Tri-State: Coal Expansion Poses Risks to Electricity Consumers

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INTRODUCTION

Tri-State Generation and Transmission Association (Tri-State) is a wholesale electric power supplier owned by the 44 electric cooperatives that it serves. Tri-State generates and transports electricity to its member systems throughout a 250,000 square-mile service territory across Colorado, Nebraska, New Mexico, and Wyoming. The Cooperative serves more than 1.4 million consumers through a combination of owned baseload and peaking power plants that use coal and natural gas as their primary fuels. Tri-State owns approximately 2,450 MW of generating capacity (75% coal, 21% natural gas/fuel oil, and 4% diesel). These resources are supplemented by purchased power, federal hydroelectricity allocations, and renewable energy sources. Tri-State’s mission is to provide its member owners a reliable, cost-based supply of electricity while maintaining a sound financial position through effective utilization of human, capital, and physical resources in accordance with cooperative principles.

In May 2008, the Kansas legislature failed to override Governor Kathleen Sebelius’s veto of a bill that would have allowed for the expansion of the Sunflower Electric Power Corporation’s 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, which was scheduled to be operational by 2012, would be owned jointly by Sunflower Electric Power Corporation, Golden Spread Electric Cooperative, and other investors. The second 700 MW unit would be owned by Tri-State, and was originally projected to be online in 2013. The Governor’s veto effectively upholds an October 2007 decision by the Kansas Secretary of Health and Environment to deny an air-quality permit due to concern that the proposed power plants’ CO2 emissions would contribute to climate change. Tri-State and the other companies involved in the proposed expansion continue to pursue legal and administrative strategies in an effort to complete the proposed expansion.

EXECUTIVE SUMMARY:

Current and future regulatory scenarios indicate that Tri-State’s decision to pursue new conventional coal-fired generating capacity, such as the proposed 700 MW at the Holcomb Station could significantly hamper its ability to fulfill its mission of providing cost-based electricity to its member owners. The addition of this new capacity would increase Tri-State’s annual CO2 emissions by more than 4.5 million tonnes. Assuming a federal cap-and-trade system in which 100% of emissions allocations are auctioned, and CO2 prices of between $21 and $48/tonne, the completion of Tri-State’s portion of the Holcomb Station expansion could result in annual CO2 costs to electricity consumers of between $95 million and $217 million.

Given that Tri-State currently relies on coal for more than 98% of its electricity generation, its decision to pursue this new coal-fired generating capacity does not adequately account for these potential costs, or the regulatory and financial trends that continue to shift the competitive balance toward cleaner forms of power generation, renewable energy, and energy efficiency. An analysis of Tri-State’s current involvement in the latter two areas relative to other US utilities suggests that it is not well positioned to mitigate the risks and capitalize on the opportunities associated with current and impending climate legislation, rising construction costs, and increases in the price of coal.

These findings are further supported by an in-depth financial analysis of coal, gas, and wind generation in a carbon constrained economy. The analysis examines Tri-State’s proposed Holcomb Station expansion under numerous
carbon pricing scenarios, and demonstrates that natural gas provides a more financially viable form of baseload generating capacity under the majority of the modeled regulatory scenarios.

The Cooperative’s decision to pursue the Holcomb Station expansion fails to account for continuing regulatory trends and therefore will place its member owners at risk.

REGULATORY LANDSCAPE

Consensus within the utility industry indicates that federal legislation on climate change is impending. President-elect Barack Obama has pledged to implement an economy-wide cap-and-trade program to reduce greenhouse gas emissions by 80% by 2050. The proposed Obama-Biden cap-and-trade policy would require all pollution credits to be auctioned. In addition, members of the 110th Congress have introduced climate change legislation at a faster pace than any previous Congress. As of July 2008, lawmakers had introduced in excess of 235 bills, resolutions, and amendments that address climate change and GHG emissions. Furthermore, in 2007, the Supreme Court ruled that the United States Environmental Protection Agency (EPA) has the authority to regulate carbon dioxide and other greenhouse gases as pollutants under the Clean Air Act.

Increasing momentum toward federal carbon regulation has shifted discussion within the utility industry from whether legislation will occur, to what shape future regulatory structures will take. A majority of the bills proposed and those favored by the two presidential candidates employ a federal cap-and-trade system in which direct costs are assigned to carbon emissions through market mechanisms. Current proposals differ in timeline, scope, and method of permit allocation, but nearly all legislative efforts target the electric power industry for a limit on GHG emissions. In addition, various legislative efforts suggest that proposed coal-fired power plants will not be ‘grandfathered’ under future regulatory schemes.

In the absence of federal legislation on climate change, regional, state, and local governments continue to develop regulations to address greenhouse gas emissions from the utility sector. Currently, 28 states and the District of Columbia have established standards that require electric utilities to derive a specified amount of electricity from renewable sources. These requirements, which generally take the form of renewable portfolio standards, serve to shift the competitive balance away from coal power plants.

Tri-State’s operations in both Colorado and New Mexico will be subject to existing mandatory renewable portfolio standards. Colorado’s standard requires municipal utilities and rural electric providers to provide 10% of their electricity from renewable sources by the year 2020. Recently, the Energy Office of the Colorado Governor requested that Tri-State and its member cooperatives develop plans to provide 20% of their electric power from renewable resources by 2020. Similarly, the New Mexico renewable portfolio mandates that 10% of a rural electric power cooperative’s power come from renewable sources by the year 2020.

In addition to renewable portfolio standards and other state-level efforts, regional partnerships such as the Regional Greenhouse Gas Initiative, the Western Climate Initiative, and Midwestern Regional Greenhouse Gas Reduction Accord have been developed to address climate change. Under these initiatives, member states have agreed to establish regional emissions reduction targets and to develop market-based systems to ensure that these targets are achieved. New Mexico is participating in, while both Colorado and Wyoming are observing, the Western Regional Climate Action Initiative, which has established an economy-wide greenhouse gas emissions reduction
target of 15% below 2005 levels by the year 2020. New Mexico has also developed a state target to reduce its statewide GHG emissions to 2000 emission levels by 2012, 10% below 2000 levels by 2020, and 75% below 2000 emission levels by 2050.

Given this state and national policy shift toward mandatory greenhouse gas emissions reductions and renewable energy development, there is significant risk associated with Tri-State’s strategic decision to pursue 700 MW of new coal generating capacity. Current and future regulatory scenarios will undoubtedly add additional costs to coal-fired electricity and will hamper Tri-State’s ability to deliver a cost-based electricity supply to its member owners.

STAKEHOLDER OPPOSITION TO THE DEVELOPMENT OF NEW COAL CAPACITY

Traditional opposition to new coal power plants centered around concern over air emissions and the associated effects on public health. These concerns continue to be relevant, and are increasingly coupled with apprehension over the contribution of greenhouse gas emissions from new coal-fired power plants to climate change. As a result, regulators across the country are beginning to favor alternative forms of power generation and increased energy efficiency initiatives over new coal capacity.

Last year, stakeholder opposition coupled with rising construction costs resulted in the delay or cancellation of more than 50 power plants in 20 states including Tri-State’s proposed Holcomb Station expansion. The following provides additional examples of some of the key regulatory developments regarding new coal generating capacity that have occurred during the last year.

In July 2008, a Georgia Superior Court revoked the air pollution permit for a new 1,200 MW coal-fired power plant in Early County, Georgia, which was being developed by Dynegy. The original air permit was challenged on the basis that Dynegy did not properly account for CO2 emissions or incorporate the required pollution control technologies in the plant design. The Superior Court Judge cited the 2007 Supreme Court ruling in Massachusetts v. EPA that CO2 is subject to regulation under the Clean Air Act and therefore must be mitigated with ‘Best Available Technology’.

In May 2008, the US EPA Environmental Appeals Board in Washington heard oral arguments in a case brought by the Sierra Club involving a waste-coal-fired plant proposed in Utah by Deseret Power Electric Cooperative. The issue before the Board is whether the Supreme Court’s Massachusetts v. EPA ruling that CO2 is a pollutant requires power plant developers to establish emission limits for CO2. The national implications of this case will be significant as a ruling in favor of CO2 limits would require all fossil fuel power plant projects to determine methods to reduce CO2 emissions.

In March 2008, the Rural Utility Service announced that it would not fund new coal plants in 2008 and 2009. Since 2001, the Rural Utility Service has issued more than $1.3 billion in low-cost financing to rural electric cooperatives for new power plant construction. The choice to suspend the funding of new coal fired power plants was a response to pending litigation and concern that the Rural Utilities Service was putting taxpayers at risk and undermining efforts to address global climate change. This decision will affect at least six proposed coal plants in Montana, Kentucky, Illinois, Arkansas, Texas, and Missouri. In addition, the Rural Utility Service’s action could impact Tri-State as the cooperative is seeking financing for a $1.8 billion transmission line from the Rural Utility Service.
PacifiCorp recently cancelled plans to develop 950 MW of new coal capacity at its existing Intermountain Power station. The company cited concern over climate change after six California cities that rely on the plant refused to support the proposed expansion. PacifiCorp will subsequently focus on developing new natural gas or wind generating capacity.

It remains unclear whether Tri-State’s continuing efforts will succeed in overriding the Kansas Secretary of Health and Environment’s decision. However, the Cooperative’s experience to date demonstrates the challenges it will face in pursuing new coal generating capacity.

TRI-STATE’S CURRENT AND PROPOSED CARBON PROFILE

Although Tri-State and other US utilities currently operate without federal limits on greenhouse gas emissions, the previous sections indicate that federal legislation on climate change is impending. Furthermore, local, state, and regional efforts to limit greenhouse gas emissions continue to shift the competitive balance away from the development of new coal generating capacity in advance of federal action. As a result, leading utilities have developed proactive strategies to reduce their greenhouse gas emissions including improved energy efficiency and renewable energy development. The following section provides an analysis of Tri-State’s current carbon and proposed carbon profile relative to the 17 US-based companies in Innovest’s Electric Power Companies – N. America sector.

The expansion of the Holcomb Station power plant would increase Tri-State’s coal capacity by over 38%, and the percentage of coal in the Cooperative’s overall generating portfolio will increase from 75% to 80%.
The addition of 700 MW of baseload coal-fired generating capacity would also increase Tri-State’s annual CO2 emissions by more than 4.5 million tonnes. This would move Tri-State from the US power sector’s 43rd largest emitter of CO2 to the 35th. More significantly, assuming a federal cap-and-trade system in which 100% of emissions allocations are auctioned, and CO2 prices of between $21 and $48/tonne, the completion of Tri-State’s portion of the Holcomb Station expansion could result in annual CO2 costs of between $95 million and $217 million. These figures would likely be adjusted downward under various regulatory scenarios that propose to provide utilities with a percentage of their emissions allocations for free such as the Lieberman-Warner Climate Security Act.

Given Tri-State’s position as a consumer owned electricity supplier, its ratepayers would bear the burden of these potential future carbon costs.
Tri-State’s ability to avoid these costs will be limited as, unlike leading US utilities, the Cooperative has failed to diversify its generating assets. Tri-State’s 614 MW of natural gas / fuel oil and diesel capacity provides only peaking capacity, and the Cooperative relies on coal for more than 98% of its actual electricity generation. Tri-State has a higher reliance on coal-fired electricity than any other company in the Electric Power Companies – N. America sector and ranks 6th among the nation’s 100 largest power producers in terms of overall dependence on coal-fired electricity. As the following graph indicates, the Cooperative’s well above average reliance on coal-fired generation translates into significantly higher emissions rates for CO₂ (lbs/MWh) relative to other producers that have more diversified generating portfolios.
Tri-State’s growing, but still limited involvement in renewable energy and energy efficiency suggests that it is aware of the risks associated with climate change. However, Tri-State’s efforts in these areas will not compensate for its decision to develop new coal capacity and to further increase its ratepayers’ exposure to the risks associated with carbon pricing. Tri-State’s pursuit of the Holcomb expansion or any other significant coal-fired power plant should raise questions about the Cooperative’s ability to fulfill its mission of providing cost-based electricity to its owners/ratepayers.
ALTERNATIVES TO NEW COAL CAPACITY

The regulatory trends described above and the increasing likelihood of carbon costs continues to place increased value on alternatives to new coal-fired generating capacity throughout the US utility industry. Although utilities have developed numerous strategies to reduce their carbon exposure, renewable energy and energy efficiency remain the most important alternatives to the development of new coal capacity. The following section describes Tri-State’s current involvement in these areas and compares those to Xcel Energy (rated BBB by Innovest), a utility with a traditional reliance on coal-fired generation that operates in similar geographic environments.

Tri-State currently purchases renewable energy output from 10 facilities that utilize wind, hydro, and biomass generation. Although the Cooperative does not report the total amount of energy purchased, the capacity of these facilities indicates that renewable energy accounts for less than 1% of the electricity delivered to Tri-State’s ratepayers. In an effort to improve performance in this area, Tri-State recently became a founding member of the National Renewables Cooperative Organization (NRCO). NRCO plans to develop new renewable energy projects for its members in response to state renewable portfolio standards and the potential for a national standard.

Xcel, which relies on coal for 68% of its owned generation, has worked to reduce its overall carbon exposure through a strategic focus on renewable energy purchasing. As of the beginning of 2008, Xcel had over 2,700 MW of installed wind capacity on its system, and had established a target to increase this capacity to 7,400 MW by 2020. The company recently developed, along with SunEdison, an 8.2 MW solar photovoltaic facility and, has announced plans to procure 200-600 MW of new concentrating solar power. The company will also purchase the electricity output from an 8.2 MW solar facility in south central Colorado. Xcel’s purchasing of wind and solar generation along with small hydro, biomass, and waste-to-energy accounts for 9% of the company’s total fuel mix.

Unlike a regulated utility, Tri-State’s accounting and reporting are not public or subject to review in any kind of regulatory proceeding. However, Tri-State reports that energy efficiency is a key component of its resource planning. The Cooperative seeks to work with its members on load management strategies to ensure the efficient use of existing resources. In January 2007, Tri-State introduced its compact fluorescent light bulb (CFL) campaign by providing 44,000 CFLs to its members. By the end of 2007, the campaign, which also provides rebates to members that buy additional CFLs, resulted in member groups providing more than 125,000 CFLs to their consumers. The CFL is part of Tri-State’s Energy Efficiency Credits (EEC) program that encourages the installation of high performance electric motors and heating and cooling systems through monetary incentives jointly offered by Tri-State and its participating member systems. Tri-State is also developing demand-side management (DSM) programs to encourage its members to shift their demand during peak periods through financial incentives.

In sum, Tri-State reports that its EEC program has resulted in the saving of approximately 35,000 MWh of electricity. For the purpose of comparison, Xcel which has developed similar strategies reports that its energy efficiency efforts have resulted in the saving of 328,314 MWh of electricity, which is equivalent to the electricity needs of 37,500 homes.

The juxtaposition between how Tri-State and Xcel are managing carbon risks is further highlighted by the Ernest Orlando Lawrence Berkeley National Laboratory’s March 2008 report, ‘Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans’. The report demonstrates that Tri-State lags behind Xcel and other peers in nearly every aspect of planning for the risks associated with carbon regulation.
Although Tri-State’s involvement in renewable energy and focus on energy efficiency remains limited, the Cooperative has demonstrated an effort to improve performance in these areas. However, Tri-State has yet to develop a comprehensive strategic focus in this area that would allow it to protect the interests of its ratepayers in a carbon-constrained economy.

**RISKS TO RATEPAYERS**

Ratepayers in Tri-State’s service territory have traditionally had low electricity rates relative to the national average. However, Tri-State’s focus on developing new coal capacity and its apparent failure to recognize the impact of carbon pricing could result in significant rate increases for its customers. The following tables compare electricity rates in Tri-State’s service territory with regional and national averages; and illustrate the potential rate increases that may occur as a result of the Cooperative’s decision to pursue 700 MW of new coal capacity under various carbon pricing scenarios. vi,vii,ix

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**FIGURE 4** Electricity Rates for States in Tri-State’s Service Territory Compared to Regional and National Averages

<table>
<thead>
<tr>
<th></th>
<th>Nebraska</th>
<th>Wyoming</th>
<th>New Mexico</th>
<th>Colorado</th>
<th>West North Central Average</th>
<th>Mountain Average</th>
<th>U.S. Average</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cents per kWh</strong></td>
<td>7.32</td>
<td>7.92</td>
<td>9.4</td>
<td>10.09</td>
<td>8.36</td>
<td>9.51</td>
<td>10.87</td>
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In addition to the likelihood of carbon pricing, rising coal prices and construction prices will also likely affect Tri-State’s planned expansion, and will therefore further impact ratepayers. Over the last year, a rise in global demand for coal has lead to a sharp increase in coal prices that is expected to continue through at least 2009. This trend is exemplified by an over 90% increase in spot prices for central Appalachia coal and a 65% increase in Powder River Basin coal in Wyoming in the last year. Moreover, rising construction costs have forced several utilities to abandon or reconsider plans to develop new coal generating capacity. Although Tri-State and its partners in the proposed Holcomb Station expansion have not revised their construction cost estimate of $3.6 billion, continuing delays and construction industry trends indicate that significant upward adjustments are likely. The following provides several examples of how construction costs have altered plans to develop new coal power plants for both the government and publicly traded utilities.

In 2008, the Department of Energy withdrew funding from FutureGen, effectively terminating the project. FutureGen had been a public-private partnership to build the world’s first near zero-emissions coal-fired power plant in Illinois. The planned 275 MW plant was intended to demonstrate the feasibility of producing electricity and hydrogen from coal while capturing and sequestering CO2 underground. The Department of Energy’s decision to withdraw funding is in part a reaction to project costs that had nearly doubled from $1 billion.

In 2006, Duke Energy submitted a filing with the North Carolina Utilities Commission seeking approval for two 800 MW coal-fired generating units at the site of its existing Cliffside Stream Station. The company’s initial May, 2005 estimates suggested that the two units would cost approximately $2 billion; however in a second filing the projected costs increased to $3 billion. The North Carolina Utilities Commission approved the construction of one 800 MW unit, but disapproved the second unit, primarily on the basis that Duke had failed to demonstrate that it needed the capacity to serve native load demands. In January 2008, Duke filed an updated cost estimate for the 800 MW unit of $1.8 billion excluding $600 million for allowance for funds used during the construction.

In 2006, Sierra Pacific Resources announced plans to develop a coal-fired power plant in Ely, Nevada. The proposed facility would utilize two 750 MW coal-fired generating units. Since Sierra Pacific announced its plans to construct the Ely Energy Center in 2006, the facility’s cost estimates have increased by more than 31% from $3.8 billion to more than $5 billion.

In 2005, a consortium of seven Midwestern utilities announced plans to build a 630 MW coal-fired power plant on the site of the existing Big Stone Plant in South Dakota. Initial cost estimates for the facility were approximately $1 billion, with an additional $200 million for a transmission line. Since the original plan was proposed, two of the utilities have withdrawn as owners and the size of the project has been scaled back to between 500 and 580 MW.
Meanwhile, regulatory delays have led to a revised project cost estimate of $1.6 billion due to higher costs of construction materials and labor.

Tri-State's decision to pursue the Holcomb Plant expansion continues to be based on the premise that coal provides the cheapest form of baseload generating capacity. However, the Cooperative appears to neglect the potential for carbon pricing, carbon restrictions under the Clean Air Act, and the continuing upward trend in coal and construction costs. The combination of these factors should prompt Tri-State and its ratepayers to reconsider its strategic focus. The following section, which provides an in-depth analysis of the costs associated with coal, natural gas, and wind generation in a carbon-constrained economy, further demonstrates the risk associated with Tri-State's strategic focus.

THE FINANCIAL CASE FOR DEVELOPING NATURAL GAS AND/OR WIND OVER COAL

Tri State's decision to expand its generation using coal-fired plants 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 and Administrative action on climate change that will likely establish a federal cap and trade system limiting the amount of GHG emissions that power plants can emit and putting a price on these emissions.

In this context, it is critical that stakeholders of 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. Using data from the 1,400 MW plant expansion in the Holcomb Station in Kansas from which Tri State would own 700 MW, this analysis reviews the relative risks of three power plant scenarios in a carbon-constrained operating environment:

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

The interested parties initially estimated construction costs for the Holcomb Station Expansion Project at $2,600 per KW. However, as construction costs are continuing to escalate, this maybe well over $3,500 per KW already. This increase in prices is due to increasing costs from, among other factors, the high demand that construction materials and services are experiencing especially in the Asian markets.

The construction prices established for the Holcomb expansion were calculated in 2005 and it is likely that these prices have already increased substantially. Nevertheless, we will use these official construction figures to build the analysis scenario in a conservative way.
The following table shows some of the key cost considerations for a new power plant of each type. xi

<table>
<thead>
<tr>
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<th>(1)</th>
<th>(2)</th>
<th>(3)</th>
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<tbody>
<tr>
<td>SC Coal Construction costs for 700MW project ($ million)</td>
<td>1800</td>
<td>550</td>
<td>1260</td>
</tr>
<tr>
<td>Fuel costs ($/MWh)</td>
<td>15.60</td>
<td>34.40</td>
<td>0</td>
</tr>
<tr>
<td>GHG emissions per MWh (tonnes CO₂e)</td>
<td>0.99</td>
<td>0.50</td>
<td>0</td>
</tr>
</tbody>
</table>

* Note that wind projects are also eligible for a 2c/kWh Production Tax Credit nationally, and are eligible to earn Renewable Energy Certificates, which have recently traded at around $5/MWh. These policy incentives for renewable energy are not included in the remainder of this analysis.

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

- First, a model was developed to assess cash flows over ten years for each, 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 each option in order to quantify a ‘switching price’ for the price of carbon, above which gas or wind provides cheaper base-load electricity than coal.

1. CREDIT RISK IMPLICATIONS OF EMISSIONS TRADING

The relative financial positions of new 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 per tonne of CO₂e 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 CO₂ 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. xiii

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 $30 per tonne of CO$_2$e. 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).

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.

<table>
<thead>
<tr>
<th>Pricing scenario</th>
<th>Level of free permit allocation</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>Min. Case $21.00 per tCO$_2$e</td>
<td>coal</td>
</tr>
<tr>
<td>Exp. Case $30.00 per tCO$_2$e</td>
<td>coal</td>
</tr>
<tr>
<td>Max. Case $48.00 per tCO$_2$e</td>
<td>coal</td>
</tr>
</tbody>
</table>

For a price of $30 per tonne of CO$_2$e where all allowances are grandfathered up to the reduction target, SC coal provides higher profitability. The pre-tax profit margin averages four 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 13 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 five 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:

<table>
<thead>
<tr>
<th>Pricing scenario</th>
<th>SC coal</th>
<th>CCGT</th>
<th>SC coal</th>
<th>CCGT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Min. Case $21.00 per tCO$_2$e</td>
<td>124.0</td>
<td>66.6</td>
<td>39.2</td>
<td>28.0</td>
</tr>
<tr>
<td>Exp. Case $30.00 per tCO$_2$e</td>
<td>171.2</td>
<td>91.9</td>
<td>54.1</td>
<td>38.6</td>
</tr>
<tr>
<td>Max. Case $48.00 per tCO$_2$e</td>
<td>269.1</td>
<td>144.5</td>
<td>85.0</td>
<td>60.7</td>
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</table>

In general, this analysis demonstrates that gas is a more financially sound choice for the construction of baseload generating capacity than coal in all scenarios except 100% free allocation of carbon allowances.
2. THE SWITCHING PRICE FOR GAS AND WIND

The choice to develop less carbon-intensive generating capacity such as gas or wind can provide a natural hedge against uncertainty in carbon prices and allocation systems. By choosing coal over gas or wind, electric utilities must count on low carbon prices 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.

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 $7.60/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 $15.40/MWh cheaper than coal, and for a $100/tonne carbon price gas is $38.30/MWh cheaper. At a carbon price of around $16.50, 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.

**FIGURE 5** Switching Prices with 100% Auctioning of Permits

![Graph showing switching prices for gas and wind](image_url)
Similarly, for higher carbon prices, wind is able to provide cheaper electricity than either coal or gas. At a carbon price of around $4.70, wind is equivalent in cost to coal, and at emissions prices above this level becomes a cheaper source of power than coal and gas. Because of issues with intermittency in wind resource though, gas still has a large role to play for baseload and as a quick-start backup for wind at carbon prices at or above the $13.60 level.

The above figure shows that the cost advantage of gas and wind continues to rise unbounded for higher carbon prices. Therefore, investing in gas and wind generation acts as a natural hedge against higher carbon prices, while investing in coal generation places ratepayers at risk in light of future carbon prices.

CONCLUSION

Tri-State’s stated mission is to provide reliable and cost-based electricity to its member owners. The addition of new coal generating capacity would likely aid in the Cooperative’s effort to provide reliable service in face of increasing consumer demand for electricity in its service territory. However, Tri-State’s strategic focus on developing new coal-fired generating capacity to meet this demand fails to adequately account for current regulatory and financial trends, which continue to shift the balance of cost-competitiveness to efficiency and demand side management programs and to cleaner forms of power generation. An analysis of these trends and the potential costs associated with coal-fired electricity generation in a carbon constrained economy suggests that Tri-State’s plan will likely jeopardize the Cooperative’s ability to provide cost-based electricity.
CITATIONS

1. Assuming greenhouse gas emissions of 0.96 tonnes/MWh.
2. Pew Center on Global Climate Change: http://pewclimate.org/what_s_being_done/in_the_congress/110thcongress.cfm
3. Assuming greenhouse gas emissions of 0.96 tonnes/MWh.
5. NRDC Benchmarking Air Emissions: http://www.nrdc.org/air/pollution/benchmarking/
7. Electricity rates reflect residential rates for February 2008 as provided by the Energy Information Administration: http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html. Wyoming, Colorado, and New Mexico are included in the Mountain region and Nebraska is included in the West North Central region. The Mountain region also includes: Arizona, Idaho, Montana, Nevada, and Utah. The West North Central region also includes: Iowa, Kansas, Minnesota, Missouri, North Dakota, and South Dakota.
8. Assuming generation output of 5,212,200,000 kWh and CO2 emissions output of 4,539,291 tonnes from the additional 700 MW at Holcomb.
9. Based on an average of annual household electricity consumption for Nebraska, Wyoming, New Mexico, and Colorado as provided by the Energy Information Administration for 2006.
11. The units will be owned by generation and transmission cooperatives Sunflower Electric, Tri-State Generation & Transmission Association, Inc., and Golden Spread Electric Cooperative, Inc.
12. For the comparative CCGT construction costs, American Electric Power’s planning to build a new gas plant, at a cost $787,500 per MW was used. For the comparative wind scenario we assumed a cost of $1,800 per KW. Other fixed and variable costs were used accordingly to the technology that was modeled. The source from coal and gas prices per MWh as well as for the emissions factor tCO2e/MWh is the Energy Information Administration (US Dept. of Energy). Consistent with using the original construction figures to build the analysis scenario in a conservative way, we use the fuel costs that the project planners were originally facing at the time of proposing the plant construction.
13. A 10 year scenario was modeled based on the Lieberman-Warner’s S-2191 Act.
14. These prices reflect expected values of tCO2e using EU ETS data.
15. Other assumptions for this analysis were: annual utilization (load factor) of 85%; weighed average cost of capital of 6.0% for the electric sector; interest rate of 4%; the average wholesale electricity for the Mid Continent Area power pool and for the Four Corners trading hub for the last three years of $64.96 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 withdrawal of US Federal funding of the FutureGen CCS project. Indicatively, including the cost of CCS would have imposed greater carbon costs on the SC based load model relative to the CCGT case.
16. For a price of $48 per tonne of CO2e and 100% auctioning, the wind option provides higher profitability. The pre-tax profit margin averages 14 percentage points higher for wind compared with gas.