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Sunflower Electric Power: Carbon Risks Outweigh Benefits of Holcomb Expansion

A Report by Innovest Strategic Value Advisors

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Introduction

In October 2007, the secretary of the Kansas Department of Health and Environment denied an air permit for Sunflower Electric Power Corporation's proposed expansion of its Holcomb Station power plant in Kansas. The proposed project involved the construction of two 700 MW supercritical pulverized coal generating units at an estimated cost of $3.6 billion. The first unit, scheduled to be operational by 2012, would be owned jointly by Sunflower Electric Power Corporation (Sunflower), Golden Spread Electric Cooperative, and other investors. The second 700 MW unit would be owned by Tri-State Generation & Transmission Association, and was originally projected to be online in 2013. The decision to deny the required air permit was based on concern that the proposed power plant's CO_2 emissions would contribute to climate change.

Executive Summary

The following report examines how current and proposed regulatory scenarios, alternatives to coal-fired generation, stakeholder opposition, and rising construction costs continue to shift the competitive balance away from coal-fired generation. Furthermore, this analysis includes an in-depth financial assessment of the benefits of constructing gas power plants over coal power plants in a carbon constrained economy. This report demonstrates the fact that Sunflower has not adequately addressed the financial risks associated with the CO_2 output from the proposed Holcomb Station. As a result, Sunflower, a consumer-owned nonprofit corporation, is putting its ratepayers and owners at significant risk.

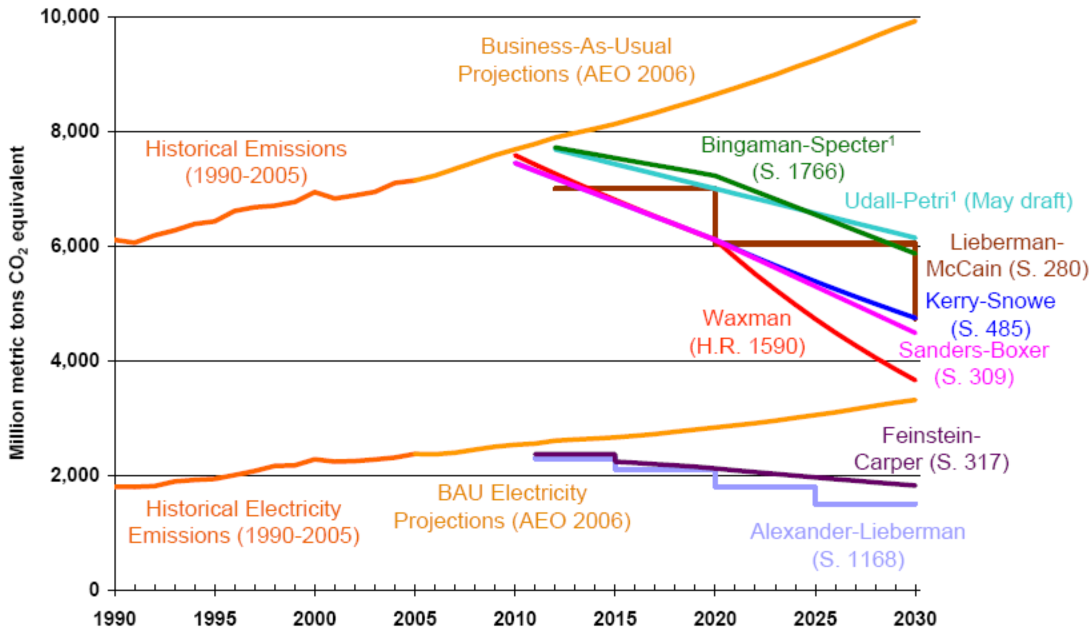
Although the proposed expansion of the Holcomb Station plant would provide Sunflower with additional baseload generating capacity, the carbon risks associated with an increased reliance on coal present significant financial risks for the company's owners and ratepayers. Given that Sunflower is a consumer-owned cooperative, the burden of future carbon costs will be placed entirely on the company's ratepayers. Assuming carbon prices between $21 and $48 per tonne, the Holcomb expansion could cost Sunflower ratepayers between $22.4 million and $51.36 million annually. Furthermore, Innovest analysis demonstrates that under federal legislation that relies on 100% auctioning of emissions allowances, natural gas generation becomes more economical at a carbon price of $13.20 per tonne. In conclusion, this analysis indicates that Sunflower has failed to account for likely regulatory scenarios, and will therefore expose its ratepayers to the significant financial exposure associated with a strategic focus on developing new coal capacity.

The Regulatory Landscape

The fundamental question regarding the regulatory scenario on climate change in the US is not whether legislation will be enacted, but when. Although there is currently no federal regulation on greenhouse gas (GHG) emissions, within the last year there has been a windfall of legislative proposals in the Congress. The following is a list of examples of these proposed Acts, which suggests that legislation is imminent:

- **Clean Air Climate Change Act of 2007 (Alexander-Lieberman), S.1168;**
- **Clean Air Planning Act of 2007 (Carper), S. 1177;**
- **Clean Power Act of 2007 (Sanders), S. 1201;**
- **Climate Stewardship Act (Olver-Gilchrest), H.R.620;**
- **Climate Stewardship and Innovation Act (McCain-Lieberman), S.280;**
- **Electric Utility Cap and Trade Act (Feinstein-Carper), S.317;**
- **Global Warming Pollution Reduction Act (Sanders-Boxer), S.309;**
- **Global Warming Reduction Act (Kerry-Snowe), S.485;**
- **Lieberman-Warner Discussion Principles, not yet introduced;**
- **Low Carbon Economy Act (Bingaman-Specter), S.1766; and,**
- **Safe Climate Act of 2007 (Waxman), H.R.1590.**

Comparison of Emission Reduction Goals in Legislative Proposals in the 110th Congress (as of August 13, 2007)[1]



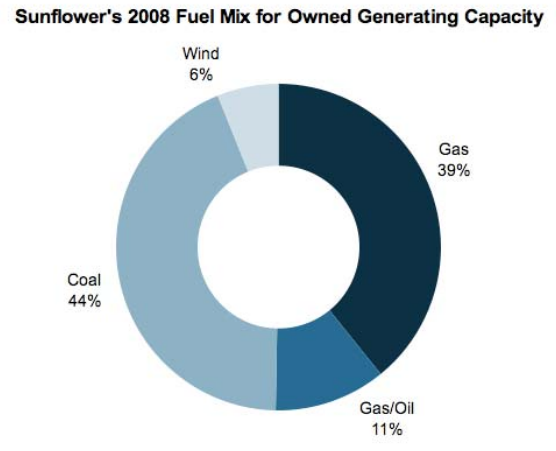
In addition to the Congress, the Supreme Court has also demonstrated a clear trend toward the regulation of GHG emissions. In April, 2007, the Court ruled that the United States Environmental Protection Agency (EPA) had the authority to regulate carbon dioxide and other greenhouse gases as pollutants. Finally, in an effort to address concern over the construction of new coal fired power plants, Rep. Markey and Rep. Waxman introduced the ‘Moratorium on Uncontrolled Power Plants Act’ in March, 2008. The bill effectively prevents federal and state agencies from issuing permits to new coal-fired power plants without state-of-the-art control technology to capture and permanently sequester GHG emissions. The moratorium extends until a comprehensive federal regulatory program for global warming pollution is in place.[2]

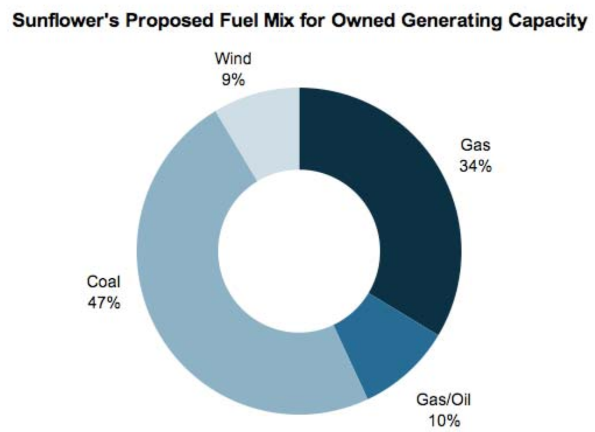
In the absence of federal legislation on climate change, more than half of all states have established legislation to address greenhouse gas emissions. Currently, 28 states and the District of Columbia have established standards requiring electric utilities to generate a certain amount of electricity from renewable sources. These requirements, which generally take the form of renewable portfolio standards, serve to further shift the competitive balance away from coal-fired generation. In addition, states have developed regional partnerships such as the Regional Greenhouse Gas Initiative and the Western Regional Climate Action Initiative. Under these programs, member states have agreed to establish regional emissions reduction targets and to develop market-based systems to ensure that these targets are achieved. Given, this national policy shift toward carbon regulation, ratepayers and stakeholders should question Sunflower’s decision to pursue new coal capacity.

[1] Resources for the Future. [1]Bill contains flexibility mechanisms which allow actual emissions to rise above the target.

Sunflower's Current and Proposed Carbon Profile

Sunflower continues to present the Holcomb expansion project as crucial to the company's effort to insulate its ratepayers from the price volatility associated with natural gas. Although the construction of the proposed coal-fired power plant will increase the company's reliance on coal by just under 7% compared to its current generating portfolio, significant risks will accompany Sunflower's strategic focus on new coal capacity.





Sunflower's decision to own 150 MW of new coal capacity will increase the company's annual CO_2 emissions by approximately 1.07 million tonnes.[3] Depending on the structure of future legislation and the associated price of carbon, the resulting financial impact on Sunflower's ratepayers could be significant. Although Sunflower will receive an annual management fee of $25 million from Tri-State, it is unlikely that this will be enough to insulate ratepayers from the costs associated with its increased carbon emissions. Assuming carbon costs of between $21 and $48 the Holcomb expansion could cost Sunflower ratepayers between $22.4 million and $51.36 million annually.[4] Using the current price of carbon under the European Union Emissions Trading Scheme (EU ETS) of $33 per tonne, Sunflower would be forced to increase its rates by approximately 3 cents per kWh.[5]

Renewable Energy in Kansas

In March, Kansas gave serious consideration to passing a renewable portfolio standard. The standard under consideration, which was included in the Kansas House of Representatives' Energy Bill, would require public utilities to have renewable generation assets of 10% in 2012, 15% in 2016, and 20% in 2020. Although Sunflower does not disclose the fuel mix for the energy it delivers to customers, the company has contracts to purchase the output from 124.4 MW of wind energy capacity in Kansas. Sunflower reports that by the end of 2008, it will have 13% of its nameplate capacity in wind energy. This positions Sunflower well to comply with the first phase of the state's proposed renewable portfolio standard; however the company's strategic focus on new coal capacity indicates a failure to capitalize on the long-term financial benefits associated with renewable energy.

[3] Assuming greenhouse gas emissions of 0.96 tonnes/MWh
[4] The price range reflects a range of expected values per tonne of CO_2 under the EU ETS. At the time that this report was published one tonne of CO2 was valued at $33 under the EU ETS.
[5] Calculation is based on an annual electricity output of 1,116,900 MWh/

Finney County, the site of the proposed expansion, and western Kansas in general have among the nation's most abundant wind resources with a Wind Power Class rating of between 4 and 5.[6,7] Meanwhile, the cost of wind energy continues to decline as technological advancements continue to increase efficiency. This has resulted in an 80% decrease in the price of wind energy from approximately 30 cents/kWh to 5 cents/kWh over the last 20 years.[8] Furthermore, the increased likelihood of federal legislation on climate change and the extension of the federal Production Tax Credit for alternative energy, indicate that the competitive balance will continue to shift away from traditional fossil fuel-fired power generation.

Stakeholder and Regulatory Opposition to New Coal Capacity

Although the decision to deny Sunflower an air permit for the Holcomb expansion marked the first time that a government agency cited climate change as a reason for refusing an air permit, this ruling is indicative of an emerging national trend. In 2007, more than 50 proposed power plants in 20 states were cancelled or delayed. As Sunflower seeks to reverse the Kansas Department of Health and Environment's decision, it is clear that the company will continue to face significant challenges in developing the Holcomb Station expansion.

Of particular concern for Sunflower is a March, 2008 decision by the Rural Utility Service not to fund new coal plants in 2008 and 2009. The Rural Utility Service, which has provided more than $1.3 billion in low-cost financing to rural electric cooperatives for new power plant construction, expressed concern over pending litigation and that new coal power plants were undermining efforts to address climate change. This moratorium on financing will affect at least six proposed coal plants in Montana, Kentucky, Illinois, Arkansas, Texas, and Missouri. Although Sunflower was not seeking financing from the Rural Utility Service for the Holcomb expansion, the company does need the agency's approval to seek outside funding.

The company's ability to secure financing could be further affected by Citi, JP Morgan Chase, and Morgan Stanley's recent release of the 'Carbon Principles'. The 'Carbon Principles' call for enhanced due diligence by banks and utilities in assessing the climate and economic risks associated with the development of new coal plants. Although this does not prevent these banks from financing carbon-intensive projects, it does point to a trend which suggests that the Holcomb Expansion will be placed under increased scrutiny by potential financers.

Increased Construction Costs

In addition to regulatory and stakeholder opposition, rising construction costs continue to derail the construction of new coal-fired power plants throughout the United States. Although the proposed Holcomb expansion is currently estimated to cost $3.6 billion, potential delays coupled with increasing costs of construction will likely result in significant upward adjustments in cost projections. This will ultimately result in increased electricity rates for Sunflower's customers.

In Nevada, the cost of Sierra Pacific Resource's proposed 1,500 MW Ely Energy Center has increased by more than 30% from $3.8 billion to $5 billion since it was first announced in 2006. Meanwhile in 2007, Duke Energy's proposal to build two 800 MW coal-fired generating units was reduced to one unit as a result of the North Carolina Utilities Commission's concern

[6] Kansas Wind Resources Map: http://www.kcc.state.ks.us/energy/kswindmap.pdf
[7] Wind Power Class is rated on a 1 to 7 scale with 7 representing the highest levels of wind capacity.
[8] American Wind Energy Association: http://www.awea.org/faq/cost.html

over the need for new capacity in light of rising construction costs and available alternatives. These two cases exemplify a national trend that has resulted from rapid increases in the cost of material inputs throughout the last several years.

The Business Case for Building Gas Over Coal

Sunflower's decision to expand its Holcomb Station plant occurs at a time of conflicting pressures on the electric power sector: from one side continuing increases in demand, and from the other looming legislation on climate change that will likely establish a federal cap and trade system limiting the amount of GHG emissions that power plants can emit.

A federal cap and trade system will in effect create *ipso facto* property rights for GHG emissions just as Title IV of the Clean Air Act Amendment in the US (a market for SO_2), and the EU ETS in Europe (a market for CO_2) have done. Currently, the US electric power industry makes operational and investment decisions based in part on the price of power and the relative costs of fuel, such as coal and natural gas. However, the introduction of a price for emissions is already modifying operating costs in the power generation sector internationally. If legislative trends continue as expected, and similar legislation is developed in the US, electric utilities will have to consider the differences in carbon content for different fuels in addition to fuel prices when making operational and investment decisions.

In this context, it is critical that stakeholders of a new power plants projects consider the potential costs of compliance coupled with emissions regulations and a range of non-financial 'carbon risks' alongside traditional financial considerations. This analysis reviews the relative risks of two base-load power plant scenarios in a carbon-constrained operating environment using data from Sunflower's proposed Holcomb expansion:

- **Super-critical black coal (referred to herein as SC coal or coal-fired); and,**
- **Combined cycle gas turbine (CCGT or gas-fired).**

The following shows some of the key cost considerations for a new power plant of each type.[9]

FIGURE 1 A Comparison of Baseload Generation Technologies

	SC Coal	CCGT
Construction costs for 1400MW project ($ million)	3600	1,102
Fuel costs ($/MWh)	6.15	20.5
GHG emissions per MWh (tonnes CO_2e)	0.96	0.59

A critical determining factor of the fuel chosen under a carbon constrained economy is its relative GHG intensity. A new coal-fired power plant has emissions almost 50% higher than that of a comparable gas-fired plant. This analysis considers a

[9] Construction costs were modeled from the Sunflower-Tristate plans for building a new coal-fired power facility. For the comparative CCGT construction costs, American Electric Power's planning to build a new gas plant, at a cost $787,500 per MWh was used. For fuel costs data from the Electric Power Research Institute cited in The New York Times on 2007/11/07 was used. Finally, the source for the emissions factor tCO_2e/MWh is the Department of Energy and the Environmental Protection Agency report on CO_2 emissions from the US Electric Power sector.

number of factors that are pivotal to a utility's choice between developing a coal or gas-fired power plant under a carbon cap and trade system:

- **First, a model was developed a to assess cash flows over ten years for SC coal and CCGT power plants, varying key parameters to quantify their effect on the plant's profitability, a key indicator of the project's credit risk; and,**
- **Second, cost functions were derived for SC coal and CCGT in order to quantify a 'switching price' for the price of carbon, above which gas provides cheaper base-load electricity.**

1. CREDIT RISK IMPLICATIONS OF EMISSIONS TRADING

The financial positions of new coal- and gas-fired power plants under any carbon legislation are highly dependent on two key factors:

- **The market price of GHG emissions; and,**
- **The degree to which emissions permits are auctioned versus freely allocated.**

The EU ETS provides perhaps the best available indication of the market price for emissions, though it is a young and still evolving market. Futures contracts on emissions permits expiring in 2010 have averaged $27 (€20) per tonne of CO_2e over time, and have recently traded at around these levels. From what can be surmised from the experience to date in the EU ETS, and from legislative proposals circulating in the Congress, electric utilities can expect to have to purchase a majority or all of their emissions permits via the market in the medium and long term.

For example, the Lieberman-Warner: America's Climate Security Act establishes that 20% of the National Emission Allowance Account will be allocated to the electric power sector. To put this figure in context, the electric power sector was responsible for more than 50% of the increase in GHG emissions between 2000 and 2006, and will remain the largest source of CO_2 emissions in the next 20 years. The bill also mandates that a 20% allocation will remain constant for the first five years and then it will transition to 0% by 2035. [10]

To demonstrate the impact of a cap and trade scheme on an electric utility's financial position, three different price scenarios for three auctioning cases were considered. The pricing scenarios included an expected maximum of $48, a minimum of $21, and a most likely case of $30 per tonne of CO_2e. [11] With regards to the auctioning, the following scenarios were modeled: 100% of permits allocated for free; 50% of permits allocated free; and 0% of permits allocated free (full auctioning). [12]

The model assumes a steady three per cent per annum increase in prices, costs, and revenues to reflect inflation so that the impacts of varying carbon prices and allocation/auctioning scenarios can be more clearly observed. Additionally, the economic viability of the project is assessed for the investment as a whole in order to further isolate the effect of carbon regulations in the decision to construct a power plant. The following summarizes the effect of varying carbon prices and the level of free permit allocation on a power plant's financial performance, measured by pre-tax profit margin.

[10] A 10 year scenarios was modeled based on the Lieberman-Warner's S-2191 Act
[11] These prices reflect the expected value of tCO_2e using EU ETS data
[12] Other assumptions for this analysis were: annual utilization (load factor) of 85%; weighed average cost of capital of 6.1% for the electric sector; interest rate of 4%; wholesale electricity rate for Kansas of $68 per MWh; and, a 100 percent in level of borrowings on capital costs. The cost of carbon capture and storage (CSS) is not modeled given the uncertainties regarding the future cost and viability of CCS. An example of this, is the recent withdrawal of US Federal funding of the FutureGen CCS project last month. Indicatively, including the cost of CCS would have imposed greater carbon costs on the SC based load model.

FIGURE 2 Pre-tax Profit Margin — Fuel Favored Under Various Pricing and Permit Scenarios

	Level of free permit allocation		
Pricing scenario	**100%**	**50%**	**0%**
Min. Case $21.00 per tCO_2e	**coal**	gas	gas
Exp. Case $30.00 per tCO_2e	**coal**	gas	gas
Max. Case $48.00 per tCO_2e	**coal**	gas	gas

For a price of $30 per tonne of CO_2e where all allowances are allocated up to the reduction target, SC coal provides higher profitability. The pre-tax profit margin averages 2 percentage points higher for coal compared with gas. With 100% auctioning, gas provides a significantly higher profitability than coal. The pre-tax profit margin is 11 percentage points higher for gas compared with coal. With 50% auctioning, gas provides a somewhat higher profitability than coal. The pre-tax profit margin is 6 percentage points higher for gas compared with coal. The following table summarizes the magnitude of carbon costs at the different price scenarios investigated, assuming full auctioning:

FIGURE 3 Carbon Costs in 2020 at Different Permit Prices

	$ million		Percentage of EBIT	
Pricing scenario	**SC coal**	**CCGT**	**SC coal**	**CCGT**
Min. Case $21.00 per tCO_2e	240.4	106.6	33.8	25.5
Exp. Case $30.00 per tCO_2e	331.8	147.1	46.7	35.2
Max. Case $48.00 per tCO_2e	521.6	231.3	73.4	55.3

In general, this analysis demonstrate that gas is the more financially sound choice for the construction of baseload generating capacity in all scenarios except 100% free allocation of carbon allowances.

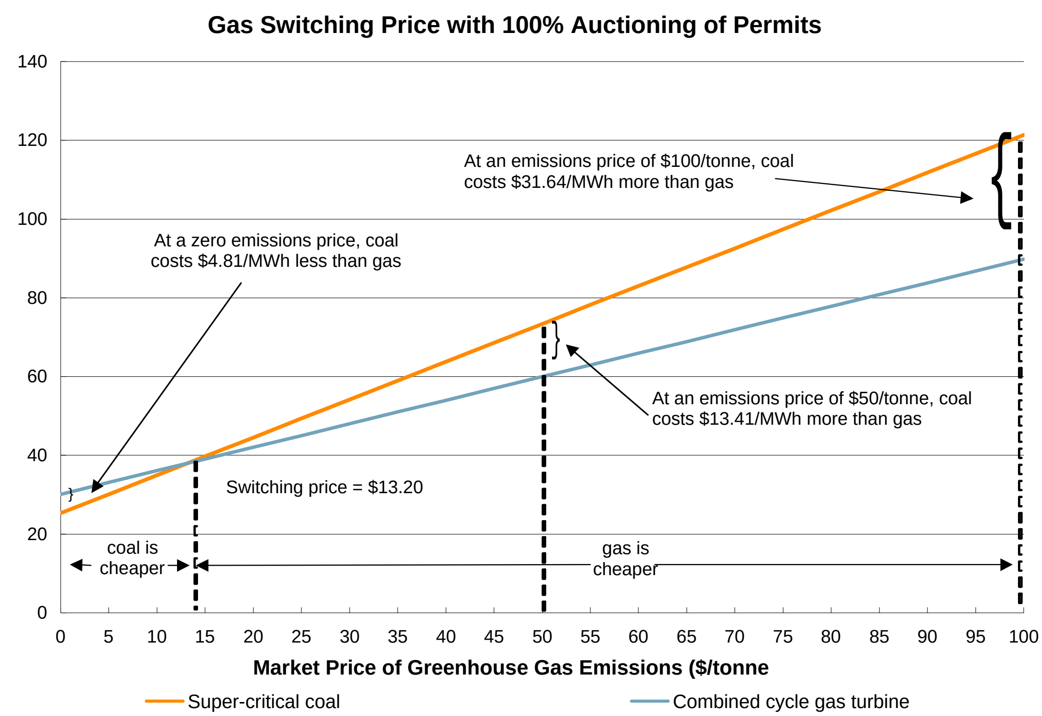
2. THE SWITCHING PRICE FOR GAS

The choice to develop less carbon-intensive generating capacity such as gas can provide a natural hedge against uncertainty in carbon prices and allocation systems. By choosing coal over gas, electric utilities must count on low carbon prices and or high allocation of free permits. It should be noted that carbon prices do not represent a symmetric risk though, as prices are bounded by zero from below but unbounded above.[13]

[13] In this assessment, it is assumed that the legislation modeled would be effective in achieving emissions reductions. In this sense, problems such as the over allocation of permits observed in the EU ETS Phase I and the consequent windfall of gains for some sectors and companies, are ruled out from the study.

The asymmetric nature of carbon price risks can be measured using a simple cost model. Solving the cost functions for various carbon price levels demonstrates the advantage of gas from the perspective of asymmetric carbon price risks.

For low carbon prices, coal becomes the lower cost generation option, and when there is no price on carbon, coal has a cost advantage of $4.81/MWh. This is the largest cost advantage attainable for coal. For gas on the other hand, the cost advantage rises continuously for higher carbon prices, reaching higher levels as the carbon price rises. For a $50/tonne carbon price, gas is $13.41/MWh cheaper than coal, and for a $100/tonne carbon price gas is $31.64/MWh cheaper. At a carbon price of around $13.20, CCGT is able to provide base-load power at an equivalent cost to SC coal in the scenario where carbon permits are 100% auctioned. For carbon prices above this level, CCGT becomes the lower cost option for base-load electricity capacity. The following graph illustrates the switching price for gas.



The above figure shows that the cost advantage of gas continues to rise unbounded for higher carbon prices. Therefore, investing in gas generation acts as a natural hedge against higher carbon prices, while investing in coal generation takes on price risk equivalent to selling a 30-40 year call option on rising carbon prices.

Conclusion

The expansion of the Holcomb Station plant would provide Sunflower with additional baseload generating capacity. However, the addition of this capacity would further expose the company's ratepayers to the environmental and financial risks associated with coal-fired generation. An analysis of the regulatory environment and the economics of developing new coal capacity under likely regulatory scenarios suggests that the risks outweigh the potential benefits and create significant financial exposure for Sunflower and its ratepayers.

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