan forecasts. Less gas usage at the peak can mean delaying new supply contracts with pipelines and other sources of supply, and possibly delaying infrastructure investment. Delayed investment results in a decline in gas resource costs.

Using Demand Response to Reduce Gas Resource Costs

Legislatures and state regulatory commissions regulate the way in which gas distribution companies plan consumer service. While the regulations differ by state, generally gas distribution firms file gas supply plans with the regulator every few years. Those gas supply plans use weather and other variables to predict sendout required to meet demand during certain peak periods. Table 1 provides examples of 13 states requiring utilities to provide gas supply plans for regulatory approval.

Table 1. **Frequency Plan Filing and Forecast Periods for Utilities in States with Gas Supply Plan Filing Requirements**

State	Regulation	Frequency of Filing (Years)	Forecast Period (Years)
Colorado	4 CCR 723-4 §4605	1	1
Delaware	26 Del. C. §1007(c)(1)	2	10
Indiana	170 IAC 4-7-1 - 4-7-10	3	20
Massachusetts	MGL c. 164 §691	2	5
Minnesota	MINN. STAT. §216B.2422 (201	2	15
New Hampshire	NH RSA §378:38	2	5
New Mexico	17.7.4 NMAC	4	4–10
Ohio	Ohio Admin. Code §4901:5-7	5	10
Oregon	OAR 860-027-0400	2	20
Pennsylvania	52 Pa. Code §59.81	1	3
Rhode Island	RI Gen L § 39-24-2 (2014)	2	5
Vermont	30 VSA §218c	3	20
Washington	WAC 480-90-238	2	10

Some states require gas utilities to file frequently, others less often. The forecast period is typically 3–5 years, but some states require 10- or 20-year forecasts. These filings give the regulator the information it needs to ensure distributors have the ability to serve customers and approve new investments in gas supply or infrastructure contracts.

As Figure 3 illustrates, demand response programs' impact on gas resource costs takes longer to observe than it does for electric demand response programs because of the gas supply planning process undertaken by gas distributors. Each step of the gas distribution utility planning process has the capacity to absorb a change from a demand response program that better signals peak costs to consumers. While it is a longer path, and it requires some work to reflect changes in behavior and empirical relationships between the variables that traditional models use, signaling to consumers the higher costs of serving peak winter months is a worthwhile endeavor.

The largest load that a gas utility is designed to serve is called the "system design standard." For electric utilities, where the product cannot be stored, there is generally only one measure of system design—the instantaneous peak. For gas distribution utilities, however, there are a few relevant measures of system design, including normal year, design year, design day, and cold snap. These measures are used to assess the utility's ability to provide reliable service for a particular time frame.

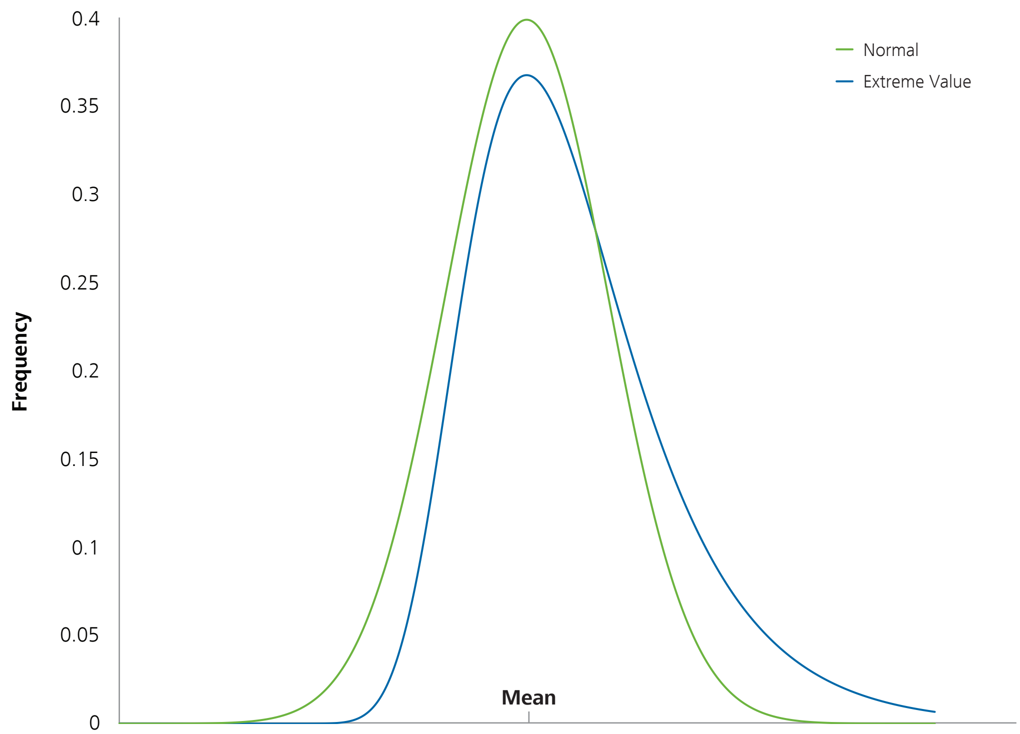
The important difference between measures for electricity and gas stems from the storability of gas; gas can be stored in the summer for use throughout the winter. In this fashion, stored gas can be used to supplement pipeline supplies to serve the winter heating season. Therefore, each utility designs its system to satisfy demand on peak days and, using pipeline supplies and storage inventory, to satisfy daily demand throughout an extremely cold heating season.

The conventional measure used to examine heating loads is known as a "heating degree day." A heating degree day is a measure of the coldness of weather based on the extent to which the daily mean temperature falls below a reference temperature—typically 65˚F. For example, on a day when the mean outdoor temperature is 25˚F, it would be a 40 heating degree day.[26]

The normal year design standard is the average weather scenario for which the company expects to serve customers as measured by historical data (for example, average weather and sendout over 20 years). Design year and design day are measures of extreme weather conditions that, in terms of statistically defined probability, occur infrequently as measured for a particularly cold year or day. The standard to meet can vary by state, but gas distributors can plan for demand in a winter or cold day that occurs infrequently. That is, utilities assess the ability of their system to meet demand during an event that has a probability of occurring once in 30, 50, or 100 years. The cold snap measure examines the utility's ability to meet customer demand over a prolonged cold period (for example, 10 days).

It is possible to calculate the probability that extreme weather will cause a distributor's design standards—on a yearly or daily basis—to be met or exceeded by analyzing the way in which weather is statistically distributed. A statistical distribution is a table or graph that shows all possible values of a dataset and the frequency of their occurrence. The simplest type is called the "normal distribution" (often called a bell curve, because of its shape), where the values of the data are symmetric around the mean. However, certain kinds of data—such as extreme temperature, rainfall, and water levels—may not be distributed in this normal fashion. Rather, the "extreme value distribution" may better fit this data. The values of a dataset with an extreme value distribution may be skewed either to the right or the left, meaning data is not distributed symmetrically around the mean. Figure 4 illustrates both types of distributions.

Figure 4. Normal and Extreme Value Distributions



While both distributions have the same mean, the extreme value distribution has a larger tail. All else equal, the larger the tail the greater the probability that a future cold weather day will, in this example, fall to the right of the level that represents the gas distribution utility's design standard. With this information, it is possible to calculate the degree day number (i.e., the design day) or degree day annual total (i.e., the design year) that led to a recurrence probability of once in 30, 50, 100, or any other number of years. The results of this probability calculation will be the design standards the utility should adopt to ensure it can meet demand.

Gas utilities with weather-sensitive customer loads also examine the relationship between weather, wind speed, and customer load use to help predict future peak sendout. A wide variety of possible weather characteristics might affect heating requirements. These include temperature patterns during the day, angle and intensity of sunlight, humidity, and windspeed. It is possible to construct a measure that considers one (or all) of these factors in developing a weather index related to gas load. For example, rather than using simple calculations of heating degree days, a utility may incorporate windspeed into its calculations by estimating effective degree days, like so:

*Effective Degree Day = Degree Day * (Index of Windspeed)*

Utilities may test whether temperature alone (heating degree day) or effective degree days, accounting for variables other than pure temperature, better fit their service territories.

Using econometric forecasting techniques, utilities forecast future sendout needs over the periods required by state regulators (examples shown in Table 1 above). Sendout forecasts account for many variables, including existing customers and expected growth; demographics such as population, industry, employment, and income; and gas and oil prices. Forecasts may also separate utility service areas (divisions) and should consider different customer classes (e.g., residential heating and non-heating, commercial and industrial customers). Utilities may also consider whether it is necessary to account for energy efficiency programs, depending on the state and if those programs are relatively new (and, therefore, not reflected in historical data). Finally, forecasts may also take into consideration the capacity of customers in states that allow customers to choose retail gas suppliers—where the retailer provides the gas and the gas distribution utility only provides transportation service.[27]

Given design standards and expected future demand, gas distributors develop a portfolio of least-cost resources to serve consumers. Depending on the location of the utility, resources include long-haul and short-haul pipeline transportation and storage contracts (i.e., infrastructure), gas supply contracts (for commodity supply), and LNG. Utilities constantly assess needs and demand growth to meet customer demand at least-cost. Regulators evaluate gas distribution supply plans and approve gas supply and forecast plans, as well as all new contracts for infrastructure investment and siting of new facilities. Regulators make decisions with the public interest standard in mind, based on economic and social concerns, including individual state climate goals and other initiatives.

With a demand response program, all else equal, the relationship between weather and sendout will change. In terms of planning standards, the point at which the utility will need to invest more (i.e., expand distribution capacity or sign incremental contracts for gas supply) will change. A demand response program as defined here—allocating fixed costs to peak winter months—will cause consumers at the margin to use less gas during peak winter months by turning down thermostats or buying more efficient heating equipment. Changed consumer behavior will alter the relationship traditionally used to develop system design standards.

Through the path of changing resource supply portfolios, demand response programs evaluated through the planning process by regulators with the public interest in mind can result in delayed investments in new pipeline, LNG, or storage supply contracts and distribution infrastructure (if demand is growing). Consumers at the margin who react to prices that better reflect the fixed costs of serving peak winter months by buying more efficient boilers, better insulation, or turning down the thermostat, will reduce demands on the system and allow utilities to delay new investments.

Conclusions

The motivation to encourage consumers to recognize and respond to resource costs today is climate change, and marginal cost pricing can reveal those resource costs to consumers. Gas demand response programs can utilize marginal cost pricing to communicate to consumers the true costs of heating homes and businesses on the coldest and windiest winter days. The goal in this incarnation of marginal cost pricing is to allocate a larger share of the costs of providing gas service to space-heating consumers—the demand most important for driving infrastructure investment.

It would be relatively straightforward to adjust rate design to reflect interstate pipeline and fixed infrastructure costs toward collecting more during the winter billing cycles for all customer classes. A change in rate design may prompt consumers to reduce gas demand during peak winter months.

All regulation starts with a public desire to see legislative change. Senator Whitehouse's Energy Infrastructure Demand Response Act of 2018 recognizes a public desire to change fossil fuel consumption. Clear signals to consumers about the costs of consuming gas during peak periods can help reduce reliance on fossil fuels. Building demand response programs into the gas market is a useful pursuit. Even if the payoff is modest, the cost in terms of regulatory action is low. Wind and temperature are not within utilities' control, but with prices that better reflect the forward-looking costs of investing in infrastructure to meet the winter peak, gas utilities can incentivize customers to lessen peak consumption and therefore delay infrastructure investment and reduce fossil fuel use.

Notes

1 S.2649, Energy Infrastructure Demand Response Act of 2018, introduced 11 April 2018, 115th Congress, 2017/2018.

2 H.R.5895, Energy and Water, Legislative Branch, and Military Construction and Veterans Affairs Appropriations Act, 2019, became law 21 September 2018, 115th Congress, 2017/2018.

3 FERC, "2018 Assessment of Demand Response and Advanced Metering," 7 November 2018, available at https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

4 Jeff D. Makholm, "Gas Industry's Version of Demand Response Cures Its 'Duck Curve'," *Natural Gas & Electricity*, February 2019, available at https://www.nera.com/publications/archive/2019/gas-industry-s-version-of-demand-response-cures-its--duck-curve-.html.

5 A polar vortex event is when high pressure in the Pacific displaces a pocket of very cold air that typically circulates around the North Pole, bringing Arctic temperatures to North America.

6 Jeff D. Makholm and Laura T.W. Olive, "Polar Vortexes in New England: Missing Money, Missing Markets, or Missing Regulation?" *Economics of Energy and Environmental Policy*, 2019 (*forthcoming*).

7 American Council for an Energy-Efficient Economy (ACEEE), "Energy Efficiency Programs," accessed 18 December 2018.

8 Examples include: (1) Massachusetts' Mass Save (https://www.masssave.com/en/saving/residential-rebates); (2) Arkansas' Energy Efficiency Programs (http://www.apscservices.info/rules/energy_conservation_rules_06-004-R.pdf); (3) Connecticut's Electric and Natural Gas Conservation & Load Management Plan (https://www.ct.gov/deep/lib/deep/energy/conserloadmgmt/2016_2018_CLM_PLAN_FINAL.pdf); (4) Colorado's Excess is Out Program (https://coloradonaturalgas.com/efficiency); (5) Illinois' Incentives and Energy Efficiency Programs (https://smartenergy.illinois.edu/resources/illinois-incentives-and-energy-efficiency-programs); (6) Efficiency Maine (https://www.efficiencymaine.com/at-home/maine-natural-gas-residential-customer-rebates/); (7) New York's Low Income Usage Reduction Program (LIURP) (https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/Program-Evaluation/2015ContractorReports/2015-EmPower-National-Fuel-Gas-Evaluation-Report.pdf); and (8) Energy Trust of Oregon (https://www.energytrust.org/wp-content/uploads/2016/12/OR-Incentive-Grid_FS_1612.pdf).

9 Equivalent to 291.8 million therms or approximately 29.2 MMBtu. The states with energy efficiency spending of $10 or more per residential and commercial customer are Arkansas, California, Connecticut, Florida, Illinois, Iowa, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Oklahoma, Oregon, Rhode Island, Utah, Vermont, Washington, and the District of Columbia.

10 The Federal Energy Regulatory Commission (FERC) differentiated energy efficiency and demand response in Order 719, defining energy efficiency as "using less energy to provide the same or improved level of service in an economically efficient way," noting that energy efficiency "saves kilowatt-hours on a persistent basis, rather than being dispatchable for peak hours as are some demand-response programs." FERC, 2008, Order 719, pp. 110–111, footnote 277.

11 FERC, "2018 Assessment of Demand Response and Advanced Metering," 7 November 2018, p. 15.

12 Ibid, pp. 12, 22.

13 C. Eid, E. Koliou, M. Valles, J. Reneses, and R. Hakvoort, "Time-based pricing and electricity demand response: Existing barriers and next steps," *Utilities Policy*, 40, 2016, pp. 15–25.

14 Ibid.

15 P. Bradley, M. Leach, and J. Torriti, "A review of the costs and benefits of demand response for electricity in the UK," *Energy Policy*, 52, 2013, pp. 312–327.

16 The California Public Utilities Commission (CPUC) approved continuing this program during the 2018–2019 winter. CPUC, Resolution G-3541, 25 October 2018. See also SoCalGas Smart Control Thermostat Programs, available at https://www.socalgas.com/smarttherm.

17 Ibid. SoCalGas's program was approved in Resolution G-3522. It was not tested until the winter of 2017–2018.

18 Nexant, "SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation," 14 August 2018. Snapback also occurs with electricity demand response, but a recent study for the Minnesota Department of Commerce found net energy savings overall from demand response. Michaels Energy, "Demand Response and Snapback Impact Study," Report for the Minnesota Department of Commerce, August 2013.

19 Other gas demand response pilots include National Grid, Implementation Plans for Gas REV Demonstration Projects—Gas Demand Response in New York City and on Long Island, 27 July 2017, and Con Edison, "Con Edison Seeks Non-Pipes Solutions to Meet Growing Natural Gas Demand," 18 December 2017.

20 Columbia University economist Harold Hotelling popularized this idea in a paper described later by James Bonbright as "one of the most distinguished contributions to rate-making theory in the entire literature of economics." H. Hotelling, "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates," *Econometrica*, 6, 1938, pp. 242–269; J.C. Bonbright, "Major controversies as to the criteria of reasonable public utility rates," *American Economic Review, Papers and Proceedings*, 30, 5, 1941, p. 385.

21 American Gas Association, "LDC Supply Portfolio Management during the 2014–2015 Winter Season," 5 June 2016.

22 For example, see Massachusetts General Laws Chapter 164, Section 69I; Rhode Island General Laws Title 39, Chapter 39-24. Section 39-24-2; California Public Utilities Code PUC Section 454.52.

23 A.E. Kahn, *The Economics of Regulation: Principles and Institutions, Volume I*, John Wiley & Sons, Inc, New York, 1970, pp. 66, 89.

24 Ibid, p. 88.

25 Jeff D. Makholm, "Gas Industry's Version of Demand Response Cures Its 'Duck Curve'," *Natural Gas & Electricity*, February 2019.

26 If the mean temperature exceeds 65˚F, then a zero heating degree day is experienced. Cooling degree days are calculated in the same fashion but reversed. That is, if the mean temperature on a day is 80˚F, then a 15 cooling degree day is experienced. Cooling degree days are relevant for electric utilities dealing with summer peak demand due to air conditioner use.

27 As of 2018, 21 states allow all customers to purchase gas supply from a provider other than the distribution utility (retailer). An additional seven states allow some customers in certain locations or customer classes to purchase retail gas supply. See https://www.electricchoice.com/map-deregulated-energy-markets/.

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