April 30, 2013   **LBNL-6105E**

Assessing Natural Gas Energy Efficiency Programs in a Low-Price Environment

Ian Hoffman, Mark Zimring, and Steven R. Schiller
Lawrence Berkeley National Laboratory

Scope

Abundant, affordable natural gas has emerged as a central feature of the U.S. energy economy. Dramatic increases in economically recoverable natural gas have made gas relatively inexpensive—at least in the short run – with resulting cost savings for consumers. However, low natural gas prices place gas efficiency programs at a crossroads. Some program administrators and state regulators are finding that conventional analyses, which only consider a narrow set of energy-savings related efficiency program benefits, are now resulting in many natural gas efficiency programs failing to pass the criteria used to screen programs for cost-effectiveness. This policy brief provides several considerations for regulators and policymakers to weigh when evaluating the costs, benefits and future of natural gas energy efficiency programs.

Introduction

A number of states have passed legislation or adopted regulatory policies that mandate natural gas savings targets.[1] These targets and related efficiency policies are driven by a number of policy objectives (e.g. greenhouse gas mitigation, customer bill savings, job creation) and could drive steep increases in spending on gas efficiency programs (Barbose et al 2013). However, for these savings targets to be reached, natural gas efficiency programs must pass cost-effectiveness screening thresholds in most states. The decrease in natural gas prices over the past several years, by reducing avoided cost forecasts, make it more difficult for gas efficiency measures and programs to pass these

---

[1] Twelve states accounted for almost 90 percent of spending on gas energy efficiency programs in 2010. Nine of these states (CA, NY, MA, IA, MN, OR, MI, CO, IL) have explicit targets for gas energy savings and accounted for more than 60 percent of gas program spending in 2010 (Barbose et al. 2013).

screenings and calls into question whether some gas efficiency programs or portfolios will continue and whether gas efficiency savings targets will be met.[2]

At the same time that future funding for gas efficiency programs is more uncertain, there is greater reliance on natural gas as more households switch fuels to natural gas[3] and utilities build natural gas-fueled electric power generators. With respect to electricity generators, low gas prices are coinciding with the effective dates of environmental controls on coal-fired generators and the declining economic viability of some of those generators as a function of age.[4] As a result, gas demand in the electric power sector is projected to rise dramatically (AGA 2012; EIA 2013). This increasing dependence on gas is delivering substantial short-term benefits, but also exposes consumers to longer-term economic and environmental risks and costs—risks and costs that can, to some extent, be mitigated by natural gas efficiency programs.

Before the recent natural gas price decline, gas prices had been high for a decade that corresponded to a significant ramp up in natural gas efficiency spending. Cost effectiveness tests did not incorporate the full range of benefits associated with natural gas, in part because some of these benefits are difficult to assess quantitatively and because programs were already deemed cost-effective without including these benefits. With the decline in natural gas prices, this policy brief provides options for regulators and program administrators to consider in making decisions regarding gas efficiency programs. These options include accounting for certain benefits that often are overlooked in cost-effectiveness analyses.[5] This policy brief describes:

- Economic, environmental and societal benefits that consumer-funded gas efficiency programs can deliver, but which are often not fully captured in conventional cost-benefit analyses;

- Cost-effectiveness screening policies that can affect the outcome of such analyses for gas efficiency programs.

Economic, Environmental and Societal Benefits of Natural Gas Efficiency Programs

---

[2] Lower gas retail prices also increase the payback times of efficiency measures for participating consumers, which may increase the efficiency measure acquisition costs faced by gas efficiency program administrators.

[3] The American Gas Association reports that conversion rates rose from historical levels of 15% to 25% of new accounts in 2010 (AGA 2012).

[4] From January 2011 to October 2012, gas consumption by electric generators increased 22 percent (FERC 2012).

[5] The focus in this brief is on benefits not often recognized in assessing natural gas energy efficiency programs. We therefore do not delve into the array of non-energy benefits, such as remediation of health and safety threats, which already are addressed in the literature (see, e.g., Skumatz, Dickerson and Coates 2000, Amman 2006; Skumatz 2010; Hefner and Campbell 2011; NMR, Inc. and Tetra Tech, 2011; Tetra Tech 2012,).

Natural gas energy efficiency (EE) programs offer a broad set of public and utility consumer benefits beyond the value of direct energy savings. These other benefits are summarized in Table 1, including a brief description of the methods that may be utilized to assess these benefits.

Value	Impact	Method of Assessment
Hedge value	Reduction of consumer exposure to seasonal and long-term volatility in gas commodity costs	Quantitative: Multiple approaches, including estimated reductions in utility hedging and storage costs
Downward price pressure on gas from reduced demand	Reduction in aggregate demand in relationship to adequate supply causes price reductions	Quantitative: Reductions in prices to consumers can be estimated from reductions in aggregate demand
Easing gas transmission capacity constraints and enhancement of electricity reliability	Lower gas demand frees up capacity for demand growth in other sectors (e.g., electricity generation), reduces the likelihood of generation curtailment, and may eliminate or delay the need for local capital intensive system upgrades	Quantitative: Lowering pipeline constraints can result in measurable reductions in price volatility and risk of outages or reliance on higher cost generators; avoided system capacity costs can be estimated
Environmental benefits	Production and consumption of gas has environmental impacts and risks. These impacts and risks can be higher for shale gas than conventional gas	Quantitative/Qualitative: Releases of greenhouse gases & other air pollutants and water consumption can be monetized. Other environmental impacts and risks can be weighed qualitatively
Access to energy savings opportunities	Low income and residential programs can be disproportionately negatively impacted by conventional cost effectiveness analyses; raises risk of differential access to gas savings across customer classes and impairment of other policy objectives (e.g., reducing disconnections and collections, alleviating health & safety risks)	Qualitative: The percentage of program participation in different utility customer classes can be calculated and considered separately from monetized costs and benefits of programs.
Economic development	Gas EE programs can support greater net job growth than natural gas supply and delivery	Quantitative: Net growth can be defined for direct, indirect and induced jobs
Avoided economic and programmatic costs of ending/suspending programs	Suspending programs raises costs of savings acquisition in the future and devalues/discourages the investments of market allies	Quantitative/Qualitative – Higher costs of re-establishing program infrastructure can be estimated. Lost opportunities with market allies can be weighed qualitatively

Table 1. Several potential benefits of gas efficiency programs beyond direct energy savings and methods that can be used to assess their value.

Hedge against volatile/rising commodity costs

While natural gas prices are near decadal lows today, wide-ranging and consistently upward sloping mid- to long-term natural gas price projections suggest that higher gas prices (in real terms) are likely in the mid- to long-term and, under some scenarios, in the near term. (see Figure 1).[6]
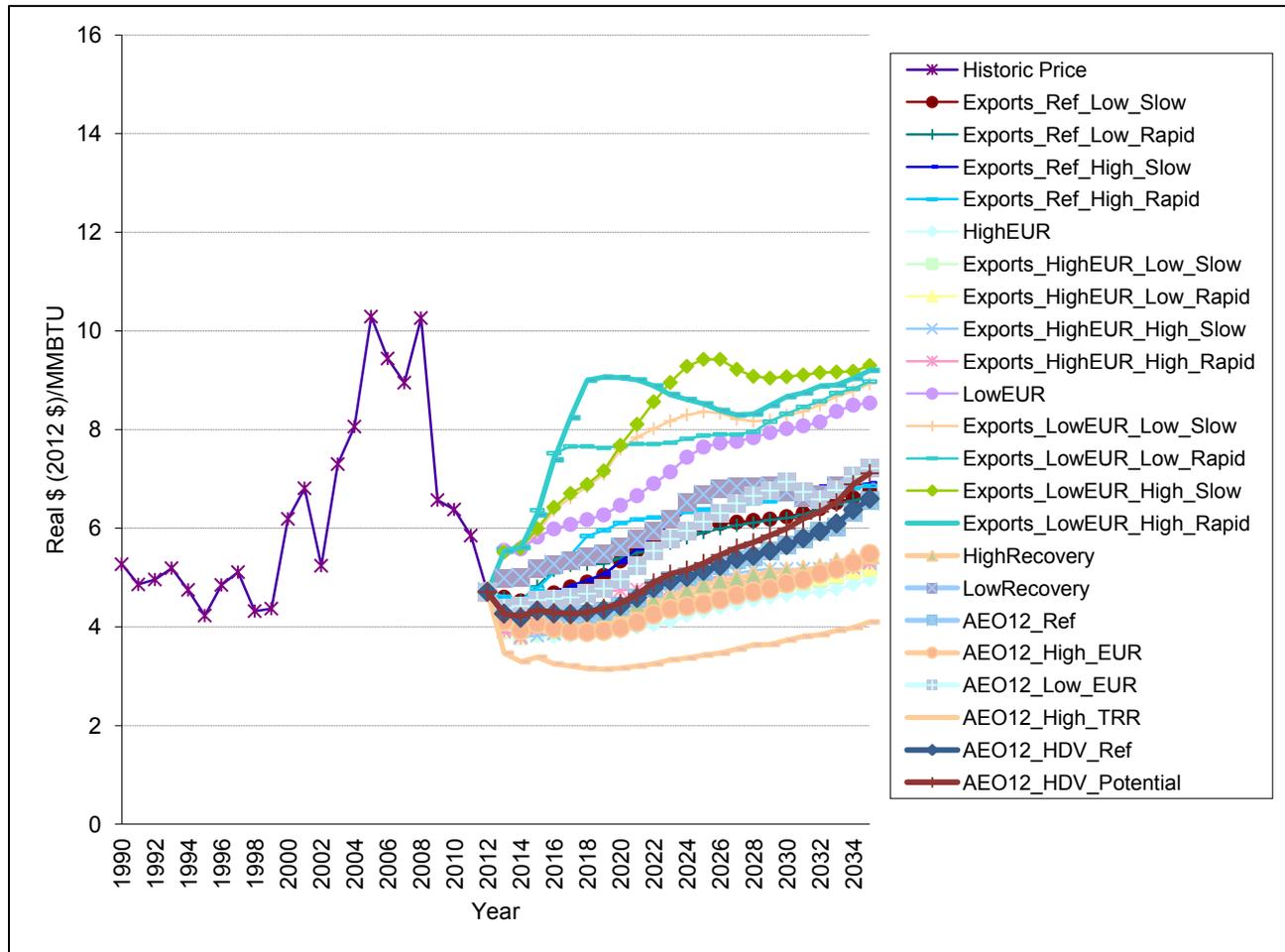

Figure 1. Historic Natural Gas Fuel Prices and Energy Information Administration Price Projections through 2035 (Bolinger 2012).

The wide range of potential future gas prices is caused by:

- ✓ Uncertain domestic natural gas demand, particularly in the electric power sector;
- ✓ Uncertain gas export supply and demand;[7]

---

[6] While the slope of these projections has flattened in recent years, this section describes a range of uncertainties about future price trends. There is, in general, a lack of market liquidity available to utilities and their regulators to "lock in" these price projections for their customers over long time periods (e.g. 10 to 20 years).

- ✓ Uncertainty about the potential implementation of regulations to mitigate shale gas environmental risks and impacts;[8]
- ✓ Insufficient storage capacity and transmission & distribution infrastructure;[9] and
- ✓ Uncertain technically and economically recoverable reserves.[10]

While all commodities bear volatility risk, natural gas prices have historically been particularly volatile (MIT 2011). In today's low natural gas price environment, the chances of prices going up are higher than the chances of prices going down.

Since the majority of natural gas utility customer bill charges are typically for fuel acquisition (Graves and Levine 2010), the inherent volatility of gas commodity prices poses significant risks of unstable energy bills to consumers. This volatility can be broken down into seasonal/short-term volatility (e.g. winter vs. summer gas commodity prices, short-term production interruptions) and long-term volatility (e.g. fundamental shifts in market dynamics). Depending on one's temporal focus, multiple approaches may be deployed to mitigate consumer exposure to this risk including storage, financial product risk reduction strategies, long-term contracting, and reduction in demand (e.g., via energy efficiency).[11]

- ✓ *Storage.* Many gas utilities use natural gas storage to reduce the impacts of seasonal peak customer demand (when commodity prices tend to be highest), for daily supply/demand balancing or to hedge against short-term base load supply disruptions. Storage, however, is limited to short term hedging and is not well-suited to mitigating consumer exposure to fundamental shifts in long-term dynamics of gas markets.

- ✓ *Financial product risk reduction strategies.* Gas utilities may deploy a range of financial product strategies (e.g. futures, swaps, calls, puts, straddles) to reduce customer gas price volatility

---

[7]Large natural gas price differentials exist between the US, Asia and Europe (estimated by the Federal Energy Regulatory Commission at $6-$16/MMBtu for March 2013) (FERC 2013). However, the future of pending applications for siting and construction of liquid natural gas (LNG) terminals that would increase gas exports is uncertain. As of February 2012, there were at least nine proposed LNG export terminal projects in the lower-48 states at some point in the federal approval process with daily potential daily processing capacity of over 10 billion cubic feet (bcf) (Ebinger et al 2012).

[8] See *"Environmental benefits of avoided direct consumption"* section below.

[9] It is estimated that by 2030, the U.S. and Canada will need from 28,900 to 61,900 miles of transmission and distribution pipelines and a 15 to 20 percent increase in storage capacity will be needed to meet gas supply and demand needs (INGAA 2009). Efficiency programs can reduce the need for some pipelines and storage capacity.

[10] Considerable uncertainty exists regarding the size of the economically recoverable U.S. shale gas resource base (primarily due to wide variations in initial production rates, rates of production decline and ultimate recovery per well). In addition, there is uncertainty about the size of the overall resource in the ground. For example, the EIA's 2012 Annual Energy Outlook (AEO) includes four shale gas scenarios, with unproved shale gas resources ranging over 450 percent (from 241 Tcf in the low well productivity case to 1,091 Tcf high well productivity/high resource case). The 2012 AEO also reduced its shale gas reserve reference case from 827 Tcf in 2011 to 482 Tcf in 2012 (US EIA 2012).

[11] Renewable energy resources are not included in this list due to our focus on natural gas utility energy efficiency programs. However, renewables do reduce natural gas price volatility exposure for electric utility customers; Renewable energy resources are, by their nature, immune to natural gas fuel price risk and renewable energy generation is typically sold under long-term fixed-price contracts.

exposure.[12] However, the prudence of these strategies has come under increasing regulatory scrutiny,[13] and regulators often restrict their use to short-term (3-5 years) hedging to minimize the introduction of new risks to utilities and their customers.[14] This leaves customers exposed to long-term natural gas price volatility.

✓ *Long term contracting.* Fixed-price, physical delivery natural gas supply contracts can provide commodity price certainty over the medium-term (5-10 years) (Huber 2012). However, few long-term contracts are truly fixed-price (BPC 2011),[15] and these types of contracts have often resulted in extensive litigation and abrogation when market dynamics fundamentally shift (BPC 2011).[16]

✓ *Energy efficiency.* Unlike other risk reduction tools, investments in energy efficiency lower overall demand for natural gas. By reducing their natural gas usage, consumers are less financially exposed to both short-and long-term[17] increases in natural gas prices; including price hikes due to (a) increasing natural gas exploration, development and transmission costs associated with meeting more demand and (b) from unlikely, but potentially devastating events (e.g. pipeline failure, unanticipated environmental regulations), against which other risk mitigation strategies often do not protect.[18] This suggests that energy efficiency is among the most robust natural gas price hedging tools, and one that can be deployed as a complement to (and reduce the need for) the other mitigation strategies described above.

---

[12] These strategies are imperfect hedges—they are typically designed to cover risks up to a certain size with a certain probability, leaving customers exposed to the risks of extreme events. If risk conditions are shifting, a hedging program designed for historical conditions may also be inadequate (Graves 2010). For a more detailed discussion of the range of financial product strategies and their relative merits and risks, visit http://www.cleanskies.org/wp-content/uploads/2011/08/ManagingNGPriceVolatility.pdf

[13] Regulated utilities pass through both fuel and hedging costs to utility bill-payers. Some regulators have questioned the "prudence" of hedging expenditures in the current low gas price environment and in the wake of instances in which hedging strategies have led to large losses. In addition, gas utilities do not typically have upside return associated with well-performing hedges, which limits their interest in these investments (particularly given the risk that backwards-looking regulator prudence reviews might leave their expenses on these hedges disallowed).

[14] These strategies are often restricted to three to five years because natural gas options markets lose significant liquidity after one to two years, increasing transaction costs and raising counterparty and liquidity risks. Losses or margin calls on long-term (and illiquid) derivatives investments in periods of structural market change could pose fundamental risks to utilities and their customers (Graves 2010).

[15] Long term contracts for fixed volumes with pricing provisions through which the cost of a unit of gas is indexed to some reference monthly commodity price elsewhere are more common (Graves 2010).

[16] These contracts are subject to supplier credit and default risks, and have higher transactions costs than more traditional hedging strategies.

[17] Multi-measure energy efficiency improvements typically have lifetimes of 10 to 20 years. In New York, for example, a 15 year expected lifetime is used to evaluate the New York Energy Smart programs (http://www.nysenergyplan.com/final/Energy_Efficiency.pdf).

[18] For example, while a long term, fixed price contract protects against these events in theory, if these events were to occur—and particularly if the event entailed a long-term structural market shift rather than short term price spike—there would be significant counterparty risk. That is, there would be significant risk that the long term contract provider would attempt to default on, or renegotiate, the contract to their financial benefit.

Gas distribution utilities routinely describe their hedging strategies and demand-side management plans in integrated resource plans (IRPs) filed every one to three years with regulators. But a sampling of gas IRPs shows that gas utilities rarely if ever describe the interaction among energy efficiency, long-term contracts and financial hedges or what cost tradeoffs exist among these different forms of risk mitigation. Thus, the value of energy efficiency as a hedge against gas commodity price volatility often goes unrecognized in program cost effectiveness screening.

In addition, many program administrators only use a base case forecast of future gas commodity prices to estimate avoided gas costs from energy-efficiency programs as part of cost-effectiveness screening. Relying solely on a base case gas price forecast ignores the risk that fuel price volatility poses to consumers. It is also inconsistent with an integrated resource planning approach, in which multiple futures (i.e. multiple scenarios in which many inputs are varied, including future fuel costs) are analyzed and low cost, low risk futures are sought (i.e. scenarios are projected with and without various levels of energy efficiency investment).

In some parts of the country, regulators do reflect efficiency's fuel price hedge value; typically in a simple manner by including a risk adder to the avoided cost forecast that is subjectively versus analytically determined. For example, the Northwest Power and Conservation Council's (NPCC) Sixth Power Plan developed an avoided cost adder that encompasses energy efficiency's carbon, capacity and risk mitigation (hedge) values for the purposes of evaluating electric energy conservation programs.[19]

Downward price pressure on gas from reduced demand

The demand reduction in price effect (DRIPE) for natural gas is the reduction in gas commodity prices and capacity & storage costs attributable to a reduction in natural gas consumption. By reducing customer demand in aggregate, gas and electric energy efficiency programs can reduce gas prices to all consumers, regardless of whether they participate in an efficiency program. In California, the Pacific Northwest and the Northeast, where regulators have accepted this demand reduction effect on wholesale electricity and capacity prices as a program benefit, policymakers have not extended that benefit to natural gas programs by placing an explicit value on the price reduction benefit of gas energy efficiency.

Some analysts question whether the price suppression effect from energy efficiency (and other activities that supplant or offset the use of a commodity) has a net societal benefit. It has been argued that the consumer benefit from the price reduction may simply be a transfer of wealth from producer profits to consumers. A Lawrence Berkeley National Laboratory study (Carnall et al 2011)

---

[19] While state regulators, not NPCC, ultimately make decisions on what costs and benefits may be included in cost effectiveness testing, the risk adder methodology that NPCC has developed is used in Oregon. while other states and program administrators have assumed that risk mitigation benefits are captured in other conservation adders. NPCC has not yet developed full demand and supply curves for natural gas, which is why its adder is limited to electric efficiency programs.

evaluated this question in the context of assessing the net economic impacts of applying a new energy performance standard for gas-fired appliances, and found that consumer benefits from the demand reduction in price are five times the wealth transfer, for a sizable net economic benefit.[20]

Like electric energy DRIPE, there are two types of gas DRIPE – commodity and capacity – and two components--the magnitude and duration of the price effect (AESC 2011). Drawing on previous LBNL work (Wiser et al 2005), we used a simplified calculation of the commodity DRIPE in Massachusetts to provide an illustrative example of its value (see Appendix A for description of our approach).[21] While the price effects from gas energy efficiency program demand reductions are negligible from an individual customer perspective – from less than a penny to a few cents per million Btu of natural gas--these price reductions accrue to all gas consumers, so that the absolute magnitude of the total consumer savings can be substantial. We estimate that from 2009 to 2011, savings to gas consumers in Massachusetts from price suppression alone was between $235,000 and $1.9 million.[22,23] Because the wholesale price effects of the gas efficiency programs in Massachusetts (or anywhere else) benefit all U.S. gas consumers, not just those in Massachusetts, the total U.S. consumer savings for those three years can be considerable, ranging from $12 million to nearly 10 times as much depending on one's assumptions. These estimates are based on multiple analyses of the relationship between gas prices and supply, with the values developed specifically for this paper derived from historical and projected values from 2001 to 2040, thus explicitly including the new market dynamics presented by unconventional gas. These DRIPE effects will be more important in regions that have, or soon will have, constraints on storage, pipeline capacity or both (e.g., the Northeast, New York, Southern California and parts of the Midwest). Commodity and capacity DRIPE are independent of the baseline commodity and capacity values used in avoided cost forecasts because those values are generally based upon recent history, not the price resulting from program-related suppression of demand.

---

[20] Carnall et al (2011) modeled the shift in benefits to consumers from producers, government royalty accounts and landowners collecting mineral leases. The analysis revealed that a producer-to-consumer transfer of wealth does occur but that the transfer is not as great as other analysts supposed because producers receive advance notice that an efficiency standard is coming into effect, usually several years beforehand. This advance notice allows the supply side of the natural gas market to adjust its demand forecasts and investment choices, reducing the risk of lost profits and costs over market prices. This advance notice feature is also typically present in energy efficiency programs. Energy-savings targets are approved for multi-year periods, often after a year or more of consideration, and multiple entities track those targets.

[21] No estimate of capacity DRIPE is offered here, in part because the value is highly specific to location. We calculated commodity savings only because insufficient information was available on capacity savings and pricing to calculate suppression of gas capacity prices resulting from energy efficiency programs.

[22] These savings do not include secondary savings on electricity bills. Electricity generators are the largest consumers of natural gas. A reduction in total gas demand from gas energy efficiency programs would reduce gas prices to generators and therefore lower the wholesale costs of generation.

[23] The wide range for this savings estimate is a function of differing estimates for the relationship between price and supply. See Appendix A for additional explanation of this relationship.

One question is how durable the DRIPE effect is or, put another way, how market participants will react to the change in demand and price (e.g., producers deciding to drill fewer wells or consumers using more of the lower-priced gas), and how long these actors will take to respond. Available evidence from studies of electric energy DRIPE suggests that it may take a dozen years for the market to reach a new equilibrium (AESC 2011). The analysis performed for this brief only accounts for price suppression effects in each of the three years analyzed, without assuming the suppression effect persisted beyond the first year in which the savings were obtained. We did not analyze the persistence of the price suppression effect for natural gas in general and suggest that more research is warranted in this area.

Energy Efficiency Impacts on Gas Transport & Distribution Capacity and Electricity Reliability

Changes in gas transmission and distribution costs are highly specific to individual market nodes and so are beyond the scope of this policy brief. It is likely, however, that demand-driven need for new capacity is rising, and closer analysis is warranted in this area.

The confluence of low natural gas prices, fuel switching at the margin in electricity markets, and planned replacements of retiring coal-fired generation with gas-fired units also has driven rapid growth in demand among electricity generators and exacerbated gas transport and distribution constraints in some regions. In those regions, system operators have raised concerns about the reliability of electricity supply during periods of high demand.[24]

For example, in Massachusetts, a recent study by the New England Independent System Operator concluded the region's gas supply infrastructure, despite planned new pipeline additions, "is inadequate to satisfy New England power sector gas demands on a winter peak (design) day over the next decade" (ISO-NE 2012).[25] These transmission constraints put customers at some risk of electricity brownouts or blackouts. Natural gas and electricity energy efficiency programs can reduce these transmission bottlenecks.   Analysts recently found that near-term natural gas demand growth among Massachusetts' gas utilities – the largest source of end-use demand in the region – was zero or slightly negative (Concentric 2011). The state's robust gas energy efficiency programs have contributed to this reduction in demand growth and have reduced customer exposure to the risks of natural gas transport and distribution capacity deficits. In other words, the transport and storage deficits and concerns about electricity reliability would be more acute if energy efficiency programs in Massachusetts and other states were not reducing gas demand. Rising dependence of certain regions on gas-fired generation now underscores the electricity reliability benefits of gas energy efficiency programs. These values typically are not taken into account among the benefits of natural gas energy efficiency programs.

---

24 These regions include the Northeast and to a lesser degree parts of the Midwest and Southern California (NE-ISO 2012) (MISO 2012) (FERC Roundtable on Electric-Gas Coordination West Region, August 2012)

Environmental Benefits of Avoided Direct Gas Consumption

The U.S. natural gas supply is expected to increasingly be met by shale gas in coming years. Shale gas holds promise in delivering large, low-cost gas supplies, but its production has environmental risks and impacts relative to conventional gas including potentially higher greenhouse gas emissions, higher water use, greater risk of water supply contamination and more significant air quality impacts. These risks and impacts are discussed in more detail in Appendix B.[26]

By reducing natural gas demand, gas energy efficiency programs can partially insulate customers from the environmental risks and impacts associated with shale and conventional gas production. In addition to mitigating the impacts and risks of natural gas production, gas energy efficiency programs can also directly reduce water use through measures such as low-flow showerheads that reduce natural gas use by reducing end use of hot water.[27]

Some of the benefits and risks (and the costs of regulations that might be reasonably expected to address them) described in this section can be integrated into the avoided-cost forecast for natural gas energy efficiency programs. For example, adders to avoided costs may be appropriate for addressing shale gas's greenhouse gas, water use and air and water quality impacts.

Contribution to Energy Savings & Low-Income Participation Targets

Customer-funded natural gas energy efficiency programs often must meet several policy objectives and/or legislative requirements, including providing an opportunity for all utility customer classes to participate, and invest, in energy efficiency. With natural gas efficiency portfolios, low-income offerings play a more important role in efficiency spending than in electric programs. Low income spending currently accounts for approximately 27 percent of gas efficiency program spending, almost double the 14 percent of electric program spending allocated to low income programs (CEE 2011). Furthermore, in the residential sector, natural gas savings account for the majority of the potential to achieve the deep energy savings necessary to meet energy savings targets.[28]

With respect to offering opportunities to low-income or disadvantaged communities, there are particularly acute cost-effectiveness challenges for natural gas programs. To address these challenges, policymakers typically use multiple criteria to evaluate low-income programs due to the variety of

---

[26] A number of these risks and impacts are present in conventional gas drilling, but shale gas production increases the risk of incidents occurring and/or environmental impacts.

[27] Customer water and sewer savings typically are credited at the retail rates for the customer class addressed by the program and, in some jurisdictions, include the avoided costs of the energy saved by not pumping that water and wastewater.

[28] For example, by 2024 over 70 percent of the technical energy efficiency potential in California's residential sector will be from natural gas savings (compared to 50 percent in the commercial sector) (Navigant 2012).

benefits they offer beyond energy savings (e.g., implied equity in access to efficiency markets and reduced bill arrearage). It may be appropriate to add more flexibility to the cost-effectiveness criteria for these multi-objective programs.

In addition, in many states, regulators and administrators delineate programs and/or activities in gas energy efficiency portfolios, beyond the low income programs, that are not subject to (or are not assessed solely based on) traditional cost effectiveness screening requirements in order to develop robust gas energy efficiency portfolios.   Typically, these programs and/or activities have benefits that are difficult to quantify, and their merits are evaluated using multiple criteria that attempt to capture other policy objectives, including:

- ✓ Support for technological innovation;
- ✓ Social equity for low income customers;
- ✓ Research, development and deployment; and
- ✓ Market transformation initiatives targeted at supporting nascent markets.

Considering multiple criteria when screening certain types of gas efficiency programs can be another strategy for ensuring that programs and activities that are in the interests of natural gas consumers —but that would not meet traditional cost-effectiveness testing criteria —receive appropriate levels of investment.

Economic Development Value of Energy Efficiency

The effects of efficiency spending and utility bill savings as these funds flow through the economy are often broader than those captured in conventional cost-effectiveness screening analysis. Additional economic benefits to customers arise from the purchase and installation of measures and achievement of bill savings. As participating households reduce their utility bills, they retain more money in their pockets for discretionary spending on other goods and services. Participating businesses face lower operating costs and can be more competitive and therefore able to support more employment. Additional rounds of economic activity can be induced as the recipients of efficiency investments (e.g., retailers, manufacturers, engineers, builders and contractors) re-spend those dollars on other goods and services.[29]

Recent studies indicate that investments in energy efficiency generally produce more jobs and business than the economic activity that the efficiency investments displace (Vermont DPU 2011; Wisconsin Dept. of Administration 2010; Environment Northeast 2009). First, energy efficiency tends to be more labor intensive than typically is the case with the operations of natural gas production and pipeline facilities. Second, more money spent on energy efficiency tends to stay in

---

[29] These additional rounds of economic activity are known as multipliers. These benefits are reduced by the economic activity foregone as a result of funding efficiency programs to yield "net" economic benefits.

the local or state economy than typically is the case with the production and transmission of natural gas (Bower et al. 2012).

Avoided Economic and Programmatic Risks and Costs of Ending or Suspending Gas Efficiency Programs

Energy efficiency programs are designed to identify and mitigate market barriers to the economically rational adoption of energy savings opportunities. Starting and stopping efficiency programs in response to price fluctuations for a volatile commodity frustrates the orderly development of a market for efficient products and services and also comes at some cost to program administrators and trade allies (e.g., vendors, contractors, retailers, architects and engineering firms).

These risks and costs fall into four categories:

1. *Cascading erosion of other measure and program cost effectiveness* – Cutting measures or programs often shifts costs onto other measures and programs and reduces their cost effectiveness. Programs typically share in the costs of administering the entire portfolio, e.g., paying for office space, staff, planning and compliance efforts, verification of savings, etc. Some program activities that enable packages of measures may not produce direct energy savings (e.g. energy audits) but are a necessary part of the process of developing and implementing projects; hence they are supported as part of the portfolio. More comprehensive programs, for example, often are based on an energy assessment or audit of specific energy efficiency opportunities in an existing home or business. The assessment may not save energy per se but is an essential component of a whole-home or whole-business energy upgrade. Cutting less cost-effective measures can remove the assessment from the program or curb the number and type of measures that can bear the costs of the assessment that identifies the necessary measures for energy savings. These shifts in measure costs and fixed administrative costs make the remaining measures and programs less cost effective and may remove them from the portfolio.

2. *Costs incurred to re-establish programs.* New programs often incur significant start-up costs. Shuttering efficiency programs or portfolios in the short run and re-establishing them at a future date would cause administrators and trade allies to shoulder, for a second time (or third time, etc.), the costs of hiring new staff, building networks of trade allies and customer relationships, and direct marketing the program and portfolio to potential participants. Regulators in the State of Washington, for example, have proposed that program administrators include these "stop and restart" costs in the avoided-costs forecasts used for cost-effectiveness screening.[30]

---

[30] See WUTC Docket UG-121207. Under the proposed rule, utilities would consider all quantifiable costs of starting and stopping a program as avoided costs, including, but not limited to: effects on conservation program delivery infrastructure; effects on trade ally networks; effects on workforce skills related to installing energy efficiency measures; administrative costs; advertising expenses.

3. *Missed energy savings opportunities.* In the absence of programs to promote more efficient choices, investment in less efficient new or replacement facilities/buildings, processes, and equipment/appliances can set higher levels of consumption for the life of that building and equipment stock. These lost opportunities may be exacerbated by accelerating customer conversions to natural gas in certain regions of the U.S. Natural gas consuming equipment tends to be long lived, e.g., space heating (15-30 years) and water heating (10-15 years). Thus this less efficient stock could persist for years beyond the current dip in gas prices and be difficult to access with energy efficiency programs. Furthermore, program administrators are likely to incur lower costs by gradually acquiring these savings on an annual basis, compared to "playing catch-up" to meet cumulative targets at later dates. Stakeholders and regulators in California and elsewhere considered the value of "lost opportunities" in sustaining gas energy efficiency programs in the early 1990s, when wellhead gas prices dropped by more than 35 percent from mid-1980s levels. Some stakeholders predicted that prices would recover strongly and bring regret over not attempting to lock in savings during the 1990s. In the next decade, wellhead prices rose 366 percent to an annual average of nearly $8 per MMBtu in 2008.

Cost-Effectiveness Screening Policies

When determining the cost-effectiveness of energy efficiency programs, the relative costs and benefits can be affected by several policy and econometric assumptions, i.e. screening policies. In this section, we discuss four policy decisions that can have a particularly large influence on whether borderline cost-effective programs will be assessed to have benefits that exceed costs, or not. The four policy decisions are:

1. Which economic test to use for assessing cost effectiveness,
2. Which discount rate to use for determining the net present of future costs and benefits,
3.   What level in the measure, project, program and portfolio hierarchy should the cost-effectiveness test be applied (i.e. do all measure and projects have to be cost-effective or just the programs or portfolios as a whole?), and
4. Whether to assess natural gas efficiency programs alone or in combination with associated electric efficiency programs.

Low and moderate gas prices and the challenges they pose for gas efficiency programs bring several of these policy choices – and the objectives that drive them – into sharper relief.

Selection of an economic test

Each test represents a different economic perspective—from minimizing utility system costs to maximizing the welfare of society at large. This perspective, in turn, determines which costs and benefits are included—and how they are valued for analysis purposes.[31]

✓ The **Total Resource Cost (TRC)** test is the primary test for more than 70 percent of states (Kushler, Nowak and Witte 2012) that have any efficiency cost-effectiveness testing. The TRC is considered an "all perspectives" test and is intended to include all costs and benefits associated with securing energy savings. Costs are typically defined as incremental measure costs plus program administration costs.[32] Benefits are defined as avoided energy, capacity, transportation (transmission pipeline) and distribution costs. Some states where the TRC is the primary test also include energy savings from other fuels, savings of water or both. A few states include other economic benefits, such as reduced utility disconnections and collections.

✓ The **Program Administrator Cost (PAC)** test **(**also known as the utility cost test) is used by five states as the primary test (Kushler, Nowak and Witte 2012). The PAC test includes costs and benefits from the perspective of the program administrator, (i.e., all incentives and program administrative costs versus system benefits, including avoided energy, capacity, transportation and distribution costs). Because the customer's share of project costs is excluded, programs are often deemed most cost effective when evaluated using the PAC.

✓ The **Societal Cost Test (SCT)** is used by five states as the primary test (Kushler, Nowak and Witte 2012). The SCT is a variant of the TRC that takes a broader societal perspective. More types of benefits are included, the benefits extend beyond utility customers and the benefits are valued over a longer time horizon than is typical for private sector investments. This test often includes benefits such as water savings and avoided health and environmental damages.

The selection of test turns on what policy objectives are valued by policymakers and how those values translate into the definition and accounting for costs and benefits of energy efficiency programs. The primary question is whether the beneficiaries of efficiency programs are defined strictly as utility customers and shareholders in the specific geographic area where the programs are implemented and therefore are limited primarily to resource benefits such as avoided or deferred system costs. This economic perspective is consistent with selection of the TRC or PACT. If policymakers reach beyond strictly resource benefits to value a broader set of benefits and

---

[31] Program administrators in most states rely upon one of three described tests as the primary determinant of cost effectiveness.

[32] Although some states include incentives as a TRC cost, the most common formulation of the TRC treats incentives as a transfer payment among utility customers so that, from an "all stakeholders" perspective, incentives are netted out and not accounted for as a cost.

beneficiaries from energy efficiency – for example, saving energy for its own sake, saving water, mitigating greenhouse gas emissions, mitigating energy poverty, improving productivity or promoting economic development – these more societal objectives are more consistent with selection of an SCT.

At a general level, the SCT and PAC test are 'easier' for natural gas efficiency programs to pass then the TRC test, albeit for different reasons: The SCT accounts for more benefits and applies a lower discount rate to these benefits, which enhances the present value of future benefits streams. The PAC test includes only program administrator costs. Recent research on the impact of cost-effectiveness screening choices and low gas prices on gas energy efficiency programs suggests that residential gas programs in particular may not be deemed cost effective under a TRC test, but often may pass a SCT or, depending on the level of incentive, a PAC test (Hoffman et al 2012).

Selection of a discount rate

The choice of a discount rate is critical in determining the cost effectiveness of gas efficiency programs, particularly in situations with low, near-term gas prices. The two predominant types of discount rates are utilities' weighted average cost of capital (WACC) and the societal discount rate. WACC values tend to be in the 6-9% range whereas societal discount rates are often in the 2-5% range.[33] TRC and PAC tests usually use WACC discount rates, and the SCT uses a societal discount rate.

The selection of a discount rate is usually entwined with the selection of the economic test used to assess cost effectiveness.[34] The PAC and TRC tests typically use a utility WACC. Those tests originated with integrated resource planning and are intended to weigh supply- and demand-side resources in a similar fashion so that decision makers may choose the least-cost, least-risk option for the investment of private capital. The nature of the investment is therefore consistent with using the cost of that capital as the discount rate.

The perspective of the SCT is societal—policymakers have chosen to value benefits that are larger in scope and often longer in time horizon than avoided system energy and capacity costs. These broader, longer-lived benefits are more consistent with public-sector investments that reflect less aversion to risk and a greater willingness to collect returns (benefits) over a longer time period. These investments usually have a lower cost of capital. In part for that reason, most states relying upon an SCT use a societal discount rate indexed to U.S. Treasury bill rates.

---

[33] These ranges for utility weighted average costs of capital and typical societal discount rates are based on a recent LBNL review of DSM plan filings in all states with substantial spending on utility customer-funded energy efficiency programs (Barbose et al 2013).
[34] There are exceptions. Several states, such as Massachusetts, employ a TRC with a societal discount rate.

Higher discount rates have an important impact on natural gas efficiency cost-effectiveness because installed measures have typically are paid for in full in the first year and then realize energy savings over the economic lifetime of the measure. This means that all the costs are not discounted while the savings in later years are heavily discounted. Lower discount rates provide more net present value to the savings that are projected to occur in later years, which is important for typically long-lived gas efficiency measures. If higher avoided commodity costs are forecast for those later years, those outer year benefits are worth less in a present-day assessment if a higher discount rate is used. A lower discount rate values those benefits more.

Level at which the test is applied

Energy efficiency cost effectiveness screening may be applied at the measure, project, program, sector or portfolio level. In measure-level screening, each energy-saving action or measure must generate more benefits than it costs to put in place, or it is deemed not cost effective. Bundling measures and projects at the program or portfolio level and thus screening at higher levels allows for: (a) greater efficiencies in implementation, (b) fewer lost savings opportunities, and (c) more flexible program designs that are aligned with businesses offering comprehensive retrofits that increase savings per facility and installation of measures with longer economic lifetimes. Screening at more aggregate levels (e.g., portfolio) is also more consistent with integrated resource planning (IRP), in which the aggregate cost effectiveness of "the energy efficiency resource" is critical to considering all resource options.

Treatment of single-fuel vs. combined electric and gas utility programs

Utility customers may be served by separate gas and electric distribution (or integrated electric generation and distribution) utilities or by a combination utility that provides both gas and electric distribution services. The organization of utility service provision often impacts the way in which energy efficiency program services are delivered and their cost-effectiveness evaluated. Most single-fuel utilities administer energy efficiency programs on their own. However, energy efficiency opportunities typically lead to savings from end uses that reduce both gas and electric energy use. Delivered together as part of the same project or program, gas and electric efficiency measures may very well pass cost-effectiveness tests even if the gas measures on their own do not.

Delivering gas and electric efficiency programs together has the benefit of avoiding the loss of technically and economically viable energy efficiency potential. Energy efficiency technical potential comes from individual end uses and the interaction of those measures with one another and the facility itself in which they are implemented.[35]   Ignoring the benefits of energy savings from "other

---

[35] One concern about the potential suspension of gas efficiency programs and continuation of electric efficiency programs is that in the absence of gas efficiency programs that address heating and shell efficiency, there is a risk of a net increase in gas consumption due to electric efficiency program participation through "interactive effects" in which the

fuels" may lead regulators and administrators of gas efficiency programs to undervalue investment in packages of measures that deliver savings across fuels. The resulting customer under-investment may foreclose on energy efficiency savings opportunities because long-lived equipment is installed that is oversized or because certain improvements can only be technically or economically installed in conjunction with a broader package of measures.

Conclusions

The shale gas revolution has ushered in a new era on both the supply and demand side. Low natural gas prices are creating significant benefits for consumers but cost-effectiveness screening challenges for gas efficiency efforts. Natural gas energy efficiency programs came to prominence in terms of spending, level of savings and geographic coverage in the last decade, when gas prices were relatively high. In the 2000s, these programs had few problems passing cost-effectiveness analyses due to these high prices, and there was less incentive to investigate the full range of benefits from gas energy efficiency—many of which are not routinely considered as part of cost-effectiveness screening. The relative impact of including these benefits varies widely. In program screening, using a lower discount rate is likely to have a substantial impact on cost effectiveness (Hoffman et al 2013). Changing from a TRC to an SCT or PAC test or moving from measure- to program- or portfolio-level screening also is likely to have a significant effect. The impact of the other benefits mentioned in this brief, each taken on its own, is more modest and may vary with the characteristics of a program administrator's market and the methodology used for to assess the benefits value. Each of the benefits of natural gas efficiency programs described in this policy brief and the various screening policy options can be integrated qualitatively, quantitatively or both into regulatory decision making, should a regulatory body seek to achieve a more holistic assessment of the costs and benefits of operating gas efficiency programs.

References

Amman, J. Valuation of Non-Energy Benefits to Determine Cost-Effectiveness of Whole-House Retrofits Programs: A Literature Review. American Council for an Energy Efficient Economy. May 2006 ACEEE Report Number A061

Barbose, G. Goldman, C.A., Hoffman, I.M. and M. Billingsley. The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025. January 2013. LBNL-5803E. http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf

---

installation of more efficient electric measures in gas-heated structures reduces cooling loads and raises the heating load in homes and other buildings.

Bolinger, M., R.H. Wiser, W.H. Golove. 2002. Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices. LBNL-50484
http://eetd.lbl.gov/sites/all/files/publications/report-lbnl-50484.pdf%20%20

Bolinger, M. "Implications of $2/MMBtu Natural Gas: Have Rumors of Wind's Demise Been Greatly Exaggerated?" AWEA's WINDPOWER 2012 Conference, Atlanta, Georgia, June 5, 2012.

Bower, Steve, S. Huntington, T. Comings and W. Poor. 2012. Economic Impacts of Efficiency Spending in Vermont: Creating an Efficient Economy and Jobs for the Future. 2012 Proceedings of the American Council for an Energy Efficient Economy (ACEEE) Summer Study.
http://www.aceee.org/files/proceedings/2012/data/papers/0193-000157.pdf

Carnall, M., Dale, L., Lekov, A. Effect of Energy Efficiency Standards on Natural Gas Prices. July 2011. LBNL -4994E
http://efficiency.lbl.gov/drupal.files/ees/Effect%20of%20Energy%20Efficiency%20Standards%20on%20Natural%20Gas%20Prices_LBNL-4994E.pdf

Consortium for Energy Efficiency (CEE). 2012. State of the Efficiency Program Industry: Budgets, Expenditures and Impacts 2011.
http://www.cee1.org/files/2011%20CEE%20Annual%20Industry%20Report.pdf

Concentric Energy Advisors. "New England Cost Savings Associated with New Natural Gas Supply and Infrastructure" Prepared for Spectra Energy Corp. 2012.

Ebinger, Charles, Massy, K. and G. Avasarala. Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas. Energy Security Initiative at Brookings. Policy Brief 12-01. May 2012.
http://www.brookings.edu/research/reports/2012/05/02-lng-exports-ebinger

U.S. Environmental Protection Agency (EPA). 2011. Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources.
http://www2.epa.gov/sites/production/files/documents/HFStudyPlanDraft_SAB_020711.pdf

U.S. Environmental Protection Agency (EPA). 2013. Summary of Technical Roundtables on EPA's Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. February 2013. http://www2.epa.gov/sites/production/files/documents/summary-of-technical-roundtables.pdf

Eto, Joseph and Charles Goldman. 1998. Ratepayer-Funded Energy-Efficiency Programs in a Restructured Electricity Industry: Issues and Options for Regulators and Legislators. LBNL-41479
http://eetd.lbl.gov/EA/EMP/http://eetd.lbl.gov/EA/EMP/

Federal Energy Regulatory Commission. Natural Gas Markets: National Overview. February 2013.
http://www.ferc.gov/market-oversight/mkt-gas/overview/2013/02-2013-ngas-ovr-archive.pdf

FERC. Roundtable on Electric-Gas Coordination West Region. August 2012.
http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=6415&CalType=%20&CalendarID=116&Date=8/1/2012&View=Listview

Friedrich, Katherine, M. Eldridge, D. York and M. Kushler. 2009. "Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs. American Council for an Energy Efficient Economy (ACEEE). Research Report U092. September 2009. http://www.aceee.org/research-report/u092

Golove, William and Joseph Eto. 1996. Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy Efficiency. **LBNL-38059** http://eetd.lbl.gov/EA/Ems/reports/38059.pdfhttp://eetd.lbl.gov/EA/Ems/reports/38059.pdf

Graves, F. and S. Levine. 2010. "Managing Natural Gas Price Volatility: Principles and Practices Across the Industry." The Brattle Group, Prepared for American Clean Skies Foundation. http://www.cleanskies.org/wp-content/uploads/2011/08/ManagingNGPriceVolatility.pdf

Heffner, G. and Campbell, N. Evaluating the Co-Benefits for Low-Income Energy Efficiency Programmes. International Energy Agency. June 2011.

Hoffman, I., Borgeson, M., and Zimring, M. Implications of Cost Effectiveness Screening Practices in a Low Natural Gas Price Environment: Case Study of a Midwestern Residential Energy Upgrade Program. **LBNL-6167E** http://emp.lbl.gov/sites/all/files/lbnl-6167e.pdf

Howarth, R., Santoro, R. and Ingrraffea, A. Methane and the green-house gas footprint of natural gas from shale formations. March 2011. Clim Chang Lett. DOI 10.1007/s10584-011-0061-5 http://www.eeb.cornell.edu/howarth/Howarthetal2012_Final.pdf

Howland, J., Murrow, D., Petraglia, L., Comings, T. Energy Efficiency: Engine of Economic Growth A Macroeconomic Modeling Assessment. Environment Northeast. October 2009. http://www.env-ne.org/public/resources/pdf/ENE_ExecSum_EnergyEfficiencyEngineofEconomicGrowth_FINAL.pdf

Huber, L. "Utility-Scale Wind and Natural Gas Volatility." Rocky Mountain Institute, 2012. http://www.rmi.org/Knowledge-Center/Library/2012-07_WindNaturalGasVolatility

Interstate Natural Gas Association of America Foundation (INGAA). 2009. Natural Gas Pipeline and Storage Infrastructure Projections Through 2030. Submitted by ICF International. http://www.ingaa.org/File.aspx?id=10509

Independent System Operator-New England, Addressing Gas Dependence. July 2012. http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf

Joust, F., and Trost, R. An Economic Analysis of Consumer Response to Natural Gas Prices. March 2007. American Gas Association. http://ad.aga.susqtech.com/SiteCollectionDocuments/ResearchStats/Studies/Consumers%20n%20Demand/0706ELASTICITYSTUDY.pdf

Kushler, M., Nowak, S. and Witte, P. "A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs" February 2012. American Council for an Energy Efficient Economy (ACEEE). Report Number U122

Litovitz, A., Curtright, A., Abramzon, S., Burger, N. and Samaras, C. Estimation of regional air-quality damages from Marcellus Shale natural gas extraction in Pennsylvania. January 2013. Environ. Res. Lett. 8 (2013) 0141017 (8pp). http://iopscience.iop.org/1748-9326/8/1/014017/pdf/1748-9326_8_1_014017.pdf

Logan, J., Heath, R., Macknick, J., Paranhos, E., Boyd, W. and Carlson, K. Natural Gas and the Transformation of the U.S. Energy Sector: Electricity. November 2012. Joint Institute for Strategic Energy Analysis. NREL/TP-6A50-55538. http://www.nrel.gov/docs/fy13osti/55538.pdf

Massachusetts Institute of Technology (MIT). 2011. "The Future of Natural Gas." MIT Energy Initiative, 2011. http://mitei.mit.edu/publications/reports-studies/future-natural-gas

Peters, L. Gas and Electric Infrastructure Interdependency Analysis. Midwest Independent Transmission System Operator (MISO). February 2012

Navigant Consulting Inc., Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond, Track 1: Statewide Investor Owned Utility Energy Efficiency Potential Study. May 2012. http://www.cpuc.ca.gov/NR/rdonlyres/6FF9C18B-CAA0-4D63-ACC6-F9CB4EB1590B/0/2011IOUServiceTerritoryEEPotentialStudy.pdf

NMR, Inc. and Tetra Tech. Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation. Madison, WI: Tetra Tech. 2011.

Nothe, J. 2012. "Demand grows in N.E. for natural gas heat." The Boston Globe. April 25, 2012. http://www.boston.com/business/articles/2012/04/25/demand_grows_in_ne_for_natural_gas_heat/?page=1 (Accessed 10/30/12)

Petraglia, L., Comings, T., Weisbrod, G. Focus on Energy Economic Development Benefits: CY09 Economic Impacts. Wisconsin Department of Administration and Public Service Commission of Washington. March 2010. http://www.focusonenergy.com/files/Document_Management_System/Evaluation/cy09economic impactsreport_evaluationreport.pdf

Rundquist, et. al. Calculating Lighting and HVAC Interactions, ASHRAE Journal, November 1993

Sezgen, O., Koomey, J. Interactions Between Lighting and Space Conditioning Energy Use in Commercial Buildings. LBNL-39795 April 1998. http://enduse.lbl.gov/info/LBNL-39795.pdf

Skumatz, L., Dickerson C. A., and Coates, B. Non-Energy Benefits in the Residential and Non-Residential Sectors – Innovative Measurements and Results for Participant Benefits. Proceedings of the 2000 ACEEE Summer Study on Energy Efficiency in Buildings. American Council for an Energy Efficient Economy. August 2000.

Skumatz, L. Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California. Report for Sempra Utilities. Revised May 2010.

Tetra Tech. Final Report – Commercial and Industrial Non-Energy Impacts Study. Massachusetts Program Administrators. June 2012.

U.S. Energy Information Administration (EIA). 2012. 2012 Annual Energy Outlook. Report Number: DOE/EIA-0383(2012) U.S. EIA: Washington, DC, 2012.

U.S. Environmental Protection Agency (EPA). 2011. Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. U.S. EPA: Washington, DC, 2011. http://www.epa.gov/hfstudy/HF_Study__Plan_110211_FINAL_508.pdf

Wiser, R. Bolinger, M. and M. St. Clair. 2005. Easing the Natural Gas Crisis: Reducing Natural Gas prices through Increased Deployment of Renewable Energy and Energy Efficiency. LBNL-56756. http://eetd.lbl.gov/EA/EMP/reports/56756.pdf

Wood MacKenzie. Rethinking Natural Gas, A Future for Natural Gas in the U.S. Economy. American Gas Association. Spring 2012. http://www.aga.org/our-issues/promise/Documents/Rethinking%20Natural%20Gas%20Version%202.pdf

Appendix A – Demand Reduction in Price Effect (DRIPE) Estimation

As energy efficiency programs reduce consumer energy usage, the energy commodity demand and supply curve intersection shifts inward (from Q_1 to Q_2 in Figure 3). Assuming no change in the supply function, the new equilibrium between supply and demand will be at a lower price (P_2 in Figure 3). The shape of the supply curve strongly influences the magnitude of the DRIPE effect: A steep supply curve – implying that producers need large increases in price to increase production – translates into a larger price suppression effect. A shallow supply curve – indicating that suppliers are willing to make substantial changes in production in response to small changes in price – translates into a smaller price effect. As discussed previously, the magnitude of the ultimate price effect depends on the sensitivity of wholesale gas prices to changes in gas demand (LBNL 2005).

In 2005, LBNL surveyed 19 studies of natural gas DRIPE under a range of energy efficiency and renewable portfolio standard scenarios (Wiser et al 2005). Part of the objective of the LBNL study was to estimate the relationship of gas prices to the quantity supplied. This relationship is reflected in the inverse price elasticity of supply, which is a measure of the responsiveness of price to changes in supply over a period of time.[36] A subsequent study performed for the American Gas Association (Joust and Trost 2007) derived the long-run price elasticity of gas demand for the period 2000 to 2006, which we take as equivalent to the price elasticity of supply and use to calculate the inverse elasticity of supply. For this policy brief, we also calculated the long-run inverse elasticity of supply from 2001 to 2040, using historical data on Henry Hub prices and actual supply to 2012, then projections for both to 2040 from the U.S. Energy Information Agency's 2013 Annual Energy Outlook.
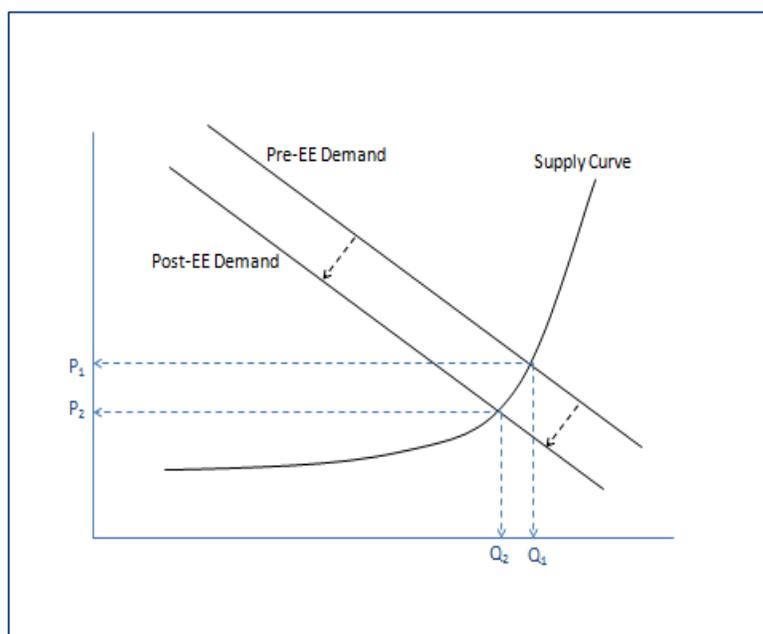

Figure 2. Illustration of the price suppression effect of a reduction in demand. As the quantity demanded falls from Q_1 to Q_2, the corresponding price drops from P_1 to P_2.

---

[36] The inverse price elasticity of supply (Inverse PEoS) dictates the shape of the supply curve. It is the ratio of the percent change in price (P) to the percent change in the quantity supplied (Q) over a period of time or for a change in policy, i.e.: Inverse PEoS = $(\%\Delta P)/(\%\Delta Q)$. If the comparison is between a business-as-usual case and a case in which a different policy is in effect, then a point estimate for the inverse elasticity of supply is appropriate. This analysis looks at the differences in price and supply over periods of six to 30 years, so it is appropriate to derive an arc value using averages for those differences.

The range of values in Table 2 is based in part on different periods of analysis, different data sources and different methods of calculation, e.g., the AGA study is an econometric analysis of data supplied by gas distribution utilities while the two LBNL studies use EIA data and projections.

Source	Inverse Long-Run Price Elasticity of Gas Supply	% Change in U.S. Wholesale Gas Prices for a 1% Change in Demand
Wiser, Bolinger and Claire 2005	0.2	0.20%
	0.8	0.80%
	1.2	1.20%
Calculated from Joust and Trost 2007	5.6	5.60%
LBNL Update, 2001-2040	6.4	6.40%

Table 2. Inverse long-run price elasticity of gas supply from a range of studies and % change in U.S. wholesale gas prices for a 1% change in demand.

To estimate the value of DRIPE from gas efficiency programs in Massachusetts, we used the low-end value from the 2005 LBNL literature survey and the high end value from the analysis completed for this policy brief.[37]

From 2009 to 2011, gas efficiency programs in Massachusetts saved 3.9 trillion Btu (about a hundredth of a percent of total U.S. gas consumption). Based on the range of values for the price/supply relationship that we analyzed, savings to gas consumers in Massachusetts from price suppression alone can be as little as $235,000 but could reach $1.9 million. Because the wholesale price effects of the gas efficiency programs in Massachusetts (or anywhere else) benefit all U.S. gas consumers, not just those in Massachusetts, the total U.S. consumer savings are considerable, ranging from $12 million to as much as ten times that, depending on one's assumptions.[38]

Appendix B – The Environmental Risks and Impacts of Shale Gas

There is considerable uncertainty about some of the environmental risks and impacts of the production of shale gas through hydraulic fracturing relative to conventional gas production. We describe these risks and impacts below based on available studies and acknowledge the need to collect additional data and information on the potential environmental risks and impacts associated with shale gas.

---

[37] We did not attempt to estimate gas capacity DRIPE although such an effect exists to the extent that pipeline and storage capacity have a volumetric component to pricing.

[38] These savings do not include suppression of gas capacity charges or secondary savings on electricity bills; generators are the largest consumers of natural gas and therefore would produce electricity at lower prices.

- *Greenhouse Gas Emissions Impacts.* Studies using different techniques and analysis boundaries, examining different shale gas formations (i.e. different geographic regions) and making different assumptions (about , for example, estimated ultimate recovery from a well and methane leakage rates) have come to dramatically different conclusions about the greenhouse gas emissions profile of shale gas production relative to conventional gas production. These results range from shale gas having similar life cycle greenhouse gas emissions to conventional gas (Logan et al. 2012) to shale gas production causing emissions at least 30 percent higher than those of conventional gas (Howarth et al 2011). These disparate conclusions clearly suggest that further measurements and technological feasibility analyses are necessary before broad conclusions can be drawn about the greenhouse gas impact of current shale gas production (and the potential additional costs for effective emissions mitigation).

- *Water Use and Quality Impacts.* Unlike conventional gas production, hydraulic fracturing entails significant water use. There is substantial variability in the water requirements of producing shale gas, but the U.S. Environmental Protection Agency (EPA) estimates that fracturing requires between two and four million gallons of water per well (EPA 2011), sometimes placing a significant stress on water availability for agriculture. Additional research is necessary for broad conclusions to be drawn about shale gas's water use and its long-term impacts,[39] but reduced local, regional and national surface and ground water quantity and quality may result from the following:[40]
    - Water withdrawal;
    - Stormwater runoff, chemical spills and leaks across gas production's "industrial footprint" (e.g. well pads, roads to transport water & equipment);
    - Well drilling, hydraulic fluid injection & fracturing and cementing & casing;
    - Hydraulic fracturing wastewater spills and leaks;
    - and wastewater treatment and discharge.

- *Non-Greenhouse Gas Air Quality Impacts.* The production of both shale and conventional gas leads to emissions of a range of air pollutants that degrade local and regional air quality, including Volatile Organic Compounds (VOCs), Nitrogen Oxides (NO_x), Particulate Matter (PM), Sulfur Dioxide (SO_2), Ozone (O_3) and Carbon Monoxide (CO) (Litovitz et al 2013). Significant uncertainty remains about the extent of emissions from shale gas production relative to those from conventional gas production due to lack of data. The harm caused by these emissions is likely to vary regionally based on the concentration of drilling activity, other sources of emissions, meteorology and photochemistry.

---

[39] The EPA is currently conducting a study titled "Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources." To more fully understand potential impacts of hydraulic fracturing gon the water supply. More information is available here: http://www.epa.gov/hfstudy/

[40] Adapted from (EPA 2013).