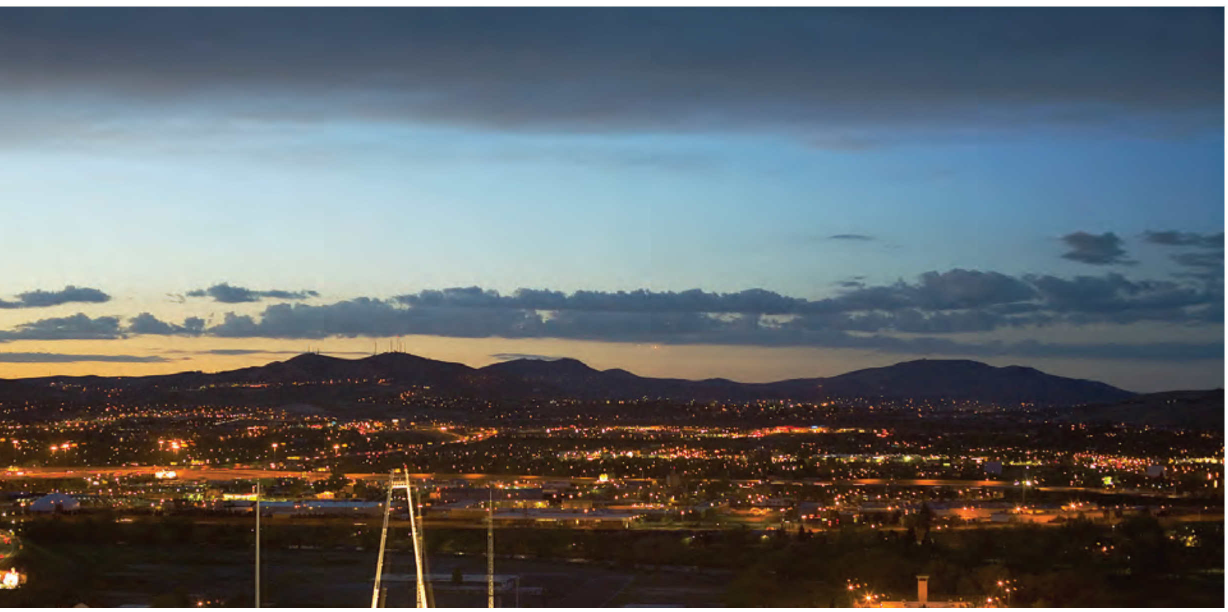
POWER SWITCH: A NO REGRETS GUIDE TO EXPANDING NATURAL GAS-FIRED ELECTRICITY GENERATION



JUNE 2012

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A NO REGRETS GUIDE TO EXPANDING NATURAL GAS-FIRED ELECTRICITY GENERATION

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AMERICAN CLEAN SKIES FOUNDATION

750 1st Street, NE, Suite 1100 | Washington, DC 20002 | Main: 202.682.6294 | Fax: 202.682.3050 | www.cleanskies.org

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About American Clean Skies Foundation

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Executive Summary

This report describes a practical "no regrets" plan for U.S. power companies and regulators to take advantage of the lowest natural gas prices in a decade. This would provide electricity ratepayers with cleaner and more affordable power for years to come.

The plan has two main components:

1. A new set of long-term gas purchase agreements (and associated hedging arrangements) that share some of the risk of future price changes between natural gas suppliers, on the one hand, and power generators and consumers, on the other. These new agreements would be designed to provide mutually beneficial incentives for gas suppliers and power generators. For example, suppliers and generators could agree to a fixed price for a portion of the fuel, with the balance priced at the market rate.
2. A level, nondiscriminatory playing field for regulatory review and approval of prudent long-term natural gas supply agreements. This would allow regulators to judge options for gas-fired power generation on a fair and level basis vis-à-vis other power sources that routinely make use of long-term supply agreements (e.g., coal, renewables).

The natural gas contracting approach described in this report is dubbed a "no regrets" plan because, by sharing the risk of future price changes, the plan seeks to minimize the potential losses and to maximize the potential gains for both gas buyers (e.g., utilities) and fuel sellers. The plan also contemplates a portfolio approach to gas supply, recommending that buyers and sellers have contract terms of different lengths to reduce price risks. In addition, the plan seeks to reduce the potential regrets associated with electricity generators' gas purchases by granting regulatory approval to prudent long-term natural gas purchases, thus ensuring that utilities (and their suppliers) will not have their contracts second-guessed by regulators if market prices change.

The economic benefits of locking in record-low prices for natural gas may total tens of billions of dollars. These potential savings are akin to the very large benefits that homeowners and businesses can realize by refinancing mortgages and long-term debt at today's historically low interest rates.

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In 2009, natural gas-fired power plants accounted for 23 percent of national electricity production. A subsequent sharp decline in the price of natural gas—largely triggered by the unprecedented growth of shale gas production—has since led to a substantial increase in gas-fired power generation such that gas is expected to account for approximately 31 percent of the market in 2012.[1] Modern natural gas plants, especially combined cycle gas turbine (CCGT) facilities, are now cheaper to run than many coal-fired power plants. This has delivered savings for ratepayers as well as significant environmental benefits because gas-fired plants emit less harmful air pollution.

1 These natural gas electricity production figures are from the Energy Information Administration's May 2012 *Short-Term Energy Outlook* and 2011 *Annual Energy Review* (see Table 7.2a).

However, this report suggests that current benefits may be short-lived. Unless key changes to commercial and regulatory frameworks are established at the state level, longer-term, large-scale fuel shifts by existing power plants and commitments to new gas-fired capacity are at risk.

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Shale gas development has prompted some controversy, particularly in regard to potential environmental impacts. Environmental risks and associated price impacts, however, are manageable with existing technologies and best practices. Responsible development of natural gas resources is necessary to sustain a successful, no regrets transition to affordable gas in the electric sector.

The new plan outlined in this report will require at least five major groups of stakeholders to be involved:

- Natural gas suppliers, including major producers and marketing groups, must be willing to offer viable, multi-year supply agreements for a portion of their inventory; they must also be willing to share some of the risk of future price changes.
- Utilities and merchant generators must be willing to consider prudent, multi-year supply agreements for a portion of their fuel needs; and they must be willing to share some of the risk of future price changes.
- Regulators and state governments must adopt a regulatory framework for the approval of prudent, long-term fuel-supply agreements that does not discriminate against natural gas. In addition, regulators must be willing to scrutinize any new short-term natural gas supply agreements and should reconsider the automatic pass-through of spot market fuel costs absent a showing that longer-term arrangements are not a more prudent course of action.
- Consumer advocates must be willing to support prudent, long-term natural gas supply arrangements before state regulatory bodies and legislatures where such arrangements, notwithstanding some price risks, can be expected to deliver significant long-term rate benefits.
- Natural gas pipeline owners and pipeline regulators must be willing to work with power plant operators to agree on appropriate transport tariffs for natural gas purchased under new, multi-year pricing arrangements.

We do not recommend that generators rely solely on long-term agreements for their gas requirements. Nor should gas suppliers sell gas solely in this manner. Instead, we believe generators and natural gas producers should supplement their current strategies with long-term agreements as a way to reduce costs and risks while increasing resource diversity and supply certainty.

This report presents the economic case for fuel switching based on three analyses: a “busbar” analysis of the comparative construction and operating costs of gas-fired plants vis-à-vis competitors; illustrative power plant retirement reviews based on different fuel costs; and a “minimax regret” analysis that evaluates risks associated with fuel procurement strategies, such as the innovative risk-sharing arrangements recommended in this report. Details on each analysis are provided in the appendices.

Introduction 1

The U.S. electricity sector is going through an unprecedented period of asset turnover and investment. Decade-low natural gas prices provide the industry with an opportunity to reduce emissions and costs and deliver savings to ratepayers at a time when many generators face budget constraints and the need to make expensive investments to comply with new environmental regulations. Action today to take advantage of low gas prices can pay off. Conversely, the opportunity costs of inaction are potentially immense, likely totaling many billions of dollars for ratepayers alone.

This hypothetical story may help to illustrate the public service commission stakes:

For several years, in docket after docket, Commissioner Miller has been hearing about shale gas and the outlook for natural gas prices from industry experts and electric utility managers. But discussions about the future always seem obtuse, and it has been hard to draw conclusions about the likely impact of natural gas prices on the electric industry and its customers.

As wholesale natural gas prices fell steadily from $10 per million British thermal units (MMBtu) in 2008 to well below $5 per MMBtu at the end of 2010, Commissioner Miller was sure that an upward spike was imminent.[2] In agency dockets, utility witnesses frequently predicted natural gas price increases, but these price increases have never materialized. By late 2011, natural gas prices have reached lows not experienced in more than a decade, and Commissioner Miller finds herself shocked when, in the spring of 2012, prices dip below $2.00 per MMBtu.

The country is flush with cheap gas she thinks, and modest prices for gas futures contracts only reinforce this conclusion. Commissioner Miller recalls a proceeding just weeks prior in which the local electric utility set forth a plan to retrofit its aging coal-fleet with environmental controls costing hundreds of millions of dollars. Utility representatives argued that the risk of future price inflation for natural gas, as compared to the historic stability of coal prices, tilted the economics in favor of environmental retrofits. But Commissioner Miller is not so sure. She thinks of the stringent environmental regulations coal units are facing, and about the uncertain regulatory and market environment for these units in the future. She also thinks about consumers struggling with a sluggish economy. She wonders if environmental retrofits to keep aging coal plants running are still the economic choice, or whether customers could be on the hook for uncompetitive assets for years to come.

"What is the utility doing to take advantage of these low natural gas prices?" she asks herself. The opportunity for ratepayers seems too big to pass up. But before she feels comfortable suggesting a fuel switch, she wonders if there's a way to make sure ratepayers will benefit over the longer term from low gas prices. Her most important job, after all, is to ensure that electric utility customers ultimately receive the most affordable and reliable service possible.

Now consider the following: What if there was a "no regrets" policy for fuel switching? What if a path existed to reduce uncertainties in providing customers with a cheaper alternative to retrofitting aging coal units? For decades, coal suppliers have utilized a competitive fuel

2 MMBtu (million Btu) is the most common quantity metric used in natural gas markets (Btu—British thermal unit—is a measure of energy content). Because prices are usually given in MMBtu, we use this unit throughout the analysis. Utility regulators, however, tend to use a slightly different but comparable, volume-based quantity metric: thousand cubic feet (abbreviated Mcf). One Mcf of natural gas is equivalent to 1.023 MMBtu.

procurement strategy that relies on multi-year bilateral contracts. These coal contracts provide coal generators with substantial certainty about future costs for operating their fleets. What if electricity generators adopted parallel practices for procuring natural gas, especially while the fuel is priced near lows not experienced in more than a decade?

Commissioner Miller is a fictional character. But the dilemma sketched on the previous page is one that now confronts state utility commissioners and power generators across the country. Shale gas is causing a paradigm shift in the electric power sector. As John Rowe, the former long-time CEO and Chairman of Exelon, one of America's largest utilities, recently said: "If we are looking at 20 years of natural gas that is between $3 and $6/MMBtu. . . that is the most disruptive change in the energy market place...that I have ever seen."[3]

Nonetheless, commissioners and generators continue to debate decisions about whether to build, retire or retrofit power plants, knowing that the projects are capital intensive and the assets are long-lived. That means the costs of equipment and related investments must be recouped over several decades, either through a regulatory mechanism or, in competitive markets, through energy and capacity revenues.[4] Like everyone else, generators cannot predict precisely what electricity demand, environmental regulations or fuel prices will be five or ten years in the future. Over the long life of generating assets, these and other market conditions can change significantly.

At this writing, the U.S. economy is still growing very slowly, electricity demand growth remains tepid, gasoline prices are high, environmental standards are becoming more stringent, and budgets are constrained at all levels, from the federal government to individual households. Should a utility commit hundreds of millions of dollars to implement environmental retrofits on a 45-year-old coal plant, or instead retire and replace the coal plant with a new natural gas plant? Making the wrong decision on investments of this magnitude can destroy a company and saddle customers with uncompetitive assets and high costs for many years.

On the other hand, low natural gas prices have made gas units cheaper to operate than many coal plants. This is already resulting in lower coal unit utilization and expanding gas-unit output. For example, data published by the U.S. Department of Energy's Energy Information Administration (EIA) show that generation from U.S. natural gas-fired plants grew by 11.6 percent between December 2010 and December 2011, while coal-fired output dropped 20.7 percent over the same period.[5]

In these circumstances, the benefits of fuel-switching may be enormous. And the opportunity to lock in these benefits through long-term natural gas contracts can be compared to locking in today's record low interest rates for home mortgages and long term corporate debt.

To take advantage of this opportunity, we propose a new, "no regrets" plan for expanding the use of natural gas in existing and new power plants. Our plan is designed to create the commercial and regulatory conditions that would make it possible to capture long-run benefits for electricity customers. It has two main components:

1. New long-term gas purchase agreements (and associated physical and financial hedging arrangements) in which the risk of future price changes is shared between natural gas suppliers on the one hand and power generators and consumers on the other hand.
2. A level regulatory playing field for the review and approval of prudent long-term natural gas supply contracts so that regulators can

3 John Rowe, Former Exelon CEO, Washington, D.C., March 21, 2012. Crawford, J. (2012, March 22) "Former Exelon CEO: Shale Gas Boom Most Disruptive Change of His Career." *SNL Financial.*
4 Energy revenues are based on day-to-day sales of electricity in wholesale markets. Capacity revenues refer to fixed payments based on a company's available generating capacity.
5 EIA (2012, March). *Short-term Energy Outlook.* Available at http://205.254.135.7/forecasts/steo/archives/Mar12.pdf

judge gas-fired power generation options on a comparable basis to other generation options that offer the price certainty of long-term contracts (e.g., coal, renewables).

Today's state utility regulations and other factors push most gas generators to rely almost exclusively on spot market gas purchases (the reasons for this bias are discussed in a later section). We believe that ratepayers are unlikely to be well served by this situation in the long run and that regulators should therefore give close scrutiny to any new short-term gas supply arrangements. In particular, regulators should reconsider the now standard practice of pre-approving the automatic pass-through of spot fuel costs absent a demonstration, by the utility, that entering into a longer-term gas supply contract would not be a more prudent course of action.

Adoption of our recommendations could save generators and consumers billions of dollars annually if gas prices rise in the future. According to the most recent EIA estimates, the U.S. electricity sector will spend $330 billion for natural gas between 2013 and 2020.[6] If 25 percent of this expected demand is met through long-term contracts based on today's low price horizon, the overall savings to electricity users could be substantial: $16 billion for every $1/MMBtu that such contracts are below average spot prices over the remainder of the decade.[7] Under the long-term risk-sharing approach proposed here, however, even if average spot prices fall further before rising in later years, ratepayers may still be better off than relying exclusively on short-term spot market purchases that are commonplace today.

In the pages that follow, we provide a more extended discussion of the case for expanding gas-fired electricity generation in the United States based on the policy framework outlined above.

Section 2 begins with a review of the current price advantages of natural gas relative to other electricity generation options; this section also discusses the outlook for future price trends. We then review the scope for increased use of natural gas in connection with the tens of gigawatts of available but underutilized combined cycle gas turbine (CCGT) capacity that already exists in the United States. We also conduct a quantitative analysis to study the comparative cost of new gas-fired plants vis-à-vis other new plant alternatives.

In Section 3 we consider some of the major reasons why, notwithstanding record-low gas prices, longer-term commitments to fuel switching have been modest. We then proceed, in Section 4, to discuss how current hurdles to fuel switching might be overcome by drawing on the electric power industry's historical experience with long-term coal purchase contracts. We evaluate the potential price risks associated with various procurement strategies, and ultimately stress the importance of crafting long-term gas purchase arrangements that are mutually beneficial for suppliers, generators and ratepayers. Equally important, we argue, is the adoption of non-discriminatory regulatory practices for reviewing new gas procurement arrangements vis-à-vis procurement arrangements for other fuels.

In sum, the U.S. electric power industry has a historic opportunity to deliver cleaner and cheaper gas-fired power to the public for years, if not decades, to come. This opportunity will not be realized, however, unless all the major stakeholders—suppliers, generators, pipelines, utility commissioners, and consumers—work together to put in place a viable framework to support the wider use of longer term gas supply contracts. This paper is designed to facilitate that process.

6 EIA (2012). *Annual Energy Outlook 2012 Early Release.* Average delivered natural gas prices to the electric power sector in data table A3 were multiplied by the electric sector's natural gas consumption from data table A2.
7 This calculation is based on 2013–2020 electric power sector natural gas consumption from EIA's *Annual Energy Outlook 2012 Early Release* (Table A2). We assumed 25 percent of the electric sector's natural gas demand was secured through long-term contracts that resulted in a $1/MMBtu savings compared to spot prices.

2 The Changing Economics of Coal and Natural Gas Fired-Power Plants

A. Recent Fuel Price Trends

Since 2005, there has been a dramatic increase in North America's estimated long-term natural gas resource base, largely stemming from the availability of advanced technologies for tapping shale gas and other unconventional resources. More efficient and cheaper production techniques have increased the supply of shale gas at a steadily lower cost, radically changing the overall price outlook for natural gas and reinforcing its competitiveness as a base load fuel for electricity generation.

The development of shale gas resources has prompted some controversy, particularly in regards to potential environmental impacts. However, several recent, independent analyses by groups outside the industry have concluded that the risks associated with shale gas development are similar to those associated with conventional onshore gas development; that many technologies and best practices already in use by some companies today can minimize these risks;[8] and that potential impacts are challenging but manageable.[9] Moreover, the GHG emissions advantages of gas-fired generation over coal are accepted even by environmental critics of shale gas production practices.[10]

It also bears noting that the National Petroleum Council, with broad representation from industry, academia and the environmental community, concluded its landmark 2011 report to the Secretary of Energy by saying that responsible and environmentally acceptable production and delivery must be ensured if America is to benefit from using its immense shale gas resource base.[11] The Council also found that many companies are committed to this goal and are working hard to achieve it.[12]

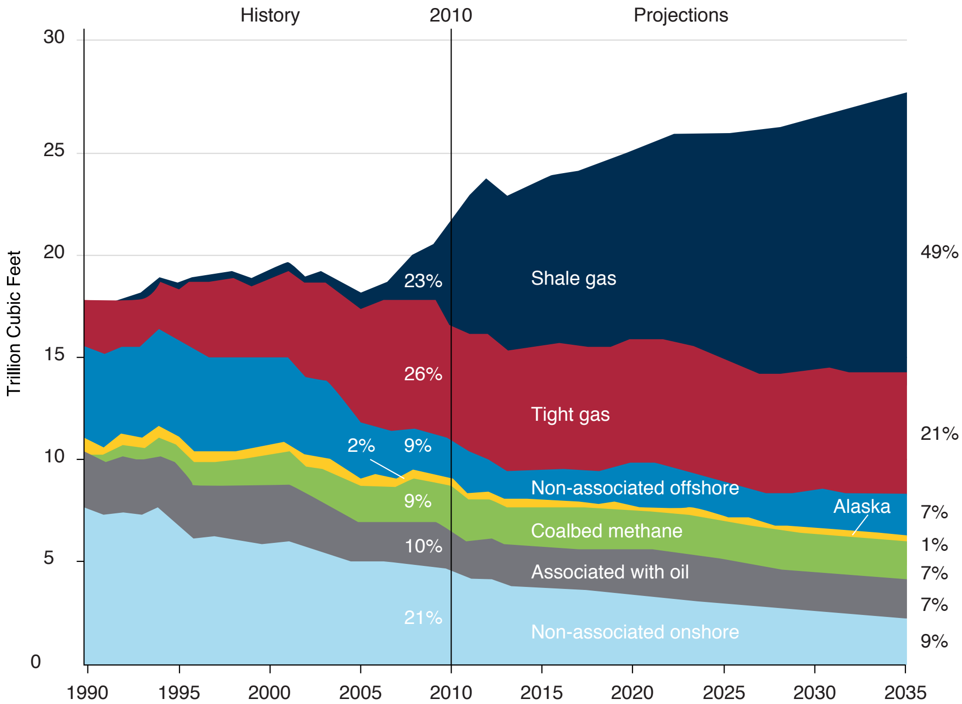
Figures 1-3 document the growing role of shale gas production in the United States. Approximately 30 percent of U.S. dry natural gas production is now from shale gas (Figure 1). This supply stream has bolstered long-term price stability in domestic gas markets (Figure 3). Notably, prices have stayed low and stable despite surging demand. Nationally, gas consumption reached new all-time highs in 2010 and 2011[13] but prices still moved steadily lower. At the time of this writing, Henry Hub futures prices are hovering around $2.90/MMBtu for October 2012 contracts.[14]

But what about the mid-to-longer term? Recent futures prices suggest that natural gas prices (per MMBtu) will remain steady in the $3–$6 range until at least 2020 (Figure 3).

In contrast to natural gas, coal prices have been trending slowly up from the lows seen in 2009 (Figure 4). This is particularly true for Appalachian coals; coals from western regions (like the Powder River Basin in Montana and Wyoming), by comparison, continue to trade at a discount. Coal prices started falling in late 2011 because of lower demand and rising supplies. However, several coal producers and Bloomberg have reported that average operating costs for coal mines exceeded market prices during the first half of 2012. This suggests that coal prices have bottomed out and that future price increases are likely.[15]

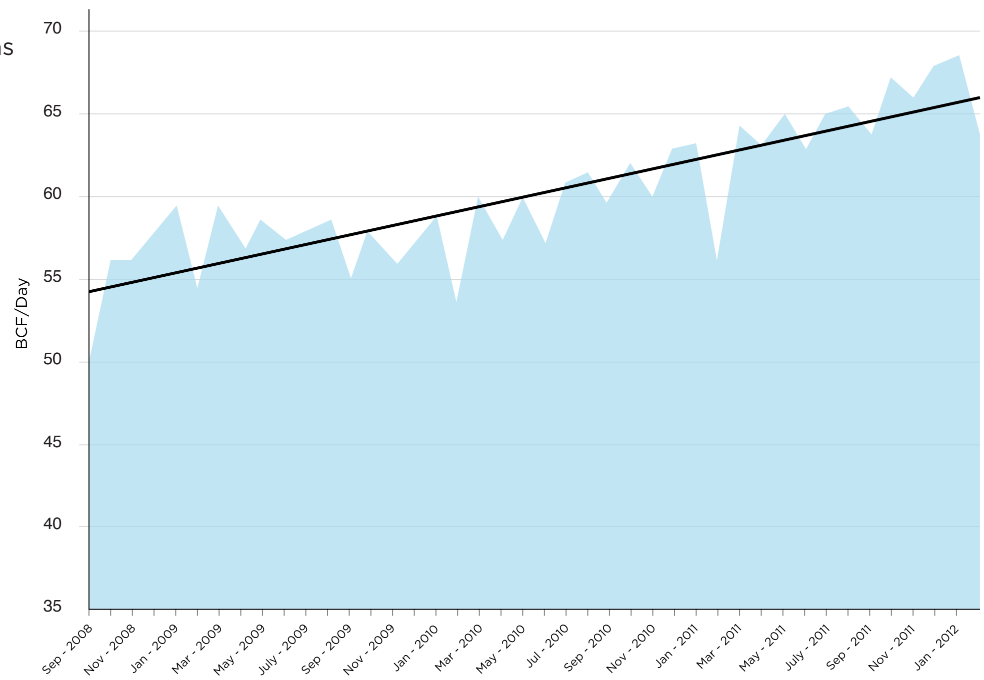
8 Zoback, M., Kitasei, S., Copithorne, B. (2010). *Addressing the Environmental Risks from Shale Gas Development*. Worldwatch Institute. Available at http://www.worldwatch.org/system/files/pdf/natural_gas_BP1_july2010.pdf *See also:* Groat, L.G., Grimshaw, T.W. (2012). *Fact-Based Regulations for Environmental Protection in Shale Gas Development.* The Energy Institutes, The University of Texas at Austin.
9 MIT. (2011). The Future of Natural Gas. Available at http://web.mit.edu/mitei/research/studies/documents/natural-gas-2011/NaturalGas_Report.pdf
10 Alvarez, R.A., Pacala, S.W., Winebrake, J.J., Chameides, W.L., Hamburg, S.P. (2012). "Greater focus needed on methane leakage from natural gas infrastructure." Proceedings of the National Academy of Sciences USA, 109(17): 6435-6440.
11 National Petroleum Council. (2011). Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources. Available at: http://www.npc.org/reports/NARD-ExecSummVol.pdf
12 Id.
13 EIA (2012). U.S. Natural Gas Total Consumption. Data available at http://www.eia.gov/dnav/ng/hist/n9140us2a.htm
14 October 2012 NYMEX Henry Hub contract as of May 22, 2012. Data source: SNL Financial.
15 See Arch Coal Inc. *First Quarter 2012 Financial Results,* which reported negative operating margins for Arch Coal's operations in Appalachia. Also, Alpha Natural Resources reported in their first quarter 2012 financial results that "spot pricing is below production costs for much of Central Appalachia and certain PRB operations." See Bloomberg article: Elmquist, S. (2012, March 21). *Appalachian Coal Fights for Survival on Shale Boom: Commodities.* Bloomberg. Available at: http://www.bloomberg.com/news/2012-03-21/appalachian-coal-fights-for-survival-on-shale-boom-commodities.html

Figure 1
Annual U.S. natural gas production by well type



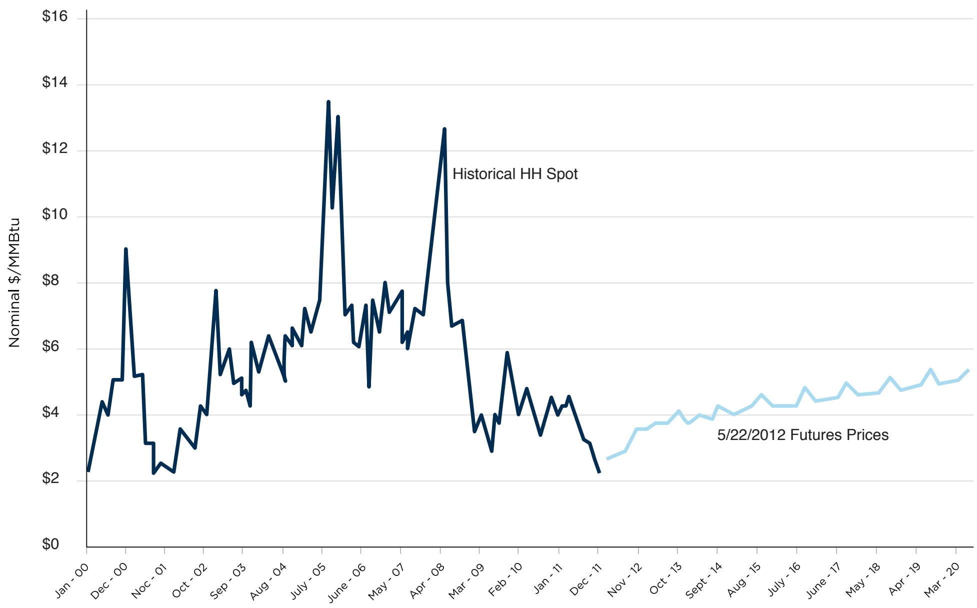
Source: U.S. Energy Information Administration, AEO2012 Early Release Overview, January 23, 2012

Figure 2
Daily U.S. natural gas production



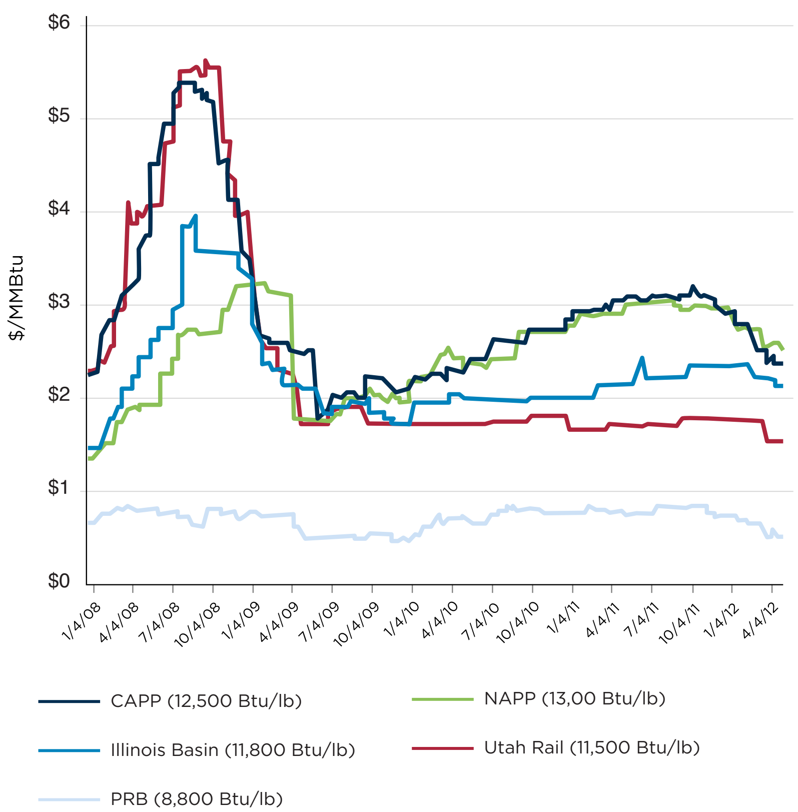
Source: EIA data

Figure 3
Historical Henry Hubs spot prices, and NYMEX futures prices



Note: Henry Hub (HH), Louisiana, is a major production area delivery point in the gas industry.
The NYMEX Natural Gas Futures contract uses the Henry Hub price as the reference point.
Source: New York Mercantile Exchange.

Figure 4
Historical average weekly coal commodity spot prices



Source: SNL Financial

B. Utilization of Existing Power Plants

The substantial fall in natural gas prices since 2009 has already had a profound effect on the U.S. electricity sector in that it has shifted the economic dispatch of power plants. For example, EIA data show that natural gas electricity generation in December 2011 was 11.6 percent higher than in December 2010, while coal-fired generation dropped 20.7 percent during the same period.[16] These trends continued in 2012. Current EIA forecasts indicate that the share of total generation fueled by natural gas will rise from 24.8 percent in 2011 to 30.9 percent in 2012, while coal's share of the market will drop from 42.2 percent to 36.2 percent.[17] Overall, coal consumption in the electricity power sector is expected to decline by 14.3 percent in 2012, dipping to about 796 million short tons[18]—the lowest level since 1992.[19]

These statistics reflect the changing relative economics of coal and natural gas. Power plants typically generate electricity for local power grids based on their per unit variable costs of production ($/MWh), whereas their capital costs are considered sunk costs. For most generators, the largest variable cost is fuel. Units with lower variable costs are committed first, while more expensive units are typically used only during periods of higher demand.

Historically, lower fuel costs made coal units less expensive to operate than their gas- or oil-fired competitors.[20] Therefore, coal units generally operated at higher capacity factors. But with natural gas prices hitting 10-year lows, growing numbers of coal units are operating well below capacity as more and more natural gas units are being dispatched first.[21,22] Gas units also offer certain advantages in terms of operational flexibility; compared to coal units they are relatively quick to start up and easy to ramp down.

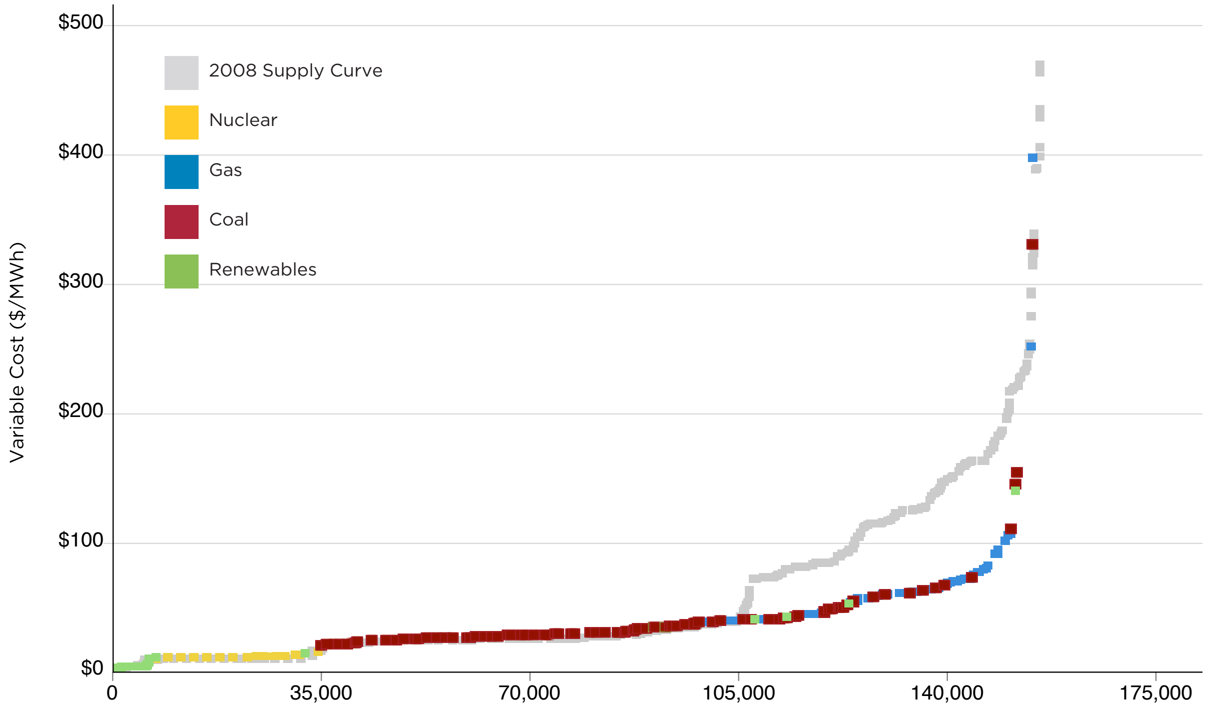
An electricity power supply curve provides an effective way to illustrate the impact that lower gas prices have on electricity production costs and on the cost of gas-fired generation relative to coal and other options. Using the most recently available data, Figure 5 plots the 2010 electricity supply curve for the Mid-Atlantic region using information collected by ReliabilityFirst Corporation (the Regional Reliability Organization that encompasses the PJM Interconnection RTO[23]). The 2010 supply curve is overlaid on the 2008 supply curve, and shows coal unit costs slightly increasing in 2010 while natural gas units became cheaper to operate. Ultimately, the net effect is a reduction in marginal costs. For example, at 120,000 MW of demand, marginal prices in the PJM region fell nearly 50 percent, from about $80/MWh in 2008 to $41/MWh in 2010. This was good news for consumers, but it meant that operating margins (and therefore revenue) for coal units fell sharply.

Market conditions for coal plants deteriorated further in 2011 and early 2012 as natural gas reached price parity with many grades of coal on an energy content basis ($/MMBtu). Modern natural gas power plant technologies, like combined cycle gas turbines (CCGT),[24] have the added advantage of being more efficient than conventional coal plants in converting fuel to electricity. In other words, CCGT units require less fuel than a coal unit to produce the same amount of electricity.

To test the broader geographic impact of fuel price changes on dispatch rates, we also completed an independent analysis of production costs for

16 EIA (2012, March). *Short-Term Energy Outlook.* Available at: http://205.254.135.24/forecasts/steo/pdf/steo_full.pdf
17 EIA (2012, May). *Short-term Energy and Summer Fuels Outlook:* Table 7D. Available at: http://www.eia.gov/forecasts/steo/tables/pdf/7dtab.pdf
18 EIA (2012, May). *Short-term Energy and Summer Fuels Outlook:* Table 6. Available at: http://www.eia.gov/forecasts/steo/tables/pdf/6tab.pdf
19 EIA (2011). *Annual Energy Review 2011:* Table 7.3. Available at: http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0703
20 Natural gas and oil units using combustion turbine technologies are also more flexible and responsive, thus making them valuable intermediate and peaking resources. Swisher, J. (2011). "The Business Case for Integrating Clean Energy Resources to Replace Coal." http://www.cleanskies.org/wp-content/uploads/2011/06/Swisher-final.pdf
21 Duke Energy CEO Jim Rogers recently said, "I think this is the first time in my career that our gas units are dispatching after nuclear and before all our coal plants… that's based on price, because gas prices are so low." See Rogers' comments from *The New York Times Energy for Tomorrow Conference*, April 11, 2012, http://www.nytenergyfortomorrow.com
22 SNL reported that CCGT utilization rates soared in 2011 while coal units operated less. See *SNL Financial* articles "Combined-cycle utilization soars in 2011 as coal plants are used less," (August 8, 2011), and "2011 recap—What a year in energy," (January 4, 2012).
23 The data used to plot the supply curve are from ReliabilityFirst Corporation, the regional reliability organization that encompasses the PJM Interconnection Regional Transmission Organization (RTO). PJM stands for Pennsylvania, New Jersey, Maryland—the three principal states served by the PJM RTO.
24 A combined cycle (CCGT) gas turbine plant includes at least one combustion turbine and one steam turbine (hence the term "combined cycle"). The heat from the gas turbine(s) is recycled and used to boil water to produce additional electricity from a traditional steam turbine. This makes CCGTs highly efficient; modern units are capable of achieving thermal efficiencies approaching 60 percent (whereas the maximum thermal efficiency of simple cycle CTs is about 40 percent). Combined cycle systems are usually fueled by natural gas, but other fuels like diesel, kerosene and jet fuel can also be used in this type of system.

Figure 5
Mid-Atlantic (Reliability First Corporation - PJM Interconnection) 2010 electricity supply curve



Source: SNL Financial

Table 1: Power Plant Production Cost Calculations ($/MWH)
Power plant production cost calculations for a generic unit operating on the different fuels considered. The results show that natural gas units are cheaper than coal units under current market conditions. The analysis assumes delivered fuel costs of $75/ton, $70/ton, $30/ton for CAPP, NAPP, and PRB, respectively, and $3.00/MMBtu for natural gas. Assumed heat rates are 10 MMBtu/MWh for coal units, 7.0 MMBtu/MWh for natural gas combined cycle units, and 10.75 MMBtu/MWh for natural gas combustion turbines. We assume emission allowance prices are $50/ton for annual and seasonal NO_x, and $1.5/ton for SO_2.

	CAPP Coal	NAPP Coal	PRB Coal	Natural Gas Combined Cycle	Natural Gas Combustion Turbine
Fuel Cost ($/MWH)	$31.25	$26.92	$17.05	$21.00	$32.25
Variable Operations & Maintenance ($/MWH)	$6.00	$6.00	$6.00	$2.75	$10.00
SO_2 Cost ($/MWH)	$0.02	$0.03	$0.01	$0.00	$0.00
Annual NO_x Cost ($/MWH)	$0.03	$0.03	$0.03	$0.00	$0.01
Seasonal NO_x Cost ($/MWH) (May-Sept.)	$0.03	$0.03	$0.03	$0.00	$0.01
Dispatch Cost per MWH (Oct.-April)	**$37.29**	**$32.97**	**$23.08**	**$23.75**	**$42.26**
Dispatch Cost per MWH (May-Sept.)	**$37.32**	**$33.00**	**$23.10**	**$23.75**	**$42.27**

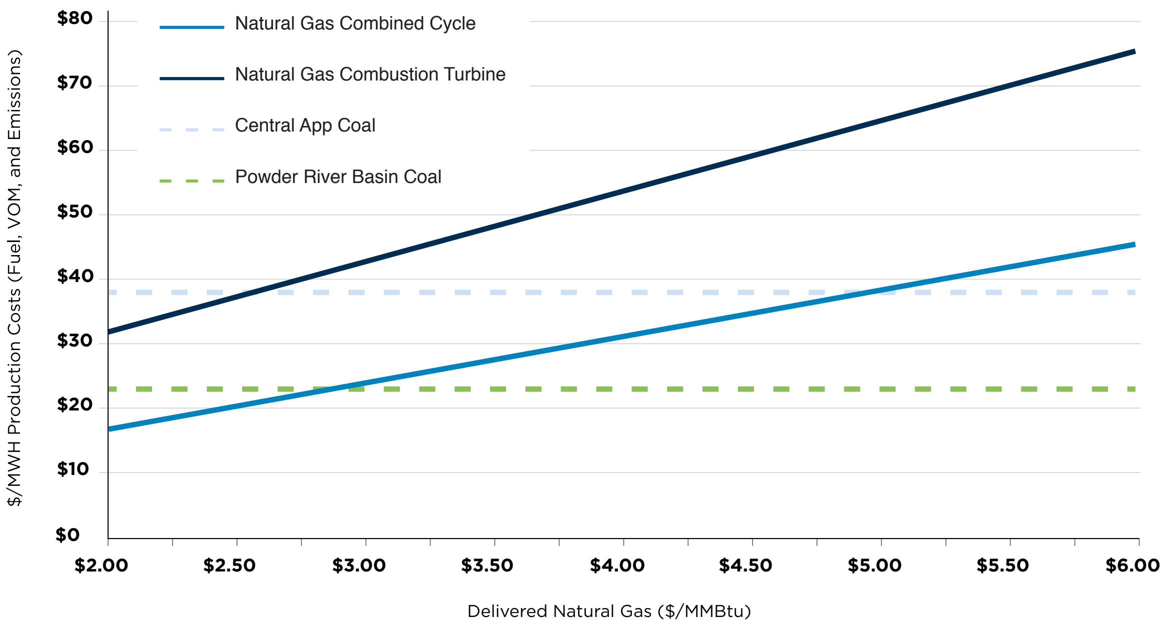
generic coal units, CCGTs and combustion turbines (CT).[25] As detailed in Table 1, our analysis finds that natural gas units are indeed cheaper to operate than some coal units with today's market conditions. Specifically, CCGTs are about $13.5/MWh cheaper than coal units fueled with Central Appalachian (CAPP) coal and about $9.00/MWh cheaper than coal units fueled with Northern Appalachian (NAPP) coal. CCGTs are also competitive with units that run on Powder River Basin (PRB) coal, which is some of the nation's cheapest coal. Even less efficient CTs, which traditionally were dispatched only during periods of peak electricity demand because they were relatively expensive to run, are becoming more competitive with CAPP units at today's natural gas prices.

To plot Figure 6, which depicts the "cross-over point" between coal and gas (that is, the point where the cost of producing electricity from either fuel is equal), we varied the price for delivered natural gas while holding coal unit production costs constant. The results show that CCGT production breaks even with PRB coal unit production at delivered gas prices between $2.75 and $3.25 per MMBtu. CTs break-even with CAPP units at delivered gas prices at or below $2.50/MMBtu. Based on this analysis, delivered natural gas prices would have to reach $4.75–$5.25/MMBtu before generation would be expected to shift back from CCGTs to CAPP units. To put this price range in perspective, the EIA's *Annual Energy Outlook 2012 Early Release* forecasts natural gas prices will remain below $5.25/MMBtu through 2017.[26]

Although recent fuel price trends have already shifted a portion of the nation's generation from coal to natural gas, a significant opportunity for further fuel shifting—and further rate relief—remains. Perhaps the largest opportunity lies in using long-term contracts and hedging arrangements to "lock in" current record-low gas prices. Such arrangements may be attractive to owners of existing capacity as well as utilities considering new gas-fired power plants. We start by looking more closely at the opportunity associated with currently underutilized CCGT capacity.

Figure 6

Power plant break-even production costs: natural gas v. coal



25 A combustion turbine (CT) is a type of power generator that works much like a large jet engine. It draws in air, compresses and combines the air with fuel, and ignites the fuel-air mixture, producing a flow of hot combustion gases that expand and turn turbine blades and a generating shaft to produce electricity. Combustion turbines are primarily fueled by natural gas, but can also use diesel, kerosene and jet fuel.
26 EIA. (2012). *Annual Energy Outlook 2012 Early Release.* Table A3.

C. Underutilized Gas-Fired Capacity

In 2010, the Congressional Research Service (CRS) examined the potential for using slack capacity at existing natural gas-fired power plants to immediately displace coal-based generation. Using a proximity analysis, CRS concluded that existing CCGTs could quickly displace 5–9 percent of total U.S. coal generation and 3–5 percent of associated carbon dioxide (CO_2) emissions.[27] A three-year research study by MIT, titled "The Future of Natural Gas" identified an even larger opportunity: "[T]here is sufficient surplus [CCGT] capacity to displace roughly one-third of U.S. coal generation, reducing CO_2 emissions from the power sector by 20% and yielding a major contribution to control criteria pollutants."[28] Shifting generation toward existing slack CCGT capacity has the added benefit that it avoids capital costs to construct new units or add environmental controls, while still preserving system reliability.

To explore the impact of recent price trends, Table 2 updates a key chart from the CRS report with more recent data.[29] Despite the sharp decline in natural gas prices from about $7/MMBtu in 2007 to about $4/MMBtu in 2011 and the related increase in natural gas-fired generation, it is surprising how much underutilized CCGT capacity remains in the United States. About 118,000 MW—or 62 percent of the nation's CCGT plants—operated at less than 50 percent of capacity in 2011. While each plant's operating circumstances are somewhat unique,[30] this figure suggests that there is still—in 2012 and over the next several years—a significant opportunity to increase electricity production by existing, underutilized and highly efficient CCGT units while at the same time reducing air pollution and CO_2 emissions by displacing dirtier, more inefficient generators.

In fact, a recent SNL Financial analysis found meaningful potential for fuel switching in the very near term (before the end of 2012).[31] Nationwide, SNL Financial estimated that CCGT units could increase gas consumption (and therefore electrical output) by 17 percent over 2011 levels. In some parts of the country, the potential for increased output from currently underutilized CCGTs is well above the national average. According to SNL Financial, output from existing units could be increased by as much as 23 percent, 41 percent, and 55 percent in the areas covered by the Southwest Power Pool (SPP), the Midwest Independent System Operator (MISO), and the PJM RTOs, respectively.[32]

Table 2
Utilization of CCGT fleet

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2007
70% and Greater	12,582	7%	5%
Under 70% to 50%	62,111	32%	24%
Under 50% to 30%	56,915	30%	35%
Under 30%	60,873	32%	37%
Total	**192,481**	**100%**	**100%**

Source: Data from SNL Financial

27 Kaplan, S. (2010, January 19). *Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants*. Congressional Research Service. Available: http://opencrs.com/document/R41027/2010-01-19/download/1005/
28 MIT. (2011). *The Future of Natural Gas*. Available at http://web.mit.edu/mitei/research/studies/documents/natural-gas-2011/NaturalGas_Report.pdf
29 A more thorough examination of the utilization rates of the U.S. CCGT fleet, including several regional analyses, is included in Appendix A. Data from EIA-923 preliminary data for 2011.
30 Other considerations that may drive the relative utilization of a particular unit include transmission issues, the availability of pipeline capacity, overall electricity demand, unit outages, competing fuel prices, the need for intermediate or peaking resources, and other issues affecting unit dispatch.
31 Piper, S., Gilbert, J. (2012, May 1). *Prospects for Coal to Gas Switching*. SNL Financial.
32 SPP covers mostly Oklahoma and North Texas as well as parts of Louisiana, Arkansas, and New Mexico; MISO covers most of North Dakota, South Dakota, Nebraska, Minnesota, Wisconsin, Iowa, Michigan, and parts of Kansas, Missouri, Illinois, Indiana, and Ohio. PJM includes Pennsylvania, New Jersey, Maryland, Delaware, the District of Columbia, Virginia, West Virginia, and parts of North Carolina, Ohio, Indiana, Michigan, and Illinois.

D. New Gas-Fired Capacity

Low gas prices have clearly increased recent dispatch rates for existing CCGTs and other gas-fired plants. However, what about the longer-term impact of low gas prices on power plant construction and on utilities' capital investment decisions? In the longer term, coal units will be at a further disadvantage compared to natural gas because of their need to comply with more stringent environmental regulations. Upgrading pollution controls on non-compliant fossil-fired generators can require significant new investments. Owners of older coal plants will have to weigh whether to make the retrofits needed to bring these units into environmental compliance versus letting them retire and replacing the capacity with new gas-fired plants. To explore the cost trade-offs facing plant owners, we created a model to examine the "all-in" levelized costs (capital plus variable) of various generation technologies.

This type of analysis—referred to as a "busbar" analysis in the electric industry—provides an apples-to-apples comparison of different alternatives. Busbar comparisons are useful for determining the lowest cost alternative across a range of likely capacity factors. This information is extremely useful for generation planners faced with determining which type of baseload, intermediate or peaking resource to build.

Our busbar analysis compares the levelized costs[33] of various new-build generation technologies to the cost of retrofitting existing coal units with environmental controls. For existing coal plants, capital costs to meet new regulatory requirements represent incremental investments, not capital costs for the original facility.[34] The environmental regulations considered in our analysis of incremental investment costs for existing coal units include the Mercury Air Toxics Standards (MATS), the Cross State Air Pollution Rule (CSAPR), Section 316(b) of the Clean Water Act, and new rules concerning coal combustion residuals (i.e., coal ash). Our base analysis does not include potential compliance costs associated with future carbon regulations or policies, though we also present results for a scenario in which a nominal price of $10 per ton CO2 is imputed to greenhouse gas emissions. (Box 1 and Appendix B provide more information about existing or potential environmental regulations relevant to the power sector.)

Cost estimates for various generation technologies are based on publically available data.[35,36] Fuel prices are from the EIA's *Annual Energy Outlook 2012 Early Release*[37] and current delivered coal prices. (Additional details about the analysis and assumptions are provided in Appendix B.)

The results of our busbar analysis indicate that new natural gas capacity is the lowest cost 20-year investment if one compares among units operating at capacity factors between 0 percent and 70 percent (Figure 7). High fixed costs to build and maintain environmental controls hurt the relative economics of coal units, while natural gas units benefit from lower variable costs due to low fuel prices. Combustion turbines provide the lowest cost option for peaking needs (0-20 percent capacity factor), while combined cycle gas turbines are the cheapest option at capacity factors in the intermediate range of 20–70 percent.[38]

Among units with high capacity utilization (i.e., capacity factor greater than 70 percent), CCGTs remain very competitive with PRB unit retrofits. Because of differences in coal quality (eastern coal has higher sulfur content than western coal, for example), and higher prices for eastern coals, CAPP units are more expensive to retrofit and operate than PRB units and CCGTs at all capacity factors. In fact, CAPP units are only cheaper than combustion turbines if they are operating at 80 percent capacity or above. This bleak picture for CAPP units is why they are expected to make up the lion's share of coal retirements in the coming years.[39] Our busbar analysis, for example, finds that a CCGT costs $475/kw-year operating at a 60 percent capacity factor. Therefore a 500 MW CCGT's annual levelized cost

33 Levelized costs include variable costs for operation, as well as revenue requirements for debt and equity financing.
34 Capital costs for the original facility are sunk, therefore they are not considered incremental in the analysis.
35 Edison Electric Institute. (2011, January). *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet.* Analysis prepared by ICF and submitted to the USEPA as part of EEI's EGU MACT comments.
36 EIA (2010, November). *Updated Capital Cost Estimates for Electricity Generation Plans.* Available at http://www.eia.gov/oiaf/beck_plant-costs/pdf/updatedplantcosts.pdf
37 EIA (2012). *Annual Energy Outlook 2012 Early Release.* Available at: http://www.eia.gov/forecasts/aeo/er/excel/aeotab_3.xlsx
38 High capital costs for solar photovoltaic and offshore wind power currently make these technologies less economic than gas-fired power. Onshore wind, however, is competitive, especially in regions capable of sustaining capacity factors greater than 30 percent.
39 Smith, A., Bernstein, P., Bloomberg, S., Mankowski, S., Tuladhar, S., (2012). *An Economic Analysis of EPA's Mercury and Air Toxics Standards Rule.* NERA Economic Consulting.

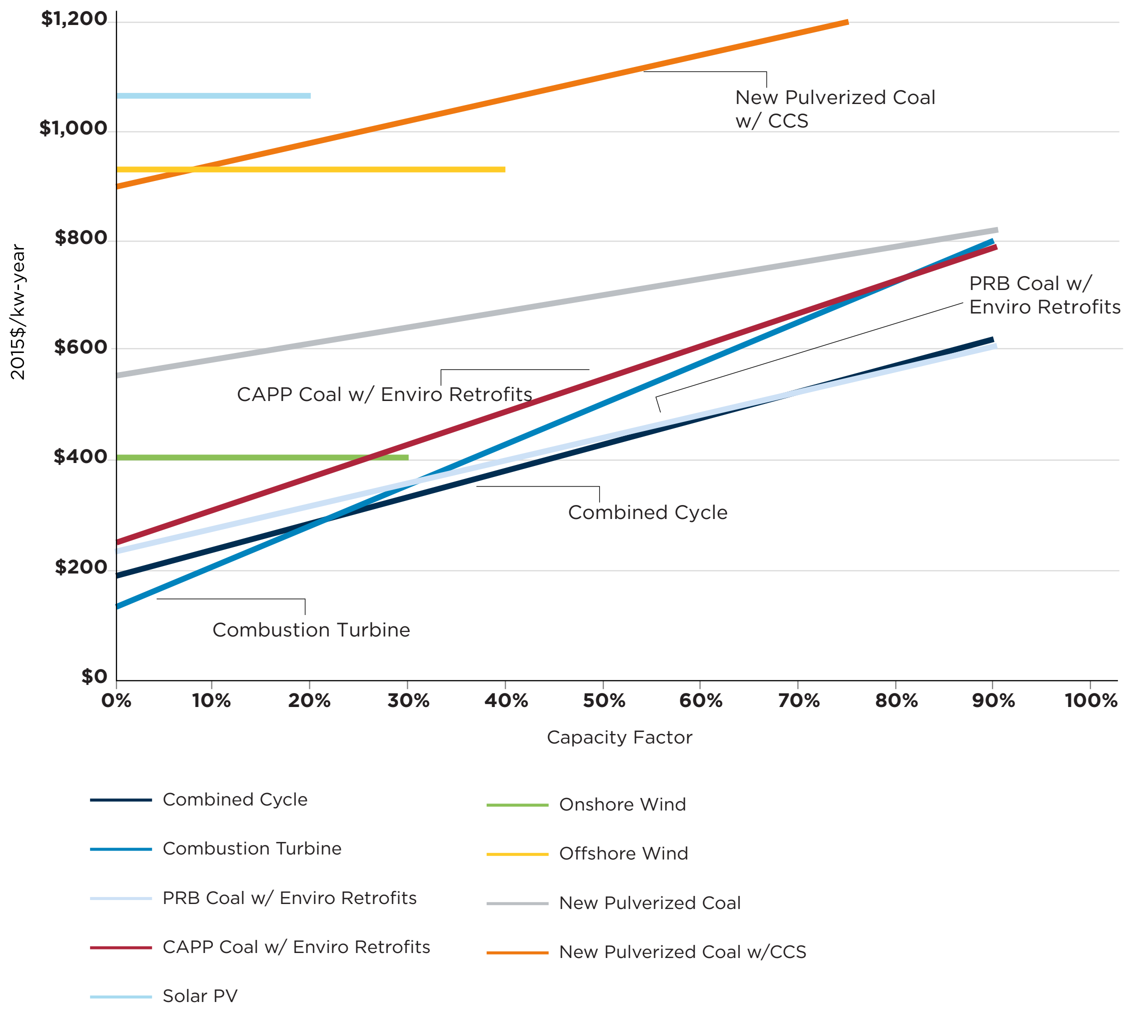
is $237.5 million.[40] By comparison, a 500 MW CAPP unit with environmental controls and operating at a 60 percent capacity factor has an annual levelized cost of $306 million.[41] Thus, replacing a 500 MW CAPP with a CCGT of the same size results in levelized savings of $68.5 million per year or cumulative savings of $1.37 billion over 20 years.

A more detailed unit retirement analysis is included in Appendix C.

The analysis in Figure 7 does not include risks or potential costs associated with the future regulation of greenhouse gas (GHG) emissions or other policies aimed at mitigating global climate change.

Figure 7

Busbar costs for different generation technologies



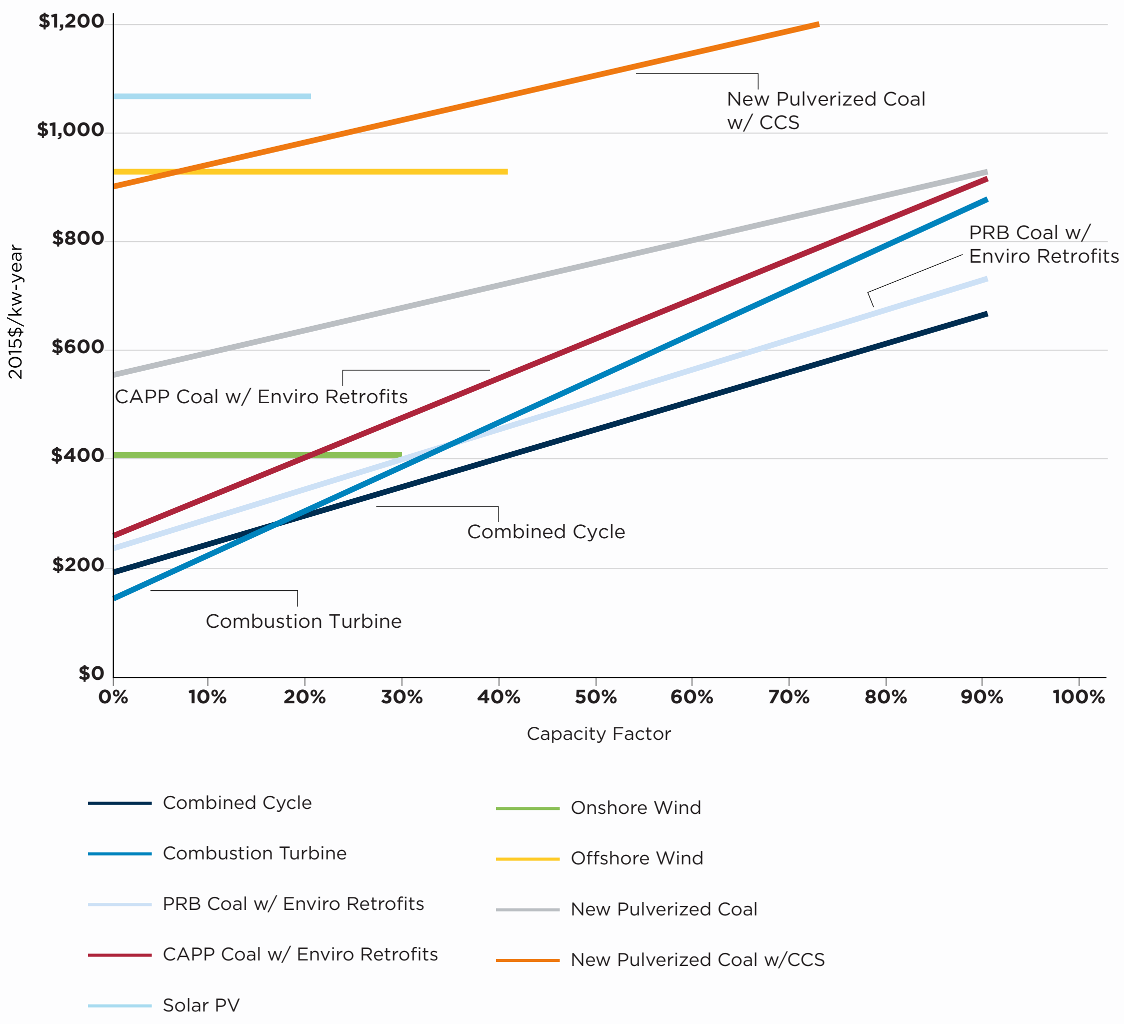
40 500 MW * $475/KW-year * 1000 KW/MW = $237,500,000 / year.
41 500 MW * $612/KW-year * 1000 KW/MW = $306,000,000 / year.

Box 1 What About the Impact of Carbon Prices?

The U.S. Environmental Protection Agency (EPA) recently proposed GHG standards for new units based on the emissions of an efficient CCGT plant and has indicated that it may consider proposing standards for existing sources as well. Just how such standards—or other potential carbon policies (like a carbon tax or cap-and-trade system)—might affect the costs of maintaining and operating fossil fuel power plants remains difficult to predict at this time. Nevertheless, imposing a nominal price on carbon emissions ($10/$CO_2$-ton) in the busbar analysis provides a sense of potential risks associated with GHG policies (Figure 8).

Carbon costs impact coal units more than other generation alternatives because coal units are more carbon intensive than natural gas units and renewables. With a $10/$CO_2$-ton price, PRB units that require environmental retrofits remain more expensive than a CCGT unit at all capacity factors. And with the same carbon price, CAPP units that require environment al retrofits are more expensive than both CCGT and CT alternatives at all capacity factors.

Figure 8
Busbar costs for different generation technologies with $10/ton-$CO_2$

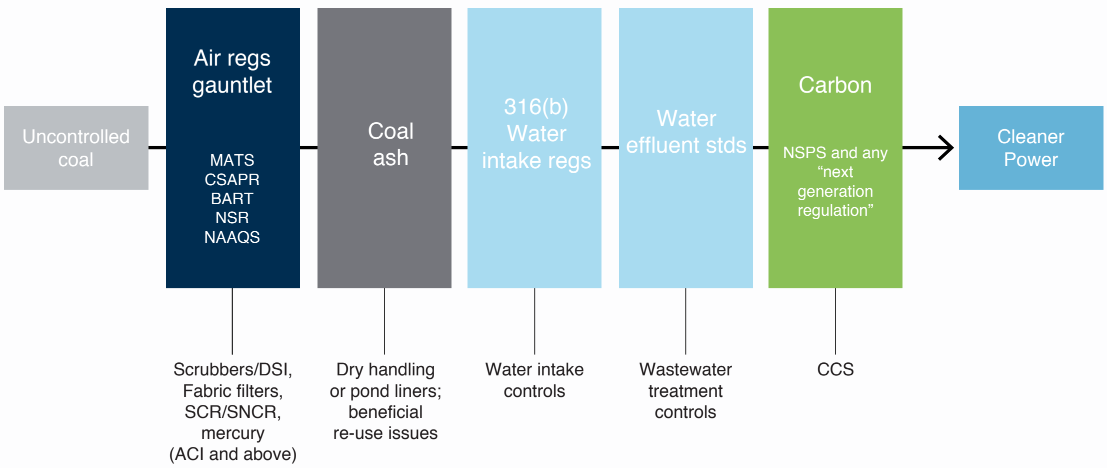


Box 2 EPA Electric Generating Unit Environmental Regulations

Owners and operators of electric generating units face several new and proposed regulations that are meant to reduce the environmental impact these units have on air, land and water quality. On the air front, EPA recently issued the Mercury and Air Toxics Standards (MATS) rule, which enforces health-based limits on emissions of mercury and other toxic air pollutants, and the Cross State Air Pollution Rule (CSAPR) to reduce power sector emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2). At the time of this writing, CSAPR is under a court ordered stay. Both of these new sets of air emission standards primarily impact coal-fired generation. Gas-fired power plants are only marginally affected because the combustion of natural gas emits miniscule amounts of SO_2 and does not emit mercury, or acid gases; in addition, natural gas units emit 50–87.5 percent less NO_x than the cleanest coal units.

While CSAPR and MATS have garnered more attention, EPA is also under court order to issue new regulations under Section 316(b) of the Clean Water Act to minimize environmental impacts from power plant water intakes. Beyond that, EPA is in the process of issuing regulations to reduce risks from coal ash handling, storage and disposal. Finally, EPA recently issued "new source" greenhouse gas performance standards for the electric power sector—these standards would apply to future capacity additions. The Agency has indicated that it may eventually follow with GHG regulations that cover existing power generators. Figure 9 summarizes the major environmental regulations considered in this analysis and related compliance requirements.

Figure 9
EPA regulations and pollution control options for electric generating units



Source: C2E2 Strategies, LLC

Additionally, some states have adopted environmental regulations that go above and beyond standards or regulations set by the federal government. North Carolina's Clean Smokestacks Act, for example, mandates additional SO_2 and NO_x reductions; North Carolina has also adopted a rule that requires all coal-fired units in the state to install mercury control technology by the end of 2017.

Making the Switch: Opportunities and Challenges 3

The busbar analysis described in the last section shows that with natural gas prices at historic, decade-low levels, gas-fired power is economic—not only in the short run, but also on a life-cycle basis. Our analysis further suggests that compliance costs linked to new environmental regulations and other factors will accelerate the retirement of many coal units and create significant new demand for cleaner generating options. In short, the case for expanded gas-fired generation appears compelling. However, despite a nationwide, 7-percentage-point increase in natural gas-fired electricity since 2009, long-term commitments to "lock-in" low fuel prices for gas-fired generation have been slower to develop. In pure economic terms, this is puzzling.

In many ways, the opportunity to lock-in low gas prices is analogous to the opportunity to refinance long-term debt when interest rates drop. In 2008 and 2009, the country experienced one of the worst liquidity crises in its history. But in late 2009, companies and homeowners rushed to refinance loans and mortgages because interest rates had fallen dramatically. That rush is still going on—as of March 2012, average yields on investment-grade bonds had fallen to a record low of 3.27 percent.[42,43] Collectively, U.S. homeowners who refinanced their mortgages over the past three years unlocked savings worth $46 billion in just the first year.[44] In this environment, few corporate CFOs (or CEOs) want to be "caught out" waiting for interest rates to rise and risk losing a once-in-a-generation refinancing opportunity.

We think that current conditions in the natural gas market offer a similar opportunity for electricity ratepayers and power producers. So, why has the industry been comparatively slow to respond? Three reasons seem to dominate: (1) loss aversion and status quo bias on the part of generators and gas suppliers; (2) a lack of regulatory incentives for generators to shoulder fuel price risks in the electric sector; and (3) asymmetrical regulation of fuel contracts for electric generating facilities.

We review each of these concerns briefly below and then show how a "no regrets" approach to longer-term fuel switching can mitigate them.

A. Buyer's Regret: Loss Aversion and the Status Quo Bias

For many utility executives, basic psychology—specifically, people's natural aversion to loss—may explain part of the reluctance to make a larger commitment to gas-fired power. Simply said, they don't trust that gas prices will stay low.

Southern Company CEO Tom Fanning recently put it this way: "While gas looks cheap today it's looked cheap in the past, only to disappoint."[45] In a similar vein, Southern Company's CFO, Art Beattie, said at a Credit Suisse Energy Summit, "there is a famous statement out there—'if you want to make gas prices rise, everybody put a bet on $4 gas long term,'—well for sure that long-term gas price would rise."[46] And, speaking about gas, Thomas Farrell, CEO of Dominion Resources and Chairmen of the Edison Electric Institute, said, "[W]e welcome it, but it makes us a little nervous," alluding to the high natural gas prices experienced in 2007 and 2008.[47] Notably, Mark Kinevan, the vice president of energy trading at The Energy Authority Inc, has warned that natural gas prices could hover near $10/MMBtu in the long term.[48]

42 Hauser, C. (2012, March 7). In Bonds, Bull Market for Firms. *New York Times.* http://www.nytimes.com/2012/03/08/business/low-rates-entice-companies-to-borrow.html?pagewanted=all
43 By comparison, yields averaged over 6.3% between 1993-2009. See: Bogoslaw, D. (2009, September 27). The Rush to Refinance Corporate Debt. *Businessweek.* Available at: http://www.businessweek.com/investor/content/sep2009/pi20090925_301374.htm
44 According to Moody Analytics. See: Timiraos, N., Simon, R. (2012, May 9). Borrowers Face Big delays in Refinancing Mortgages. *The Wall Street Journal.*
45 Smith, R. (2012, March 15). Cheap Natural Gas Unplugs U.S. Nuclear-Power Revival. *The Wall Street Journal.*
46 Poszywak, A. (2012, February 9). Southern CFO: 'Bet totally on gas is not the right answer'. *SNL Financial.*
47 Gonzalez, A. (2012, March 8). Despite Some Reluctance, Natural Gas making Impact on Power Cos. *Dow Jones Newswires,* available at http://www.foxbusiness.com/news/2012/03/08/despite-some-reluctance-natural-gas-making-impact-on-power-cos/
48 Crawford, J. (2012, March 21). CEOs caution against overreliance on gas-fired power, stress diversification. *SNL Financial.*

The tendency of utility executives (and, no doubt, many regulators) to fear a long-term prospective "loss" (arising from future fuel price increases) over and above a near-term ratepayer "gain" (arising from today's low prices) is consistent with studies of market conduct in other transactions. This type of loss-aversion, coupled with a status quo bias, is well known to behavioral economists.

Loss aversion refers to a psychological bias that rates losses higher than gains (i.e. a $100 loss outweighs a potential $150 gain even though the odds of winning and losing are equal). Daniel Kahneman—a psychologist and recipient of the 2002 Nobel Prize in Economic Sciences—observed this bias in his research and concluded "losses loom larger than gains."[49] Kahneman goes on to explain: "loss aversion does not imply that you never prefer to change your situation... Loss aversion implies only that choices are strongly biased in favor of the reference situation (and generally biased to favor small rather than large changes)."[50]

Hence, entities typically value their current operations more than alternatives (status quo bias). While this behavioral inertia appears to be deeply ingrained in human nature, it is nonetheless "irrational" and may be downright harmful to ratepayers.[51]

The behavior of gas suppliers exhibits a similar aversion to change and fear of loss, albeit fear of a different type of loss. Gas suppliers fear that they could miss future revenue or profit opportunities if they enter into long-term contracts to supply fuel at current, low prices. For example, why would a gas producer want to sell any amount of gas for $5/MMBtu over the long-term if there might be an opportunity to sell it for $7/MMBtu on the spot market next year or the year after? In that case, the producer's "loss" (or foregone revenue opportunity) amounts to $2 for every MMBtu he sells at the long-term contract price. We explore these issues further in Section 4, but our key point is that gas suppliers—as much as electricity producers—want to maximize their profits and revenues. To date, this has led them to maintain the status quo of short-term (day-ahead to three years) gas marketing.

B. No Incentive for Taking Fuel Risks

In March 2011, Thomas Farrell, the CEO of Dominion and Chairman of EEI, said to the crowd at a major Houston energy conference:

> "Utilities are very reluctant to enter into long-term contracts for any source, because of volatility, and the situation we're in is we have a regulator looking over our shoulder, asking why we [signed a long-term deal]."[52]

Another statement, by Susan Arigoni, Xcel Energy's Vice President of Fuels, nicely summarizes the utility perspective: "We are not paid for taking risks with fuel."[53,54]

Utility executives also point to another major disincentive to entering into long-term natural gas supply contracts: regulators discourage it. Specifically, the concern is that public utility commissions will disallow the recovery of fuel costs for fuel purchased under a long-term contract if the spot market price drops below the long-term contract price. In that case, regulators may conclude that ratepayers should not be penalized for the utility's inability to take advantage of changing market conditions.[55] In

49 Kahneman, D. (2011). *Thinking, Fast and Slow.* Farrer, Straus and Giroux: New York, NY.
50 *Id.*
51 Evidence of this inertia can be seen in the cautious comments about natural gas made by utility executives, even when their customers currently benefit from low natural gas prices. In March 2012, for example, Xcel Energy's Southwestern Public Service Company (SPSCo) announced that Texas customers would see a 3.7 percent reduction in rates now and a 4.5 percent reduction in the summer months due to the lower cost of natural gas. Yet, one month later, in April 2012, when SPSCo announced an additional 5.5 percent reduction for Texas customers SPSCo's CEO said: "This is great news for area customers because it helps offset some of the higher prices they're paying for food and gasoline. But we know that natural gas prices are volatile, so we remain committed to investing in a mixed-resource portfolio to help offset possible price increases in the future." See Xcel Energy Press Release "Xcel Energy Texas customers to see lower bills April 1." (March 22, 2012); and April 19, 2012 Press Release: "Xcel Energy to lower Texas bills again as fuel surcharge expires early."
52 Passwaters, M. (2011, March 11). Dominion CEO: 'This time it's different' for natural gas. *SNL Financial.*
53 Holland, B. (2011, August 3). "US electric utilities still wary of embracing natural gas: Xcel official." *Platts.* Available at http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/6344570
54 At the same meeting, however, Arigoni said natural gas suppliers need to get more creative with their contracts, and that electric utilities want protections from price spikes because "$1 increases in gas costs equal a $7 increase for us." Hutton, M.R. (2011). Mission: Accepted. The 2011 Rocky Mountain Energy Epicenter Conference. Conference Summary Paper available at: http://www.coga.org/pdf_articles/EE_ConferenceWhitePaper.pdf

contrast, regulators have typically allowed utilities to pass the cost of short-term gas procurements (spot purchases) directly through to customers.[56] This difference in regulatory treatment, and hence risk, creates strong incentives for utilities to stick to short-term fuel procurement strategies.

Utilities' ability to recover their fuel costs is a legitimate concern. However, in the current market environment for natural gas, regulatory policies that continue to reward routine spot purchases may do a disservice to ratepayers and the public interest. Prior to approving future requests for the automatic pass-through of spot market fuel costs, regulators should require utilities to provide information and analysis comparing the benefits and risks of alternative mid- to long-term purchase arrangements.[57] Only then can regulators make an informed review of the available options

C. Asymmetric Regulation of Fuel Contracts

Asymmetric regulation of long-term fuel contracts provides a third reason why longer-term fuel switching agreements (for example, to underpin the construction of new capacity) have lagged current price declines for natural gas.

Simply stated, in contrast to long-term coal purchase arrangements (Box 3), current regulatory policies and practices generally place the full risk of medium- to long-term gas supply contracts (those lasting longer than two or three years) on utilities and their shareholders. The intent is to protect ratepayers from imprudent forward purchases in volatile markets. However, the end result is also to discourage forward thinking—an outcome that is just as likely *or more likely* to penalize ratepayers—when markets reach historic lows, as is currently the case.

For the most part, operators of coal-fired units purchase fuel under contracts that range from a few months to more than 10-years duration. Generators seeking a supply contract typically issue requests for proposals and evaluate bids outside a formal regulatory proceeding. Regulators are periodically briefed about generators' new coal contracts and overall fuel procurement strategy, but the regulatory review process is reactive rather than proactive in the sense that it occurs *ex post*—that is, after the generator and coal supplier have already entered into a contract.

A largely short-term approach to gas procurement also contrasts with many regulators' willingness to approve "prudent" long-term power purchase arrangements for renewable power and other generation resources. Long-term contracts for nascent technologies like wind and solar are often necessary for renewable energy developers to secure financing and construct their projects (similar to coal mining operations described in Box 3). These contracts also provide value for ratepayers in the form of resource diversity and environmental benefits—attributes that are typically not reflected in market prices.

To secure long-term power purchase agreements with renewable generators, utilities typically issue requests for proposals and then seek regulatory approval prior to signing the agreement. Regulators (and typically an independent evaluator) review the long-term agreements before granting approval. For example, to date, Detroit Edison Co. has received regulatory approval to sign six 20-year contracts for 381.4 MW of wind, biomass, and landfill gas.[58]

To expand its role in the nation's electricity supply mix over the long term, natural gas-fired generation must be able to compete on a level playing field, from both a commercial and regulatory standpoint. We turn to the challenge of creating that level playing field in the next section.

55 For example, in 2009 the Florida Public Service Commission disallowed $8 million (a staff consultant recommended disallowing over $60 million) of Progress Energy Florida's fuel costs because Progress failed to purchase Powder River Basin coal in 2006-2007, which resulted in higher costs for consumers.
56 The risk of disallowed fuel costs causes utilities to purchase gas on the spot market rather than through long-term agreements. An American Electric Power spokesman said: "All the penalties are ours if we hedge and we are wrong, and there is no benefit when we are right. As a result, we go with the spot market." See de Rouffignac, A. (2000). "Big Power cost pass-throughs deepen hedging controversy." *Power Engineering*. Available at http://www.power-eng.com/articles/2000/09/big-power-cost-pass-throughs-deepen-hedging-controversy.html
57 Alternatively, regulators might require information and analysis for a supply portfolio that includes a mix of long- and shorter-term contracts, much as is often required for natural gas utilities when purchasing gas to meet heating and commercial needs.
58 Cordner, C. (2012, May 3). Detroit Edison issues request for wind generation. *SNL Financial.*

Box 3 Long-Term Coal Delivery Contracts

The electric power sector has extensive experience with long-term coal purchases; in contrast to gas, spot market purchases of coal are the exception. The coal supply chain is very capital intensive and long-term agreements are necessary to develop mines, purchase heavy machinery, and build the necessary transportation infrastructure (rail lines, barge load-outs, coal preparation plants, etc.). Long-term supply contracts allow coal producers to confidently invest in their operations, while electric generators gain cost certainty to effectively plan and operate their units.

Generators typically create portfolios with coal contracts of varying lengths to reduce their fuel cost risks. Most deals range from two to three years, but generators also sign some longer-term deals of five to ten years. As AEP spokesman Pat Hemlepp recently told a reporter: *"Traditionally, AEP has layered contracts in place, different durations, so they roll off at a variety of times. It softens any blow if coal prices go up. We benefit as much if prices go down, but it benefits customers overall because they're protected from rapid fluctuation."*[59]

For example, one AEP subsidiary recently reported 16 long-term coal contracts of varying lengths with 13 vendors, with one contract extending through 2021.[60]

59 Kasey, P. (2012, March 20). Coal may face tougher negotiations with utility purchasers. *The State Journal.* Retrieved from http://www.state-journal.com/story/17194301/coal-may-face-tougher-negotiations-with-utility-purchasers
60 Public Service Commission of West Virginia. (2012). Direct Testimony of Jason T. Rusk on behalf of Appalachian Power Company and Wheeling Power Company. Case number: 12-0399-E-P.

A No Regrets Approach to Gas Supply Contracting 4

Section 3 outlined the hurdles that have so far prevented utilities and gas producers from entering into long-term natural gas supply arrangements. Costs to ratepayers for failing to address these hurdles and thereby foregoing the opportunity to lock in historically low gas prices could be immense, potentially in the billions of dollars. We outline a practical "no regrets" plan for leveraging today's favorable supply situation by expanding the role of long-term natural gas supply contracts. This plan has both commercial and regulatory elements.

It is important to emphasize from the outset, however, that our goal is not to push utilities toward sole reliance on long-term contracts to meet their future natural gas supply needs. Nor are we proposing that gas producers sell all of their gas supplies in this manner. Rather we advocate a portfolio approach in which a mix of different types of contracts and procurement arrangements provides the long-term risk management, supply security, resource flexibility, and cost/revenue certainty that is in all stakeholders' best interests. Indeed, a vital component of a "no regrets" approach is resource flexibility and portfolio diversity. Portfolio theory tells us that diverse portfolios can reduce risks and create more value than focusing on a single action or arrangement; therefore optimal portfolios can be created to achieve the highest expected return for a given degree of risk, or the lowest degree of risk for a given level of desired return.[61] The theoretical advantages of a portfolio approach can be seen in practice with mutual funds and in the coal procurement strategies of coal-fired generators. However, most natural gas procurement strategies rely on short-term agreements and do not include any long-term deals.

Rather than have transactions that are largely dominated by *either* long- or short-term contracts, we believe generators and natural gas producers should supplement their current strategies with long-term agreements to reduce costs and risks, while increasing resource diversity. The recommendations described in the remaining sections seek to harmonize long-term natural gas agreements with the regulatory and commercial policies and procedures that the electricity industry already uses for procuring coal and entering into power purchase agreements.

A. Mutually Beneficial Long-term Agreements

The current low-price environment for natural gas is obviously attractive for electric generators, but the same cannot be said for gas suppliers. The two industries have distinct and often conflicting interests. Gas suppliers want to maximize revenues[62] while electric generators want to minimize fuel costs. Gas suppliers need certainty that they can achieve a reasonable return on their investment when entering long-term agreements and want to minimize the risk that they will forgo future revenues if prices go up. Therefore, when prices are low, gas suppliers have little incentive to sell supplies forward or to enter into traditional, long-term bilateral agreements (Box 4). That is why this paper proposes a fresh approach.

61 Brigham, E.F., Ehrhardt, M.C. (2012). *Financial management: Theory and Practice, Thirteenth Edition*. South-Western Cengage Learning.
62 The true goal is to maximize profits, but because the cost side of the profit equation is unknown, ACSF makes the simplifying assumption that gas suppliers will attempt to maximize revenues as a means to maximizing profits.

Effective long-term supply agreements should be designed to align the interests of sellers and buyers, incentivizing both parties and offering mutually beneficial protections from risk. A fresh approach that holds promise for achieving this result is to create a hybrid agreement that involves both fixed and market prices. For example buyers and sellers can agree on a fixed price for a portion of the fuel supply with the remaining portion priced at market.

To illustrate how a hybrid agreement might work, assume that a gas supplier and a generator contract for a defined volume of fuel based on a 50/50 split between fixed and variable (market) prices. If the fixed price is set at $4/MMBtu and

Box 4 The Shortcomings of Current Long-Term Contracts and Hedges

Most electric generators have active hedging programs to manage the risks associated with future changes in fuel prices and electricity sales. Hedging strategies provide price stability and can reduce uncertainty, along with the risk that decisions made under current market conditions will come to be regretted in the future. Hedging can be accomplished through both physical and financial means.[63] An example of a financial hedging mechanism is a futures contract; such contracts generally include a premium to cover financing costs. Examples of physical hedging mechanisms include buying fuel while the price is low and then storing it for future use and entering into long-term procurement contracts.

Traditional long-term procurement contracts, however, may not be mutually beneficial for natural gas suppliers and electric power generators. A closer look at fixed price agreements helps illustrate why. Assume a generator and gas supplier sign a five-year $5/MMBtu fixed price agreement to fuel a 500 MW CCGT (Figure 10). Both parties have certainty about the future sale price, but their opportunity costs are uncertain at the moment they sign the agreement. If gas prices on the spot market average $3.5/MMBtu over the contract period, the generator is saddled with paying a fuel price that is 43 percent higher than the market rate. The generator and the state public utility commission would regret the decision to enter into the supply agreement, because utility customers would end up paying $142 million more for the gas than if it was purchased on the spot market.[64]

The gas supplier, on the other hand, benefits from the long-term contract because he gains $142 million more in revenue than if he had sold the gas on the spot market.

Winners and losers are reversed, of course, if spot prices for natural gas rise above the contracted price of $5/MMBtu. For instance, if the spot market price averages $7/MMBtu over the term of the contract, the electric generator and his customers effectively avoid $189 million in fuel costs while the gas supplier foregoes the same amount in additional revenue that he could have earned by selling the same gas at the higher spot market price.

A "collar" (Figure 11) is a low cost hedging strategy that provides both generators and fuel suppliers with a range of price certainty. In this kind of arrangement, both parties to the transaction agree to set a price floor and a price ceiling. The generator can specify both the floor and ceiling in return for paying a contract premium (to compensate the gas supplier for taking the price risk). Or, for little or no additional cost, the generator can set either the floor or the ceiling while the supplier sets the corresponding upper (or lower) price bound.

63 For more information about hedges, see: Graves, F.C., Levine, S.H. (2010). *Managing Natural Gas Price Volatility: Principles and Practices Across the Industry.* The Brattle Group, prepared for the American Clean Skies Foundation. Available at http://www.cleanskies.org/wp-content/uploads/2011/08/ManagingNGPriceVolatility.pdf

64 These figures assume a 500 MW CCGT unit, with a 7.2 MMBtu/MWh heat rate, operating at a 60 percent capacity factor, over a contract term of five years.

Box 4 Continued

For example, a generator may want protection from the possibility that gas prices will rise significantly in the future and propose to set the ceiling at $6/MMBtu. The supplier then needs to value the risk of capping prices at $6/MMBtu and propose a floor price that adequately protects him against the risk that prices will fall too low. For purposes of this example we assume the floor price is set at $4/MMBtu. Generators pay the spot market price as long as that price falls within the $4–$6/MMBtu range. For the generator, the downside risk is that market prices fall below $4/MMBtu; for the gas supplier, the downside risk is that market prices rise above $6/MMBtu. Both sides still face a degree of price uncertainty depending on the width of the collar (that is, the size of the gap between the ceiling price and the floor price).

Figure 10
Fixed price agreement

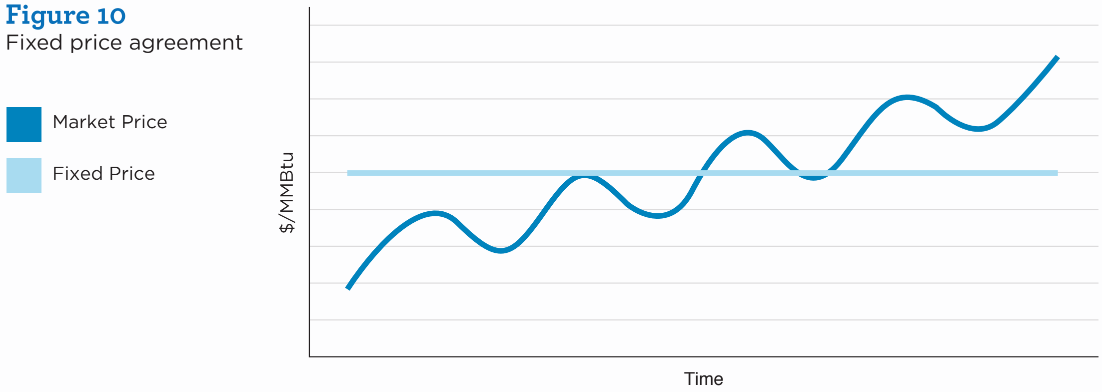


Figure 11
Price collar agreement

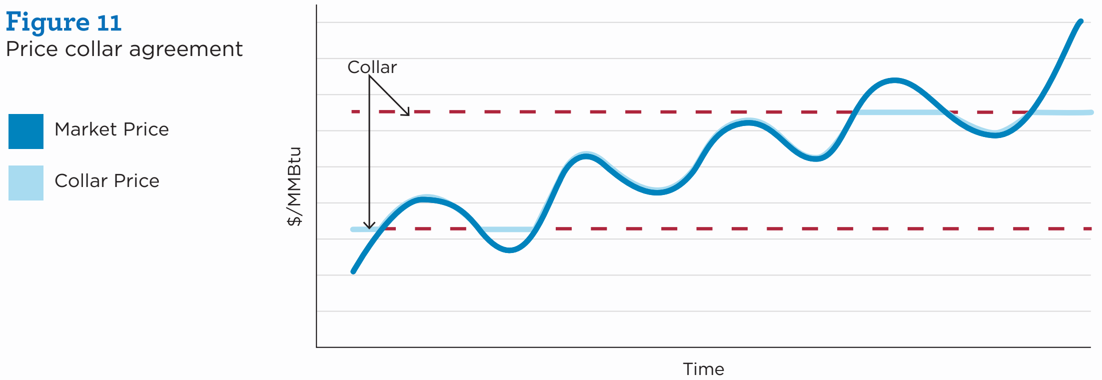
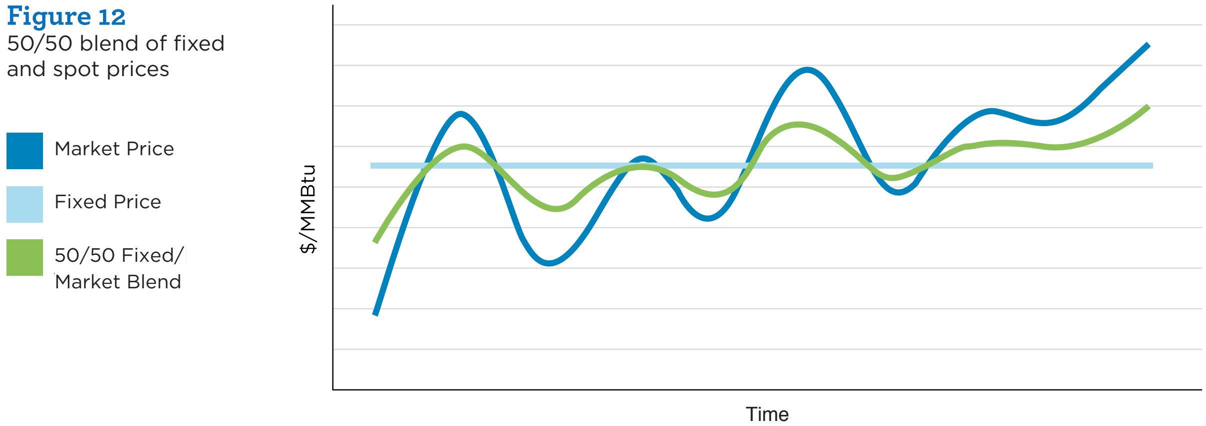


Figure 12
50/50 blend of fixed and spot prices



if spot market prices average $6/MMBtu over the term of the contract, this arrangement yields an effective price of $5/MMBtu. The supplier benefits from the higher spot price on half the volume while the electric generator receives a $1/MMBtu discount to market on the balance of the supply. Similarly, if the spot market price falls to $3/MMBtu, the effective transaction price becomes $3.50/MMBtu. The generator still benefits from falling prices, while the gas supplier has some downside protection and sells at a $0.50/MMBtu premium to the market.

Blending fixed and market prices provides a level of price certainty, while also protecting electric generators from rising prices and suppliers from falling prices. In addition, such agreements would tend to reduce swings in electricity prices. Figure 12 shows how a 50/50 blend between fixed and spot prices smoothes out fluctuations in the market price. The blended price fluctuates in a tighter band than the spot price, but provides more flexibility than the fixed price.

By constraining fuel-price fluctuations, the hybrid approach also reduces the risk that either party to the contract will default. A simple fixed price contract may be viewed as inflexible and risky by credit agencies and regulators, especially given the potential for upside or downside consequences in the event of large price movements in the future. If spot prices diverge significantly from the fixed price, each party may require collateral in case the counterparty defaults on the contract terms. A hybrid mechanism, because it limits the effect of price movements, can help limit the amount of collateral required.

Ultimately, a hybrid contract that blends fixed and market prices offers a risk-sharing mechanism that should be attractive to electric generators and gas suppliers alike. In contrast, fixed-price agreements may be too rigid and price collars may not provide generators with adequate protection from volatility. To show how a hybrid approach can benefit sellers and buyers—and also electric utility ratepayers—ACSF used a minimax regret analysis to quantify potential downside risks for different types of long-term agreements under various price scenarios.

Minimax regret analysis is a method for making decisions when the likelihoods of various potential outcomes are uncertain. Outcomes are simulated and considered in hindsight to quantify the potential for regret under different decision options. The objective of the analysis is to identify the decision that minimizes the maximum regret (hence the term "minimax")—in other words, a decision that performs well no matter how the future unfolds. Decision theorists consider minimax analysis to be a sound method for solving problems that involve decisions under uncertainty because it is neither too optimistic nor too pessimistic.[65] It is also an especially good decision-making approach for electric utilities because of their low risk tolerance.[66]

Applied to fuel procurement strategies, the objective of the analysis is to identify the contract structure that minimizes the maximum regret of electric generators and gas suppliers. In other words, our goal is to find a mutually beneficial, risk-sharing agreement that is suitable for both generators and gas suppliers.

For generators, we quantify regret in terms of differences in fuel costs, whereas for gas suppliers regret is measured in terms of change in revenues. For example, we know a generator wants to minimize fuel costs. Suppose the generator has to choose between two options, Decision A and Decision B. Decision A results in fuel costs of $100 million, while Decision B results in fuel costs of $150 million. In this scenario, Decision A is the optimal choice because it results in the lowest cost. Decision B, on the other hand, yields a regret of $50 million.

For this report we evaluated nine different contract structures across six different gas price scenarios,[67] for a total of 54 combinations. Fuel costs for generators, and conversely, revenues for gas suppliers, were calculated for each scenario.[68] Regrets were calculated for each of the 54 scenarios to identify the largest (maximum) regret for each of the nine different gas procurement structures analyzed (results are tabulated in Appendix D).

The results of our minimax analysis clearly show how the interests of generators (to minimize costs) conflict with those of gas suppliers (to maximize revenues). Table 3 ranks the different procurement strategies according to how effectively they minimize the potential for regret from the perspective of the generator. The table also shows how each strategy ranks from the perspective of the gas supplier. The contracts that minimized the risk of regret for generators are among those that yielded the highest risk of regret for gas suppliers.

The same divergence of interests can be seen in Figure 13, which compares the maximum regret results for generators versus suppliers for each type of contract analyzed. While fixed price contracts that lock in today's affordable prices may be attractive for limiting the risk to generators and hence ratepayers ($118–$189 million regret risk), these contracts may prove costly for gas suppliers ($284–$355 million regret risk). On the other hand, selling on the spot market is relatively low risk for gas suppliers ($189 million regret risk), but potentially costly for generators ($355 million regret risk).

More importantly, the analysis shows that mutually beneficial agreements can be created that effectively limit price risks for both parties. Among the scenarios considered in our analysis, a 50/50 hybrid agreement, in which half the gas is sold at a fixed price of $4.25/MMBtu and half is sold at the spot market price equalizes the risk of regret for both parties ($177 million). Additionally, the maximum regret risk from either perspective (supplier or generator) is relatively low under this type of contract compared to the other arrangements considered.

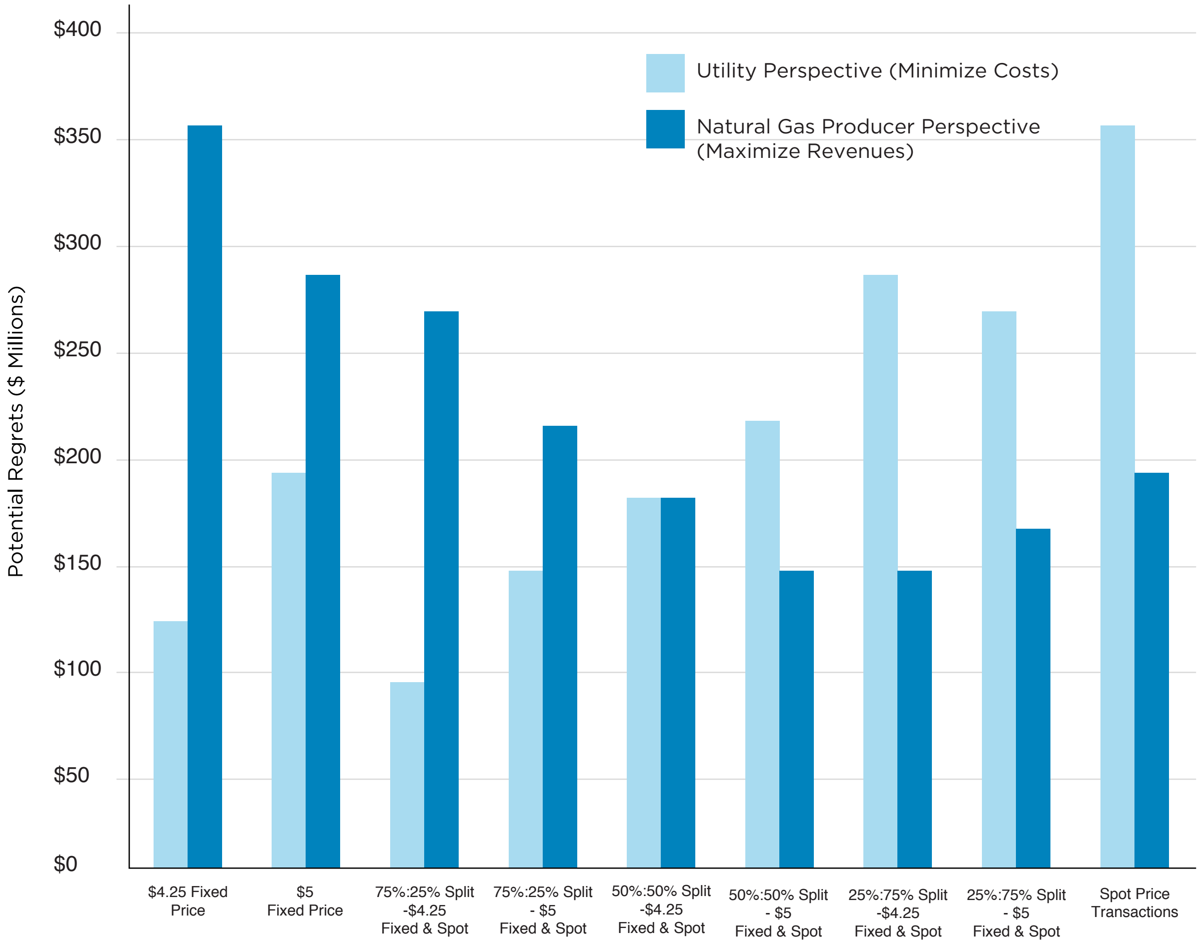
The minimax regret analysis reveals that while electricity generators and gas producers have opposing interests, a structure exists that allows both parties to share risk in an equitable manner while also diversifying fuel sales and purchases. Although our analysis points to an optimal fixed price of $4.25/MMBtu, it would be up to electric generators and gas suppliers—if they choose to pursue this approach—to agree on an appropriate fixed-price based on their own price expectations, tolerance for risk, and required return on long-term investments.

65 Colman, A. (1995). *Game Theory and its Applications.* Routledge Press: New York, New York.
66 Some utilities are beginning to move toward similar approaches for long-term planning purposes. For example, TVA's 2011 Integrated Resource Plan used a "No-Regrets" analysis that "balances competing objectives while reducing costs and risk and retaining the flexibility to respond to future risks and opportunities." TVA's 2011 Integrated Resource Plan is available at http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf
67 The six gas price scenarios evaluated assumed average spot market prices of $3/MMBtu; $4/MMBtu; $5/MMBtu; $6/MMBtu; $7/MMBtu; and $8/MMBtu for the duration of the contract term.
68 Costs and revenues were based on a five-year period for a 500 MW CCGT operating at a 60 percent capacity factor.

Table 3
Minimax regret analysis rankings for electricity generators and gas suppliers

Contract Type	Electricity Generator Perspective	Natural Gas Supplier Perspective
75%:25% Split–$4.25 Fixed & Spot	1	7
$4.25 Fixed Price	2	9
75%:25% Split–$5 Fixed & Spot	3	6
50%:50% Split–$4.25 Fixed & Spot	4	4
$5 Fixed Price	5	8
50%;50% Split–$5 Fixed & Spot	6	1
25%:75% Split–$4.25 Fixed & Spot	7	3
25%:75% Split–$5 Fixed & Spot	8	1
Spot Price Transactions	9	5

Figure 13
Maximum regrets for electricity generators and gas suppliers



B. Overcoming Demand Uncertainty

The risk allocation structure described above helps mitigate price uncertainty among the parties to a longer-term supply agreement, but it does not address another source of uncertainty: future power demand. Generators may balk at entering into long-term fuel supply agreements because of uncertainty about the volume of gas they will require in future years. Demand for gas-fired power is difficult to predict in advance since it depends on overall electricity demand and the market prices of other fuels and generation options.[69] Demand uncertainty is a very significant concern for generators and a major hurdle to the formation of long-term agreements. This prompts the question: are there simple innovations in long-term contracts that could further bridge the gap between gas suppliers and electricity generators?

69 Moreover, in comparison to long-term coal contracts, where excess fuel may be stored onsite, utilities typically have limited storage available for natural gas and would need to contract with third parties for underground caverns and salt domes. Beyond that, grid operators dispatch power plants hourly, and manage output instantaneously. Therefore, electric generators tend to purchase gas on a short-term basis to lower their operational fuel risks. These risks include paying for gas they cannot use because the power plant is not dispatched, or not having enough gas during peak times. In short, generators need volume flexibility even in long-term contracts. Again, contract arrangements can be developed to address this concern.

Box 5 Basics of Natural Gas Procurement

When electricity generators need to purchase natural gas, whether they prefer to buy on the spot market or through a longer-term contract, they contact natural gas suppliers or marketers. Marketers are typically gas producers (e.g., Anadarko, Chesapeake Energy, or Shell) or gas aggregators from financial institutions (e.g., JP Morgan or Louis Dreyfus). Some gas producers also serve as aggregators by marketing gas from other producers.

The supplier and generator agree on a price and delivery point, and then work with pipeline operators to schedule delivery. Some electricity generators have firm capacity (essentially volumetric reservations) on the pipelines that serve their facilities, while others purchase pipeline capacity on a short-term (non-firm) basis. If generators and/or producers do not have adequate existing transportation agreements, they may need to purchase additional pipeline capacity. In most cases, capacity can be purchased directly from pipeline owners or from other reservation holders that have unused capacity. Pipelines function much like toll roads: most pipelines are common carriers open to all, and the pipeline owner charges a tariff to ship gas from the supply point to the delivery point. States have jurisdiction over intrastate pipeline tariffs, while the Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate pipeline rates.

In crafting new contracts, however, it is important to take into account certain attributes of the natural gas system. First, because natural gas suppliers and generators make use of a common pipeline network, gas that is contracted for but not needed generally can be resold in spot markets and rerouted—subject to pipeline capacity and contract terms—to a new buyer (see further discussion in Section 4-D below).

Second, it is important to understand the conditions that might cause a falloff in the electric sector's demand for natural gas. Generators do not need gas at all while their units are off-line for maintenance; in addition, they may require less gas when units are uneconomic to operate or in shoulder months when overall electricity demand falls. During these periods, a generator with a long-term gas supply contract may be able to use the excess gas at other gas-fired facilities located on the same pipeline network. But that alone may be insufficient to offset the contract cost of the gas.

Owners of gas-fired power plants may also face reduced demand when spot fuel prices are high enough to knock gas units out of economic dispatch. How can generators protect themselves in this situation?

In theory, generators should price their units at the value of their next best alternative (opportunity cost)—therefore, dispatch prices should reflect market fuel costs rather than contracted prices. For example, assume a generator signs a 50/50 natural gas supply contract with the fixed price portion of the contract set at $4/MMBtu. If spot market prices subsequently spike to $9/MMBtu, the effective contract price is $6.50/MMBtu. This is attractive to the generator who receives a discount of $2.50/MMBtu relative to the spot market price, and it allows the natural gas supplier to still benefit from rising prices.

The generator, however, must consider the opportunity cost of operating. Since unused gas can be resold for $9/MMBtu on the spot market (which translates to about $63/MWh),[70] the

70 Indicative dispatch prices in this section are based on a CCGT with a heat rate of 7 MMBtu/MWh, and therefore the fuel portion of dispatch price is the heat rate multiplied by the gas price.

generator faces an opportunity cost if he sells electricity based on a fuel price of $6.50/MMBtu (which equates to $46/MWh). In that case, the generator would be leaving $17/MWh ($2.50/MMBtu) on the table.[71] As long as replacement electricity can be purchased for less than $63/MWh, the generator is better off not running, and instead, selling the unused gas. Without suitable storage for natural gas, however, this situation leaves the generator in the unenviable position of taking delivery of the gas and remarketing it, potentially hour by hour.

One way to overcome the burden of excess supply is to create simple, mutually beneficial mechanisms to facilitate the re-marketing of unused natural gas. In the above-described example, the fact that the spot market price has reached $9/MMBtu implies that there is significant demand for the fuel somewhere in the market. Re-selling the generator's unused gas for $9/MMBtu is a better deal for the gas supplier, netting incremental revenues of $2.50/MMBtu. In that case, however, electricity generators and their customers do not benefit from the deal;[72] they are not protected from rising prices nor are they compensated if they have to purchase replacement electricity at a higher price than if the electricity had been produced at their contracted gas price.

One way to make long-term agreements more attractive is to include a contract provision for sharing the incremental revenue between the gas supplier and electricity generator if there is a significant increase in spot prices. For example, if the gas supplier shares 25 percent of the incremental revenue ($2.50/MMBtu) with the generator, the effective selling price for the supplier in the above-described scenario is $8.37/MMBtu. The electricity generator avoids $6.50/MMBtu of cost and nets $0.63/MMBtu from the resale of unused gas. In regulated markets, utility commissions could require utilities to return the $0.63/MMBtu in additional revenues to ratepayers. In other words, in these markets utility shareholders would not directly profit from this mechanism, rather it would solely benefit customers. The existence of a mutually beneficial mechanism for sharing risks would give utilities and natural gas suppliers a greater incentive to enter into long-term contracts: the gas supplier benefits from stronger cash flows if a high-price environment develops, while the utility gains protection against high prices and delivery concerns.

Similar mechanisms can be used in competitive wholesale markets also, although the dispatch method used in these markets provides additional flexibility for generators to mitigate delivery concerns. This is because generators determine the price at which they want to bid their units to the market, and then independent system operators determine the economic dispatch order by compiling bids and calling on the lowest-cost generators first. Rather than worrying about delivery logistics or re-marketing gas, generators with long-term contracts have the ability to bid their units based on the contracted fuel price. For example, a contracted price of $6.50/MMBtu would result in a bid price of $46/MWh. If the bid clears the auction, the generator is paid the clearing market price, which should be at or above $46/MWh. Generators with favorably priced gas contracts can improve their operating margins (which are very important in competitive wholesale markets).

C. Non-Discriminatory Regulation of Gas-Purchase Agreements

For utilities to enter into long-term gas supply agreements, they also need a supportive state regulatory regime. We believe that to best serve ratepayer interests, public utility commissions should work with utilities to create a transparent and competitive process for purchasing natural gas through long-term agreements. Colorado and Oklahoma have pioneered new public interest rules for this purpose that can serve as models for other states.

71 Inversely, the gas supplier has an opportunity cost of $2.50/MMBtu by selling at the contracted price rather than at the spot market price.
72 Removing the logistical headache of taking delivery of fuel that they have no use for would, of course, still be of some benefit to generators.

Notably, in April 2010, Colorado Governor Bill Ritter signed the "Clean Air Clean Jobs Act." This new law required the state's investor-owned electric utilities—Xcel Energy and Black Hills Energy—to reduce emissions from coal-fired power plants. The law was prompted by a desire to modernize Colorado's generation resources; utilize cleaner, indigenous fuels; and benefit the state's overall public health, environment and economy. Recognizing that natural gas-fired generation could play an important role in advancing these goals, the law explicitly encouraged long-term gas supply contracts by specifying procedures for commission approval and discouraging subsequent "look back" by future commissions.

Prompted by this legislation, Xcel entered into a 10-year competitively bid natural gas contract with Anadarko Petroleum Corporation. The contract limited annual price changes for volumes up to 50,000 MMBtu per day.[73] A presentation by Anadarko's Vice President of Marketing, Scott Moore, noted that the deal addressed Xcel's price volatility concerns while enabling Anadarko to diversify its sales portfolio.[74]

In April 2012, the Oklahoma Corporation Commission (OCC) approved a new competitive procurement rule that created new opportunities for Oklahoma utilities to enter into long-term (i.e., two to more than five years) contracts for natural gas and other fuels. The rule revised existing request for proposal (RFP) procedures, and created "an open, transparent, fair and nondiscriminatory competitive bidding process" that would enable Oklahoma utilities to obtain a presumption of prudence for approved agreements.[75] The rule also provides fuel suppliers with added flexibility during the bidding process to update their bids if market conditions change while proposals are being evaluated. The new rule allows utilities, the OCC, and an independent evaluator to determine the lowest reasonable cost for long-term reliable power or reliable long-term fuel. Utilities may also consider non-price factors in concluding a contract. Under Oklahoma's new rules, utilities may still use managerial discretion to enter into long-term fuel purchase agreements without going through the competitive bidding process. However, such contracts will not enjoy a presumption of prudence.

At an Oklahoma business school forum on April 10, 2012, AEP CEO Nick Akins said that the Oklahoma plan for prudence review of long-term gas contracts "is one of the key prerequisites for us to make a commitment to natural gas."[76] It will be a "game changer in making decisions on new facilities," he added, because "historically utilities have not had an incentive to enter into longer-term agreements."[77]

The developments in Colorado and Oklahoma can serve as models for other states, and ultimately help lay the groundwork for more long-term gas deals that reduce ratepayer risks. Additionally, many states with natural gas utilities (local distribution companies) already have extensive experience reviewing long-term natural gas contracts. In 2011, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution urging state regulators to give serious consideration to long-term contracts and mechanisms that can ensure stable natural gas markets.[78] NARUC also passed a resolution in 2005 that encourages long-term procurement strategies and pre-approval of long-term contracts.[79] These resolutions provide another building block for establishing the type of non-discriminatory regulatory platform we are proposing here.

Specifically, we recommend that state regulators—as a first step—provide a level playing field for all fuels and resources by developing defined procedures for competitive procurement. Second, regulators ought to reconsider the practice of pre-approving

73 Moore, S. (2011, February 15). *Long Term Contracting for Natural Gas.* NARUC Winter Meeting. Available at http://www.narucmeetings.org/Presentations/NARUC%202011%20Winter%20Meeting%20-%20Scott%20Moore.pdf
74 *Id.*
75 Oklahoma Corporation Commission. (2012). Subchapter 34: Competitive Procurement, Section 165:35-34-1.
76 Remarks of Nicholas Akins, CEO American Electric Power, at Meinders School of Business, Oklahoma City University, April 10, 2012.
77 *Id.*
78 NARUC. (2011, July 20). *Resolution on Ensuring Stable Natural Gas Markets.* National Association of Regulatory Utility Commissioners. Available at http://www.naruc.org/Resolutions/Resolution%20on%20Ensuring%20Stable%20Natural%20Gas%20Markets.pdf
79 NARUC. (2005, November 16). *Resolution on Long-Term Contracting.* National Association of Regulatory Utility Commissioners. Available at http://www.naruc.org/Resolutions/GAS-1Long-TermContracting.pdf

standard fuel-cost pass-through arrangements. Third, the regulatory review process should be expedited and also should be flexible enough to allow parties to update bids if market conditions change quickly. Finally, an independent evaluator should participate in the process to ensure customers are receiving the best deal possible.

Utilities already have experience requesting and evaluating long-term bids for coal supplies and renewable generation resources. Our recommendations rely on mechanisms and procedures that are already familiar to utilities, paired with more proactive regulatory oversight and reforms to ensure that no energy resource is receiving discriminatory treatment relative to others. The policy we propose adds work in the sense that utilities, regulators, and gas suppliers will have to develop and evaluate a more varied set of contract arrangements. But this extra effort is well justified in light of the enormous potential cost savings that could be achieved by a portfolio-based approach that incorporates long-term as well as short-term considerations. Given the investment needs and regulatory costs facing the electric utility industry and acute budget constraints at all levels of American society, from government to businesses and individual households, the promise of abundant and affordable natural gas represents an economic opportunity we cannot afford to ignore.

To provide utilities with the confidence needed to sign long-term fuel agreements, regulators should provide certainty in the form of a presumption of prudence if the fuel is procured in an open and transparent bidding process. This policy ought to apply to purchases of coal, natural gas and other fuel sources, as well as renewable energy agreements. Of course, utilities can bypass the competitive bidding process to purchase fuel and resources as they see fit, but such agreements should not be awarded with the presumption of prudence.

In competitive wholesale markets, merchant generators should evaluate creative agreements, like the structure discussed in Section 4-A of this report, with the aim of improving their operating margins or bundling similar agreements with power purchase agreements to reduce fuel and revenue risks.[80] Regulators in states that have implemented utility restructuring could encourage generators to enter into longer-term procurement arrangements for service in which prevailing fuel-price conditions could deliver ratepayer benefits, thereby helping to spur long-term natural gas and other energy agreements.[81]

With a foundation of regulatory acceptance, gas suppliers and electricity generators can develop simple, innovative, and mutually beneficial agreements. This would help electricity generators reduce the risks of transitioning to natural gas and allow them to confidently retire older coal plants that lack modern pollution controls. The long-term agreement structures proposed in this report would also benefit gas suppliers, providing stability and price certainty while also creating incentives for the construction of new natural gas power plants and thereby stimulating decades of incremental demand growth. All parties stand to gain from innovations that offer greater certainty regarding future costs while protecting electricity customers from volatility and price increases. Ultimately, signing long-term gas contracts at current price levels can lay the foundation for a "no regrets" transition to a more flexible, clean and affordable electricity system.

D. Pipeline Arrangements

A final step in crafting a no-regrets strategy for expanding the role of natural gas in the U.S. electric power sector is to recognize the importance of the natural gas pipeline network and the growing need for coordination between generators and pipeline owners. Pipelines are the critical arteries that connect natural gas suppliers with demand. As the

80 Such agreements would improve the overall credit quality of proposals to build new natural gas-fired units.
81 Commissions in restructured states approve suppliers to provide default electric generation service to customers who have not selected an alternative generation supplier. The default service should reflect prevailing market prices.

electric sector's supply needs increase, electricity generators must work with pipeline companies to ensure that sufficient pipeline capacity is available to serve demand. So long as the number of signed, long-term supply contracts is very small, pipeline providers will not be getting an adequate market signal to justify the investments needed to expand their capacity.

In comments filed with FERC about the need for greater coordination between the natural gas industry and electricity generators, Charles River Associates said, "At present, there is no mechanism to bridge the gap between the collective need for new gas pipelines and the (commercially sensible) reluctance of individual companies to commit to long-term gas contracts."[82]

Natural gas pipeline owners need assurances from major gas users and customers (like electricity generators) to plan and finance future expansions or upgrades. Any long-term commitment an electricity generator makes to gas suppliers must be matched with an equal commitment to pipeline providers. This can be done by signing "firm" transportation agreements—essentially a reservation for capacity on the pipeline network. Without a firm agreement, electricity generators may not be able to take delivery of the gas supplies they have contracted for, unless pipeline capacity is "released" (i.e., sold from one demand source to another) by customers with existing firm agreements. Because reliability is paramount in the electric industry, it is imperative that electricity generators include firm pipeline agreements as part of any long-term fuel procurement strategy they undertake.

82 Tabors, R., Englander, S., Russo, C. (2012) Comments filed with the US Federal Energy Regulatory Commission: Coordination between Natural Gas and Electricity Markets. Docket No. AD12-12-000.

Conclusion 5

At the beginning of this report, we introduced the fictional character of Commissioner Miller to illustrate the predicament facing regulators as the electricity sector goes through a historic period of asset turnover and investment. To sum up our case for the policy approach outlined here, we return to the story of Commissioner Miller:

Commissioner Miller thought of the stringent environmental regulations facing older coal units and of customers struggling with a sluggish economy. Electricity planning decisions, because they involve large investments and long-lived assets, are fraught with uncertainty. But she saw a silver lining in today's low natural gas prices. The key was finding a way to enable the state's utilities to take advantage of those low prices over the longer term.

So Commissioner Miller asked her Chairman to convene a formal meeting to review utility generation plans and fuel procurement strategies. She also urged the Chairman to review the Commission's rules to ensure that utilities could receive a prudence determination for appropriate long-term natural gas contracts. Her goal was to work with her fellow commissioners to ensure that ratepayers would benefit from affordable gas prices for as long as possible, while maintaining reliable service.

At the onset, this report posed two questions: What if there was a "no regrets" policy for fuel switching in the electric power industry? And, what if a path existed to reduce uncertainties and confidently provide customers with a cheaper alternative to retrofitting aging coal units?

This report outlines such a path. The analysis in Section 2 points to the significant opportunities, both in the short-term and in the longer term, for expanding the role of natural gas in the U.S. electric sector. Under-utilized CCGT capacity is substantial and could support a considerable expansion of gas-fired electricity production in the near term. Longer term, our busbar analysis indicates that natural gas units are the most economic source for new generating capacity.

As we have stressed at several points in this report, we do not recommend that generators rely solely on any one type of contract or procurement strategy, whether short- or long-term, to meet their gas requirements; nor do we recommend that gas suppliers sell gas solely in either a short- or long-term fashion. Instead, we believe generators and natural gas producers should supplement their current strategies with long-term agreements as a way to reduce costs and risks, while also increasing resource diversity and certainty.

"Locking in" the economic benefits of an abundant natural gas supply requires fresh and simple approaches in view of the various hurdles to change outlined in Sections 3 and 4. We believe that long-term, risk-sharing agreements similar to those described in Section 4 are capable of overcoming these hurdles. Creating the regulatory and policy environment needed to support such agreements will do much to lay the foundation for a smooth transition to a more flexible, clean and affordable electricity supply.

6 Appendices

A. Natural Gas CCGT Utilization Trends

A 2010 Congressional Research Service (CRS) report examined the potential for slack capacity at natural gas-fired power plants to immediately displace coal-based generation and the associated carbon dioxide emissions reductions that could be realized. Based on a proximity analysis, the report concluded that existing CCGTs could quickly displace 5-9 percent of total U.S. coal generation, and 3-5 percent of the associated CO_2 emissions.[83]

To explore the impact of recent trends, a key chart from the CRS report updated with the most recent data available [EIA-923 preliminary data for 2011] is presented in Table A1. All the same gating criteria used in the CRS report were utilized.[84]

Despite the sharp decline in natural gas prices from about $7/MMBtu in 2007 to about $4/MMBtu in 2011 and the related shift towards natural gas-fired generation, it is surprising how much underutilized CCGT capacity remains. About 118,000 MWs—or 62 percent of the nation's CCGT plants—operated with a capacity factor below 50 percent in 2011. While each plant has its own unique considerations, there is still a large opportunity for underutilized, highly efficient generating capacity to create significant emissions reductions by displacing dirtier, more inefficient generators.

This same analysis was then extended to examine specifically the PJM, MISO, and SPP regions (Tables A2-A4). PJM clearly shows the most significant increase in CCGT fleet utilization rates (though considerable slack capacity remains). MISO and SPP continue to have enormous underutilization of their CCGT resources, with 87 percent of MISO's CCGT fleet operating below a 30 percent capacity factor in 2011.

Table A1
Utilization of CCGT fleet

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	12,582	25	7%	5%	5%	5%	5%
Under 70% to 50%	62,111	84	32%	32%	29%	27%	24%
Under 50% to 30%	56,915	88	30%	31%	31%	30%	35%
Under 30%	60,873	118	32%	32%	35%	38%	37%
Total	**192,481**	**315**	**100%**	**100%**	**100%**	**100%**	**100%**

83 Kaplan, S. (2010, January 19). *Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants*. Congressional Research Service. Available: http://opencrs.com/document/R41027/2010-01-19/download/1005/
84 To replicate CRS Study, the group of combined cycle plants included those meeting the following characteristics: minimum net summer capacity of 100 MW; operation at some point during 2011/2007 respectively, and was in operational condition at the end of 2011. Additionally the plant's primary fuel was natural gas and primary purpose was to sell power to the public. Industrial and commercial cogenerators (providing electricity and steam to a single business entity) were excluded.

Table A2

Utilization of CCGT fleet in the PJM Interconnection

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	669	1	3%	0%	0%	0%	0%
Under 70% to 50%	10,159	13	46%	24%	19%	0%	0%
Under 50% to 30%	7,290	10	33%	30%	24%	34%	28%
Under 30%	4,080	11	18%	46%	56%	66%	72%
Total	**22,198**	**35**	**100%**	**100%**	**100%**	**100%**	**100%**

Table A3

Utilization of CCGT fleet in the Midwest ISO

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	0	0	0%	1%	1%	0%	0%
Under 70% to 50%	0	0	0%	0%	0%	1%	1%
Under 50% to 30%	1,606	3	13%	13%	2%	2%	30%
Under 30%	10,805	19	87%	86%	97%	97%	68%
Total	**12,411**	**22**	**100%**	**100%**	**100%**	**100%**	**100%**

Table A4

Utilization of CCGT fleet in the Southwest Power Pool

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	450	1	4%	4%	4%	0%	0%
Under 70% to 50%	2,350	5	19%	12%	23%	12%	19%
Under 50% to 30%	2,969	5	24%	35%	30%	25%	20%
Under 30%	6,381	11	53%	50%	43%	63%	61%
Total	**12,150**	**22**	**100%**	**100%**	**100%**	**100%**	**100%**

B. Environmental Regulations and Busbar Analysis

Upgrading non-compliant fossil-fired generators to meet stricter environmental safeguards can require significant new investments. Recent data compiled by the Edison Electric Institute (EEI), summarized in Tables B1 and B2, provide cost ranges on a dollar per kilowatt basis for installing various coal plant control technologies.[85] Ultimately, some generators may require billions of dollars of investments to maintain operations at their coal facilities. For example, AEP said costs could range from $6 billion to $8 billion,[86] while Southern Company disclosed it expects to spend between $13 billion and $18 billion for compliance.[87]

Table B1

Environmental control retrofit costs

MW	Wet Flue Gas Desulfurization (FDG) System	Dry Flue Gas Desulfurization (FDG) System with Fabric Filter	Selective Catalytic Reduction (SCR)	Selective Non-Catalytic Reduction (SNCR)	Pulse Jet Fabric Filter	Activated Carbon Injection (ACI)	Activated Carbon Injection (ACI) with Fabric Filter	Dry Sorbent Injection
125	750	655	486	28	418	27	445	40.17
200	657	573	467	25	359	26	385	38.54
350	560	489	430	17	277	23	300	-
500	506	442	393	10	231	20	251	-

Table B2

Fixed O & M for environmental retrofits technologies

MW	Wet Flue Gas Desulfurization (FDG) System	Dry Flue Gas Desulfurization (FDG) System with Fabric Filter	Selective Catalytic Reduction (SCR)	Selective Non-Catalytic Reduction (SNCR)	Pulse Jet Fabric Filter	Activated Carbon Injection (ACI)	Activated Carbon Injection (ACI) with Fabric Filter	Dry Sorbent Injection
125	19.8	14.7	2.1	0.6	3.1	0.4	3.1	3.19
200	14.3	10.9	1.3	0.5	2.7	0.4	3.1	3.19
350	10.0	7.8	0.7	0.3	2.1	0.4	3.1	-
500	8.2	6.5	0.7	0.2	1.7	0.4	3.1	-

Source for Tables B1-B2: Edison Electric Institute. (2011). *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet: Final Report.*

85 Additional information on capital and variable costs for meeting possible coal ash disposal requirements, cooling tower installations, or carbon capture and storage retrofits are also provided by Edison Electric Institute in the same document: Edison Electric Institute, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet: Final Report*, January 2011.

86 AEP. (2011, June 9). AEP Shares Plan for Compliance with Proposed EPA Regulations. AEP Press Release, available at http://www.aep.com/newsroom/newsreleases/?id=1697

87 Southern Company (2011). *Comments of Southern Company: National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units; Proposed Rule*. Pg. 44. Retrieved at http://www.southerncompany.com/news/docs/Southern%20Company%20Utility%20MACT%20Comments%208-4-11_w%20cover%20letter.pdf

ACSF constructed a busbar to compare (a) levelized costs of retrofitting existing coal units with environmental controls; and (b) various new-build generation technologies. Coal capital costs represent incremental investments required for environmental compliance, but not costs to build the original facility as those costs are considered sunk. For the PRB unit requiring retrofits, a dry scrubber, fabric filter baghouse, and activated carbon injection were assumed for MATS compliance. The CAPP unit includes costs for a wet scrubber, fabric filter baghouse, and activated carbon injection. Costs for complying with 316(b) and coal combustion byproducts regulations are also included because it would be imprudent for planners not to consider potential impacts of the pending regulations. Variable costs of operating the controls and existing coal unit are considered incremental and included. Revenue requirements covering debt and equity financing costs for each alternative's capital expenditures were included.

Assumptions for capital costs, fixed O&M, and variable O&M for each technology are based on the EEI dataset disclosed above[88] and EIA's technology performance specifications.[89] Delivered natural gas prices are from EIA's *Annual Energy Outlook 2012 Early Release*,[90] and current delivered coal costs for CAPP and PRB were escalated annually by 100 basis points above inflation. Subsidies, such as product tax credits, were not included in the analysis. Levelized costs are shown on a $/kw-year basis, and the lowest line at a specific capacity factor indicates the cheapest alternative to build and operate.

C. Unit-by-Unit Retirement Analysis

Decisions by power generators to retire and replace or make environmental retrofits to major power plants typically involve an extensive analysis of costs and other factors. ACSF performed an analysis similar to these unit retirement studies to study the economic viability of several sample power plants. To support our work, Analysis Group, Inc. provided three hourly marginal price scenario forecasts for various independent system operators (ISO) markets through 2025.

The three scenarios created by the Analysis Group included a base case, low electricity price scenario, and high electricity price scenario that based upon varying natural gas prices. Further details on the assumptions underlying the Analysis scenarios are provided at the end of this Appendix.

The Analysis forecasts were used by ACSF to calculate energy margins for existing coal units and potential new replacement units. To find suitable example coal units, ACSF screened units based on their age, heat rate and whether announcements have been made about the unit's future.

The economic analysis compared net present-value (NPV) costs and benefits between retrofitting a coal plant and replacing it with a natural gas CCGT or CT of the same size. Benefits include the plant's energy "value" or margin compared to marginal costs (lambdas), and capacity revenues or values. Costs include capital expenditures associated with environmental controls or construction of a new unit, fixed operating expenses and variable operating expenses for fuel and maintenance.

Each example unit's annual production cost was calculated on a $/MWh basis based on data from SNL Financial. Cost estimates for environmental controls, as well as characteristics for generic combined cycles and combustion turbines, was based on data from EEI[91] and the EIA.[92] Existing delivered coal prices for each coal unit were inflated annually, and fuel prices for natural gas units were based on EIA's Annual Energy Outlook forecasts.[93] Upon calculating production costs on a $/MWh for each alternative, the units were dispatched against the hourly marginal price forecasts provided by

88 Edison Electric Institute. (2011, January). *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*. Analysis prepared by ICF and submitted to the USEPA as part of EEI's EGU MACT comments.

89 EIA (2010, November). *Updated Capital Cost Estimates for Electricity Generation Plans*. Available at http://www.eia.gov/oiaf/beck_plant-costs/pdf/updatedplantcosts.pdf

90 EIA (2012). *Annual Energy Outlook 2012 Early Release*. Available at: http://www.eia.gov/forecasts/aeo/er/excel/aeotab_3.xlsx

91 Edison Electric Institute. (2011, January). *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*. Analysis prepared by ICF and submitted to the USEPA as part of EEI's EGU MACT comments.

92 EIA (2010, November). *Updated Capital Cost Estimates for Electricity Generation Plans*. Available at http://www.eia.gov/oiaf/beck_plant-costs/pdf/updatedplantcosts.pdf

93 Natural gas prices for the base scenario were based on EIA's *2012 Annual Energy Outlook Early Release.* To create low and high price scenarios, EIA's low and high shale gas production scenarios from the *2011 Annual Energy Outlook* were used to calculate an annual percent deviation from the 2011 Annual Energy Outlook Reference Case. The percent deviations were then applied to the *Annual Energy Outlook 2012 Early Release* data to develop low and high price scenarios.

Analysis Group. Forced and potential outages were accounted for in unit dispatch.[94] If the unit's production cost was lower than marginal prices, the unit was economic and dispatched. Conversely, if the unit's production cost exceeded the marginal price, the unit was uneconomic and did not dispatch. Hourly margins were calculated by multiplying the unit's capacity by the difference between marginal prices and production costs[95], and were summed into annual totals.

As with any economic comparison, only incremental differences between the two alternatives were investigated. Capacity is valuable for reliability, and in some markets for revenue purposes, but forecasting capacity values may have considerable uncertainty. This analysis did not require capacity price forecasts because coal units are compared to alternatives of the same size and availability. Thus, no incremental difference in capacity value exists between the two alternatives.

Total net benefits for each alternative were compared to determine the lowest cost alternative, and therefore, the option with the greatest net benefit for customers. The net benefit of continuing coal operation was compared relative to other alternatives. For example, if a coal unit's relative value to a replacement CT was -$100 million, that means the CT is the better option by $100 million. Equally, if retrofitting a coal unit relative to a CCGT yields a $200 million result, which means retrofitting the coal unit with environmental controls is the optimum alternative.

A good example of the economic challenges facing many older, smaller, and uncontrolled coal facilities is the Pulliam coal plant located in Green Bay, WI. Owned by Wisconsin Public Service Corporation, the 330 MW Pulliam coal plant consists of four operational units (units 5-8) built between 1949 and 1964. The plant's thermal efficiency is about 28% (while a new CCGT achieves about 50% thermal efficiency). The analysis shows retiring Pulliam 5-8 and replacing the capacity with a CT is the lowest cost compliance alternative (Table C1).

For the Pullium coal plant example, the facility was assumed to require baghouses, activated carbon injection and dry sorbent injection in 2015 to comply with MATS. Additional expenses

Table C1

Net present value of retrofitting Pulliam 5-8 compared to alternative compliance options

Pulliam 5-8 Net Present Value through 2025 (in $ millions)	Low Price Scenario	Base Case	High Price Scenario
Retrofit value relative to combined cycle value	$(85)	$(71)	$(46)
Retrofit value relative to combustion turbine value	$(125)	$(120)	$(109)

94 Unit maintenance cycles for each unit alternate annually between 2- and 4- week planned outages occurring in off-peak months like March and April. Expected forced outage rates of 2.8 percent were also assumed. Expected forced outage rate is the percent of a year that a unit is unavailable due to an unplanned component failure or other condition requiring reduced output of the unit. Ultimately, units were available between 90 percent and 93 percent each year.
Forced Outage Rate = (Forced Outage Hours) / (Hours in a Year – Planned Outage Hours)
95 For example, if marginal prices are $45/MWH in an hour and a 250 MW unit produces electricity for $35/MWH, the unit's energy value (margin) during that hour is $2500.

for 316(b) and CCR were included in 2019-2020. Production costs for Pulliam 5-8, a combustion turbine and combined cycle were compared to projected MISO prices.

Even though the environmental controls for Pulliam 5-8 are not capital intensive, the unit's high heat rate and relatively expensive delivered PRB prices drive up variable costs. The CT achieves similar energy margins as the coal unit, but has lower fixed operating and maintenance costs than Pulliam, and has lower capital costs than a CCGT. Depending on the scenario, a combustion turbine is between $110 million and $125 million cheaper than controlling Pulliam 5-8 and continuing operation. Meanwhile, a CCGT is $46 million to $85 million cheaper than controlling Pulliam, but about $40 million to $60 million more expensive than a CT.

Another compliance option for aging coal plants is to convert the existing boiler to fire natural gas. This fuel switching alternative may be attractive if natural gas pipelines are nearby and generators are trying to minimize capital costs associated with their compliance plans. Although capital costs for fuel switching are cheaper than other alternatives, the units sacrifice energy margins because their operating characteristics are similar to CTs, although less flexible than CTs due to the existing facility utilizing steam cycles.

AES Corp. has not yet announced plans for their six-unit, 371 MW O.H. Hutchings plant in Ohio, but disclosed the plant is being considered for fuel-switching to natural gas.[96] The first unit was built in 1948, and the final unit was completed in 1953. AES is looking at fuel-switching two or more units, but for this analysis we assumed conversion of all six units in order to evaluate all alternatives on the same capacity basis.

AES Corp's O.H. Hutchings plant was assumed to require installation of wet-scrubbers and baghouses in order to maintain operation and environmental compliance. Additional expenses for 316(b) and CCR in 2019-2020 were also included. A nominal $50 million charge was assumed for fuel-switching, but no heat rate adjustment was applied. Energy margins were calculated for continuing operation on coal, fuel-switching to gas, and replacing with a combined cycle or combustion turbine based on forecasted hourly prices in the PJM market.

Table C2

Net present value of retrofitting O.H. Hutchings 1-6 compared to alternative compliance options

O.H. Hutchings 1-6 Net Present Value through 2025 (in $ millions)	Low Price Scenario	Base Case	High Price Scenario
Retrofit value relative to combined cycle value	$(277)	$(273)	$(233)
Retrofit value relative to combustion turbine value	$(244)	$(236)	$(207)
Retrofit value relative to natural gas conversion	$(403)	$(396)	$(374)

96 AES Corporation. (2012). 2011 Form 10-K. Page 73.

As seen in the table on, the preceding page the lowest cost option for AES is to fuel-switch the units to natural gas, as it is provides the largest savings relative to continuing operation on coal. Converting to natural gas provides between $374 million and $403 million in savings through 2025 compared to installing environmental controls. Retiring and replacing the units with a combined cycle or combustion turbine provides greater energy margin benefits, but fuel-switching the existing units to fire natural gas has much lower capital costs than other alternatives. In fact, fuel-switching to natural gas is an optimal choice as long as the conversion is done for less than $200 million.

Background on Analysis Group Price Forecasts

The Analysis Group, price forecasts include hourly prices from 2012 through 2025 for PJM, MISO, and SPP, with basecase, low, and high price forecasts.

The model used to create the price forecasts was developed and calibrated using historical data from 2010 and 2011. For each region, the model combines electrical generator supply with actual hourly demand to determine the marginal unit for every hour, and records the total variable cost of that unit as the marginal electricity price. Modeled electricity prices are compared to actual historical prices to confirm that the model produces reasonably accurate results. Once the model had been successfully calibrated, input assumptions for demand growth and fuel prices in future years were used to develop the electricity price forecasts for the 2012-2025 period. Below we summarize the supply curve data and the inputs used to generate price forecasts.

Supply Curves

2010 supply curves were obtained from SNL Financial for all three regions. These supply curves include plant-level information on fuel and technology types, heat rates, total variable costs, and capacity factors. When matching supply to demand to develop the hourly prices, the supply curves were adjusted in the following ways:

1 Monthly data were grouped into summer (Jun-Aug), winter (Dec-Feb), and shoulder months (Mar-May, Sep-Nov);

2 Outage performance was modeled by derating units by season, based on actual plant capacity factors and operational function (e.g., baseload or peaking); and

3 Adjustments were made to break total variable costs into fuel costs and variable O&M. SNL Financial data includes aggregated variable costs. We identified average non-fuel variable O&M by fuel/technology type, in order to isolate the fuel and non-fuel variable O&M cost components. This was necessary for the model to be able to forecast changes in electricity prices as a function of changes in underlying fuel prices.

Unit Additions and Retirements

In order to adjust the supply curve for future years, future additions and retirements are taken into account. These are based on data from SNL Financial and are applied to the supply curve data. Only known additions and retirements are added, which include (according to SNL Financial) (1) units either “under construction” or in “advanced development,” and (2) reported retirements. The vast majority of both known additions and known retirements occur between 2012-2015. Additions are modeled based on the costs, heat rates, and capacity factors for recently installed and operating units. Retirements are for specific units.

A test is performed to determine whether the changing supply and demand conditions assumed using the SNL Financial data would result in a breach of the reserve margin stated for that region. When that condition holds, additional capacity is added to ensure that reserve margins are not broken. This happens only in PJM over the forecast period; in this case sufficient combined cycle gas capacity is added to meet the reserve requirements of the region.

Due to the lack of data regarding future of additions and retirements beyond 2015, the model holds constant the supply/demand configuration as it exists in 2015, thus effectively holding constant the supply mix that is in place at the end of the period. Consequently, price changes beyond this point reflect primarily the effect of changes in fuel prices on marginal electricity prices with no changes to the capacity mix.

Demand Forecasts

Once additions and retirements have been factored in, demand forecasts are included. Peak demand forecasts for each region are used, based on several different documents from the ISO/RTOs themselves. These peak demand forecasts are used to calculate an annual growth percentage that is applied to all hours of the historical demand curve to grow it forward. The historical demand curve for MISO and SPP is from SNL Financial and for PJM is directly from PJM.

Fuel Prices

Finally, once supply and demand is finalized, fuel price forecasts are used to grow the fuel cost portion of total variable costs for the plants in the supply curve. Fuel price forecasts are based on several sources:

Natural Gas: Natural gas price forecasts are based on NYMEX futures contracts out to December 2018. These futures are for the Henry Hub and are adjusted for each region based on a historical monthly basis differential with a regional trading hub. After December 2018, liquidity in trading diminishes in NYMEX contracts, so monthly prices are grown at the annual regional growth rates for delivered prices to electric sector from the EIA *Annual Energy Outlook 2012 Early Release*. Forecasted fuel prices in $/MMBtu are multiplied by plant heat rates from the SNL Financial supply curve values to determine the fuel cost component of total variable cost.

Coal: Coal price forecasts are based on annual regional growth rates for delivered prices to electric sector consumers from the EIA *Annual Energy Outlook 2012 Early Release*. These growth rates are applied to the calculated coal fuel costs from the SNL Financial supply curve values.

Oil: Oil price forecasts are based on annual regional growth rates for delivered prices to electric sector consumers from the EIA *Annual Energy Outlook 2012 Early Release*. These growth rates are applied to the calculated oil fuel costs from the SNL Financial supply curve values.

D. Minimax Regret Tables

Table D1

Regrets analysis: total fuel cost table for electricity generators

	Future Natural Gas Price Scenario ($/MMBtu)					
Procurement Option	**$3**	**$4**	**$5**	**$6**	**$7**	**$8**
Spot Purchases	$284	$378	$473	$568	$662	$757
$4.25 Fixed Price	$402	$402	$402	$402	$402	$402
$5 Fixed Price	$473	$473	$473	$473	$473	$473
50:50 Split - $4.25 Fixed:Spot	$343	$390	$438	$485	$532	$579
50:50 Split - $5 Fixed:Spot	$378	$426	$473	$520	$568	$615
25:75 Split - $4.25 Fixed:Spot	$313	$384	$455	$526	$597	$668
25:75 Split - $5 Fixed:Spot	$331	$402	$473	$544	$615	$686
75:25 Split - $4.25 Fixed:Spot	$373	$396	$420	$443	$467	$491
75:25 Split - $5 Fixed:Spot	$426	$449	$473	$497	$520	$544
Lowest Cost Option	**$284**	**$378**	**$402**	**$402**	**$402**	**$402**

Table D2

Regrets analysis: regret table for electricity generators

	Future Natural Gas Price Scenario ($/MMBtu)						
Procurement Option	**$3**	**$4**	**$5**	**$6**	**$7**	**$8**	**Maximum Regret of Decision**
Spot Purchases	-	-	$(71)	$(166)	$(260)	$(355)	$(355)
$4.25 Fixed Price	$(118)	$(24)	-	-	-	-	$(118)
$5 Fixed Price	$(189)	$(95)	$(71)	$(71)	$(71)	$(71)	$(189)
50:50 Split - $4.25 Fixed:Spot	$(59)	$(12)	$(35)	$(83)	$(130)	$(177)	$(177)
50:50 Split - $5 Fixed:Spot	$(95)	$(47)	$(71)	$(118)	$(166)	$(213)	$(213)
25:75 Split - $4.25 Fixed:Spot	$(30)	$(6)	$(53)	$(124)	$(195)	$(266)	$(266)
25:75 Split - $5 Fixed:Spot	$(47)	$(24)	$(71)	$(142)	$(213)	$(284)	$(284)
75:25 Split - $4.25 Fixed:Spot	$(89)	$(18)	$(18)	$(41)	$(65)	$(89)	$(89)
75:25 Split - $5 Fixed:Spot	$(142)	$(71)	$(71)	$(95)	$(118)	$(142)	$(142)

Table D3

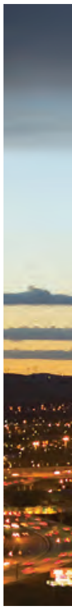
Regrets analysis: total fuel revenues table for natural gas suppliers

	Future Natural Gas Price Scenario ($/MMBtu)					
Procurement Option	**$3**	**$4**	**$5**	**$6**	**$7**	**$8**
Spot Purchases	$284	$378	$473	$568	$662	$757
$4.25 Fixed Price	$402	$402	$402	$402	$402	$402
$5 Fixed Price	$473	$473	$473	$473	$473	$473
50:50 Split - $4.25 Fixed:Spot	$343	$390	$438	$485	$532	$579
50:50 Split - $5 Fixed:Spot	$378	$426	$473	$520	$568	$615
25:75 Split - $4.25 Fixed:Spot	$313	$384	$455	$526	$597	$668
25:75 Split - $5 Fixed:Spot	$331	$402	$473	$544	$615	$686
75:25 Split - $4.25 Fixed:Spot	$373	$396	$420	$443	$467	$491
75:25 Split - $5 Fixed:Spot	$426	$449	$473	$497	$520	$544
Highest Revenue Option	**$473**	**$473**	**$473**	**$568**	**$662**	**$757**

Table D3

Regrets analysis: regret table for natural gas suppliers

	Future Natural Gas Price Scenario ($/MMBtu)						
Procurement Option	**$3**	**$4**	**$5**	**$6**	**$7**	**$8**	**Maximum Regret of Decision**
Spot Purchases	$(189)	$(95)	-	-	-	-	$(189)
$4.25 Fixed Price	$(71)	$(71)	$(71)	$(166)	$(260)	$(355)	$(355)
$5 Fixed Price	-	-	-	$(95)	$(189)	$(284)	$(284)
50:50 Split - $4.25 Fixed:Spot	$(130)	$(83)	$(35)	$(83)	$(130)	$(177)	$(177)
50:50 Split - $5 Fixed:Spot	$(95)	$(47)	-	$(47)	$(95)	$(142)	$(142)
25:75 Split - $4.25 Fixed:Spot	$(160)	$(89)	$(18)	$(41)	$(65)	$(89)	$(160)
25:75 Split - $5 Fixed:Spot	$(142)	$(71)	-	$(24)	$(47)	$(71)	$(142)
75:25 Split - $4.25 Fixed:Spot	$(101)	$(77)	$(53)	$(124)	$(195)	$(266)	$(266)
75:25 Split - $5 Fixed:Spot	$(47)	$(24)	-	$(71)	$(142)	$(213)	$(213)



750 1ST Street, NW, Suite 1100
Washington, D.C. 20002
T: 202-682-6294 | F: 202-682-3050
www.cleanskies.org