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The Economic Effect of Efficiency Programs on Energy Consumers and Producers

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ABSTRACT

An increase in the efficiency of natural gas fired residential appliances allows users to realize the same level of service, heating water for example, while using less natural gas. In addition to this technological benefit to the residential sector, the reduced demand for natural gas depresses the price of natural gas resulting in pecuniary gains to other energy consumers and pecuniary losses to energy producers.

The question we address in this study is whether purely pecuniary effects, those that follow from the price changes elicited by lower usage of natural gas, should enter the debate concerning the implementation of efficiency standards. To that end, we explore the price and social welfare impacts of natural gas energy efficiency standards by evaluating the impacts of a specific efficiency standard[1] using the National Energy Modeling System. Our analysis indicates that purely pecuniary losses to producers are largely offset by pecuniary benefits to consumers, and therefore do not provide the deciding factor with respect to establishment of efficiency standards. Our analysis also provides useful insight into the sources of these benefits and losses.

Although our results are based on a specific model and efficiency standard, we believe that the results generalize to other efficiency programs, and would be reproduced using other energy models.

Keywords: energy efficiency, appliances, standard, economic benefit, transfer.

[1] The residential water heater portion of "Energy Conservation Standards for Residential Water Heaters, Direct Heating Equipment, and Pool Heaters", docket number EE-2006-BT-STD-0129.

1. Introduction

An increase in the efficiency as a result of efficiency programs allows consumers to obtain the same level of service, water heating for example, using less fuel. Development and adoption of the technological improvements required to accomplish this may arise spontaneously as appliance producers compete for customers; it may also be influenced by policy instruments such as building codes or minimum efficiency standards that mandate or provide incentives for improved appliance efficiency. Whatever the motivation, an increase in the efficiency of available appliances will raise the average efficiency of the stock of appliances as the older appliances are replaced.

The direct benefit of increased efficiency to appliance owners is the value of the savings on fuel, less the additional capital and operating cost of the more efficient appliances. In addition to the direct benefit to appliance owners, reduced usage of natural gas in the residential sector depresses the price of natural gas to all consumers. Natural gas resources, like any exhaustible resource, tend to be exploited in inverse order of the cost of extraction, with the lowest cost gas being extracted first (Hotelling, 1931). Slowing the pace of gas consumption slows the transition from lower to higher cost sources, reducing the current and future wellhead price of natural gas.

Natural gas-fired generation provides about one quarter of all electricity used in the United States (EIA 2012b). The effect of lower gas prices on electricity prices depends on the extent to which gas is used as a fuel and the mechanism, regulation or competitive markets, used to set wholesale electricity prices. However, in general lower gas prices will lead to a reduction in the cost of generating electric power, leading to lower electricity prices. Lower natural gas and electricity prices reduce the cost of manufacturing as well as retailing goods (EIA 2013e). Manufacturers, and to the extent that savings are passed on through prices, consumers, will benefit from higher efficiency appliances, either through lower natural gas prices, lower electricity prices, or lower prices for other goods that require natural gas or electric energy as a direct or indirect input. These benefits increase available income, some of which may be used to purchase additional energy, either in the form of additional fuel or embodied in other goods or services.

At the same time, lower natural gas usage and prices will reduce natural gas producer revenues. To the extent that they cannot reduce their cost of production, the profitability of producer investments will also fall. More important, lower usage and prices will reduce owner compensation and the value of natural gas reserves. Federal, state and local governments are owners of extensive natural gas resources and receive compensation for extraction of these resources. Governments also collect taxes based on the value of the gas produced within their jurisdictions. Reduced usage and price of natural gas will therefore lead to reduced government revenue. To the extent that revenues decline more than costs, tax collections on other sectors may need to be increased.

To the extent that the benefits from lower energy prices reflect reductions in the cost of producing goods and services, they represent an increase in social welfare. However, if they simply reflect reduced compensation to resource owners, lost profits to the producing sectors, or shifts in tax burden, the reductions are transfers to consumers from the adversely affected sector (Pigou 1924). While these transfers do not indicate a decline in economic efficiency, i.e. a decline in social welfare, when they result from government action, they are necessarily subject to political review. With respect to policy instruments that affect natural gas demand, sectors that may be adversely affected include natural gas producers, the natural gas transmission and distribution sector, electricity generation sector, owners of natural gas resources, and government entities that receive taxes or fees based on natural gas production.

In this paper we identify and quantify, using the U.S. Energy Information Administration's (EIA) National Energy Model (NEMS), the benefits and loses, both the direct technological effects and pecuniary or price effects, resulting from an increase in appliance efficiency associated with a representative minimum efficiency standard. We focus on benefits to energy consumers and losses to the energy producing sectors. We find substantial technological benefits to the residential sector of $1.94 Billion along with pecuniary benefits of $1.81 Billion. These pecuniary benefits are offset by pecuniary losses of $1.95. Our results provide support the theoretical finding that pecuniary losses resulting from technological change tend to be offset by pecuniary benefits (Pigou, 1924)

The remainder of the paper is organized as follows. Section 2 provides background on appliance minimum energy efficiency instruments; Section 3 provides an overview of the energy consumption and production sectors and how they are affected by an increase in appliance efficiency; Section 4 describes our methods of quantification; Section 5 presents our results and finally Section 6 provides some cautions and discussion of policy ramifications.

2. Background

There is an extensive literature addressing the observed level of appliance efficiency and the utility maximizing level of efficiency (Hausman and Joskow, 1980, Sutherland, 1991, 1994; Sanstad and Howarth, 1994). This literature is focused on the question of whether standards mitigate market defects or informational deficiencies that impede consumers purchasing decisions or simply preclude them from purchase lower levels of efficiency levels that would maximize their private utility. A related body of research explores the role of efficiency standards as a means of reducing energy consumption and greenhouse gas emissions (Sanstad et al., 2006). Others observe that conservation programs tend to lower energy expenditures and price, but in some cases the high fixed costs of transmission and distribution may instead lead to higher retail prices redistribution among participating and non-participating residential consumers (Croucher, 2012). More energy efficient appliances provide consumers with additional disposable income. Noting that the additional income and lower prices will tend to increase usage of the affected appliances and increase the use of natural gas for all other uses, the rebound literature, beginning with Khazzoom in 1980, explores the extent of these “rebounds in usage” on the net effect of changes in energy efficiency and operating cost on total energy usage (Berkhout et al, 2000) (Sorrell and Dimitropoulos, 2008), (Borenstein, 2013).

Wiser et al (2005) summarize estimates of the magnitude of the effect of reduced demand on natural gas prices, focusing primarily on national level markets. They also raise the question of whether some part of the benefit claimed for efficiency standards represents a transfer from producers and utilities to consumers. Others, Burtraw (2012) and Linn et al (2014), for example, point out that falling natural gas prices will reduce electricity prices and adversely affect the profitability of coal generating assets in the electric power industry.

3. Energy Sector Background

3.1. Energy Consumers

Natural gas is delivered to consumers through a system of interstate and intrastate pipelines and local distribution facilities. The cost of transmission and distribution comprise a substantial portion of the delivered price. Most residential, commercial and some industrial customers purchase natural gas from a utility that provides the gas and distribution service as a “bundle”. Some large commercial and industrial customers purchase gas directly from an intermediate supplier or pipeline, receiving the gas directly from the supplier or purchasing distribution service from the local utility. EIA estimates that over 60 percent of the average per unit price of gas delivered to residential, commercial and transportation customers is associated with the cost of transmission and distribution (EIA 2013b). The percentage for industrial and electric power customers is smaller, reflecting the lower cost of delivering larger volumes to a single point of use.

Under traditional rate of return regulation, customers pay a single bundled rate for each unit of gas purchased. These bundled rates are determined by estimating the utility's cost of providing the bundled service to all customers, its "revenue requirement", and dividing that amount by the expected volume to be delivered to determine the per unit rate that would recover the utility's revenue requirement. If actual usage is below expected volume the utility will not fully recover its costs and if usage is above expectations it will over recover its cost. In either case, the discrepancy is made up by adjusting rates. In reality, rates are calculated for each customer class and sometimes modified to achieve local public policy goals, but the guiding principal is that the expected consumption will provide the required revenue to the utility.

Traditionally, regulated rates were recalculated only at intervals of several years so the effects of usage above or below the original forecast accumulated for some time before correction. Some states and utilities have "decoupled" their rates, providing annual or more frequent "true ups" to eliminate this distortion (DOE, 2010). These adjustments may be augmented by using two part tariffs which collect a fixed fee that covers, or partially covers, the fixed cost of transmission and distribution services (Borenstein and Davis, 2012).

Much of the cost of transmission and distribution is fixed and does not vary significantly with small changes in the volume delivered. Under a single part tariff, if a customer reduces his usage of gas he saves the full amount of the tariff but the utility's cost declines only by the fraction associated with the purchase of gas. In this case the customer receives a benefit but some of it is simply a transfer from the utility These transfers disappear when rates are recalculated.

Residential consumers directly benefit from the use of more efficient appliances by achieving the same level of appliance service while using less fuel. The benefit of a more efficient appliance to a single residential consumer is simply the reduction in the cost of natural gas required to operate the more efficient appliance. Where single part tariffs are used, reduced usage will necessitate an increase in the portion of the price required to recover the fixed cost of transmission and distribution. Where the portion of the price representing recovery of fixed cost is high, as it is for residential customers, this increase can overwhelm the reduction in the cost of gas resulting in an increase in the delivered price even though the customers' total expenditure for the reduced quantity of gas will be lower.

Commercial customers purchase natural gas in much the same way as residential customers, through a local distribution utility. Depending upon their volume of usage, industrial users may purchase gas directly from a wholesale pipeline. Lower natural gas prices result in savings to these customers and may elicit additional usage, increasing their usage but also tempering the decline in wellhead price resulting from reduced usage in the residential sector. Benefits realized by these sectors are either passed on to consumers or held as additional profit.

3.2. Natural Gas Producers

Natural gas is extracted from underground geological formations either by itself or in association with crude oil or other liquids. The development of a natural gas field is not only costly but also risky. Natural gas producers routinely face, and manage, several types of risk: geological risk, that the field will not produce its estimated volume; financial risk, that financing costs will be higher than expected; cost risk, that the cost of exploration, completion or production will be above expected values; demand risk, that demand will be reduced by weather or other factors; and price risk, that prices will be adversely affected by reduced demand or competition from other producers. All of these risk factors must be considered in the producer's decision to proceed with the procurement or development of natural gas resources.

Before exploitation of a reservoir can begin, a producer must acquire from the landowner the right to explore and produce the gas. The process of discovery and development of a new formation can require a number of years. Once the economic viability of production has been established, gathering and processing facilities must be installed, along with pipelines connecting to established transmission and distribution systems; only then can production wells be drilled and completed.

Producers make investment decisions on the basis of the expected future revenue and cost streams associated with those investments (Kuuskraa, 2008). Projects that are projected to generate sufficient revenue to cover their cost, plus an appropriate profit, are undertaken; those that fall short of that criterion are delayed or abandoned. These profitability analysis techniques are quite sophisticated, recognizing the multiple stages of a project and allowing determination of the optimal decision at each stage in the project (Vannan, 1999).

Once a natural gas well is drilled and completed, the cost of producing the gas accessible through that well is relatively low. For that, and other reasons, producers do not routinely shut down natural gas wells in response to low prices (NaturalGas.org, 2013). Total production thus responds to changes in price primarily through changes in the number of new wells drilled and completed rather than changes in the volume of gas produced by wells already in production. As a result, there is a substantial lag in the response of production to a decline in price (NaturalGas.org, 2013). Figure 1, a plot of wellhead price, marketed production, operating drill rigs, and producing wells, shows that, over the past twenty-three years, the number of operating drill rigs has risen and fallen in step with changes in wellhead price, while marketed production has continued to increase even as the price fell substantially.

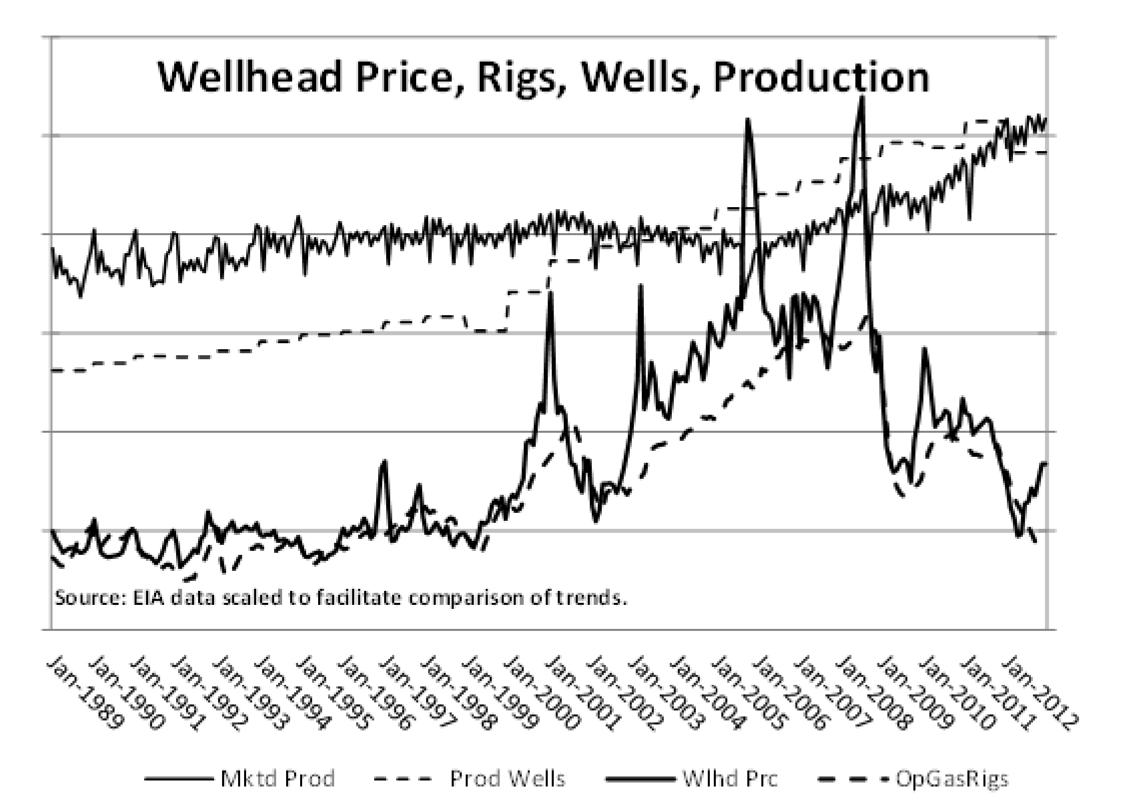

Figure 1. Wellhead Price, Marketed Production, Active Rigs and Producing Wells.

In general, natural gas producers receive the wellhead price for gas produced and from that revenue pay compensation to mineral rights owners, taxes, fees, and the cost of exploration, development, and production, including sufficient profit to attract the capital necessary to finance the equipment and operations required for exploration and production. The scarcity of profitably exploitable natural gas gives rise to an economic rent equal to the difference between the wellhead price of the gas and the cost of its extraction (Watkins, 2001). Owners of the right to those resources, usually the owners of the overlying land in the United States, receive a portion of that rent from producers in exchange for the right to find and extract the natural gas under their land. In practice, the landowners' share of the economic rent consists of a combination of one-time bonus payments, fixed rents, and royalties based on the value of the gas extracted. The amount of this compensation is determined through some form of negotiation between producers and rights owners. In the United States, ownership of land usually includes ownership of the minerals, including gas or oil, underlying the property. On public lands, the mineral rights are owned by the government entity holding title to the land. Historic EIA data indicate that 18 percent of natural gas produced in 2012 came from Federal onshore (12 percent) or offshore (6 percent) lands (EIA, 2013a). Small, but significant quantities of natural gas are also produced from state and local government lands. As rights owners on these lands, local, state, and federal governments may receive a substantial portion of the economic rent. In addition to compensation as rights owners on land they own, Federal, State, and local governments capture a share of the economic rent through the imposition of taxes and fees even where the rights are owned by other government entities or private parties.

The combination of taxes, fees, royalties, and other payments to landowners that make up the economic rent is generally referred to as a "fiscal system" and represents the portion of wellhead revenue that is captured by government and landowners. The terms of a fiscal system – the magnitude of compensation and the extent to which required payments are based on fixed charges rather than the value of gas actually produced -- determine how risks are shared between the landowner, government, and producer and thus the incentive of producers to explore and develop new fields. It is not uncommon for governments to cede some of the rent, either by reducing royalties or taxes, to producers as an incentive to development of new fields.

Fiscal systems are complex and vary throughout the world and within the United States depending upon the ownership of mineral rights, the political structure of the state or country, and the geologic characteristics of the resources within the area. Rigorous estimation of the shares of revenue received by landowner, government, and producer would require discovering and applying the terms of the appropriate fiscal system to each well affected by a change in demand, an exercise far beyond the scope of this study.

Studies of fiscal systems in the United States indicate that the combined government-ownership share of revenue—taxes and fees plus payments to landowners— varies substantially (Van Meurs, 2007; U.S. GAO, 2007). Kepes et al (2011) estimates that in the US, the average landowner-government share of net revenue (wellhead revenue less capital and operating cost) is about 75 percent on public lands and 82 percent on private lands.

Reduced consumption of natural gas inevitably leads to a reduction in opportunities for profitable investment in the natural gas production. However, as long as producers are able to anticipate the decline and investors can shift capital to other sectors, investments will be limited to those projects that provide a suitable return and profitability maintained. Only when the decline is unanticipated will the profitability of investments fall below the level necessary to justify the project. Where the reduction in consumption is the result of a government imposed standard, and the standard-setting process is sufficiently transparent that producers can include its effects on future demand in their projections, the profitability of producer investments will not be adversely affected by the reduction in demand associated with the eventual introduction of the standard. If there is some period within which the decline could not be foreseen, only the profitability of investments made during that period when the effect of a standard cannot be foreseen will be adversely affected. The process of defining and introducing an appliance efficiency standard is long and subject to public review (DOE 2013), which greatly increases the time when a standard can be foreseen.

It should be noted that the incremental reduction in natural gas demand directly resulting from the increase in efficiency associated with the water heater standard we use as an example —a 0.45 percent decline in residential usage—is very small relative to the overall variation in usage. For example, analysis of EIA data (EIA, 1999; EIA, 2006) indicates that annual variation in residential natural gas usage due to annual weather variation is about four percent, almost 10 times the 0.45 percent decline in residential use due to the standard.[2]

The compensation received by mineral rights owners is, either directly or indirectly, based on the value of the gas extracted. Although reduced usage of natural gas may not affect the total volume ultimately extracted from a parcel, it will delay its extraction and, through lower prices, reduce the present value of

[2] Standard deviation of U.S. heating degree days is 4.34 percent of the mean and the elasticity of residential consumption is 0.9 so the standard deviation of consumption due to weather variation is approximately 4 percent of its mean. Reduction for the water heater standard used for our analysis is 0.45 percent of residential usage, almost an order of magnitude lower than weather induced variation. Source: EIA 1999, 2006.

the compensation received by the owner. At the same time, reduced usage may also lower the future cost of natural gas extraction resulting from delayed depletion. This offsetting depletion impact is both uncertain and difficult to estimate and we have not attempted to calculate or include these savings in this report.

Underlying minerals are an endowment associated with the overlying land. Unlike the capital investments required to produce natural gas, mineral rights cannot be transferred to other, more profitable activities or locations. Whether the owner paid for the rights in anticipation of higher or lower demand, or unknowingly acquired them while acquiring the land for other purposes, does not alter the effect of reduced prices. However the right was acquired, compensation for the resource is reduced by a reduction in natural gas usage associated with a standard, less any associated future extraction cost savings that might occur by delayed depletion. The reduction in owner revenue is thus an offset to the benefit realized by other sectors from natural gas conservation.

As noted above, many government entities collect taxes and fees based on natural gas extraction and sales. These collections include severance taxes, environmental fees, conservation fees, and property taxes on plant and equipment; income taxes are also collected on compensation to mineral rights owners and the profit of producers. The value of the resource extracted provides the basis for many of these taxes, and revenue will be reduced as a result of the introduction of a standard.

Reduced production of natural gas may reduce the need for some government services, offsetting some of the reduced tax revenue. However, in order to maintain the required level of services, in most cases the government entities receiving these revenues will have to either increase the rates of the existing taxes or increase taxes on other sectors. Unless the rates on taxes associated with natural gas are adjusted in anticipation of changes in usage, the burden of these taxes may shift from natural gas consumers to other sectors. Where that is the case, a corresponding amount of the benefit to consumers should be considered a transfer from the sectors whose tax burden is increased.

Reduced usage of natural gas by the residential sector will, to the extent that their rates are based on volume, reduce the revenue of the transmission and distribution sectors. However, these sectors remain largely under a rate-of-return regulation, and any shortfall in revenue will, with some delay, be made up as rates are adjusted to reflect current levels of usage. As long as regulated rates provide full compensation, including the cost of regulatory delay, consumers bear the full cost of these services, the sector is not harmed, and no transfer to consumers can exist.

3.3. Electric Power Producers

The electric power sector consumes large amounts of natural gas to produce electrical power. Lower natural gas prices will tend to reduce the fuel cost of gas fired generation, increase the use of gas for generation and reduce the total cost of generating electricity. Exactly how that affects producing and consuming sectors depends upon the regulatory regime in the particular region.

The electric power sector in the United States was traditionally organized as vertically integrated, regulated public utilities, each of which provided generation, transmission and distribution of electricity to a specific area at regulated prices. In some areas, the sector has been transformed to a more competitive structure in which wholesale generation is provided by independent generators at competitive prices while transmission and distribution rates remain regulated. Where the generation sector remains within the utility and under rate of return regulation, the reduced cost of fuel is passed on to customers through adjustment to the revenue requirement of the utility and there is no gain or loss to the sector. However, where the sector has been restructured and generation is supplied under competitive prices, the reduction in natural gas price has a much different effect on the revenue of the generation sector.

Where generation is competitively priced, the price of all generation is determined by the marginal cost of the most expensive generator required to reliably serve the load during each particular time period. When natural gas fired generation is the marginal source, a reduction in the price of natural gas will result in a reduction in the price of natural gas generation and thus the price of all generation, no matter what fuel is used, during that time period (EIA 2012a). As a result, under competitive pricing, the revenue of the electricity producing sector may decline in absolute terms much more than the decline in the cost of natural gas purchased for generation.

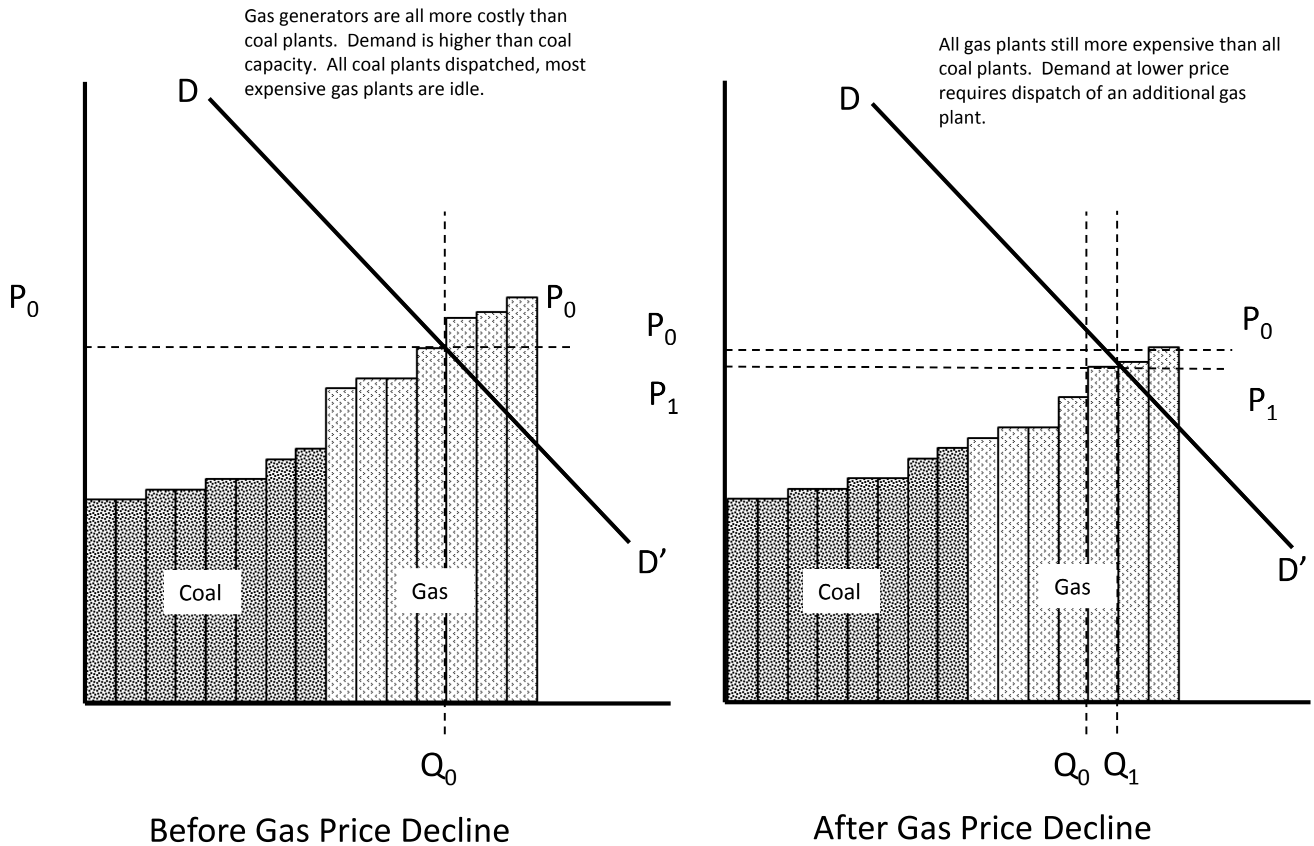

Figure 2, Illustration of Competitive Generation Pricing

Figure 2 shows how competitive wholesale prices are determined. For the period shown, demand, represented by line D-D’, exceeds the capacity of all available coal fired generation, shown as dark bars. Natural gas fired generation has a higher marginal cost than coal fired generation but four gas generators are required to meet demand. The compensation to all generators is determined by the marginal cost of the most expensive plant dispatched to meet demand. All generators thus receive P_0 for each unit of electricity they generate.

If the price of natural gas declines, the marginal cost of gas fired generation will decline as shown on the right, while he marginal cost of coal fired generators is unaffected. Following the marginal cost of gas generation, the price falls to P_1, inducing additional demand which requires dispatch of an additional gas fired generator. The effect of the lower price on natural gas fired generators is offset by the lower cost of their fuel, but the loss of revenue to coal fired generators is not offset by reduced fuel costs so their revenue net of fuel cost declines. This phenomenon occurs only in areas where the electric power sector has been restructured and there only when natural gas generation is the marginal generation. When coal fired plants are marginal, i.e. the lowest cost source, the change in natural gas price has no effect. A recent report by Linn et al (2014) provides empirical analysis of this phenomenon and its consequences are discussed in a recent paper by Burtraw (2012).

The decline in revenue, net of the change in cost of fuel used, is a loss to the electricity producing sector. Because end user electricity rates remain, in general, regulated even where generation has been restructured, the reduction in wholesale price is passed on to the consumers served by the utility[3]. The loss to coal fired generators is thus transferred to consumers in the form of lower electricity prices.

The transmission and distribution of electricity, like that of natural gas, remains largely under regulation. The sector is, therefore, not directly affected by changes in natural gas prices. Where shifts in generation source require addition of new facilities or reduce usage of other facilities, we assume that tariff rates will provide compensation for the cost of those projects.

4. Quantification of Effects

4.1. Benefits

We use the “equivalent variation” to measure a change in consumer welfare. The equivalent variation is the “income change at the current prices that would be equivalent to the proposed change” (Varian, 1984). That is, it is the amount of additional income that would make a consumer indifferent between the establishment of the efficiency standard and the status quo. Residential consumers are affected in two ways by the introduction of an efficiency standard: directly through the technological change that allows them to achieve the same level of utility using less energy and indirectly through the change in prices elicited by the reduced demand for natural gas. The technological benefit, B_T, is an increase in income of:

$$B_T = \Delta q \, p_0 \tag{1}$$

Where Δq is the reduction in usage of natural gas, electricity, or other fuel required to maintain the same appliance service level at the increased efficiency, and p_0 is the delivered price of the fuel in the reference case. The technological effect is the savings, calculated at pre-standard prices, that is realized by using more-efficient appliances or the additional income that would make the consumer indifferent between the less efficient and more efficient appliance.

In addition, the income of all consumers, whether directly affected by the standard or not, is affected by

[3] More than one-quarter of all residential customers in New England pay a retail supplier other than the regulated utility for the generation of their electricity. Customers of both full-service utilities and restructured retail suppliers have experienced similar rate increases of just under 12% so far this year.(Source: http://www.eia.gov/todayinenergy/detail.cfm?id=17791).

the change in energy prices resulting from the change in demand by consumers in the directly affected sector. This price benefit, B_p, is:

$$B_p = \sum_i^N (q_{i0} - \Delta q_i)(p_{i0} - p_{is}) \quad (2)$$

where q_{i0} is the quantity of natural gas, electricity, or other fuel used in the reference case, and p_{is} is the price of the energy in the standard case. Note that Δq_i is zero for all sectors not directly affected by the standard. The price effect is the savings that would be realized by purchasing the quantity of fuel used in the reference case at the post-standard prices.[4] Alternately, it is the increase in income that would make the consumer indifferent to the price change. These savings or increases in income are used by consumers to purchase additional goods or services, including additional quantities of natural gas. Our method captures the not only the additional consumer welfare from increased usage of natural gas induced by lower prices but also the benefit from additional purchases of all other goods and services.

Residential consumers receive both the direct, or technological, benefit of reduced natural gas usage and the indirect, or pecuniary, benefit resulting from the change in prices of all goods and services. All consumers receive the pecuniary benefit of lower prices for goods and services resulting from lower energy costs; however, our model does not directly model the prices of all goods and services, precluding direct estimation of that benefit. Instead, since energy cost savings are either passed on to consumers through lower prices or held by producers, we estimate the benefit to the commercial, industrial, and transportation sectors as an alternative to direct estimation of the benefit to society. Usage by the commercial, industrial, and transportation sectors is not technologically affected by the standard. They benefit only from the pecuniary effect resulting from the reduction in the price of energy they would have purchased in the reference case.

4.2. Losses

As discussed previously, revenue from natural gas production, wellhead revenue, is divided among producers, mineral rights owners, and taxes. As a simplifying assumption to facilitate estimation of these pecuniary losses, we calculate compensation to mineral rights owners and payments to governments as a portion of the wellhead value of gas produced. We use a typical split, as indicated by current literature, of 50 percent to producers and 25 percent to mineral rights owners and 25 percent to

[4] This estimate is approximately equal to the change in consumer surplus where consumers are assumed to spend the entire savings from the price change on additional quantities of the same good. The change in consumer surplus can be calculated as $(p_0 - p_s)q_0 + \frac{(p_0 - p_s)(q_0 - q_s)}{2}$. Our formulation omits only the last term which, for small changes in p and q is extremely small.

government entities as taxes and fees.[5] We calculate these losses as the change in revenue net of any change in cost.

As noted previously, producers' investment decisions are made on the basis of projected demand, including variations resulting from anticipated policy instruments as well as all other factors. Therefore, any investment made with full anticipation of the effect of a standard on demand must have been judged to provide a sufficient return on investment. Only investments made before the effect of the standard could be anticipated are subject to losses from the decline in demand. We therefore estimate the pecuniary loss to producers as the reduction in producer revenue only from reserves (wells) that began production before the standard could have been anticipated.[6]

The standard used in our analysis received final approval in 2010, five years before it began to affect demand (DOT, 2009). Therefore, as a measure of maximum loss to producers, we estimate the effect of the standard on production from wells that began producing more than five years before the standard takes effect. We further assume that neither the volume nor cost of production from pre-standard wells is reduced in response to lower price. NEMS estimates end-of-year "reserves"—the ultimate recoverable volume remaining in producing wells – and production for each year, allowing us to estimate, based on the average production-reserve ratio for each year, the portion of production attributable to each reserve cohort. To the extent that producers are able to predict the effects of a standard before its final approval, or decline rates are more front-loaded than a constant production-reserve ratio would indicate, our method overestimates the contribution of older reserves and thus overestimates the loss to producers. This is consistent with our goal of identifying and quantifying all potential pecuniary losses. To summarize, we calculate the loss to producers as the change in wellhead price times the production volume of pre-standard wells in the reference case.

We estimate that the loss of taxes and fees is 25 percent of the total reduction in revenue from the production of natural gas. Recognizing that some of these taxes and fees fund activities, permitting and inspection of production facilities for example, that decline with production, we assume that 25 percent of the lost tax and fee revenue is offset by service reductions or cost savings. The net loss of tax and fee revenue is thus only 18.75 percent of the lost revenue.

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[5] This is equivalent to a 75 percent government take−the average determined by Kepes et al. (2011)−where production costs are one third of revenue. . I.E. 3/4 of 2/3 of revenue is ½ of revenue.

[6] Here, the term "reserves" is used as defined in the NEMS model rather than exactly complying with the SEC or other definitions.

In theory, a reduction in the rate of depletion will affect the value of all natural gas resources, even those not yet discovered. However, limiting our evaluation to the 25 year period of our analysis, we estimate reductions in compensation to mineral rights owners as 25 percent of the reduction in wellhead revenue. This formulation somewhat overestimates the owners' losses in that it counts as a loss the full value of gas that will ultimately be produced at a later date. It also ignores any future extraction cost savings that may result from delayed resource extraction and depletion

The technological effect of the adoption of our example standard on the demand for electric power is extremely small. However, the reduction in the price of natural gas results in a significant reduction in the price of electricity and an associated increase its usage. We calculate the effect of the standard as the change in sector revenue net of the change in sector expenditure for fuel.

Assumptions & Calculation Methods

Calculation of Benefits	
Technological Effect	$B_T = \Delta q p_0$
Pecuniary (price) Effect	$B_P = q_0(p_S - p_o)$
Natural Gas Production Sector	
Mineral Rights Owners	25% of revenue reduction
Tax	18.5% (75% of 25%) of revenue reduction
Producer	50% of revenue reduction on production from pre 2010 wells
Electric Power Sector	Revenue reduction less change in fuel cost

Table 1. Assumptions & Calculation Methods

5. Modeling Issues

In order to determine the effect of the introduction of an appliance efficiency standard on other sectors we use the 2012 version of the National Energy Model (NEMS) to provide reference and standard forecasts. The reference forecast is that of the 2012 EIA Annual Energy Outlook (EIA, 2013b). To that forecast we apply exogenous decrements to residential usage calculated by DOE for the example water heater efficiency standard (DOE, 2009). These decrements are an engineering estimate of the annual changes in natural gas and electricity usage that would result from the use of the more efficient appliances mandated by the standard. The magnitude of the decrements reflect estimated rate of adoption as well as the increase in efficiency. The model is then rerun to determine the new equilibrium that reflects those changes in residential usage. The effect of the standard is obtained by calculating the annual differences between the reference run and the values obtained with the decrements applied, the reference run and the standard run. These annual differences are then summarized as a present value, in 2010 dollars as of 2015, using a discount rate of 7 percent. The accuracy of such a counterfactual analysis does not rely on the accuracy of the model's forecast but only on the accuracy of its modeling of incremental changes.

The decrements begin in 2015, when the standard becomes effective, and increase over the analysis period as the appliance stock reflects the higher efficiency of new appliances purchased after the introduction of the standard. The particular example used applies an average decrement to residential natural gas usage of about 0.45 percent of residential usage or 0.08 percent of U.S. dry gas production. It also includes a small negative decrement (increase) to residential electricity usage of about 0.003

percent of residential usage, representing the electrical requirements of more sophisticated controls. [7]

5.1. Response of Prices

The response of energy prices, primarily natural gas and electricity prices, to a change in the demand for natural gas is central to our results. The magnitude of pecuniary benefits and transfers from losers is determined by the changes in price and the changes in usage that those price changes elicit. Since we rely on the NEMS model to provide these price and usage changes, it is appropriate to explore in some detail how the model determines those values and whether the model produces reasonable results.

Delivered prices of natural gas to consumers consist of the cost of gas at the wellhead and the cost of transporting the gas to the consumer. Transportation and distribution costs are primarily fixed and do not vary substantially with small changes in the volume delivered. As noted in section 3.2, the characteristics of natural gas exploration and production result in a complex relationship between wellhead price and quantity produced. A simple supply function, constant elasticity for example, is inconsistent with increasing production in the face of falling prices evident in Figure 1.

Rather than using an analytical representation, the NEMS model builds its supply function by mimicking, as closely as possible, the actions of the producing sector. Using regional and technology specific costs of exploration and production the model constructs, project by project, a long term potential production function which represents the current and future output of actual production wells. The level of new investment in productive capacity is determined by the profitability of each potential project, based on projections of future demand, cost and price, all specific to the economic and geological conditions applying to the potential project. As the level of future demand increases, more expensive projects become profitable and are added to the productive capacity, increasing the average cost of production. If lower demand is projected, as is the case in our example, some of the more expensive projects are foregone or delayed, reducing the average cost of production. NEMS estimates that the reduced demand resulting from our example standard will require 650 (0.045 percent) fewer wells over the 25 year study period.

While the long term supply function accounts for most changes in production. A short term supply

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[7] Because the decrements are very small we apply multiples (4x, 6x and 8x) of the decrements to three separate runs of NEMS and construct the results actually used as a linear interpolation between the results of those three runs and the reference run. Other, larger multiples were also run but not used because the estimated responses did not form a linear set with the lower multiples.

function is used to balance supply with unforeseen changes in year to year demand. This balance is achieved by varying imports and the production from dry gas wells (EIA 2013d). Over the 25 years after our example water heater standard becomes effective the NEMS model estimates that natural gas usage is 0.056 percent less than it would be in the reference case. This decrease in usage of natural gas leads to a decline in natural gas production and an associated decline in the wellhead and delivered prices of natural gas. The average wellhead price is, on average, 0.10 percent lower in the standard case than in the reference case. This implies an average inverse price elasticity of supply of 2.05. It is important to recognize that the response of price to changes in usage is generated by the very non-linear and discontinuous supply function built within the NEMS model. It is specific to the magnitude of the decrements as well as the time period over which they are imposed.

In order to verify the reasonableness of that value, we examined results of other studies of the effect of demand on natural gas prices. Wiser et al (2005) conducted a review of studies that examined the impacts of reductions in natural gas demand on natural gas prices using various versions of NEMS. They found that the average values of the inverse price elasticity throughout the forecast period in each study ranged from 0.7 to 4.7. Other widely used, complex energy demand/supply models have generated inverse price elasticities that are similar to those generated by NEMS for our specific example. Table 1, which was taken from the U.S. Department of Energy's "Residential Heating Products Final Rule Technical Support Document" (DOE, 2009) compares the results of several studies that modeled the response of natural gas prices to changes in gas consumption.

The average effective inverse price elasticity of 2.05, implied by our study, is somewhat larger than the value obtained from the 2002 version of NEMS, but is consistent with the range of values from several other models and much lower than the average, 3.20, of the values shown in Table 1.

Inverse Supply Elasticities

Model	Average
NEMS	1.2
POEMS	2.1
CRA	2.0
NANGAS	6.3
E2020	1.1
MARKAL	2.1
NARG	7.3

Table 2. Natural Gas Inverse Supply Elasticity from Several Energy Models

It is important to recognize that the inverse price elasticity of supply is not an input to NEMS; it is a summarization of the reaction of wellhead price predicted by the model based on its detailed modeling of the natural gas supply sector under the specific changes associated with a particular standard. The NEMS model determines its predicted wellhead price using detailed information on current operation and capital costs as well as the geological characteristics of known gas plays (EIA, 2013c).

As described above, many utilities are moving away from single part tariffs in which the customer pays a single price for each unit of gas delivered. In some cases a fixed fee is charged to cover some or all of the fixed cost of transmission and distribution. Another approach is to provide a "true up" to adjust the payment for differences between actual and projected usage. Although the NEMS model does not capture the full variety and complexity of actual tariffs, it adjusts its delivered prices annually so that they reflect current costs of gas, transmission and distribution.

NEMS determines its delivered prices of natural gas by estimating regional and seasonal tariffs for storage, interstate and intrastate transmission and local distribution, adding these to the cost of natural gas to obtain tariffs for each user class. Although these internal estimates are regional and seasonal, they are summarized as a single per unit price for each year in the model output. Tariff rates for storage and interstate transmission are estimated from actual costs (EIA 2013d). Distribution tariffs are estimated econometrically from regional variables such as total households, commercial floor space. For customers in the residential and commercial sectors, transmission and distribution constitutes over 60 percent of the delivered price. For customers in the industrial and electric power sectors it is less than one quarter of the delivered price (EIA 2013b). The relatively large decrease in residential usage along with the large component of the delivered price that is made up of transmission and distribution costs results in a net increase in the residential delivered price.

The simplifying assumption that all consumers pay a single per unit rate does not affect the magnitude of total benefit to the residential sector. It does affect distribution of benefits within the sector. It also affects the reaction of residential consumers to the change in price elicited by a decline in residential usage. If transmission and distribution costs were covered by a fixed monthly fee, separate from the fuel price, residential consumers would see a decline in the fuel price. When gas, transmission and distribution are included in a single per unit price, a decline in usage yields an increase in the bundled rate. The first will elicit additional usage while the second will elicit reduced usage. By assuming that all consumers see a single per unit price, NEMS will therefore understate the increase in usage by residential consumers.

As noted above, the price of electricity is determined differently depending upon the status of restructuring in the region. This difference is recognized in the NEMS model. As stated in the model documentation:

> The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched.
>
> The price of electricity in the regions with a competitive generation market consists of the competitive cost of generation summed with the average costs of transmission and distribution.
>
> The price for mixed regions is a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region that has taken action to deregulate. (EIA 2012)

Table 2 shows the average effect of the standard on natural gas and electricity prices. The effect on electricity prices is somewhat larger than would be expected given the change in delivered price of natural gas to the electric power sector, the portion of electricity generated by gas fired generators, about 25 percent, and the portion of the cost of generation represented by the cost of fuel, about 50 percent. That apparent discrepancy results because a large share, about 33 percent in 2012, of generation is subject to marginal rather than average cost pricing (EIA 2014).

Effect of Standard on Energy Prices

	Effect on Price (%)	
Sector	Natural Gas	Electricity
Wellhead	-0.10%	
Residential	+0.11%	-0.02%
Commercial	-0.06%	-0.03%
Industrial	-0.08%	-0.02%
Electric Power	-0.07%	

Table 3. Effect of Standard on Energy Prices

6. Results and Discussion

6.1. Benefits

Over the 25-year period, the introduction of the water heater standard is projected to result in a 0.55 quad (580 petajoules) or 0.45 percent reduction in natural gas consumption by residential consumers while maintaining the same level of service. That results in a direct benefit of $2.59 Billion (all benefits are in real 2010 dollars discounted to 2015 at 7.00 percent summed over 25 years). As noted previously, continued recover or fixed transmission and distribution costs at the lower volume requires an increase in the delivered price. The higher price reduces residential consumer welfare by $0.58 Billion, partially offsetting the benefit from reduced usage. The technology associated with the standard also requires an small increase in the usage of electricity by the residential sector, resulting in a reduction in consumer welfare of $0.06 Billion. The total technological benefit to residential consumers is $1.94 Billion. This is the benefit directly attributable to the more efficient technology.

Reduced usage of natural gas by the residential sector elicits a reduction in the price of natural gas. The lower price provides benefits to other consumers of natural gas. We find that the commercial, industrial and transportation sectors realize a benefit of $0.71 Billion. This benefit is an increase in social welfare that is either retained as profit or passed on in lower prices. The electric power sector also benefits from the lower price of natural gas. We estimate that benefit to be $0.33 Billion. This benefit is, as discussed below, passed on to electricity consumers in the form of lower electricity prices. The total pecuniary benefit due to reduced natural gas prices is thus $1.03 Billion as shown in Table 4.

Summary of Benefits

Billions of 2010 Dollars, 2015-2039, discounted to 2015 at 7 percent

Sector Benefits	NPV
Technological Benefit to Residential Consumers	
Technological (Change in Usage) Natural Gas	$2.59
Tariff Adjustment (Change in Price) Natural Gas	-$0.59
Technological (Change in Usage) Electricity	-$0.06
Total Technological Benefit to Residential Consumers	$1.94
Pecuniary (Price Effect) Benefits	
Natural Gas Prices	
Commercial-Industrial-Transportation Sectors	$0.71
Electric Power Sector	$0.33
Total Pecuniary Benefit Due to Change in Natural Gas Prices	$1.03
Electricity Prices	
All Sectors	$0.77
Total Pecuniary Benefit Due to Change in Electricity Prices	$0.77
Total Pecuniary Benefits	$1.81
Total Benefit to Consuming Sectors	**$3.75**

Table 4. Summary of Benefits

As discussed in Section 3.3, lower natural gas prices result in a reduction in electricity prices greater than would be justified by a simple pass through of the benefit from lower natural gas prices. We estimate the additional benefit to all electricity consumers, including residential consumers, to be $0.77 Billion. As shown in Table 4, we estimate that the increased appliance efficiency results in a technical benefit to the residential sector of $1.94 Billion and pecuniary benefits to all sectors of $1.81 Billion for a total increase in social welfare of $3.75 Billion.

6.2. Losses

The reduced natural gas prices induced by the lower residential usage provide benefits to other energy consumers. However, they also result in losses to other sectors, primarily the natural gas and electric power sectors. These pecuniary losses are offsets to the benefits generated by the increase in appliance efficiency. They should be considered transfers from the harmed sectors to benefited sectors and must be properly accounted for in order to determine the net effect on the society.

As noted, the loss of tax revenue, net of reduced costs, is a transfer from those who will pay increased taxes to consumers who benefit from the standard. To the extent that taxes fund services that are related to natural gas production, any reduction in tax revenue would be associated with an equal cost savings. We calculate lost tax revenue as 25 percent of the total reduction in wellhead revenue, $0.52 Billion, but further assume that one quarter of that value is offset by reduced cost of government, leaving a net loss of tax revenue of $0.39 Billion. We estimate reductions in compensation to private mineral rights holders for gas produced through 2039 to be $0.36 billion. Government entities also own mineral rights and receive compensation for the sale or lease of those rights. We estimate their reduction in revenue to be $0.15 Billion.

Consistent with our aim of identifying and quantifying all potential transfers, we estimate the potential loss to producers as the reduction in producer revenue from all wells that began production before the standard could have been anticipated by producers. Assuming that the effect of the standard could not have been estimated prior to 2010, five years before it began to reduce demand, and that costs could not be reduced to mitigate the reduction in revenue, we estimate the loss in producer revenue from reserves created prior to that year. We estimate that pre-2010 reserves contributed 22 percent of production from 2015 to 2039 and that the present value of the total reduction in revenue from that contribution is $0.30 Billion.

We find that the electric power sector uses more natural gas and less coal for generation and that it sells more electricity to consumers but at a lower average price. The effect is a decline in sector revenue greater than the decline in its expenditure for fuel. Our model forecasts a decline in the average price of electricity of 0.02 percent and an increase in usage of 0.002 percent resulting in a decline in revenue of $0.88 Billion or 0.02 percent. The price of natural gas to the electric power sector declines by 0.065 percent and its usage by the sector increases by 0.095 percent resulting in an increase in expenditure for natural gas of $0.14 Billion. Bothhe usage and price of coal decline resulting in a reduction in expenditure for coal of $0.28 Billion. The net effect on the sector is a decline in net revenue of $0.75 Billion.

Summary of Pecuniary Losses

Billions of 2010 Dollars, 2015-2039, discounted to 2015 at 7 percent		
Pecuniary Losses (negative indicates loss)		NPV
Natural Gas Production Sector		
Taxes and Fees		
Taxes & Fees (25%)	-$0.52	
Cost Savings (25% of T&F)	$0.13	
Net Loss of Taxes & Fees		-$0.39
Owners' Compensation (25%)	-$0.52	
Government Share (30%)		-$0.15
Private Owners (70%)		-$0.36
Producers		
Loss From Pre 2010 Reserves		-$0.30
Total Pecuniary Loss to Natural Gas Production Sector		**-$1.21**
Electric Power Sector		
Change in Revenue		-$0.89
Change in Expenditure for NG	$0.14	
Change in Expenditure for Coal	-$0.28	
Net Change in Expenditure for Fuel		-$0.14
Total Pecuniary Loss to Electric Power Sector		**-$0.75**
Total Pecuniary Losses		**-$1.95**

Table 5 Summary of Pecuniary Losses

Subtracting the total transfers from the total benefits yields a net benefit to society of $1.79 Billion.

7. Conclusion

An increase in the fuel efficiency of a natural gas appliance provides its users with a technological benefit, primarily the savings in fuel required to achieve the same level of service. It also has pecuniary effects, effects that result from the changes in prices induced by the reduced usage. These benefits and losses accrue to other consumers of natural gas and electricity, producers of natural gas and electric power producers. These pecuniary effects occur whether the increased efficiency is due to a technological breakthrough, competition among appliance producers or a minimum efficiency standard imposed by government.

Summary of Pecuniary Effects	
Billions of 2010 Dollars, 2015-2039, discounted to 2015 at 7 percent	
Natural Gas	
Benefit	$1.03
Losses	-$1.21
Net	-$0.17
Electric Power	
Benefit	$0.77
Losses	-$0.75
Net	$0.03
Unaccounted for Loss	-$0.15

Table 6, Summary of Pecuniary Effects

Pigou (1924) argued that the technical benefits of improved technology represent increases in social welfare while the associated pecuniary benefits and losses represent transfers from producers to consumers. As shown in Table 6, the pecuniary benefit from reduced natural gas prices is about $0.17 Billion (16.7 percent) less than the loss to producers and the benefit from reduced electric power prices is $0.03 Billion (3.5 percent) greater than the loss to producers. In total there is an unaccounted for loss of $0.15 Billion, only 8.1 percent of the total pecuniary benefits. Thus, our result supports the position that pecuniary effects, those resulting solely from changes in price, do not affect total social welfare. Although we find real and substantial pecuniary losses to producers, we find pecuniary benefits to consumers of a similar magnitude.

We have attempted to be very conservative in our estimation of losses. The loss to producers depends on our assumption that they are unable to foresee even the long term trend in demand associated with the promulgation of efficiency standards is somewhat at odds with the long history of that process. Removing that assumption eliminates the loss to producers and decreases the total loss to $1.65B. We have calculated the loss to mineral rights holders as a share of the full decline in wellhead revenue, even though they will ultimately sell the lost production. Removing that assumption and calculating their loss as the volume produced in the reference case times the change in price reduces the loss to $1.54B. If it seems unreasonable to consider a fall in the price of natural gas a loss to owners who may not have known of its presence when the land was acquired, the loss is reduced to only $1.29B.

We estimate a pecuniary benefit of $0.77B resulting from lower electricity prices which is partially offset by a pecuniary loss to the electric power sector of $0.75B. Since prices in traditionally regulated areas reflect the average cost of generation, this loss is apparently associated with areas subject to competitive wholesale pricing and, following the discussion in section 3.3 above, falls largely on coal fired generators. Other authors have noted this loss in relation to the downward temporal trend in natural gas prices and suggest that it has contributed to decisions to close several coal fired generation plants (Burtraw, 2012, EIA 2014). Whether the shift of generation capacity away from coal and toward natural gas is in itself beneficial is the subject of much debate.

The question we address in this study is whether purely pecuniary effects, those that follow from the price changes elicited by lower usage of natural gas, should enter that debate. We provide verification of the notion that benefits and losses resulting from price changes balance and therefore do not provide the deciding factor with respect to establishment of efficiency standards. Our analysis also provides useful insight into the sources of these benefits and losses. We acknowledge that our analysis relies on many assumptions and approximations and have been careful to identify them as clearly as possible so that any debate about inclusion or exclusion of a specific benefit or loss is as informed as possible.

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