



Holcomb Station



Tri-State Generation and Transmission Association's Resource Development Plan



Update 1: Forecast Review and Rate Impacts

December 2006



WESTERN RESOURCE
ADVOCATES

Preface

Tri-State Generation and Transmission Association, Inc. is an important wholesale electric power supplier in Colorado, Nebraska, New Mexico, and Wyoming. Tri-State provides power to 44 member electric cooperatives that together distribute this power to nearly one million people. Tri-State has proposed investing over \$5 billion in three new coal-fired power plants along with associated transmission lines. If Tri-State proceeds with this plan, it will come at great cost to the customers served by its members as well as to the environment.

In April of this year, Western Resource Advocates and the Southwest Energy Efficiency Project released a critique of Tri-State's proposal. The objective of this new report is to update the analysis of the electricity demand projections underlying Tri-State's resource plan and to examine the rate impacts of the proposed coal plants.

The primary author of this report is Rick Gilliam of Western Resource Advocates. The author would like to thank Bruce Driver and David Berry for their significant contributions. Thanks also to Penny Anderson, Matt Baker, Eric Guidry, Susan Innis, Jake Meffley, John Nielsen, and Anita Schwartz for their comments and editing of drafts of this report, as well as the many friends who have allowed me to draw upon their expertise and knowledge.

The author would appreciate receiving any comments or suggestions via email to Rick Gilliam (rgilliam@westernresources.org).

About Western Resource Advocates: Founded in 1989, Western Resource Advocates is a non-profit conservation organization dedicated to protecting the Interior West's land, air, and water. Working in collaboration with other environmental and community groups, WRA develops solutions that are appropriate to the unique environmental, economic, and cultural framework of this region. For more information, visit the WRA website at <http://www.westernresourceadvocates.org>.

Table of Contents

Executive Summary	1
Introduction	4
Forecasted Energy and Demand Growth	4
Energy Forecasts	5
Demand Forecasts	7
Oil Shale	10
Ethanol Development	11
Gas Compression	11
Load Factor	12
Conclusion on Forecasted Load Growth	14
The Price of Tri-State's Resource Development Plan	15
Capital Cost Projections	16
Operating Expense Projections	18
Cost of Service Summary	20
Projected Year 2006	20
Projected Year 2007	20
Rate Structure	21
Further Risks Inherent in Tri-State's RDP	22
Global Warming and the Likelihood of Carbon Regulation	22
Examples of Current Efforts to Control CO ₂ Emissions	23
Implications of Environmental Impacts of Tri-State's Financing Plan	24
Delivered Coal Prices	25
Sensitivity Analyses	27
Capital Costs	27
CO ₂ Regulation	27
Coal Price Increases	29
Cumulative Impact of Risk Factors	29
Conclusion	30
Attachment A: Executive Summary of WRA's April Analysis	31

Executive Summary

In April 2006, Western Resource Advocates and the Southwest Energy Efficiency Project jointly released an analysis of Tri-State Generation and Transmission Association's resource plan. The executive summary of that report is included as Attachment A.

This update focuses on a review of the Tri-State forecasts and makes a more detailed analysis of the rate impacts of Tri-State's Resource Development Plan (RDP), including a quantification of several risk factors.

Together with our earlier April analysis, this report shows that:

- Tri-State does not need the capacity of even one of the coal units contained in the RDP, much less the full 2,100 MW of capacity of all three units, to meet the projected loads of its members at least through 2019.
- Tri-State has not explained the "total obligations" it says it must meet, including loads beyond its members' loads.
- Even if Tri-State must meet "total obligations," the coal units will be of no help in the short run since they cannot be built fast enough, and are not needed in the long-run, since total obligations exceeds available capacity by only roughly 500 MW in 2019.
- Tri-State system load factors suggest that, if any capacity is needed, it is not baseload but rather peaking capacity.
- Constructing and operating the coal units will put enormous, unnecessary upward pressure on Tri-State rates, on top of the high costs of shorter-term power purchased on the open market.
- Tri-State's rate design imposes charges for power that do not distinguish between those members who are growing rapidly and those who are not; as well, the rate design does not encourage cost-effective conservation to keep system costs down.
- The RDP also ignores global warming, a serious problem that, in the name of our children and grandchildren, it is prudent to begin to address now, like other utilities are doing.
- Ignoring global warming translates into substantial rate-related risks when CO₂ emissions are regulated, which is nearly inevitable during the lifetimes of the new coal units, as well as risks related to the ability to finance these units.
- The RDP ignores the substantial risk that coal prices will increase and experience volatility, as has been the case with natural gas prices.

- The base case rate impact on Tri-State members is nearly 65% by 2011 and over 110% by 2019. If additional capital costs for the increased unit size, global warming, and coal price risks are factored into the analysis, rates could rise by 160% over the long run as a result of the construction and operation of the coal units.

Given these factors, it is difficult to see how the construction of three pulverized coal units on the Tri-State system is in the interest of its members and their owners.

What, then, should be done? There are three steps that Tri-State members should take:

Step 1 is to tell Tri-State that the RDP is not appropriate as presently designed and that a new plan must be developed.

Step 2 is for each Tri-State member to refrain from executing the 10-year contract extension that Tri-State seeks. The purpose of this contract is to provide the promise of a revenue stream to Wall Street that gets closer to the expected lifetimes of the new coal units than the present all-requirements contracts, thereby easing financing for these units. However, why would Tri-State members, who legally must act in the interest of their owners, make it easier for Tri-State to finance its deeply flawed plan? Moreover, there is substantial reason to think that a new plan will not need Tri-State to assure Wall Street bankers of a revenue stream lasting beyond the current contract, which expires in 2040.

Step 3 is for Tri-State to develop a new plan that fully integrates the abundant energy efficiency, renewable, and combined heat and power resources that exist in the areas served by Tri-State members. Estimates of these resources are contained in our April analysis. They provide enough capacity and energy for Tri-State easily to meet even its “total obligations” in 2019.

With regard to energy efficiency, Tri-State members need to tell Tri-State that it must overcome its reluctance to help its members harvest low-cost energy efficiency. Our estimate, provided in the April 2006 report, is that there is easily enough cost-effective energy efficiency on the systems of Tri-State members to meet the roughly 500 MW need for resources in 2019 under Tri-State’s yet-unexplained total obligations forecast. In the short run, energy efficiency can help Tri-State overcome any short-term resource deficits.

As an energy provider, Tri-State has an obligation to harvest economies of scale in financing, planning, and program development for energy efficiency, and to pass those economies on to its members. Tri-State’s rate design for its members can also send important price signals to encourage member energy efficiencies, as many utilities have discovered. In particular, Tri-State can send a price signal through its rate design, such as through inverted block rates, to encourage the most rapidly growing of its members to encourage their owners to conserve energy when it is cost-effective to Tri-State, thereby enabling growth on the system to pay its own way.

With regard to renewable energy resources, Tri-State members should tell Tri-State that intermittent resources like wind and solar have capacity value, as most other utilities have long

acknowledged. There is abundant information as to how to model intermittent resources so as to integrate the capacity value of these resources into the Tri-State system and to reduce imbalance payments that may become due when the wind does not blow or the sun does not shine.

Tri-State members should also tell Tri-State to conduct a detailed survey of the abundant combined heat and power resources that exist on some of the systems of its members, acquiring these resources when to do so is cost-effective to Tri-State.

Finally, Tri-State members should tell Tri-State staff that Tri-State needs to stop resisting integrated gasification combined cycle (IGCC) technology.¹ While we do not foresee the need for a new coal baseload facility of any kind on the Tri-State system through 2019, the future, as always, remains murky. In the event that Tri-State members believe such a facility is needed, after cost-effective energy efficiency, renewable, and combined heat and power resources have been acquired, Tri-State should pursue IGCC. IGCC facilities are now producing reliable grid-connected power on two systems. Twenty-four more are planned by U.S. utilities, including one by Xcel Energy in Colorado.

There are some issues to resolve surrounding the optimal design for IGCC facilities using some kinds of western coal at elevation. However, these issues will almost certainly be resolved in time for Tri-State to make a commitment to IGCC, if needed, and to find financing for it.

The authors greatly appreciate the attention that Tri-State members pay to this report. We think that there is a path forward for Tri-State that will save members money and allow Tri-State to join the growing chorus of utilities and other businesses that are moving to reduce their global warming emissions. But it will take action from Tri-State members to place Tri-State on that path.

¹ For a review of IGCC technology and its role in meeting U.S. electric loads, please see *Western Coal at the Crossroads* (Western Resource Advocates, April 2006), available at www.westernresourceadvocates.org.

Introduction

In April 2006, Western Resource Advocates (WRA) and the Southwest Energy Efficiency Project (SWEET) jointly released an analysis of Tri-State Generation and Transmission Association's resource plan (the executive summary of this report is included as Attachment A). The report, *Tri-State Generation and Transmission Association's Resource Plan: Analysis & Alternatives*, was based largely on information acquired from the Tri-State Electric Least-Cost Resource Plan Annual Progress Report filed with the Colorado Public Utilities Commission (PUC) in October 2005.

While the Tri-State 2005 progress report remains the most recent, official, detailed information from Tri-State about its resource needs, other information has subsequently come to light. For example, at its annual membership meeting in April of this year, Tri-State presented dramatic increases to its projected load growth and associated costs of providing service, based largely on serving expanding oil and gas extraction, including oil shale in Colorado. In addition, Tri-State conducted a public integrated resource plan meeting at its headquarters on October 9, 2006, which presented in graphical form another set of projected load data.

There have been other new developments since the WRA/SWEET April analysis was finished, the most significant of which is the increase in the capacity of the coal plants being proposed by Tri-State. This resource plan update is designed to provide more current information on Tri-State's resource development plan (RDP) and its ramifications. It focuses on the various load forecasts and rate impacts of the RDP.

Forecasted Energy and Demand Growth

This section of the report focuses on three different sets of energy and demand forecasts presented by Tri-State. The first is the forecast included in Tri-State's 2005 progress report to the PUC, and upon which the WRA/SWEET April analysis was based. The second is a forecast presented by Tri-State management to Tri-State members at the association's April 2006 membership meeting. The third forecast was presented on October 9, 2006 in a public meeting held to comply with the integrated resource planning (IRP) requirements of the Western Area Power Administration (WAPA). The data underlying the first two forecasts are available, but only charts were made available to elucidate the third forecast.² As a result, we have estimated the data presented in the October 9 charts for use in comparing forecasts.³

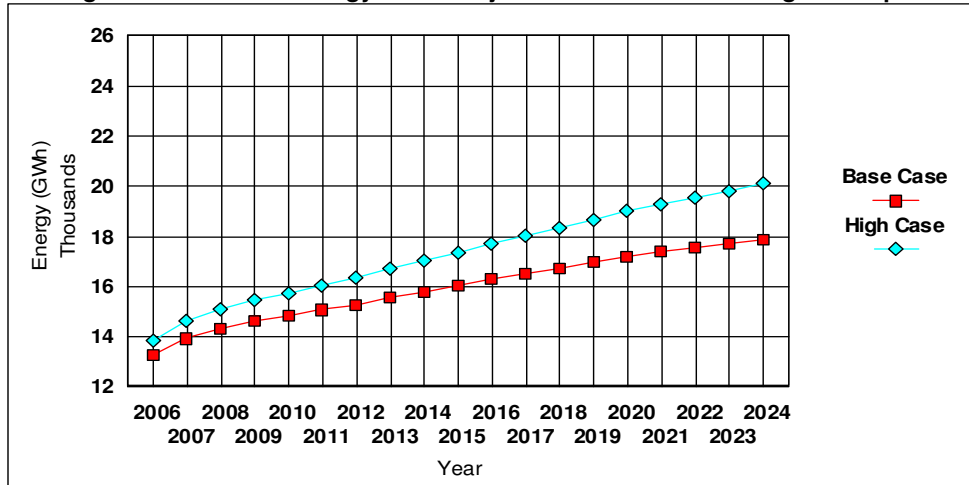
² Tri-State would not provide the underlying data.

³ Note that the charts in this section exclude the loads of Tri-State members located in Nebraska. These six members are not electrically connected to the remainder of Tri-State's system and are served directly by WAPA and Basin Electric. Basin Electric is responsible for all load growth for these member co-ops. For the purposes of comparing forecasts, the projected Nebraska energy sales were excluded from all total Tri-State estimates.

Energy Forecasts

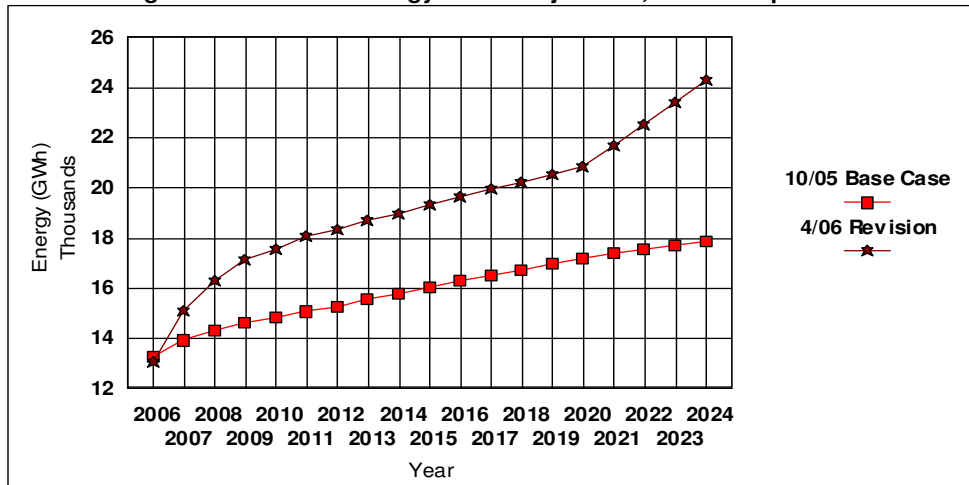
Tri-State's 2005 progress report, filed with the PUC two months *after* its board decision to move forward with the construction of 1,800 MW of new coal generation, indicated a 4% growth in energy sales for several years, leveling out to a 1% to 2% long-term growth rate, as depicted in Figure 1.⁴

Figure 1. Tri-State's Energy Sales Projections from its 2005 Progress Report



However, at its annual membership meeting in April 2006, Tri-State presented a new forecast that projected growth in energy sales exceeding 7% annually over the next six years, far in excess of the earlier October 2005 forecast. Figure 2 illustrates the comparison.

Figure 2. Tri-State's Energy Sales Projections, Revised April 2006



At the April 2006 meeting, Tri-State also presented a chart depicting a set of new load additions underlying the new forecast. The projected energy requirements of these new sources are replicated in Table 1.

⁴ Nebraska loads were deleted from all forecasts analyzed in this section, since these loads are served by Basin Electric and are not electrically connected to the remainder of the Tri-State system.

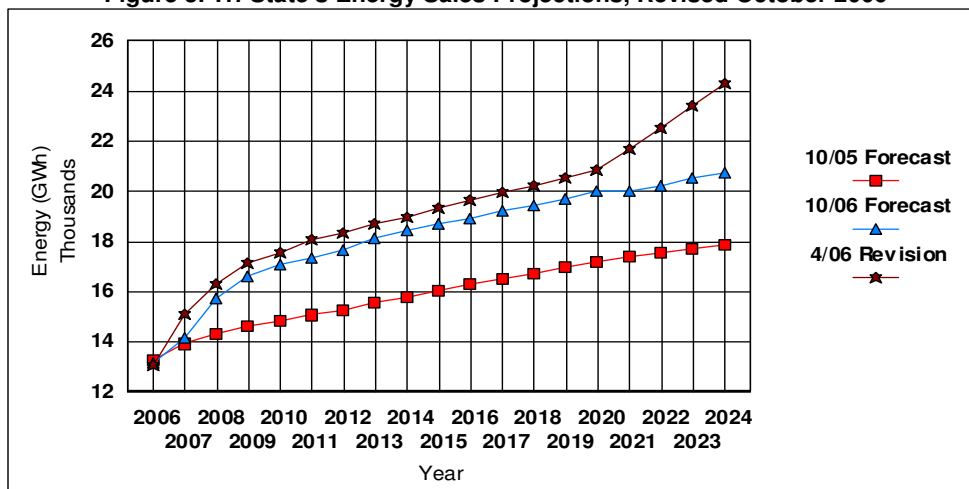
Table 1. Tri-State’s Projected New Energy Requirements, April 2006

Customer Load	Total Energy (GWh)
“Normal growth”	2,000
Gas and oil shale	1,514
US Biogen (ethanol plant)	63
Pioneer CBM conversion	581
El Paso Cheyenne Pipeline	433
Gas tighter well spacing/casino	315
Gas compression	112
Armento area compression	37
Devon CBM	11
Frontier Pipeline	9
Total	5,075

These new loads are discussed in more detail below.

In its preparation for the filing of its integrated resource plan with WAPA, Tri-State developed yet another energy forecast that was presented at the October 9, 2006 public meeting. This most recent forecast was identified as “Member Energy Requirements.” The three energy forecasts are represented in Figure 3.

Figure 3. Tri-State’s Energy Sales Projections, Revised October 2006

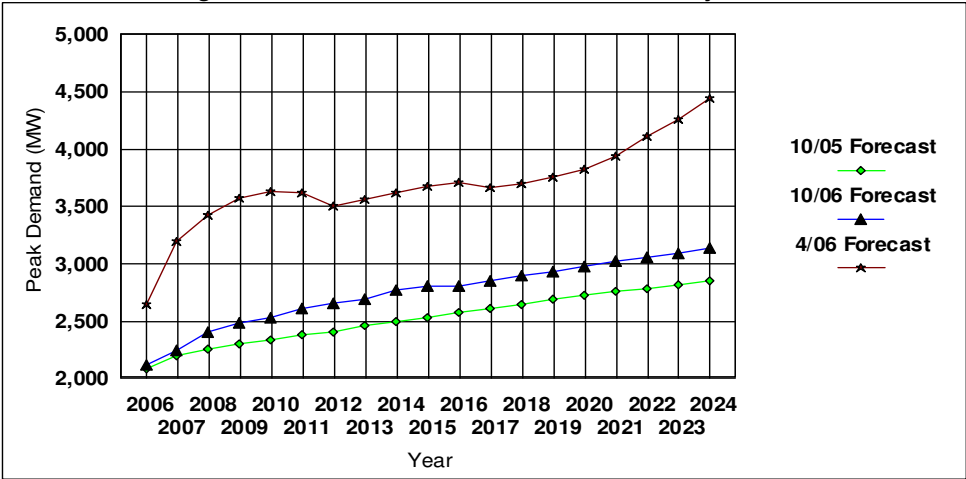


It seems reasonable to think that the most current energy forecast—the October 2006 IRP forecast—is the one being used for the purposes of determining future resource needs, along with the corresponding demand forecast discussed below. However, the higher April 2006 energy forecast was presented by Tri-State’s General Manager at a meeting of the Board of County Commissioners of Gunnison County on November 14, 2006 as the rationale for building the new baseload coal plants.

Demand Forecasts

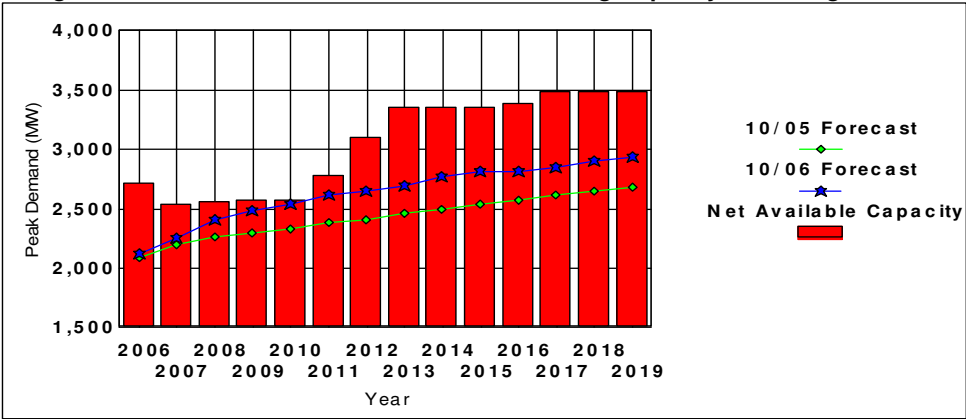
Similarly, Tri-State presented a revised peak demand forecast at the April 2006 membership meeting showing much higher growth rates than previously projected both in the 2005 progress report and in the new member demand forecast presented at the October 2006 IRP public meeting. A comparison of the October 2005 demand forecast with the newer forecasts is presented in Figure 4.

Figure 4. Tri-State’s Various Peak Demand Projections



As with the energy forecasts, it seems reasonable to think that the most current demand forecast from the October 2006 IRP presentation is the one used to determine future resource needs. Indeed, the October 2006 forecast depicted above was labeled “Member Summer Peak” and it is this peak demand for which utilities like Tri-State acquire resources. A comparison of the demand forecasts from October 2005 and October 2006 with Tri-State’s available capacity without the three new coal units is shown in Figure 5.

Figure 5. Tri-State’s Demand Forecast and Existing Capacity Excluding the RDP

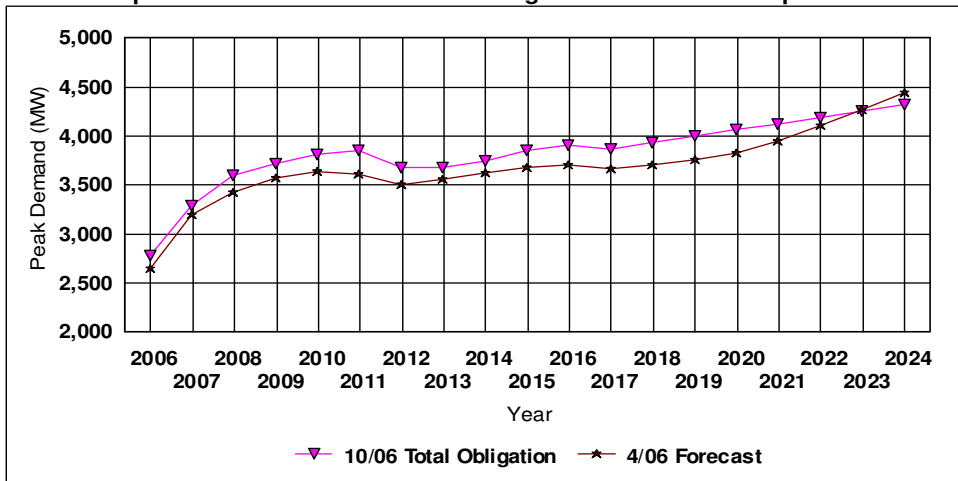


This comparison indicates that Tri-State already has sufficient capacity to meet both its October 2005 and its October 2006 peak demand forecasts in 2011, the year in which the first new coal plant would be available, and in subsequent years through at least 2019. What, then, is

the purpose of the April demand forecast, presented at the April membership meeting, together with the higher energy forecast noted above? What is Tri-State’s justification in building three new large pulverized coal units if they are not needed, according to Tri-State in the October 2006 forecast, to meet the demand of Tri-State’s members?

Tri-State’s answers to these questions may be found in its October 2006 IRP presentation, in which it also presented something that Tri-State calls its “total obligations.” By plotting Tri-State’s projections of its total obligations from the 2006 IRP meeting together with the very high peak demand forecast presented at its April 2006 membership meeting, similarities are apparent. Figure 6 presents this comparison.

**Figure 6. Tri-State’s Peak Demand Projections:
Comparison of October 2006 Total Obligation Forecast with April 2006 Forecast**



The comparison set forth in Figure 6 appears to show that Tri-State seeks to build the new coal units in order to meet “total obligations,” not only to meet member demands. To reiterate, projected member demand can be served by existing resources. Thus, projected loads over and above member demands are responsible for the expenditure of \$5 billion to \$6 billion on new coal units.

Of what new loads, above projected member demand, might “total obligations” be comprised? Our assumption is that they are comprised, at least in part, of the new loads that were set forth in Table 1 above and which were used as the basis of the very high sales and demand forecasts at the April 2006 membership meeting. We take a harder look at these loads now.

Table 2 identifies the major new loads over the next six years that Tri-State anticipates will drive its near-term resource needs. Note that the final column of Table 2 corrects several mathematical errors in this chart.

Table 2. Tri-State's Projected New Load Requirements, April 2006⁵

Six-Year Load Growth	Total Energy (GWh)	Assumed Load Factor	Demand (MW)	Corrected Demand ⁶ (MW)
"Normal growth"	2000	65%	360	351
Gas and oil shale	1514	80%	300	216
US Biogen (ethanol plant)	63	75%	96	10
Pioneer CBM conversion	581	80%	83	83
El Paso Cheyenne Pipeline	433	75%	66	66
Gas tighter well spacing/casino	315	60%	60	60
Gas compression	112	75%	17	17
Armento area compression	37	60%	7	7
Devon CBM	11	65%	2.0	2.0
Frontier Pipeline	9	75%	1.4	1.4
Total	5,075		992	813
Total less "normal growth"	3,075		632	462

Again, the information in this chart was presented at the April 2006 membership meeting to explain the significant growth in the demand forecast depicted in Figure 4. Table 3 compares the October 2005 forecast with the April 2006 forecast.

**Table 3. Change in Tri-State's Projected Demand
April 2006 vs. Oct. 2005 (in MW)**

	2006	2007	2008	2009	2010	2011
April 2006	2,650	3,196	3,423	3,570	3,634	3,616
October 2005	2,383	2,513	2,584	2,633	2,670	2,722
Difference	267	683	839	937	964	894

Note that neither the net "new growth" of 632 MW nor the corrected growth of 462 MW (Table 2) fully explains the difference with the October 2005 forecast of peak demand.

Table 4 makes a similar comparison for the two October 2006 demand forecasts ("total obligations" and total member loads), with results that show an even greater gap between these two forecasts.

**Table 4. Difference in Tri-State's Projected Demand:
Member Load vs. Total Obligations, Oct. 2006 (in MW)**

	2006	2007	2008	2009	2010	2011
IRP total obligations	2,788	3,296	3,598	3,715	3,821	3,849
IRP member demand	2,119	2,406	2,488	2,538	2,538	2,613
Difference	669	1,046	1,192	1,228	1,284	1,237

This table shows that "total obligations," upon which the need for the new coal plants appears to be based, is more than 1,200 MW greater than member demand. Tri-State's table of new loads from the April 2006 membership meeting, as corrected, explains less than half of this difference. Thus, clearly other new loads that are not represented in Table 2 must be part of the "total obligations" or Tri-State has significantly overestimated the new loads.

⁵ Source: PowerPoint presentation to members at April 2006 membership meeting.

⁶ The demands were corrected based on the energy projections and the load factors.

Turning to the new loads that are represented in Table 2, the largest new load is gas and oil shale. With an anticipated load of some 300 MW, this load projection alone represents an enormous 12% of Tri-State's current peak load. Even when mathematically corrected to 216 MW, it is still a huge new load and merits further investigation.

Oil Shale

In 2005, the RAND Corporation prepared a report on oil shale development in the U.S., addressing issues relevant to the potential load for Tri-State. The potential energy needs for commercial-scale development of oil shale resources using in-situ technologies being explored by Shell Exploration, Inc. in western Colorado could be significant. It is estimated that an operation producing 100,000 barrels per day using Shell's method requires approximately 1,200 MW of dedicated electric generating capacity.⁷ This scale of development, however, is far in the future. The RAND Corporation estimates that Shell will be unable to even make a determination to go forward toward commercial production until the end of the decade, and production of 100,000 barrels per day could not occur until 2020 or later. Obviously, it is premature to build capacity to meet this demand, and at this point entirely speculative, even assuming that it would be Tri-State's responsibility to meet this demand rather than Shell's.

The key question, then, is what is the possible peak demand of oil shale development in the short run, in the next six years, the period in which Tri-State assumed an annual growth rate exceeding 7% in its April member meeting presentation? In this regard, the Bureau of Land Management (BLM) is currently considering five proposals for research and development leases for in-situ development of federal oil shale resources in Colorado's Piceance Basin. Three of the proposals—all submitted by Shell—would use electrical resistance heaters to heat the shale. Shell has been markedly tight-lipped about the energy needs for its proposed processes, but a recently available working paper from the University of California-Berkeley's Energy and Resources Group presents a net energy and greenhouse gas emissions analysis of the Shell in-situ conversion process.⁸

The paper quantifies the energy requirements for various process-stages of Shell's three R&D test sites, as detailed in the company's Plans of Operation submitted to the BLM in early 2006. Specifically, the paper examines the electrical energy requirements for the down-well heaters for the R&D sites and estimates them to be as much as 1,200 terajoules (TJ), or 324,000 megawatt-hours (MWh). The power requirement for this amount of annual energy usage would be roughly 37 MW. Likewise, the RAND Corporation estimates that about 250 to 300 kilowatt-hours (kWh) are required for down-hole heating per barrel of oil produced. Shell estimates production at its three proposed R&D sites to reach 2,700 barrels per day by the end of activities on its three 10-year leases. Using RAND's figures, the power requirement would be similar—34 MW. The energy requirements for the refrigeration portion of the proposed freeze wall construction at Shell's sites are estimated to be as much as 383,900 MWh. Assuming all of the energy requirements for the refrigeration are met with electricity, the power required for this

⁷ James T. Bartis et al., *Oil Shale Development in the United States* (RAND Corporation, 2005), pg 21.

⁸ A. Brandt, "Net energy and greenhouse gas emissions analysis of synthetic crude oil produced from Green River oil shale," in review (2006) at *Energy*. Working paper available upon request at <http://abrandt.berkeley.edu/>.

amount of annual energy usage would be roughly 44 MW.⁹ Thus, the total electrical power needs for the heating and refrigeration systems at these three R&D sites appears to be approximately 80 MW. By comparison, Tri-State's figure of 300 MW (or even the corrected figure of 216 MW) appears to be out of line with this analysis.

Moreover, recently Shell has indicated that it will likely build its own electrical generating capacity to meet its needs for this project. Together with the likelihood that Tri-State's analysis of the power needs for oil shale is overstated, this suggests that Tri-State members should look at this new load with skepticism.

Ethanol Development

The next-largest new load projected by Tri-State is for the US Biogen ethanol plant planned for Morgan County, Colorado. This 100-million-gallon facility is expected to require 63 GWh at a load factor of 75%. Mathematically, this results in a peak load of 9.6 MW rather than the projected 96 MW. To verify that this difference was a simple calculation error and not an error in projected energy consumption, a review of ethanol plant energy requirements was undertaken. It was reported in the cover story of the September 2006 issue of *RE Magazine*, published by the National Rural Electric Cooperative Association, that a 100-million-gallon ethanol facility in Albert City, Iowa, would have "about a seven- to eight-megawatt load with an 85 to 90 percent load factor." This is consistent with the 9.6 MW calculated using the projected consumption and load factor.

Gas Compression

Virtually all the remaining new load appears to relate to natural gas extraction and compression. Without analyzing these specific projects in detail, the same concerns exist regarding the nature of the load. Are these loads overstated? Are they short- or long-term in nature?

The new load requirements presented by Tri-State at its April membership meeting require careful scrutiny, as they appear to be the drivers of an investment exceeding \$5 billion and rate increases of unprecedented proportion, as detailed below. The oil and gas industry in the West has a history of boom and bust, so careful attention should be paid to the appropriate spread of costs and risks related to the viability and volatility of this industry. Otherwise, Tri-State members could be left holding the bag, as some of them were when Colorado-Ute went bankrupt after overbuilding generation capacity that did not materialize.

Tri-State must be able to credibly assure its members that it has done everything in its power to mitigate the risks associated with new loads. Examples of some methods and mechanisms for risk mitigation include:

- Long-term purchase agreements, with provision for stranded cost recovery.
- Posting of bonds for potential stranded cost recovery.

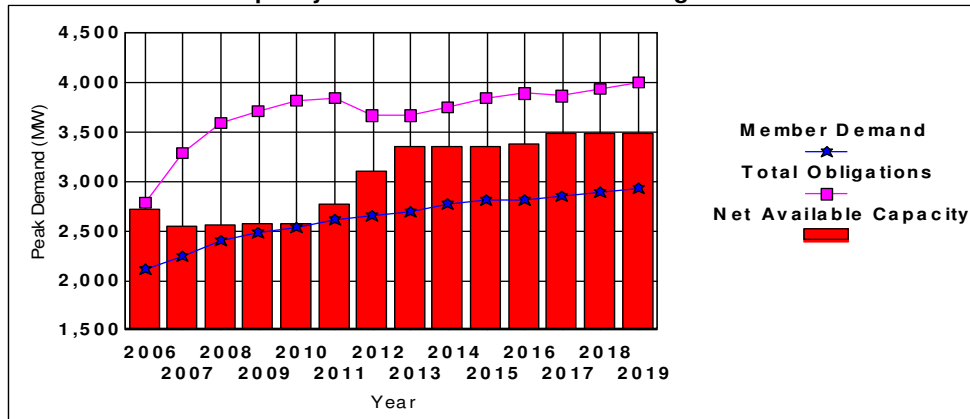
⁹ The assumption that electricity will be the prime energy source for the refrigeration process is based on a review of Shell's Plans of Operation, which do not account for any on-site capability to generate the power needed for the refrigeration.

- Contributions in Aid of Construction for the necessary generation and transmission.
- Investigation of self-generation options.
- Construction of distributed local facilities to serve these loads or a portion thereof.
- Utilization of applicable combined heat and power technologies.
- Maximizing the efficiency of these facilities' operations.
- Initiating rate structures that encourage more efficient use of energy.
- Surcharges for unusual and risky loads.

Even in the event that sufficient new loads materialize to result in the October 2006 forecasted total obligations, the resource need remains far less than the resource plan proposes to construct.¹⁰

Figure 7 shows the resource picture through 2019 reflecting that total load obligation.

Figure 7. Tri-State's October 2006 Peak Demand Forecast Showing Capacity Shortfall Relative to Total Obligations



This summary of the October 2006 IRP forecast clearly indicates that, in the next few years, the shortfall could exceed 1,000 MW. However, the coal units Tri-State plans to build will be of no help, since the first of them will now not be online until 2012. After 2011, the shortfall as far out as 2019 is only about 500 MW, and nowhere near the 2,100 MW Tri-State plans to build. Perhaps Tri-State intends to sell the excess capacity on the open market, or has unpublished firm off-system commitments for this power. In any event, this difference indicates some level of engagement in the merchant coal generation market.

Load Factor

Load factor is a measure that compares average demand for electricity with the peak demand. The higher the annual load factor, the more consistently and efficiently the system is being utilized. Residential customers tend to have lower load factors, while industrial consumers often have high load factors. Some of the best utility load factors approach 80% annually.

¹⁰ This would require all of the loads in Table 2 plus approximately 700 MW of new presently unidentified additional demand to make up the difference between the member load forecast and the total obligations.

Utilities with sharp peaks driven by air conditioning tend to have lower load factors, sometimes below 50%. Generally, the lower the load factor, the more gas resources one might expect to see on a given system. In reviewing forecasts of peak demand and energy consumption, one might expect to see gradual changes in load factor over time. Such a review is a good method for checking consistency of energy and demand forecasts.

Load factor can also be used to help understand the drivers of growth. For example, declining load factors are observed as the penetration of air conditioning increases. This has been the experience of Xcel Energy over the past decade, with its load factor declining from around 70% to the mid to low 60s.

In Tri-State’s case, the demand growth from 2004 to 2005 of 9.9% has far exceeded the 3.8% growth in sales. This result is likely related to the suburban Front Range growth described in our April analysis. In its April 2006 forecast, Tri-State predicts that the peak load will increase by 22% and 37% in 2006 and 2007, respectively (including Nebraska members) over the actual 2005 peak demand. Over the same two years, energy consumption is projected to increase by about 5% and 14%, respectively (including Nebraska members).

One of Tri-State’s responses to our April analysis was that its high load factors necessitate baseload generation to serve its members. Tri-State’s actual member load factors for 2001 through 2005 are shown in Table 5. These figures are generally in decline, and do not support Tri-state’s contention.

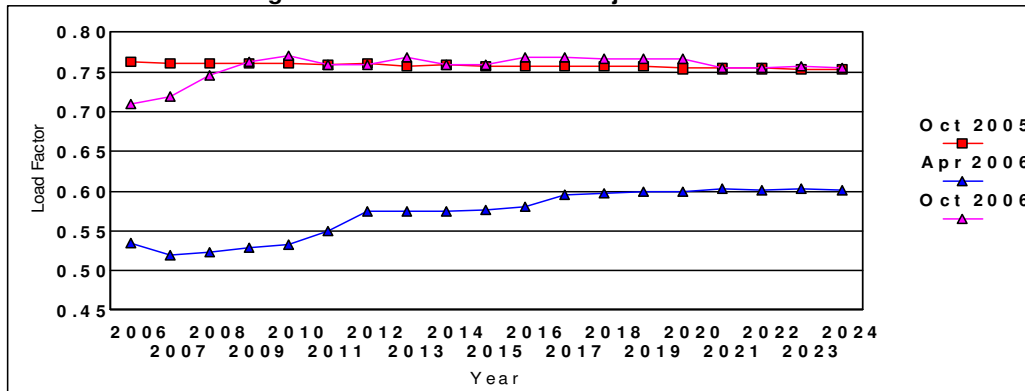
Table 5. Tri-State’s Actual Load Factors, 2001-2005

	2001	2002	2003	2004	2005
Member demand	1,879	2,050	2,110	2,091	2,299
Member sales	10,952	11,731	11,729	12,010	12,466
Load factor	67%	65%	63%	66%	62%

The relatively low load factors of Tri-State’s system currently indicate a peak demand significantly higher than average energy use throughout the year, and also indicate opportunities for energy efficiency programs that can be designed to improve load factors.

Figure 8 shows the load factors associated with projected member energy and demand data for Tri-State’s three forecasts. The load factors derived from the October 2005 and October 2006 base case projections indicate a stable, but perhaps optimistic, 75%. The load factors associated with the April 2006 forecast (keeping in mind that this forecast is closest to the “total obligations” upon which the need for the new coal units appears to be based) is considerably lower.

Figure 8. Tri-State's Various Projected Load Factors



All of Tri-State's projections are inconsistent with the present experience of declining load factors on the Tri-State system. Even with the addition of the new high-load factor loads (Table 2) in the future, the load factors associated with the forecast being utilized to justify the coal capacity additions (April 2006) indicate a need not for baseload generation, but for intermediate or peaking resources, if any are needed at all.

Conclusion on Forecasted Load Growth

As a result of contracts that Tri-State has entered into with other utilities, including Public Service Company of Colorado, Tucson Electric Power, Pacific Power and Light, and Public Service Company of New Mexico, Tri-State faces a capacity shortfall through about 2011. The three new coal plants that comprise its RDP will not help with the shortfalls indicated by any of the demand forecasts.

Based upon the forecasted energy and demand for electricity of its members, Tri-State does not need to acquire new resources. The member demand forecast presented at the October 2006 IRP meeting is within the capability of the existing resources.

Even using the "total obligations" demand forecast presented at the October 2006 IRP meeting, which far exceeds member demand and is without documented support, the resource need in 2019 (the year the third coal plant is scheduled to come online) is about 500 MW.

These facts beg some questions. Is Tri-State speculating on the future energy market by overbuilding its system? Does Tri-State intend to sell excess capacity on the open market? Does Tri-State have firm off-system sales commitments for this power? Do Tri-State's members want Tri-State to build coal units that are not needed to meet the demand of Tri-State's members for electricity?

And, even if there is a need for new resources, perhaps up to 500 MW, what are all the resource options available to meet those requirements? Our April 2006 report on Tri-State's resource plan laid out numerous alternatives, including demand-side resources capable of providing 550 MW by the year 2019.

The question is simple: Will Tri-State's membership spend over \$5 billion to serve the unidentified load that is over and above member requirements?

The Price of Tri-State's Resource Development Plan

"It should be emphasized that Tri-State is committed to the concept of operating the company at the lowest possible cost to minimize rates charged to members."

- Hub Thomson, Chairman and President, Tri-State

Our analysis strongly suggests that Tri-State's proposed resource development plan is not consistent with Mr. Thomson's commitment.

In our April analysis, we roughly estimated that \$5 billion of capital expenditures would increase rates by at least 50%, recognizing that this figure only approximated the impact of the capital requirements. However, Tri-State did not dispute this figure. According to Tri-State spokesperson Jim Van Someren, as reported in the *Montrose Daily Press*,¹¹ "Tri-State estimates that wholesale utility costs to its members will increase 7 to 12 percent annually for the next three to five years." Put another way, Tri-State projects price increases ranging from a minimum 23% in three years to 76% in five years.

In order to provide a more accurate estimate of the price increases associated with Tri-State's plan to build three new large pulverized coal generating units, a review of its costs of providing electric service was undertaken. Using information gleaned from Tri-State's annual reports (2001 through 2005), as well as from presentations made at its April 2006 membership meeting, it was possible to establish capital and expense trends and relationships that could then be used in a revenue requirements model to project future costs for providing service, incorporating the proposed coal plants.

Since the specific underlying data for the forecasts presented at the October 2006 IRP public meeting were not available, data from the similar April 2006 membership meeting forecast were utilized. Indeed, these data likely understate the rate impact, given that the latter is lower than the October 2006 forecast.

The revenue requirements model derives a year-by-year projection of costs and rates that are based on the following:

- Tri-State's projected annual capital expenditures for Holcomb 3 and 4 (the first two Tri-State coal units) and the Colorado Power Project (the third Tri-State coal unit), and for the associated transmission capacity.
- Tri-State's projected energy growth.
- Tri-State's target equity to total capitalization ratio of 25% by 2025. The rate model increases equity as a percent of total capitalization by about .5% per year until it reaches 25%, using the Tri-State schedule.

¹¹ May 10, 2006.

- Tri-State’s projection of annual spot purchases, estimated to reach \$350 million prior to the Holcomb units coming online, based upon projections of spot market purchases from gas generators in the \$70 to \$80 per MWh range for the next 5-7 years.
- Tri-State’s projected rate of inflation of 3% annually.

In addition, historical information derived primarily from Tri-State’s annual reports, its website, and reports to the PUC was utilized to project capital and expense trends. The results of this analysis for the next five years (2007-2011) are presented below, broken down into two categories. First, the projected capital costs are reviewed and summarized, including those related to RDP. Next, the expenses associated with financing and operating the new capital additions are combined with the projected costs of operating the existing system. We then estimate the rates necessary to recover the total costs.

While Tri-State does not operate in a traditional regulated environment, where rates are determined by the sum of return on rate base and operating expenses, there are many similarities. As a cooperative, its members are its de facto shareholders. It is “regulated” by a board of directors comprised of a board member from each of its individual member cooperatives. The theory behind this self-regulation is that the board will not do anything that is not in Tri-State’s self-interest, or in the interest of its member co-ops, including effective due diligence on capital expenditures.

There is no group other than members from which to draw capital to pay for cost overruns, or to enjoy the benefits of revenue acquired in excess of the costs of operation. Each year, Tri-State declares a net margin representing the bottom-line difference between revenue and expenses. In 2005, this figure was \$47.4 million. From this amount, a portion of patronage capital is refunded to members—\$5 million for each of the last three years (down from \$15 million annually from 1996 to 2000).

Tri-State’s rates can be projected by summing its estimated expenses for future periods and dividing this by the projected sales for the corresponding period. The cost of providing service to its members will be the sum of the projected capital costs and the projected operating costs. The former component represents the borrowing costs related to the funds required for outlays of capital to construct new assets. For this analysis, it was assumed that equity, or patronage capital, has no cost.

Capital Cost Projections

Tri-State proposes to spend over \$5 billion on the production and transmission components of its RDP. While the majority of the capital requirements (over 80%) will be for generation, approximately \$1 billion is projected for the transmission requirements, also known as the Eastern Plains Transmission Project.

The projected expenditures based on three 600 MW units in the RDP are broken down by year in Table 6.

Table 6. Tri-State's Schedule of Resource Plan Expenditures (\$ in millions)

Year	Production	Cumulative Production	Transmission	Cumulative Transmission	Total Cumulative
2006	\$33	\$33	\$12	\$12	\$45
2007	\$37	\$70	\$49	\$61	\$131
2008	\$293	\$363	\$51	\$112	\$475
2009	\$557	\$920	\$101	\$213	\$1,133
2010	\$625	\$1,545	\$194	\$407	\$1,952
2011	\$680	\$2,225	\$223	\$630	\$2,855
2012	\$306	\$2,531	\$121	\$751	\$3,282
2013	\$5	\$2,536	\$18	\$769	\$3,305
2014	\$6	\$2,542	\$9	\$778	\$3,320
2015	\$12	\$2,554	\$19	\$797	\$3,351
2016	\$412	\$2,966	\$49	\$846	\$3,812
2017	\$412	\$3,378	\$49	\$895	\$4,273
2018	\$412	\$3,790	\$49	\$944	\$4,734
2019	\$412	\$4,202	\$49	\$993	\$5,195

Bearing in mind that Tri-State's current assets total about \$2.1 billion, the RDP is a very aggressive plan from a financial standpoint. Aside from the RDP, Tri-State has ongoing capital needs. For the purposes of this analysis, a baseline capital budget figure of \$50 million was assumed for 2006 (i.e., not included in the above table), which is 10% below the lowest annual amount in the last six years and well below the 10-year average.¹² The model then adjusts the planned capital additions for depreciation and develops Tri-State's total utility asset base by adding the net additions to the existing plant. It then estimates total interest expense by adding the expense associated with the current (i.e., 2005) asset base¹³ to the interest expense associated with the net additions over the period based upon the current prime lending rate.¹⁴

It is important to note that, as mentioned above, Tri-State's target equity ratio is 25% by 2025, representing a substantial increase from the 2005 ratio of 12.2%. The model increases equity as a percent of total capitalization using the Tri-State schedule and reduces the portion of capital additions that must be financed by the same amount.

Due to the cooperative structure, any additional equity required must come from members. While it may come from members as a lump sum outside of the rate structure, it would still represent an additional cost to the members. Thus, for the purposes of determining the financial impact of the RDP on Tri-State's member cooperatives, the additional equity is deemed to be derived through the rate structure. The additional equity is derived by using the 12.2% equity ratio projected by Tri-State for 2006 as a starting point, adding the incremental plant additions to total capitalization, and determining the total equity and debt required to achieve the desired ratios. The debt service and the annual equity (net margin) amounts are the capital costs that will be recovered through the wholesale rates that Tri-State's charges its member cooperatives. These are depicted in Table 7 below.

¹² A low number was used to be conservative. Any ongoing capital needs exceeding the \$50 million baseline will further increase rates.

¹³ The 2005 average interest rate is held constant and applied to the depreciating asset base.

¹⁴ Tri-State does not intend to use Rural Utilities Service (RUS) funding for the first unit, but has not ruled it out for the next two units. The model described here assumes non-RUS financing at the prime lending rate for all three units.

Table 7. Summary of Tri-State's Capital Requirements (in \$000)

Year	Electric Plant	Net Electric Plant	Interest Expense	Net Margin Requirements
2005 actual	2,750,631	1,552,201	100,261	47,413
2006	2,800,631	1,514,675	101,973	11,929
2007	2,852,131	1,478,603	104,376	46,066
2008	3,017,176	1,553,367	125,520	78,441
2009	3,071,812	1,520,333	169,341	119,150
2010	3,128,088	1,488,887	224,011	150,300
2011	4,969,551	3,196,738	283,962	171,963
2012	6,415,754	4,518,702	310,285	105,319
2013	6,477,248	4,492,311	305,982	74,339
2014	6,540,586	4,467,707	300,671	80,396
2015	6,651,825	4,489,851	296,997	78,461
2016	6,719,021	4,468,984	328,959	78,469
2017	6,788,232	4,450,070	360,700	83,158
2018	6,859,521	4,433,167	388,903	128,110
2019	8,799,947	6,236,399	415,861	145,356

These figures were derived using the capital costs Tri-State projected for three 600 MW units in its RDP. Tri-State has recently announced an increase in the capacity of the three proposed plants. It is unknown whether the increase from 600 to 700 MW for each unit will result in higher capital costs, although it seems reasonable to think that it will, notwithstanding Tri-State's belief, as stated in a presentation to the Board of County Commissioners of Gunnison County on November 14, 2006, that it will not. In any event, we assume that the cost of three 700 MW units will have a cost somewhere between the cost of the 600 MW units and a cost that is about 17% higher. Table 8 estimates the cost of three 700 MW units, assuming the cost per kW is the same as the current proposal. The rate impact of this potential \$700 million increase in capital costs will be discussed in more detail later in this report.

Table 8. Potential Cost of Tri-State's 700 MW vs. 600 MW Units

RDP Unit	Cost (\$ billion)	Capacity (MW)	\$/Kw	Cost of 700-MW Units
Holcomb 2	\$1,265.5	600	\$2,109	\$1,476
Holcomb 3	\$1,265.5	600	\$2,109	\$1,476
Colorado Power Project	\$1,671.0	600	\$2,785	\$1,950
Total	\$4,202.0	1,800		\$4,903

Operating Expense Projections

The other major category of costs that must be recovered from customers are those related to the operations of the production and transmission assets and of the business in general. These costs are generally broken down into major categories and many, many subcategories. For the purposes of this analysis, trends in the expense categories were reviewed and adjustments made, as appropriate, to arrive at projected costs that are representative of anticipated future conditions. The major categories can be reduced to three:

- Operating and maintenance expenses
- Depreciation and amortization expenses
- Taxes

For the purposes of this analysis, it was assumed that Tri-State incurs no income taxes payable on future operations. In addition, it has reported no other taxes separately; thus the assumption is made that any and all wage-related and asset-related taxes are incorporated into other operating expense accounts. Thus the tax category is effectively empty of costs.

Depreciation and amortization expenses include not only the normal depreciation associated with capitalized assets, but also amortizations of other financial assets, including regulatory assets. For the purposes of this analysis, it was assumed that the 2005 amount for depreciation and amortization expense would remain unchanged except for the depreciation of new assets added to electric plant in service described in the previous section. The new assets are comprised of the annual baseline capital budget amount (\$50 million for 2006) and the RDP, according to the timing outlined in Table 9.

Table 9. Summary of Tri-State's Resource Plan-Related Plant Additions

Function	Year	Asset	Description
Transmission	2008	\$112.0	Eastern Plains Transmission planning and construction
Transmission	2011	\$518.0	Transmission construction to support Holcomb 3 and 4
Transmission	2012	\$121.0	Transmission construction to support Holcomb 4
Transmission	2015	\$46.0	System reinforcement
Transmission	2019	\$196.0	Transmission upgrades
Production	2011	\$1,265.5	Holcomb 3
Production	2012	\$1,265.5	Holcomb 4
Production	2019	\$1,671.0	SE Colorado power project
		\$5,195.0	Total generation and transmission expenditures

Operating and maintenance (O&M) expenses made up some three-quarters of total expenses in 2005. Since Tri-State is a generation and transmission association, its O&M expenses can be subdivided into three categories: production, transmission, and administrative/general. A large component of production expense in the near term is power that will be purchased on the open market to meet the anticipated demand and energy shortfalls. Tri-State's estimates for the near term are reflected in Table 10.

Table 10. Tri-State's Purchased Power Projections

(000)	2006	2007	2008	2009	2010	2011
Purchased power	\$83,321	\$229,250	\$331,538	\$336,585	\$357,264	\$297,699

A number of the components in these categories were projected based upon historic trends from 2001 through 2005. For example, the four-year trend for administrative/general expense yielded an annual escalation factor of 6.33%. Production and transmission O&M expenses were projected in a similar fashion, but unitized based upon an appropriate scale factor.¹⁵

¹⁵ Line miles in the case of transmission; capacity or energy as appropriate for production.

Cost of Service Summary

The end result of these projections for operating expenses and capital costs are then summed and divided by Tri-State's projected sales to yield average annual rates per kWh. These rates and percentage increases, coming on the heels of rate increases of 7% in 2003 and 13.8% in 2005, are summarized in Table 11.

Table 11. Tri-State's Base Case Rate Summary (\$ in thousands)

	Actual 2005	2006	2007	2008	2009	2010	2011
Net margin	\$47,413	\$11,929	\$46,066	\$78,441	\$119,150	\$150,300	\$171,963
Interest expense	\$100,261	\$101,973	\$104,376	\$125,520	\$169,341	\$224,011	\$283,962
Other expense	\$5,994	\$6,174	\$6,359	\$6,550	\$6,746	\$6,949	\$7,157
O&M expense	\$625,726	\$711,622	\$1,030,212	\$1,096,338	\$1,151,003	\$1,208,026	\$1,268,752
Other income	\$21,774	\$22,427	\$23,100	\$23,793	\$24,507	\$25,242	\$25,999
Total costs	\$757,620	\$809,272	\$1,163,912	\$1,283,055	\$1,421,734	\$1,564,043	\$1,705,835
Member rate	\$48.30	\$47.05	\$60.34	\$63.04	\$67.53	\$73.76	\$79.46
Cumulative change		-2.6%	24.9%	30.5%	39.8%	52.7%	64.5%
Actual rate changes		4.0%	16.3%	??	??	??	??

The primary sources of the rate increases projected in this chart are the short-term power purchases to meet shortfalls over the next few years and the construction of the first two coal units. The purchased power costs fall precipitously between 2010 and 2012, effectively dropping to near zero. The cost of the proposed coal plants keeps rate levels high subsequent to the reduction in purchased power costs. The increases to rates above 2005 levels for Tri-State's resource plan are 64.5% by 2011 and over 110% by 2019.

Projected Year 2006

The last year of actual data is 2005, and the projections for 2006 are derived as described above. Since the model calculates the revenue required to meet all expenses with sufficient cushion to achieve the desired equity ratio—in this case the same 12.2% obtained in 2005—the net margin required drops considerably. As a result, the net margin required declined from the actual \$47.4 million in 2005 to only \$11.9 million in 2006. This decline was sufficient to overcome expense increases and, combined with an unprecedented 12% sales growth, resulted in a projected decline in required revenue per kWh. As a practical matter, Tri-State increased rates by 4% in 2006; thus the actual net margin is likely to be higher than the model predicts. This will serve to help offset the rather large rate increase otherwise required in the following year.

Projected Year 2007

The nearly 25% increase required in 2007 (over 2005 rate levels) is largely due to dramatic increases in Tri-State's projected purchased power costs and a peak in projected lease costs. The increase in power purchase costs itself is related not only to high projected gas costs, but also a projected 15% increase in member sales. Tri-State has already announced a rate increase of 11.8% for 2007, resulting in a cumulative increase of 15.4% over 2005 rate levels, or almost 42% including the 2003 and 2005 increases.

Rate Structure

While insufficient data are available to design rates, general utility practice at the wholesale level is to create a two-part structure based upon customer (in this case, member) demand (kW) and energy (kWh). While this may sound simple, it can be a complex process. There are multiple cost allocation and rate design methods that could be used, as well as multiple billing quantities possible to use within those designs.

Rates can be designed to provide an incentive to change the behavior of customers—be they large or small. Such incentive rates are used around the country in places where the cost of serving the incremental growth is high. These rates can be designed to both reward desired load patterns and penalize (economically) undesirable or costly load patterns, to increase the efficient use of resources across a system. Tri-State’s rate to its members could be designed to provide incentives to manage the growth on its system that it perceives is driving future costs.

Tri-State sells power to its members according to a “postage stamp” rate in which the level of the charges to each member is the same, regardless of whether or not a member is contributing to system growth. The Tri-State postage stamp rate collects 58% of its total revenue through the kW or demand charge, benefiting those members with higher load factors—that is, those that have comparatively deeper penetrations of high load factor industrial customers than lower load factor residential customers.¹⁶ Table 12 presents the member cooperatives at both ends of the industrial penetration spectrum.

Table 12. Highest and Lowest Industrial Penetrations of Tri-State’s Member Cooperatives, 2005

Top Ten		Bottom Ten	
Southwestern	92%	Y-W	26%
Springer	91%	Mora-San Miguel	24%
White River	87%	Roosevelt	23%
High Plains	84%	Midwest	21%
Empire	80%	Sierra	20%
La Plata	75%	San Luis Valley	19%
Big Horn	71%	Chimney Rock	19%
Continental Divide	70%	Panhandle	14%
Wheatland	67%	Garland	9%
Socorro	62%	Northwest	8%

¹⁶ Individual member cooperatives can compare their own system load factors with those of their fellow Tri-State members to determine where they might fall in the load factor hierarchy, as such data is not publicly available.

Further Risks Inherent in Tri-State’s RDP

Our April analysis of Tri-State’s resource plan included a section that addressed certain risk factors. We revisit two of these factors here—global warming/carbon regulation and coal price increases—as a means of setting the stage for sensitivity analyses of the rate projections.

Global Warming and the Likelihood of Carbon Regulation

In recent years, the science supporting the notion that human activities are warming the atmosphere has become overwhelmingly compelling. For example, on the basis of ice-core data taken from Antarctica, scientists now believe that there is a higher concentration of carbon dioxide (CO₂) in the atmosphere than at any time over the last 650,000 years.¹⁷ At the same time, data released by the World Meteorological Organization and NASA indicate that the 10 warmest years in the last 150 years (the period for which there are good global temperature records) have occurred since 1990.¹⁸ There is near unanimity within the scientific community that human activities, particularly the combustion of fossil fuel, are warming the atmosphere.

The potential impacts of global warming are serious. They include more intense storms, sea-level rise creating tens of millions of refugees, and extinction of a quarter or more of the world’s species.¹⁹ In the American West, the risks include much deeper droughts, impacts on agricultural production and water supply, greatly increased wildfire danger, and loss of wintertime recreation and related impacts on local economies attributable to loss of snowpack.²⁰ On the basis of impacts like these, the science academies of 11 nations—including the U.S., China, India, Russia, Japan, and several European countries—told the G8 Summit in 2005, “The scientific understanding of climate change is sufficiently clear to justify nations taking prompt action.”²¹

Given that a large portion of CO₂—the principal global warming gas by volume—stays in the atmosphere exercising its warming influence for decades and longer, we cannot simply wait until the Earth’s climate becomes intolerable and then stop emitting global warming gases. There is gathering opinion that we must make substantial reductions in CO₂ emissions, perhaps

¹⁷ U. Siegenthaler et al., “Stable Carbon Cycle–Climate Relationship During the Late Pleistocene,” *Science* 310 (November 25, 2005): 1313-1317.

¹⁸ See World Meteorological Organization press release, December 15, 2005, WMO-No. 743. See also J.E. Hansen et al., “GISS Surface Temperature Analysis, Global Temperature Records: 2005 Summation,” Goddard Institute for Space Studies, <http://data.giss.nasa.gov/gistemp/2005/>.

¹⁹ See “U.S. Environmental Protection Agency, Global Warming – Impacts,” <http://yosemite.epa.gov/oar/globalwarming.nsf/content/impacts.html>. See also Tim Flannery, *The Weather Makers* (New York: Atlantic Monthly Press, 2005); R. Warren and M. Meinshausen, in H. Schellnhuber, et al. (eds.), *Avoiding Dangerous Climate Change* (Cambridge University Press, 2006); C.D. Thomas et al., “Extinction Risk from Climate Change,” *Nature* 427 (2004): 145–148; and the Stern Review Report, a comprehensive review of the economic impact of global warming, carried out for the government of the United Kingdom, which estimated that, if we do nothing about global warming, global GDP may be reduced by at least 5% to 10%.

²⁰ See Rocky Mountain Climate Organization, www.rockymountainclimate.org; in particular, Stephen Saunders and Maureen Maxwell, “Less Snow, Less Water: Climate Disruption in the West,” 2005.

²¹ Joint Science Academies Statement: Global Response to Climate Change, at the Gleneagles G8 Summit, 2005.

on the order of 60% to 80% from today's levels, within a few decades or we shall have committed the planet to the impacts just summarized.²²

Examples of Current Efforts to Control CO₂ Emissions

Motivated by these considerations, many in the U.S. are moving to control emissions of CO₂ and other global warming gases. For example, as of November 15, 2006, 330 U.S. municipalities had adopted the Mayors Climate Protection Agreement, requiring emissions reductions as great or greater than those embodied in the Kyoto Protocol.²³

At the state level, California, the largest electricity market in the West, recently enacted two pieces of legislation: AB32 requires the state's global warming emissions to be reduced to 1990 levels by 2020, accomplished through an enforceable statewide cap on global warming emissions; and SB1368 allows new capital investments in power plants for baseload generation (in state and out of state) by any load-serving entity if and only if their greenhouse gas (GHG) emissions are as low or lower than GHG emissions from new combined-cycle natural gas power plants.²⁴ Effectively, this means that California will no longer be a market for out-of-state coal-based generation unless at least 50% of the carbon dioxide is sequestered.

Other states in the West, such as Arizona, New Mexico, Oregon, and Washington, are moving in a similar direction. For example, recognizing the profound implications that global warming and climate variation could have on the economy, environment, and quality of life in the Southwest, New Mexico Governor Bill Richardson signed Executive Order 05-033 on June 5, 2005, establishing the New Mexico Climate Change Action Council to review and provide recommendations to the governor's office regarding climate change policy. In addition, the New Mexico Climate Change Advisory Group (CCAG) was charged by the governor with presenting a report to the Climate Change Action Council by December 1, 2006, to include:

- Proposals for reduction of GHG emissions to reduce New Mexico's total greenhouse gas emissions to 2000 levels by the year 2012, 10% below 2000 levels by 2020, and 75% by 2050.
- An inventory of existing and planned actions that contribute to GHG emissions reductions.
- Findings on initiatives to create meaningful regional and national policy to address climate change.

Factors under consideration by the CCAG include increasing the state's renewable portfolio standard (RPS) to 30% by 2021; financial incentives for distributed renewable energy and renewable energy transmission and storage; financial incentives for centralized renewable energy, advanced coal with carbon capture, nuclear energy, and combined heat and power; demand-side management opportunities; integrated resource planning requirements; a generation performance standard similar to California's; and regulatory reform for electric cooperatives.

²² M. Meinshausen, "On the Risk of Overshooting 2 degrees C," presented at the Avoiding Dangerous Climate Change conference, Exeter, U.K., 2005.

²³ See <http://www.seattle.gov/mayor/climate/default.htm#cities>.

²⁴ See "California, Taking Big Gamble, Tries to Curb Greenhouse Gases," *New York Times*, Sept. 15, 2006.

Nationally, there is movement, too. Notwithstanding the President's rejection of the Kyoto Protocol, the U.S. Senate has twice considered global warming legislation that would have required capping U.S. global warming gas emissions in 2010 at 2000 levels. While this legislation has been defeated, the Senate did pass a non-binding resolution in 2005 declaring that global warming gases are linked to climate change and calling upon a future Congress to pass a national program of mandatory, market-based limits on these gases.²⁵ In this regard, the incoming chairperson of the Senate Committee on the Environment and Public Works, Senator Boxer of California, has stated her intention to address global warming in the new Congress.

The absence of binding national policy on global warming has not impeded many U.S.-based multinational companies from announcing voluntary commitments to reduce their global warming gases. Among these companies are 3M, Eastman Kodak, General Motors, IBM, Pfizer, Johnson & Johnson, and General Electric.²⁶ These companies see the handwriting on the wall: A recent survey of major multinational corporations showed that, of the 31 who completed the survey, 90% of them believe that the U.S. will enact binding global warming gas reductions by 2015.²⁷ Even electric utilities have called for limitations on global warming gases or have taken actions to get ready for regulation of CO₂ emissions, among them Exelon, Cinergy, and now Xcel Energy.

At the same time, Tri-State has ignored global warming. Its RDP makes no mention of it at all, and its choice of resources is focused solely on pulverized coal. Moreover, Tri-State offers no mitigation for the roughly 13 million tons of CO₂ that its new coal plants will emit annually, not to mention the CO₂ emissions of its existing coal-fired facilities, and no plan as to how to buffer its membership against oncoming carbon regulation.

Is this the position that Tri-State members truly want Tri-State to take, given the dangers inherent in global warming? Even if some Tri-State members remain skeptical about global warming, others at the state and federal level with the power to affect Tri-State's costs have moved beyond skepticism and toward action. Thus, Tri-State's plan to build three new pulverized coal units has implications for electric rates. These implications arise from the near inevitability of limitations on CO₂ emissions during the lifetimes of these units. The limitations will likely take the form of a cap and trade system or a carbon tax. Either way, Tri-State members will pay for the carbon emissions of these three units. Below, we model the effect of CO₂ emission reduction requirements from these units on the system. Next, we look at whether Tri-State's plan may run into trouble on Wall Street.

Implications of Environmental Impacts of Tri-State's Financing Plan

Tri-State plans to use private financing to fund the RDP, rather than funding through the Rural Utilities Service. Concern has been increasing among financial institutions on Wall Street about both the environmental impacts and the potential liabilities associated with projects for which financing is sought.

For a number of years, banks working in the project-finance sector had been seeking ways to develop a common and coherent set of environmental and social policies and guidelines

²⁵ Vote of the U.S. Senate on Amendment 826 to H.R. 6, June 22, 2005.

²⁶ See U.S. Environmental Protection Agency Climate Leaders, <http://www.epa.gov/climateleaders/partners>.

²⁷ See Pew Center on Global Climate Change, <http://www.pewclimate.org>.

that could be applied globally and across all industry sectors. In October 2002, a small number of banks convened in London, together with the World Bank Group's International Finance Corporation, to discuss these issues. The banks present, including Citigroup, decided jointly to try to develop a banking industry framework for addressing environmental and social risks in project financing. This led to the drafting of the first set of Equator Principles by these banks, which were then launched in Washington, DC on June 4, 2003. These principles were ultimately adopted by over 40 financial institutions, including two more American companies—JP Morgan Chase and Bank of America—during a three-year implementation period. A subsequent updating process took place in 2006, leading to a newly revised set of Equator Principles, which were released in July 2006.

The preamble to the principles provides a good description of their purpose:

Project financing, a method of funding in which the lender looks primarily to the revenues generated by a single project both as the source of repayment and as security for the exposure, plays an important role in financing development throughout the world. Project financiers may encounter social and environmental issues that are both complex and challenging, particularly with respect to projects in the emerging markets.

The Equator Principles Financial Institutions (EPFIs) have consequently adopted these Principles in order to ensure that the projects we finance are developed in a manner that is socially responsible and reflect sound environmental management practices. By doing so, negative impacts on project-affected ecosystems and communities should be avoided where possible, and if these impacts are unavoidable, they should be reduced, mitigated and/or compensated for appropriately. We believe that adoption of and adherence to these Principles offers significant benefits to ourselves, our borrowers and local stakeholders through our borrowers' engagement with locally affected communities. We therefore recognise that our role as financiers affords us opportunities to promote responsible environmental stewardship and socially responsible development. As such, EPFIs will consider reviewing these Principles from time-to-time based on implementation experience, and in order to reflect ongoing learning and emerging good practice.

These Principles are intended to serve as a common baseline and framework for the implementation by each EPFI of its own internal social and environmental policies, procedures and standards related to its project financing activities. We will not provide loans to projects where the borrower will not or is unable to comply with our respective social and environmental policies and procedures that implement the Equator Principles.²⁸

As financial institutions take the environment into account, the increasing attention to environmental impacts may result either in difficulty in financing Tri-State's RDP or in higher financing costs.

Delivered Coal Prices

Future coal prices are uncertain and can exhibit significant changes from year to year. As a consequence, future coal prices are difficult to predict, as indicated by the large errors in price forecasts made by the Energy Information Administration.²⁹ Figure 9 shows delivered coal prices paid by the electric power sector in Kansas and Colorado in constant 2006 dollars per MMBtu.³⁰

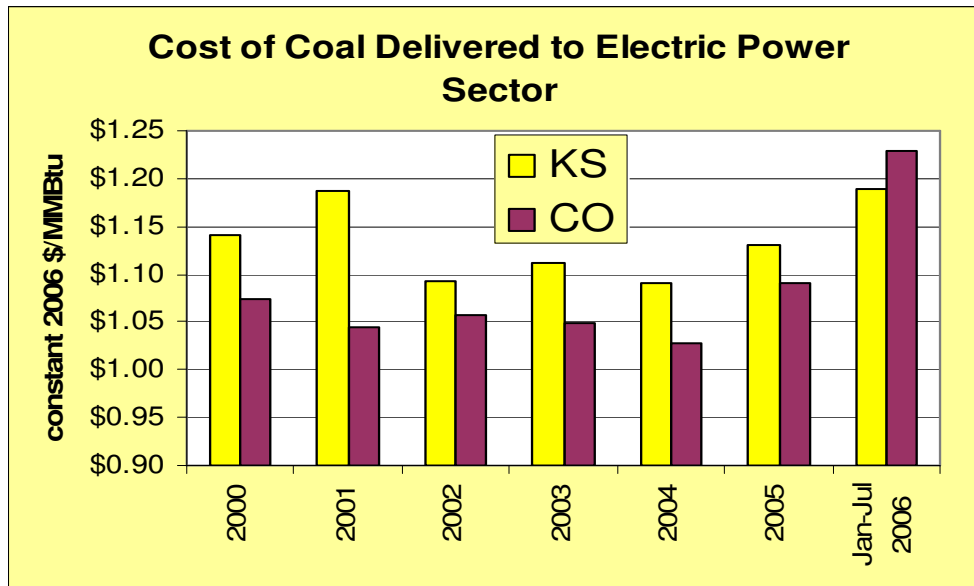
²⁸ See <http://www.equator-principles.com/principles.shtml>.

²⁹ The average absolute percent errors in forecasts of coal prices paid by electric generating plants was 47.8% for forecasts made between 1982 and 2004. Energy Information Administration, *Annual Energy Outlook Forecast Evaluations*, 2004, Table 1.

³⁰ Data from Energy Information Administration, *Electric Power Monthly*, various issues. Costs converted to constant dollars using the Gross Domestic Product Implicit Price Deflator.

Prices in Colorado and Kansas have fluctuated and recently have increased substantially. From 2004 through the first half of 2006, delivered prices have increased 20% for the electric power sector in Colorado and 9% for the electric power sector in Kansas in constant dollars. These increases are in addition to increases due to general inflation.

Figure 9. Coal Prices Paid by Electric Power Companies in Kansas and Colorado



Several factors contribute to upward pressure on coal prices and to uncertainty in coal prices:

- Changes in the cost of sulfur dioxide emission allowances, which in turn affect the relative prices of low sulfur coal and high sulfur coal.
- Changes in rail transport costs due to changes in fuel costs for railroads and limited competition in rail service from coal mines.
- Short-term interruptions in rail transport, forcing electric power producers to pay spot market prices for substitute coal supplies.
- Changes in prices of substitute fuels, such as natural gas. Long-term trends in natural gas prices have been upward, with considerable volatility from year to year. As gas prices increase over the long run, coal prices may increase.
- Increasing worldwide demand for coal. U.S. imports and exports of coal have increased in price in the past few years.³¹ These international price increases may affect domestic prices.

Thus, investments in new coal-fired generating plants are risky: the stream of coal prices over the 30- to 50-year life of each new unit could be much different than prices paid in the past few years.

³¹ Energy Information Administration, *U.S. Coal Supply and Demand: 2005 Review*. Energy Information Administration, *Quarterly Coal Report: April–June 2006*, Tables 11 and 19.

Sensitivity Analyses

This section examines the potential impacts of three risk factors on Tri-State's rates: possible higher capital costs attributable to increasing the proposed new plant capacities from 600 MW to 700 MW, possible future carbon dioxide regulation, and possible higher-than-expected coal prices.

Capital Costs

The potential for increased capital costs in changing the RDP from three 600 MW units to three 700 MW units was noted above. The rate impact model was reconfigured and run using the higher capital cost figures with the expected result of larger rate increase requirements. The actual rate impact is likely to be between the base case impact and the projected impact shown in Table 13.³²

Table 13. Rate Impact of Increased Unit Size for Tri-State's Proposed Plants

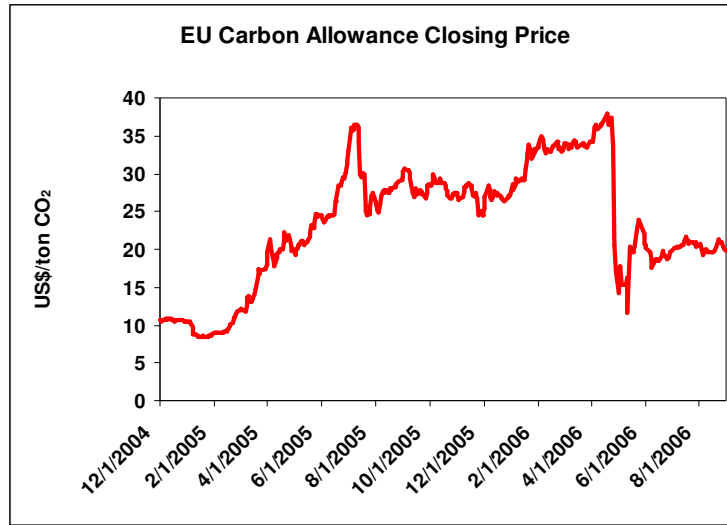
	Actual 2005	2006	2007	2008	2009	2010	2011
Member rate with 600 MW units	\$48.30	\$47.05	\$60.34	\$63.04	\$67.53	\$73.76	\$79.46
Cumulative change		-2.6%	24.9%	30.5%	39.8%	52.7%	64.5%
Member rate with 700 MW units	\$48.30	\$47.13	\$60.45	\$63.70	\$68.89	\$75.62	\$82.11
Cumulative change		-2.4%	25.1%	31.9%	42.6%	56.6%	70.0%
Actual rate changes		4.0%	16.3%	??	??	??	??

CO₂ Regulation

Our April analysis outlined the potential costs related to CO₂ emissions across Tri-State's existing power production system, and separately for the new units only. The low trading point of CO₂ costs under the European Union Greenhouse Gas Emissions Trading Scheme (ETS) was about \$10 per ton. While the ETS has seen prices in excess of \$35/ton and seems to be stabilizing at about \$20/ton (see Figure 10), \$10/ton was modeled as a conservative starting point, but in calculating annual costs, we also modeled \$30 per ton, based on Tri-State executive J.M. Shaefer's statement (made on November 14, 2006 at the work session called by the Gunnison County Board of Commissioners) that Tri-State had used \$30 in its modeling.

³² As noted above, Tri-State indicated at the Gunnison meeting on November 14, 2006 that the cost of the 700 MW units would be the same as the originally planned 600 MW units.

Figure 10. Carbon Allowance Closing Prices in the European Union



First, the liability was applied beginning in 2009 to all of Tri-State’s coal generated electricity, including the Holcomb and Colorado Power Project units. Then it was applied to the new units only. The rate impacts of these two scenarios are depicted in Table 14.

Table 14. Rate Impact of \$10/ton CO₂ Costs on Tri-State’s Proposed Plants

	Actual 2005	2006	2007	2008	2009	2010	2011
Member rate without CO ₂ costs	\$48.30	\$47.05	\$60.34	\$63.04	\$67.53	\$73.76	\$79.46
Cumulative change		-2.6%	24.9%	30.5%	39.8%	52.7%	64.5%
Member rate with CO ₂ costs on all coal generation	\$48.30	\$47.05	\$60.34	\$63.04	\$75.41	\$81.34	\$87.29
Cumulative Change		-2.6%	24.9%	30.5%	56.1%	68.4%	80.7%
Member rate with CO ₂ costs on new coal generation only	\$48.30	\$47.05	\$60.34	\$63.04	\$67.53	\$73.76	\$81.04
Cumulative change		-2.6%	24.9%	30.5%	39.8%	52.7%	67.8%
Actual rate changes		4.0%	16.3%	??	??	??	??

The *annual* CO₂ liability for the new units is shown in Table 15, based upon capacity factors of 80% and emission rates of 1,747.05 pounds of CO₂ per kWh of generation.

Table 15. Estimated CO₂ Emissions and Costs for Tri-State’s Proposed Plants

	Annual Generation (GWh)	Annual CO ₂ Emissions (millions of tons)	Annual Liability at \$10/ton (in millions)	Annual Liability at \$30/ton (in millions)
Holcomb 2	4,906	4.3	\$43	\$129
Holcomb 3	4,906	4.3	\$43	\$129
SE Colorado 1	4,906	4.3	\$43	\$129
Total new units only	14,717	12.9	\$129	\$387

Coal Price Increases

The model was adjusted to determine the impacts of two additional rates of price escalation, based on the increasing correlation between coal prices and the price of utilities’ key alternative fuel—natural gas. The base case rate impact reflects coal prices escalating at less than 1% in real terms. Coal price escalators were developed based upon a doubling of current coal prices over five years and over 10 years. The rate impact of these two scenarios is depicted in Table 16.

Table 16. Rate Impact of Higher Coal Prices on Tri-State’s Proposed Plants

	Actual 2005	2006	2007	2008	2009	2010	2011
Member rate with historic escalation	\$48.30	\$47.05	\$60.34	\$63.04	\$67.53	\$73.76	\$79.46
Cumulative change		-2.6%	24.9%	30.5%	39.8%	52.7%	64.5%
Member rate with 10-year doubling of coal costs	\$48.30	\$47.46	\$61.17	\$64.23	\$69.18	\$75.86	\$82.21
Cumulative change		-1.7%	26.6%	33.0%	43.2%	57.0%	70.2%
Member rate with 5-year doubling of coal costs	\$48.30	\$48.43	\$63.20	\$67.32	\$73.69	\$81.88	\$90.50
Cumulative change		0.3%	30.8%	39.4%	52.5%	69.5%	87.4%
Actual rate changes		4.0%	16.3%	??	??	??	??

Cumulative Impact of Risk Factors

The impact of these three risk factors, as applied to member rates over the period through the in-service year of the third coal plant, is shown in Table 17.

Table 17. Cumulative Rate Impact of Three Risk Factors on Tri-State’s Proposed Plants

Year	Member Rate	Cumulative Increase
2005	\$48.30	---
2006	\$47.71	-1.2%
2007	\$61.62	27.6%
2008	\$65.39	35.4%
2009	\$71.24	47.5%
2010	\$78.60	62.7%
2011	\$87.58	81.3%
2012	\$85.74	77.5%
2013	\$86.55	79.2%
2014	\$89.81	85.9%
2015	\$93.04	92.6%
2016	\$99.14	105.2%
2017	\$106.01	119.5%
2018	\$114.52	137.1%
2019	\$126.07	161.0%

It is not at all unreasonable to expect that each of these risks could actually happen on the Tri-State system for the reasons explained above. If these risks do occur, Tri-State members could see rate increases as high as 160% by 2019.

Conclusion

In a nutshell, Tri-State sold too much of its existing capacity to other utilities, leaving it short over the next few years. Now Tri-State may compound the mistake and raise rates further by building expensive units that solve neither a short-term nor a long-term problem.

None of Tri-State's several load forecasts justifies the three pulverized coal units contained in its resource plan. The coal units cannot help Tri-State overcome any short-term resource deficit, which was mostly a result of Tri-State having sold a portion of its capacity to other utilities. Over the longer term, Tri-State does not need any of the new units to meet member loads, since the resource deficit, at worst, appears to be roughly 500 MW in 2019. This deficit, if any, can be more cheaply and easily met by investments in energy efficiency and other alternative resources.

Yet, unless Tri-State members act now, Tri-State is on track to build these units and impose unprecedented rate increases of as much as 160% on its members and their owners.

We urge Tri-State members to let Tri-State know that it they will not stand for these developments, starting by rejecting the RDP and refusing to execute the 10-year contract extension that Tri-State seeks to enable financing of the RDP.

Attachment A

Executive Summary of WRA's April Analysis

Tri-State Generation and Transmission Association is a wholesale electric power supplier owned by the 44 electric distribution cooperatives that it serves. Tri-State generates and transmits electricity through 5,096 miles of lines to its member systems throughout a 250,000-square-mile service territory across Colorado, Nebraska, New Mexico, and Wyoming, providing electricity for over a million people.

The customers of the cooperatives that Tri-State serves will bear the consequences of Tri-State's electric resource choices — good or bad — for decades to come. They are entitled to a thorough and honest analysis of all potential costs, risks, and liabilities associated with these choices, and to a full and honest assessment and comparison of different resource options.

Due in large part to the increased cost of fuel, fuel transportation, and purchased power, Tri-State's operating expenses in 2006 are projected to be nearly \$90 million higher than in 2005. As a result, Tri-State increased rates to members by 4% effective January 1, 2006. This comes on the heels of a 7% increase effective January 1, 2003 and a 13.8% increase effective January 1, 2005. All told, Tri-State's members are paying some 27% more for wholesale electricity now than they were paying only four years ago.

The demand for electricity among the 44 cooperatives served by Tri-State grew by 3.3% annually in recent years, and Tri-State projects that electricity demand will continue to grow rapidly over the next two decades. As a result, Tri-State's Board of Directors "authorized a comprehensive resource development plan to include 1,800 MW (net) of new coal-based generation, and up to 1,000 miles of new transmission line" at its August 2005 meeting. It proposes to build two 600-megawatt (MW) conventional coal-fired units at the Holcomb plant site in Kansas and a third 600 MW generator in southeast Colorado. The estimated cost of these three new power plants, along with new transmission lines, is a whopping \$5 billion.

If completed, these projects will increase Tri-State's assets by 238%. In total, this resource expansion by itself will put each man, woman, and child in Tri-State's service territory into debt for over \$5,000. In addition, interest payments, depreciation, and other costs associated with this proposed \$5 billion investment will add some \$500 million to Tri-State's annual revenue requirement. The end result will be additional rate increases in excess of 3.0¢ per kilowatt hour (kWh) — more than a 50% increase over today's wholesale rates.

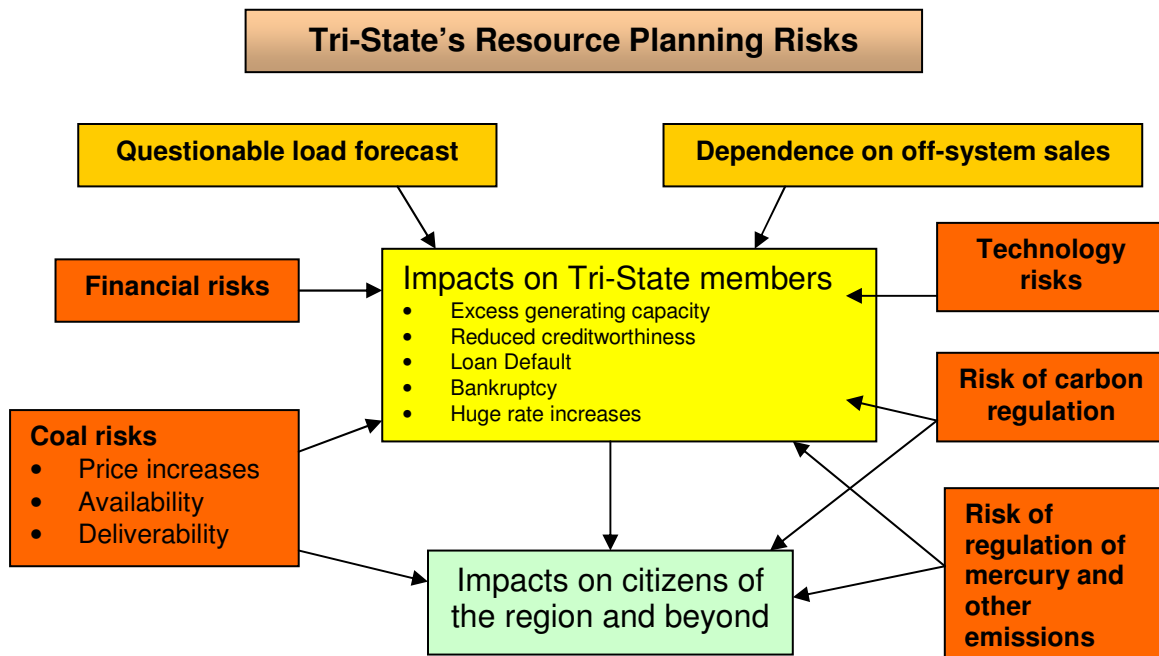
Customers in Tri-State's service territory are growing concerned. For example, the New Mexico legislature passed two memorials, HM 40 and HM 49. The former requests "the New Mexico legislative council to direct the appropriate legislative interim committee to conduct a study of the adequacy of the protection of New Mexico consumer interests with respect to current regulation of generation and transmission cooperatives" while the latter requests "that the Energy, Minerals and Natural Resources Department create a task force to study the use of renewable energy within the service territories of electric cooperatives."

Tri-State's Flawed Resource Plan

Does Tri-State really need to build three large power plants over the next 15 years? We believe the answer to this question is no. It appears that Tri-State's anticipated load growth outpaces its ability to provide energy (with adequate reserves) in only three years (2008–2010) out of the 20 years considered in the company's last resource plan. The shortfalls in those years are modest and can be resolved in a variety of ways. In any event, the construction of three large baseload power plants does not appear to be reasonable in the context of Tri-State's own forecast.

A review of recent growth on the Tri-State system reveals that the three members serving suburban areas along the Front Range in Colorado comprise nearly two-thirds of Tri-State's growth between 2002 and 2004.³³ These suburban areas are experiencing considerable home construction, meaning that air conditioning is driving up peak demand. The load profiles of these "bedroom communities" lend themselves to alternative resources, such as rooftop solar, energy efficiency, and load management programs.

In addition to the apparent lack of load growth to support such a massive coal generation build-out, factors such as financial risk, technology risk, the risks of future carbon dioxide regulation and regulation of other emissions, coal price increases and volatility, and coal deliverability have not been addressed by Tri-State in its Resource Plan (see chart). There is considerable risk that costs could escalate well beyond the \$5 billion level if coal prices continue to rise, if new environmental regulations are adopted on coal-fired power plants or on greenhouse gas emissions, or if other factors do not "go Tri-State's way."



³³ The three members are Poudre Valley REA, United Power, and Mountain View Electric Association

Decisions to build major power plants should not be made lightly. Tri-State members and their customer-owners must ask themselves the following important high-level questions:

- Is investing \$5 billion to construct 1,800 megawatts of coal-based generation and associated transmission lines absolutely essential?
- If new resources are needed, are these the right resources?
- Do the benefits exceed the costs?
- Are the risks limited and manageable?

Tri-State's proposed expansion plan places enormous financial burdens and responsibilities on rural Westerners — those in the worst position to shoulder them. At the very least, due diligence would dictate additional scrutiny in a public forum and in an open process prior to embarking on such a massive capital commitment.

Prior to making such a massive investment, Tri-State and its member cooperatives should ask, and respond to, the following specific questions:

- Has Tri-State overestimated future resource needs by preparing a biased and poorly justified load forecast?
- Could Tri-State save its member cooperatives and their customers considerable dollars by investing instead in energy efficiency and load management to reduce, delay, or possibly eliminate Tri-State's projected need for additional high-cost conventional coal-fired generation?
- If in fact Tri-State needs new electricity supply facilities, are there better alternatives than conventional coal-fired power plants? Can wind and solar resources, on-site combined heat and power systems, and/or advanced coal-based facilities provide equivalent or lower-cost electricity at reduced risk?

Alternative Resource Opportunities

While we question whether Tri-State really needs large-scale new sources of power, there are lower-cost and more desirable alternatives to building three conventional coal-fired power plants. First, there is considerable opportunity to increase the efficiency of electricity use by customers served by Tri-State's Wyoming, Colorado, and New Mexico members.

Utility-sponsored demand-side management (DSM) programs that focus on well-proven and cost-effective measures can acquire significant amounts of the energy efficiency resource. Beginning in 2007 with a small surcharge of 0.06¢ per kWh (about 1.1% of 2006 wholesale rates) that grows to 0.15¢ per kWh (about 2.8% of 2006 wholesale rates) in 2009, sufficient funding is raised to support comprehensive DSM programs across the Tri-State service area. We estimate that these programs could achieve 736 MW of peak demand reduction in 2024 along with 1,931 gigawatt-hours (GWh) per year of energy savings, resulting in \$760 million in net economic savings for consumers and businesses in the Tri-State service area. Such savings far outpace the need for new resources, even if high economic growth occurs in the Tri-State service area over the next 20 years.

Second, renewable resources provide opportunities to help meet energy demand while reducing some of the financial, environmental, and regulatory risks associated with coal-fired generation. While other utilities, such as Xcel Energy and Public Service Company of New Mexico, are moving ahead with the addition of hundreds of megawatts of wind power to their utility systems, Tri-State has no plans to do so. Tri-State has overlooked or inadequately examined wind resources in its resource assessment and plan.

In addition, there is considerable potential for developing solar electric, bioenergy-based power generation, and combined heat and power systems in the Tri-State service area. These distributed resource options reduce the need for transmission and distribution grid investment, as well as rely on renewable, environmentally friendly resources. But Tri-State did not consider these options in its resource assessment and plan.

In summary, Tri-State's most recent resource plan, and its proposal to invest \$5 billion in new coal-fired power plants and associated transmission lines, is flawed for the following reasons:

- Tri-State's load forecast is too high and is not supported by sufficient analysis.
- Tri-State's resource plan ignores many significant costs, risks, and liabilities.
- Energy efficiency improvements stimulated by DSM programs have great potential for addressing Tri-State members' growing resource needs, but were ignored by Tri-State.
- Tri-State has overlooked and improperly analyzed opportunities for wind power, solar energy, and other renewable resource development in its service area.

Tri-State's proposal to build three new large coal-fired power plants and related transmission is very costly and risky, and in our view is unnecessary. When it comes time to sign onto this multi-billion-dollar boondoggle, Tri-State's member cooperatives should say, "Try again, Tri-State."