THE IMPACT OF THE RENEWABLE ENERGY STANDARD IN AMENDMENT 37 ON ELECTRIC RATES IN COLORADO

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September 2004

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Introduction

On November 2, Colorado voters will decide whether Colorado's electric utilities should be required by law to acquire a specified minimum amount of electric power from renewable energy sources. They will be voting on Amendment 37, a citizen-initiated measure that applies to Colorado utilities serving more than 40,000 customers – collectively about 80% of Colorado consumers.

The purpose of this report is to estimate the impact that such a requirement will have on the retail price of electricity in Colorado. The report will also consider other impacts of a "renewable energy standard" (RES) for Colorado. Specifically, this report addresses the following questions:

- What impact will the requirements of Amendment 37 have on the electric rates paid by Colorado consumers?
- How sensitive are estimates of the rate impact to changes in federal tax policy and future natural gas prices?
- What other impacts will an RES likely have in Colorado?
- How does the proposed Colorado RES compare to similar laws in other states?

The cost of electricity from renewable resources has fallen in recent years. Electric power generated by wind turbines in large "wind farms," for example, is now price-competitive with power produced using traditional fuels. On the other hand, while solar power continues to decrease in cost, it remains significantly more expensive than traditional energy sources. Finally, the price of electricity generated using natural gas as a fuel has risen sharply in recent years and fluctuates with the volatile price of natural gas. Discerning the bottom line impact on retail electricity prices from these interconnected price effects requires a relatively complex model and important assumptions about future technologies and prices.

Renewable and non-renewable energy sources also differ in many other important respects. This includes their predictability, sensitivity to changes in fossil fuel costs, environmental impacts and their potential to affect rural economic development.

This report examines these distinctions between renewable and fossil fuel electric production and estimates the rate impact of requiring utilities to use a specified level of renewable resources. The author hopes that this information is useful to Coloradans as they go to the polls in November to decide this important public policy issue.

Major Findings

- AMENDMENT 37 WILL INCREASE RENEWABLE ENERGY USE OVER THE NEXT TWENTY YEARS, RAISING ITS MARKET SHARE TO 8.5% IN COLORADO BY 2025. EVEN WITH THIS INCREASE IN RENEWABLE ENERGY, ELECTRICITY FROM NON-RENEWABLE SOURCES WILL DOUBLE IN THE SAME PERIOD.

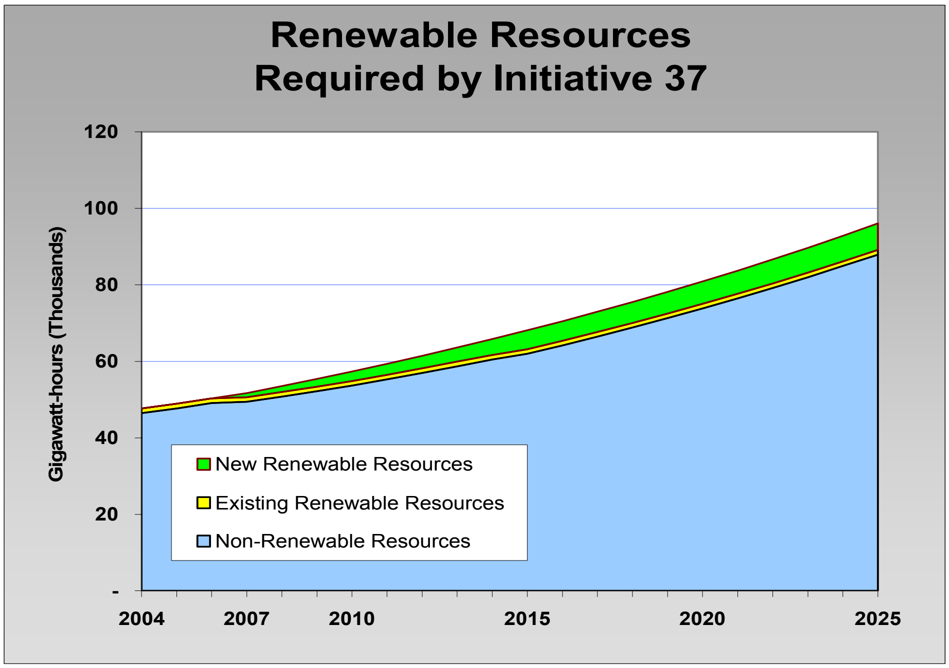


Figure 1 – Renewable Energy Required by Amendment 37

- THE RES WILL HAVE A MODEST IMPACT ON COLORADO UTILITY BILLS. THE IMPACT WILL VARY BY UTILITY, BUT THE <u>MOST LIKELY OUTCOME IS THAT STATE-WIDE ELECTRIC RATES WILL BE VIRTUALLY UNCHANGED.</u>

- THE MOST LIKELY OUTCOME IS TO <u>DECREASE</u> STATE-WIDE UTILITY COSTS BY $14.0 MILLION, ABOUT ONE CENT PER MONTH FOR THE AVERAGE RESIDENTIAL CONSUMER OVER THE PERIOD 2005-2024. SIMILAR SMALL REDUCTIONS WOULD APPLY TO BILLS OF COMMERCIAL AND INDUSTRIAL UTILITY CUSTOMERS.

- THE RATE IMPACTS OF THE RES WILL VARY BY UTILITY. BUT THE BILL IMPACT IS HIGHLY UNLIKELY TO APPROACH THE 50¢ PER MONTH CEILING CONTAINED IN THE BALLOT MEASURE.

HERE IS A SUMMARY OF THE EFFECTS, CALCULATED FOR EACH UTILITY:

Xcel Energy:

The most likely outcome of the RES for customers of Xcel Energy is a cumulative increase of $12.6 million in rates over the period 2005-2024. This translates into an average increase of about 1 cent in the monthly bill of the average residential consumer each month over the next 20 years.

Using less likely assumptions, residential rates would fall by 27 cents per month on average over the next 20 years; under much less likely assumptions, the RES of Amendment 37 could increase electric rates by about 50 cents per month for the average Xcel residential customer over the study period.

Commercial and industrial customers of Xcel Energy would see similar changes in their bills. An Xcel commercial customer with a 500 KW demand would have a normal monthly bill of about $12,000. The most likely outcome of the RES would be to increase such a bill by $3.94.

City of Colorado Springs Utilities

Colorado Springs Utilities (CSU) is the state's second largest utility and will be required by the RES to acquire more than 10,000 gigawatt-hours (GWh) of renewable energy over 20 years. We assume that CSU exercises its option under the new law to adopt its own RES and be exempt from the solar energy requirement of Amendment 37.

If CSU meets its RES using wind energy purchases beginning in 2006, residential rates will be lower by an average of 33 cents per month; the utility's revenue requirement will be lower by a total of $63.6 million over the twenty-year period. If Colorado Springs Utilities delays wind acquisition and fulfills its RES requirement by purchasing Renewable Energy Certificates (RECs) in a regional market, rates for the average residential customers would increase by an average of about 14 cents per month. A combination of the two strategies would yield residential rates that are lower by about 9 cents per month over the 20-year study period.

Intermountain REA

Intermountain REA is the state's third largest utility and is a full-requirements customer of Public Service Company of Colorado. This means that IREA will share in the costs and benefits of renewable energy obtained or produced by Public Service Company. We assume that IREA will exercise the option to exempt itself from the solar energy requirement by the self-certification option in the amendment.

Under these assumptions, the most likely outcome for IREA consumers is a bill reduction of 45 cents per month for the average residential customer. This equates to wholesale power costs charged to the utility that are lower by a cumulative $24.6 million over the twenty years 2005-2024.

Other REAs

Holy Cross Electric Association and Yampa Valley Electric Association and are also full-requirements customers of PSCo. Assuming these cooperatives exempt themselves from the solar requirement by exercising their self-certification option, the most likely outcome for the average residential customer of Holy Cross is a reduction of 48 cents per month; the total savings to the utility will be $14.1 million over twenty years. Similar results occur for Yampa Valley.

United Power, Mountain View Electric Association, La Plata Electric Association, Poudre Valley REA, Delta Montrose Electric Association and San Isabel Electric Association are all full requirements customers of TriState Generation and Transmission Cooperative. We assume that these distribution coops will exempt themselves from the solar requirement and that the RES is satisfied by renewable resources that are no more costly than wind power.

It is difficult to assess the impact of wind purchases on TriState, since the majority of TriState members are not subject to the RES. We cannot predict whether TriState would acquire enough wind capacity to meet the needs of the members that are subject to the RES requirement.

Therefore, for modeling purposes we assume that these six coops meet their RES obligations by purchasing Renewable Energy Certificates in the regional market. This is a conservative estimate and is likely to be more costly than if TriState actually purchased wind power directly. With this assumption, the impact of Amendment 37 on residential customers of these coops will average an increase 19 cents per month, although that could be mitigated, depending upon TriState's strategy. Details for each coop are found in the table on page 50.

Aquila, Inc.

Aquila is an investor-owned utility that serves retail customers in southern Colorado. Aquila is a partial requirements customer of Public Service Company. As such, Aquila will share in the costs and benefits incurred by PSCo as it complies with the RES. The balance of Aquila's non-solar requirements can be met with Renewable Energy Credits associated with the company's wind farm in western Kansas.

We assume that Aquila will meet the solar requirement of Amendment 37 in a similar fashion to Public Service Company – 50% from central station solar generation and 50% from distributed generation. With these assumptions, the average monthly bills of Aquila's residential customers are estimated to increase by 1 cent per month due to compliance with Amendment 37.

City of Fort Collins

In 2003 the City of Fort Collins adopted an Energy Plan that calls for the city to acquire renewable resources equivalent to 15% of the utility's load in 2017. This is a more aggressive schedule than the Colorado RES contained in Amendment 37. Therefore we assume that the City of Fort Collins will self-certify compliance with Amendment 37 through its existing RES. We do not include Fort Collins in the rate impact analysis since any rate impact, up or down, will be due to the pre-existing Energy Plan, and not Amendment 37. However, the experience of Fort Collins should be similar to that of the cities of Longmont and Loveland, since these three cities share the same wholesale energy provider.

Cities of Longmont and Loveland

Longmont and Loveland purchase their power from the Platte River Power Authority (PRPA), which operates wind turbines in Wyoming and purchases Renewable Energy Certificates (RECs) from another Wyoming wind farm. We assume that Longmont and Loveland will exempt themselves from the solar requirement and satisfy the RES through PRPA with a strategy that combines wind acquisition and REC purchase. Under these assumptions, residential monthly bills are expected to decrease slightly: 9 cents per month for Longmont and 14 cents per month for Loveland consumers.

- **RENEWABLE ENERGY SOURCES CAN SAVE CONSUMERS MONEY BY ACTING AS A "HEDGE" AGAINST SPIKES IN NATURAL GAS PRICES.** Renewable sources such as wind will result in consumer savings of up to 48¢ per month (in additional savings) in years when natural gas prices spike as they did in 2000 and 2003.

- **THE EXPANSION OF RENEWABLE ENERGY CAPACITY MANDATED BY THE COLORADO RES WILL HAVE POSITIVE BENEFITS FOR WATER USE, AIR QUALITY, AND RURAL ECONOMIC DEVELOPMENT.**

    - The RES mandate could save between 65,000 and 127,000 acre-feet of water over 20 years that would otherwise be consumed by energy production. This larger number is equivalent to half the storage capacity of Dillon Reservoir.

- By substituting renewables for a portion of generation from fossil fuels, the RES can significantly reduce emissions from Colorado power plants. Depending on the mix of the avoided fuel, emissions of the greenhouse gas carbon dioxide would be reduced by between 32 million and 81 million tons of CO_2 between 2005 and 2024.

- Renewable resources can affect rural economic growth, offering rural counties opportunities for an increased tax base and landowners' opportunities for income from leases to wind generators.

Other Findings

- **COLORADO UTILITIES HAD DEVELOPED ABOUT 300 MW OF RENEWABLE ENERGY BY AUGUST 2004, REPRESENTING ABOUT 1.8% OF THE ELECTRICITY GENERATED IN THE STATE. COAL AND NATURAL GAS REMAIN THE DOMINANT FUEL SOURCES WITH 78% AND 20% OF THE MARKET, RESPECTIVELY.**

- **FIFTEEN STATES HAVE ADOPTED RENEWABLE ENERGY STANDARDS THROUGH LEGISLATION OR REGULATORY RULES. THE EXPERIENCE OF THESE STATES APPEARS TO SHOW THAT AN RES CAN BE EFFECTIVE IN INCREASING BOTH THE SUPPLY AND DEMAND FOR RENEWABLE ENERGY WITHOUT INCREASING ELECTRIC RATES.**

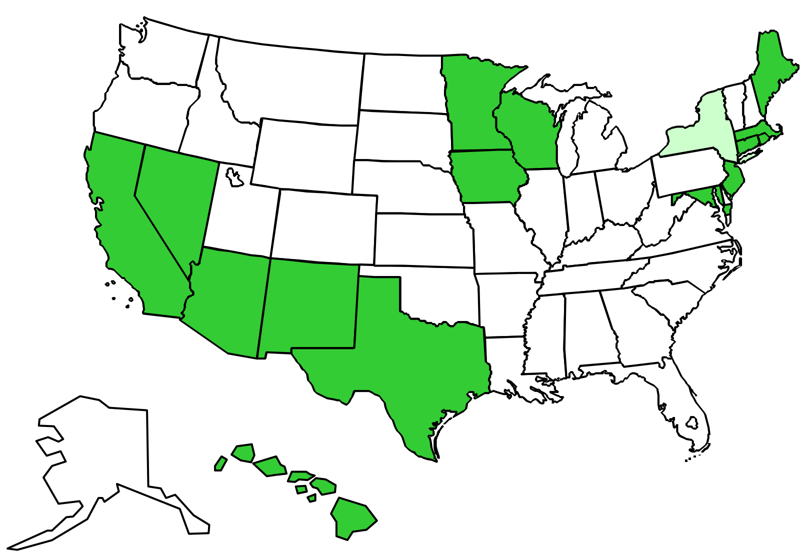


Figure 2 – Renewable Energy Standards in 15 States

- **THE PASSAGE OF AMENDMENT 37 WOULD PLACE COLORADO IN THE MIDDLE OF THE FIFTEEN STATES WITH RESPECT TO RES REQUIREMENTS.**

- **THE MOST IMPORTANT FACTORS AFFECTING THE RELATIVE COST OF RENEWABLE AND NON-RENEWABLE RESOURCES ARE:**
  - The future price of natural gas;
  - The future of the federal Production Tax Credit (PTC);
  - Improvements in the efficiency of both fossil-fueled plants and wind generation;
  - The future cost of electric generation using solar energy.

- **THE 2004 ESTIMATE OF FUTURE NATURAL GAS COSTS PUBLISHED BY THE U.S. DEPARTMENT OF ENERGY PROJECTS THAT THE WELLHEAD PRICE OF NATURAL GAS WILL REMAIN ABOVE $3.50/MCF IN THE NEAR TERM, INCREASING TO PRICES THAT REMAIN CONSISTENTLY ABOVE $4.00/MCF IN THE LONGER TERM.**

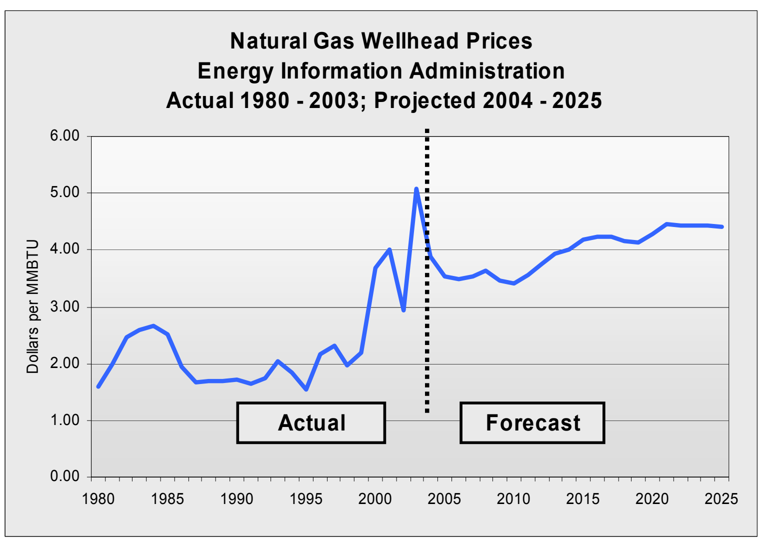


Figure 3 – DOE Forecast of Natural Gas Wellhead Prices

- **COLORADO HAS A LARGE POTENTIAL RENEWABLE ENERGY RESOURCE IN WIND POWER, RANKING 11TH AMONG THE 50 STATES. THE STATE HAS SIGNIFICANT CLASS 4 AND CLASS 3 WIND AREAS, SUITABLE FOR COMMERCIAL WIND GENERATION.**

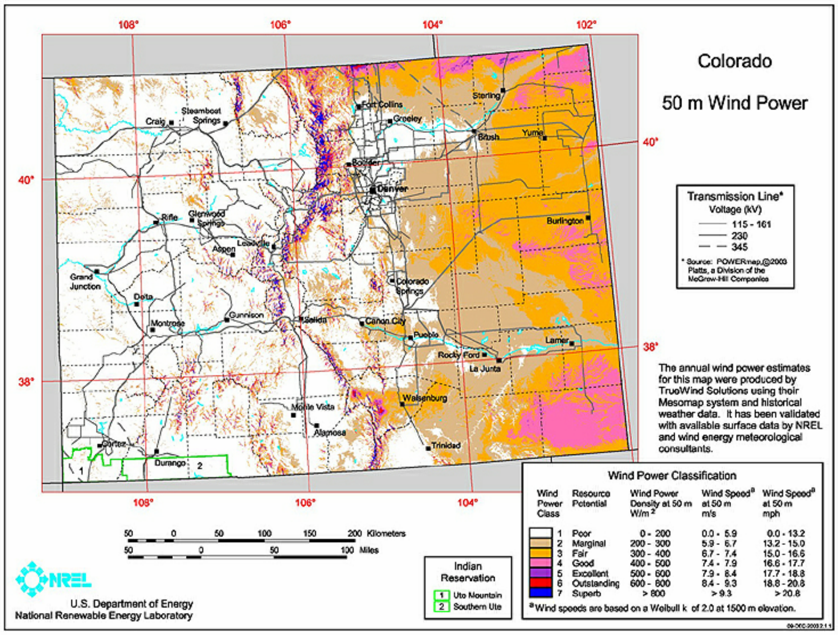


Figure 4 – Colorado Wind Resource Map

- **COLORADO HAS A RELATIVELY LARGE POTENTIAL FOR PHOTOVOLTAIC ENERGY, SHOWN IN THE FOLLOWING "INSOLATION" MAP.** A leading photovoltaic system marketer lists Colorado among 24 states where photovoltaic development is either "Suitable" or "Highly Suitable."

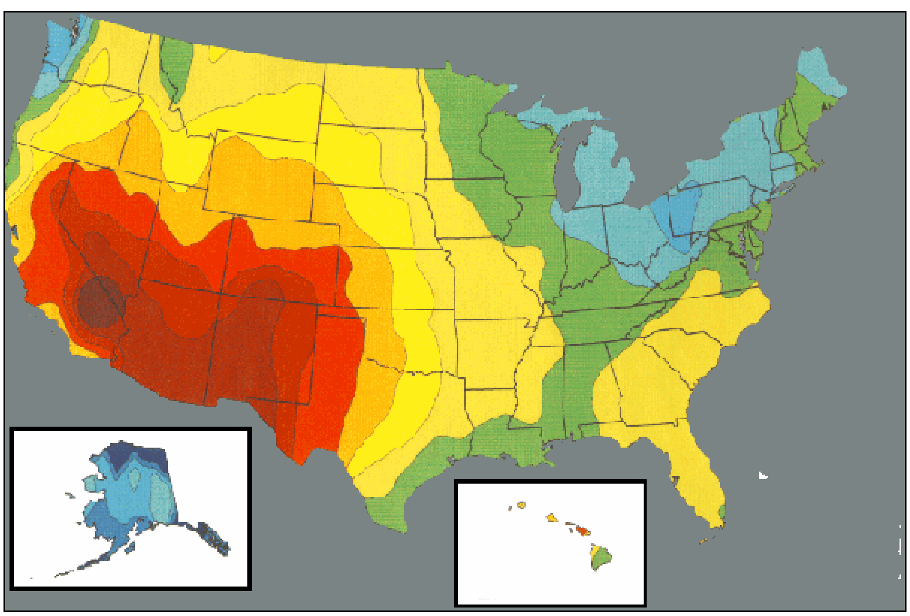


Figure 5 – Average U.S. Daily Solar Radiation 1961-1990

INTRODUCTION

Across the country, many state legislatures and state public utilities commissions have mandated that electric utilities acquire a minimum amount of electric power produced from renewable energy resources. By August 2004, fifteen states had adopted such policies, called "Renewable Portfolio Standards" (RPS) or "Renewable Energy Standards" (RES).[1]

Some of the mandates have been adopted as part of an electric industry restructuring plan (e.g., Texas); others were adopted as stand-alone proposals (e.g., Iowa, Minnesota). In November 2004, Colorado voters will decide whether to adopt a standard in their state, the first time that such a proposal has appeared on a state-wide ballot anywhere in the country.

Here are some reasons commonly cited for states adopting an RES:

- Renewable energy from some sources (wind power, biomass generation and geothermal energy) has caught up with traditional fossil fueled generation in cost;
- Renewable energy is still fairly unfamiliar to utilities; mandates will speed up adoption of new technologies which are (or soon will be) cost effective;
- Renewable energy has environmental benefits compared to fossil fuels;
- Renewable energy is often "home-grown" and will produce economic development advantages for a state, especially in rural areas;
- There is strong public support for the expanded use of renewable energy by utilities;
- Federal tax policy encourages the use of renewable energy through the Production Tax Credit (PTC) for wind power and business tax credits for solar installation;
- The price of natural gas, which powers most of the generating plants built in recent years, is subject to considerable uncertainty and fluctuation. Some renewable resources (e.g., wind and solar) can stabilize consumer energy prices since these technologies have little or no marginal cost.

Purpose of this Report

The primary purpose of this report is to estimate the effect that a specific RES proposal will have on the retail rates of the affected Colorado utilities.

[1] In this report, we will use the term Renewable Energy Standards (RES) to refer to the collection of similar requirements on public utilities across the country.

Using the RES requirements contained in Amendment 37, which will appear on the November 2004 Colorado general election ballot, this report first estimates the amount of renewable energy that would be obtained by Colorado's affected utilities over the next twenty years. The report then compares the cost of renewable energy with new fossil-fueled generation to estimate the effect that the RES requirement will have on retail electric rates.

The report also examines the degree to which renewable resources can act as a hedge against price fluctuations in the natural gas market. Finally, the report explores other likely effects of an RES, such as its environmental and economic development aspects.

It is well known that the cost of electricity produced using renewable resources has fallen in recent years. Electric power generated by wind turbines in large "wind farms," for example, is now price competitive with power produced using traditional fuels. At the same time, the price of electricity produced from fossil fuels has generally increased and fluctuated as the price of natural gas has risen in recent years.

While the cost per kilowatt-hour of renewable and fossil-fueled electricity may be growing closer together, there are important distinctions between the two energy sources. Energy from traditional fossil resources is usually more predictable than power produced by wind or solar resources since the availability of these renewable resources varies naturally. On the other hand, wind and solar systems have essentially zero fuel cost, so that the price of their electrical output is unaffected by fluctuations in domestic natural gas markets and regional electric power markets.

These two energy sources differ importantly in their environmental impact as well. Fossil-fueled electric resources can contribute substantial amounts of carbon dioxide (CO_2), sulphur oxides (SO_x), nitrogen oxides (NO_x), and mercury to the environment. Thermal electric plants also have relatively high requirements for the consumptive use of water, needed for cooling. Renewable resources such as wind generation do not produce emissions and do not require cooling water. Of course, there are a variety of renewable resources and some, such as burning biomass, may not have the same environmental benefits as solar and wind.

In addition to the positive environmental effects, proponents of renewable energy also point to two other external benefits that may distinguish them from more traditional energy sources: 1) economic development opportunities, especially in rural areas and 2) reduced risk of future energy price fluctuations.

Methodology

In preparing this report, the author employed two methodologies: research and modeling.

The author first conducted an extensive review of the literature on energy price forecasts, renewable energy standards, estimates of the rate impact of an RES in other states, and the current state of traditional and new generation technologies. The report contains an extensive list of articles that comprise its references and bibliography.

Second, the author modeled the 20-year future of retail electric prices for Colorado's major utilities and developed an avoided cost against which the future costs of renewable energy can be compared. The model renewable resource is assumed to be mainly wind power for analytic purposes; the fossil fuel resource is assumed to be advanced combined cycle natural gas-fired generation. The author also developed two independent models of distributed solar generation – a "top-down" and a "bottom-up" approach.

In addition to developing point estimates of the impact of a renewable energy standard on retail electric rates, the report also examines the sensitivity of the analysis to certain key variables, including the future cost of natural gas and changes in federal tax policy.

Finally, the report simulates the change in electric prices caused by spikes in natural gas prices similar to those that occurred in 2000 and 2003. This analysis permits us to illustrate the "hedge" value of wind and solar renewable resources.

Sponsorship and Funding

This report was funded by a grant from the Energy Foundation. Opinions expressed in this report are those of the author and do not necessarily reflect the opinions of the Energy Foundation. Any errors or omissions are the sole responsibility of the author.

About the Author

Ron Binz is a veteran analyst of the utility industry, with more than 25 years of experience. He is President of Public Policy Consulting, a firm specializing in regulatory policy issues in the energy and telecommunications industries. His clients include residential consumer organizations, business customer associations, state agencies, telecommunications carriers, and industrial and commercial energy users. For eleven years until 1995, Binz was Consumer Counsel for the State of Colorado.

Complete information about Public Policy Consulting may be found at www.rbinz.com. Click here to download a copy of this report.

THE COLORADO ELECTRIC UTILITY INDUSTRY

Colorado ranks 26th in size among the 51 state jurisdictions, measured by energy sold at retail in 2002, at 45.9 million megawatt-hours (MWh). Ninety-one percent of the energy generated in Colorado in 2002 was produced by regulated utilities; nine percent was produced by non-utility generators.

To put the Colorado electric industry in perspective, the retail electric market in Colorado is about twice the size of the retail market in Utah or Nebraska, but only one-seventh of the size of the Texas retail electric market, the country's largest.

Colorado Utilities

The state's load is served by 60 electric utilities, including 2 investor-owned companies (Xcel Energy and Aquila); 30 municipal utilities (including Colorado Springs, Fort Collins and Longmont) and 28 rural electric cooperatives (including Intermountain REA, United Power and Holy Cross Electric Association).

The following chart shows the relative size of these three sectors of the Colorado electric industry, measured by megawatt-hours sold in 2002, the latest year for which data are available.

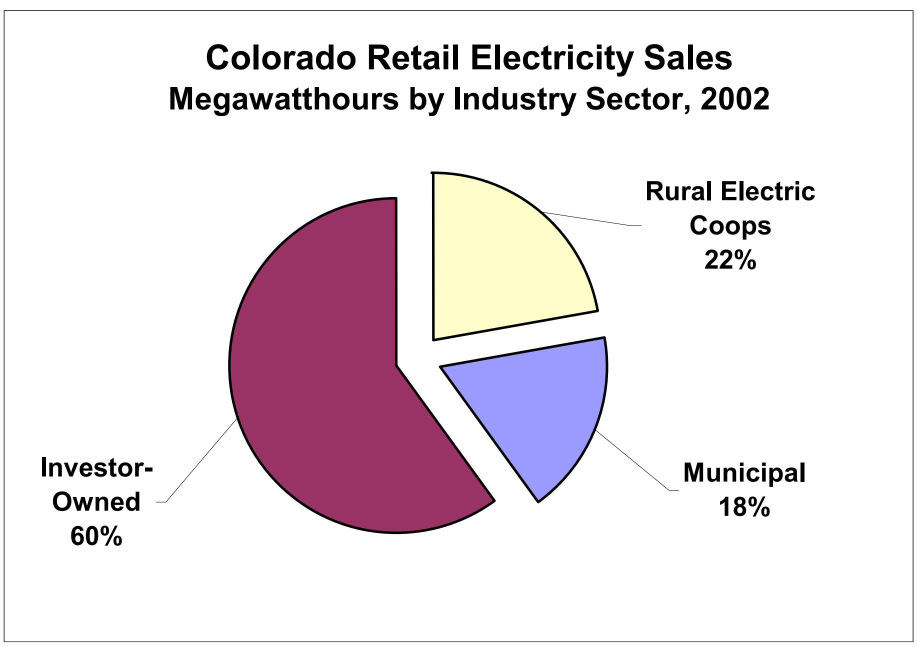


Figure 6 – Market Share of Colorado Utilities by Sector

Source: Energy Information Administration (EIA)

Generation Fuels Used in Colorado

Across the state's utility and non-utility generators, coal is the predominant fuel used in Colorado, accounting for 77.6% of the electric energy produced. Next is natural gas with 20% of the market; hydroelectric power comprises about 2.2% of total generation; all other sources, including renewable energy, accounted for less than 1% of the electricity generated in the state in 2002.

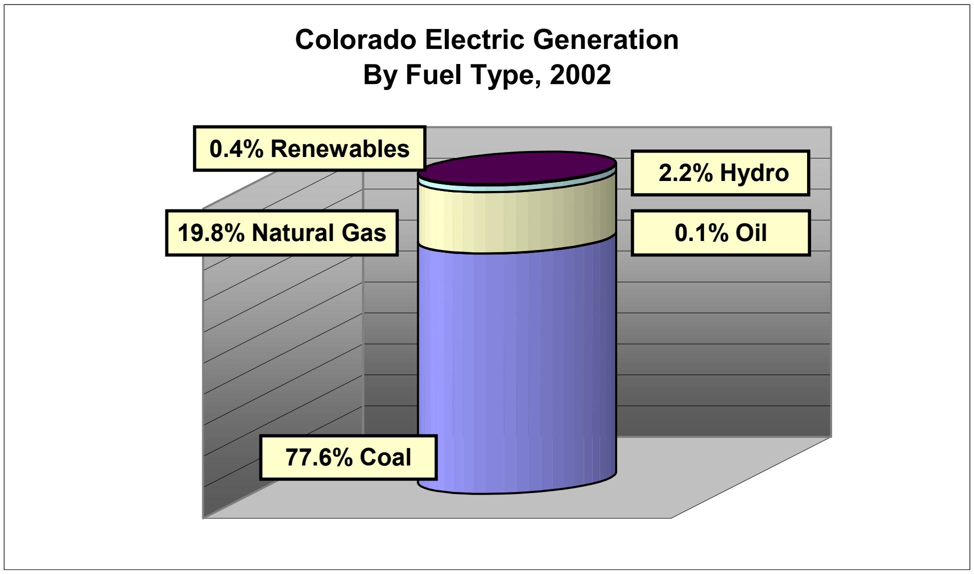


Figure 7 – Fuel Mix of Colorado Electric Generation

Source: Energy Information Administration (EIA)

As in most other states, the fuel mix in Colorado has been changing, with the relative use of natural gas as a fuel for electric generation increasing sharply in recent years. Natural gas fired power plants have been the technology of choice for independent power producers because of the lower capital costs and shorter lead times associated with gas turbine technology.

In 1993 natural gas produced 4.4% of the state's electricity; a decade later, natural gas use had quadrupled to 19.8% of the market – an annual growth rate of 22%.   The shift has been especially notable for the state's two largest utilities: Public Service Company of Colorado (Xcel Energy) and Colorado Springs Utilities.

The Retail Price of Electricity in Colorado

Overall, Colorado's utilities ranked 34th in the country for the average price of electricity per kilowatt-hour in 2002. In other words, electricity was more expensive in 33 states; it was less expensive in 16 states. The following table shows the average retail price of electricity for three customer classes, segregated by utility type:

Colorado Retail Electric Rates, 2002			
Sector	**Residential Price/KWh**	**Commercial Price/KWh**	**Industrial Price/KWh**
Total State	7.37	5.67	4.52
Investor-Owned Utilities	7.21	5.36	4.12
Municipal Utilities	6.63	5.76	4.55
Rural Cooperatives	8.19	7.06	5.23

Figure 8 – Colorado Retail Electric Rates by Ownership and Customer Class

Source: Energy Information Administration (EIA)

Current Utility Use of Renewable Energy in Colorado

By August 2004, Colorado was home to three wind farms; three other wind farms supply power to Colorado consumers from their locations just north of the Colorado-Wyoming border. In addition, Aquila owns a wind farm in southwestern Kansas.

Thus, Colorado utilities were producing or purchasing renewable energy (from wind and small hydro) totaling 299 megawatts from instate sources; at least 50 megawatts from Wyoming facilities. (Aquila's wind farm is not connected to the Colorado grid.)

Wind Power Sites Supplying Energy to Colorado, 2004			
Facility	**Location**	**Rating**	**Date**
Ponnequin	Weld County, CO	30 MW	1998
Arlington	Albany County, WY	25 MW	1999
Peetz	Logan County, CO	30 MW	2001
Lamar	Prowers County, CO	162 MW	2003
Medicine Bow	South Central Wyoming	~ 6 MW	1998
Pleasant Valley	Southwestern Wyoming	~20 GWh	2003

Figure 9 – Wind Generation Supplied to Colorado in 2004

With the addition in 2003 of the 162 MW wind farm in Lamar, the level of renewable generation (as defined in the proposed legislation) in Colorado has risen significantly since 2001. However, generation from all renewable sources still comprises only about 1.8% of Colorado's total generation in 2004.

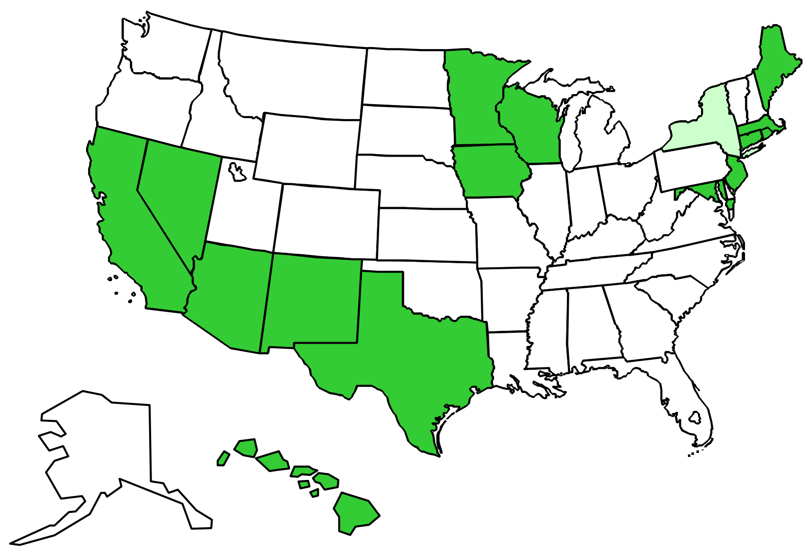
The proposed Colorado RES legislation defines renewable energy sources to include small hydroelectric facilities (less than 10 MW of capacity). In 2004, Public Service Company had 52 MW of capacity from small hydroelectric facilities.

Platte River Power Authority (PRPA) is the power supplier to the cities of Fort Collins, Longmont, Loveland and Estes Park. PRPA owns the majority of the 6 MW Medicine Bow wind farm in south central Wyoming and is purchasing at least 30 gigawatt-hours wind energy (through the purchase of renewable energy certificates) from the Pleasant Valley wind facility in southwestern Wyoming. The wind energy obtained from these two projects is sold to residents of these cities through their optional "green energy" program.

Some distribution utility members of the TriState Generation and Transmission Cooperative offer voluntary green energy programs. Customers who purchase energy through this program are supplied through the TriState's 25% ownership of the Medicine Bow wind farm.

RENEWABLE ENERGY STANDARDS IN OTHER STATES

By mid-2004, fifteen states had adopted a renewable portfolio standard either through legislation or rule making by the state utility regulatory agency. In addition, New York is in the process of adopting RES regulations; Pennsylvania has a limited RES for one utility. Here is a map of the states that have adopted an RES:



The RES standards vary somewhat from state to state, but share the common feature of requiring utilities to acquire a targeted amount or percentage of capacity or energy from renewable resources by specific dates. Here is a brief summary of the standards adopted in the states that have taken action on the issue by mid-2004:

State	Adopted	Renewable Energy Standard
Arizona	1998	1% in 2005; 1.05% in 2006; 1.1%/year 2007 to 2012
California	2002	At least 1%/year; 20% by 2017
Connecticut	1998	10% by 2010
Hawaii	2004	10% in 2010; 15% in 2015; 20% in 2020
Iowa	1991	105 MWa, approximately 2% of 1999 sales
Maine	1999	30% of sales including high efficiency cogeneration
Maryland	2004	7% by 2017 from non-hydro and non-WTE renewables
Massachusetts	1997	4% new renewables on 7% base by 2009; 1%/year thereafter

Minnesota	2003	10% of 2015 sales
Nevada	2001	5% in 2003, increasing to 15% of retail sales by 2013
New Jersey	2001	4% by 2012
New Mexico	2002	10% of sales by 2011
New York	2004	PSC in process of setting standard
Pennsylvania	1998	Limited renewable requirements for one utility
Rhode Island	2004	3% in 2007; 4.5% in 2010; 8.5% in 2014; 17% in 2019
Texas	1999	2880 MW by 2009, approx 3% of sales
Wisconsin	1999	0.5% by 12/31/01, increasing to 2.2% by 12/31/11

Figure 10 – Renewable Energy Standards in Other States

How the Proposed Colorado RES Compares to Others

The proposed Renewable Energy Standard, discussed in detail in the next section, requires utilities that serve more than 40,000 customers to acquire a certain percentage of their energy from renewable resources, 4% of which must be from solar energy sources.

Benchmark Date	Renewable Energy Required (% of sales)	Solar Energy Required (% of sales)
2007	3%	0.12%
2011	6%	0.24%
2015	10%	0.40%

Figure 11 – Colorado's Proposed RES Requirements

As can be seen by comparing the standards in these two tables, the requirements proposed in Amendment 37 will put Colorado in the middle of the pack, compared to the renewable energy standards adopted by other states.

Major Features of Amendment 37

Here is a list of the major features of the ballot measure with explanatory comments:

- **The measure establishes a resource standard for renewable energy that applies to Colorado utilities that serve at least 40,000 customers.**

***Comment**: The RES applies to seven utilities initially, covering approximately 80% of the state's electric utility sales:*

Utility	Retail Customers
Xcel Energy (Public Service Company)	1,258,101
Colorado Springs Utilities	189,437
Intermountain Rural Electric Association	108,332
Aquila, Inc.	86,954
City of Fort Collins	56,604
Holy Cross Electric Association	48,003
United Power	39,175

Figure 12 – Utilities Subject to RES in 2005

Eight additional utilities are likely to pass the 40,000 customer threshold within twenty years, pushing up the statewide percentage to about 90% by 2024.

Utility	Year Threshold Met
City of Longmont	2006
Mountain View Electric Association	2007
La Plata Electric Association	2007
Poudre Valley REA	2009
City of Loveland	2013
Delta Montrose Electric Association	2015
San Isabel Electric Association	2021
Yampa Valley Electric Association	2024

Figure 13 – Utilities Subject to RES 2006-2024

The following chart shows the relative size of these utilities that are initially subject to the Renewable Energy Standard:

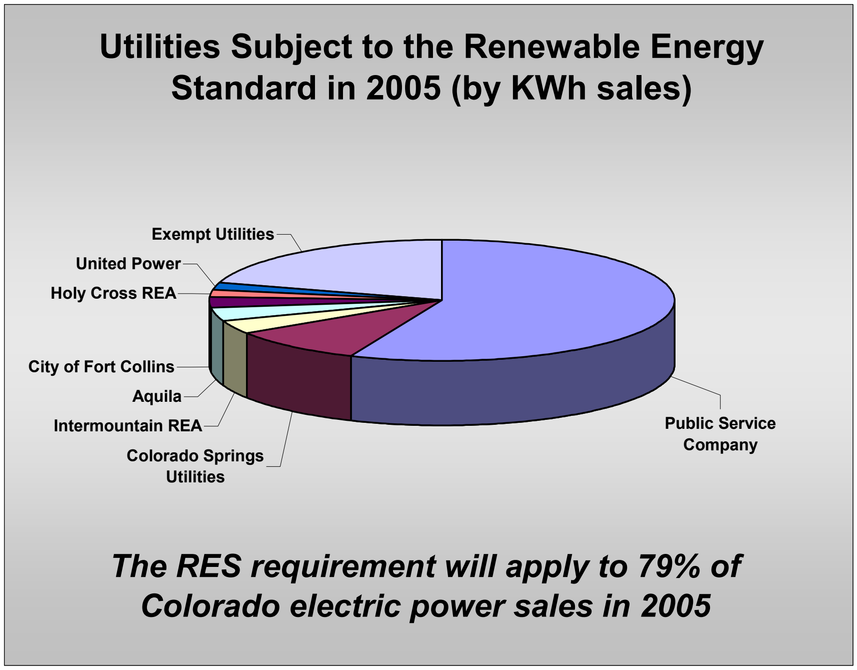


Figure 14 – Relative Size of Utilities Subject to RES in 2005

- **The measure requires affected utilities to generate or acquire a specified minimum amount of renewable energy each year. The standard is as follows:**
  - **3% of retail sales by January 31, 2006**
  - **6% of retail sales by January 31, 2010**
  - **10% of retail sales by January 31, 2015**

  In addition, at least 4% of the renewable energy must be produced from solar energy, half of which must be generated at the customer's location.

Comment: *The following chart show the estimated level of new renewable resources required under the law, compared with non-renewable sources for the subject utilities.*

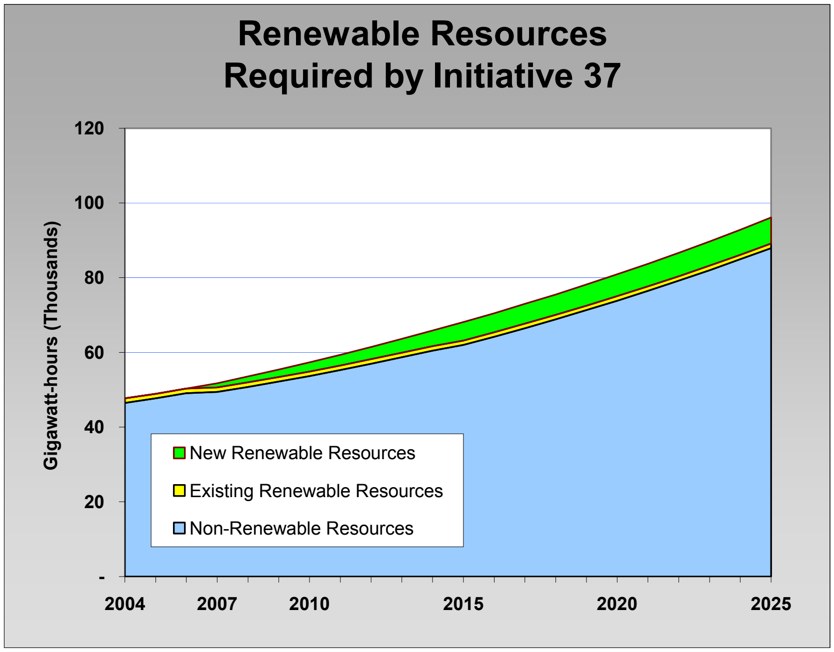


Figure 15 – Impact of Renewable Energy Standard

- **Defines renewable energy to include energy generated using biomass, geothermal, solar, small hydroelectric, wind, and hydrogen derived from renewable energy sources.**

Comment: *The bill permits small hydroelectric facilities to qualify as renewable resources for purposes of the requirement. The bill also includes a "multiplier" that allow utilities to count renewable resources located in Colorado at 125% of their energy value toward the standard.*

- **Allows rural electric cooperatives and municipal utilities to remove themselves from PUC oversight of the RES by "self-certifying" that they have adopted a renewable portfolio standard that is substantially similar to the statutory requirement.**

Comment: *One municipal utility, the City of Fort Collins, adopted a renewable energy standard in 2003 that appears to be substantially similar to the requirements of Amendment 37. In fact, the Fort Collins RES is more aggressive with respect to the amount of renewable energy that the city utility will acquire.*

Importantly, utilities that self-certify their compliance with a comparable RES are not subject to the solar energy provision of the RES in Amendment 37.

- **Permits rural electric cooperatives and municipal utilities to exempt themselves from the RES requirements by a vote of their customers.**

Comment: *A majority of customers voting in an election can decide to remove the rural electric cooperative or municipal utility from the RES, provided that the voter turnout is at least 25% of the number of customers. A utility that votes to exempt itself is not required to comply with any of the provisions of Amendment 37.*

- **Requires the Colorado Public Utilities Commission to adopt rules to establish a system of tradable renewable energy credits.**

Comment: *Implementation details are left to the PUC, but the measure requires the agency to adopt rules to establish a system for trading credits. Such a system could be integrated with WREGIS, the renewable energy credit tracking and trading system being created by the Western Governors' Association.*

- **Limits the rate impact of the RES to no more than 50¢ per month for residential customers.**

Comment: *This report concludes that the monthly bill impact of the RES on residential consumers will generally be much smaller than the 50¢ ceiling in Amendment 37. For that reason, we did not assume that renewable energy acquisition would be curtailed in any year by any utility subject to the RES requirement.*

- **Authorizes the PUC to award regulated utilities a bonus for acquiring renewable energy that yields a net economic benefit.**

- **Requires each affected utility to file an annual report detailing its compliance with the renewable resource requirement.**

- **Authorizes the Colorado Public Utilities Commission to establish penalties for non-compliance with the Renewable Energy Standard.**

THE COST OF WIND ENERGY IN COLORADO

The renewable portfolio standard in Amendment 37 defines a variety of resources as qualifying renewable resources for purposes of meeting the standard:

- Biomass
- Geothermal Energy
- Solar Energy
- Small Hydroelectricity
- Wind Energy
- Hydrogen derived from other Renewable Energy sources

Colorado will likely be home to many, if not all, of these renewable resources in future years. However, in 2004 wind energy is the most economical and most widely deployed renewable resource, with about 250 MW already in place in the state and over 200 MW nearby in bordering states. In addition, scientists rank Colorado as the 11th "windiest" state in the nation for suitable resources for generating electricity from wind, so that economical wind energy is a relatively abundant resource.

For these reasons, this report makes the simplifying assumption, *for estimation purposes only*, that the state's utilities will meet 96% of their renewable resource requirements using wind energy. (Solar energy must be used to meet at least 4% of the RES, unless the utility is relieved of that obligation.)

In practice, other renewable sources, such as small hydro or electricity generation from biomass combustion, are likely to compete successfully with wind in a competitive bidding process used to select renewable projects. In other words, the assumption that wind is used for 96% of the requirement is conservative: the actual costs of meeting the RES might be lower than those estimated in this report.

Colorado's Wind Resources

Wind power engineers classify geographic areas according to the average speed and "density" of the wind at each location. Wind quality classifications vary from 1 to 7 and are defined as follows:

Wind Power Class	10 Meters		50 meters	
	Wind Power Density (watts/m^2)	**Wind Speed** (mph)	**Wind Power Density** (watts/m^2)	**Wind Speed** (mph)
1	<100	<9.8	<200	<12.5
2	100 – 150	9.8 - 11.5	200 - 300	12.5 - 14.3
3	150 – 200	11.5 - 12.5	300 - 400	14.3 - 15.7
4	200 – 250	12.5 - 13.4	400 - 500	15.7 - 16.8
5	250 – 300	13.4 - 14.3	500 - 600	16.8 - 17.9
6	300 – 400	14.3 - 15.7	600 - 800	17.9 - 19.7
7	>400	>15.7	>800	>19.7

Figure 16 – Wind Resource Classification, 10 and 50 Meter Hub Height

At the present state of wind generation technology, wind power classes of 4, 5 and 6 are the most desirable for electric power generation, although the Department of Energy is devoting a significant amount of research to "Low Wind Speed Technologies" (LWST) designed to improve the commercial value of sites that are Class 3 and below.

Class 4 areas are usually described as "good"; class 5 areas are "excellent" and Class 6 areas are described as "outstanding."

Turning to the "wind map" of Colorado, we see that the eastern portion of the state contains significant areas of Class 4 wind power as well as large areas of Class 3 wind power. This map is of recent vintage and shows wind power at a hub height of 50 meters, reflecting the move toward wind machines with larger blades and hubs and at greater height where wind power is more consistent. All these factors contribute to the higher efficiency output of new turbines.

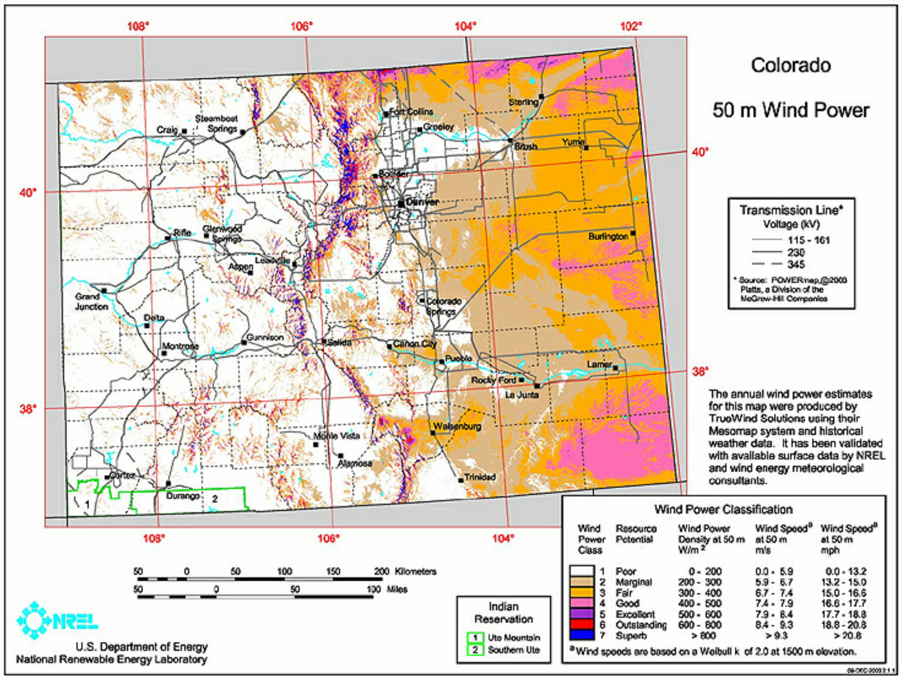


Figure 17 – Colorado Wind Resource Map

The wind resources available in Colorado make it one of the better states in the country for wind power prospects. Here is a ranking of the top twenty states in the country by potential for wind energy production:

THE TOP TWENTY STATES for wind energy potential, as measured by annual energy potential in the billions of kWhs, factoring in environmental and land use exclusions for wind class of 3 and higher.

1	North Dakota	1,210	11	Colorado	481
2	Texas	1,190	12	New Mexico	435
3	Kansas	1,070	13	Idaho	73
4	South Dakota	1,030	14	Michigan	65
5	Montana	1,020	15	New York	62
6	Nebraska	868	16	Illinois	61
7	Wyoming	747	17	California	59
8	Oklahoma	725	18	Wisconsin	58
9	Minnesota	657	19	Maine	56
10	Iowa	551	20	Missouri	52

Source*: An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States, Pacific Northwest Laboratory, 1991.*

Figure 18 – Top Twenty States for Wind Energy Potential

Modeling the Cost of Wind Power

The cost of wind power has fallen dramatically in the past twenty years. The Department of Energy reports that the cost was 40¢ per kilowatt-hour in the 1980s. The DOE's research and development program estimates that the (unsubsidized) cost of wind power in Class 4 areas is about 5¢ per KWh currently; the agency has as its goal a decline to 3¢ per KWh in 2012. (All values in constant 2002 dollars).

For purposes of this report, we use the following values for the cost of wind power production:

Unsubsidized cost per KWh: 5.0 cents per KWh in 2004 decreasing linearly to 3.5 cents per KWh in 2023.

The initial value appears to be conservative. A 15-year wind contract was offered in late 2003 in Oklahoma for a (PTC-subsidized) price of 2.48¢ per KWh. Assuming that the levelized, pre-tax value of the PTC is 2.0¢ per KWh, this implies an unsubsidized rate of about 4.5¢ per KWh for this project.

The (PTC subsidized) cost of the Lamar Wind project was estimated to be 3.2¢ per KWh. The capital costs of wind systems have declined in real terms since the Colorado PUC's decision three years ago, so that it is reasonable to assume the 2004 cost would be no higher than 5¢ per KWh. In addition, Public Service Company of Colorado, in its Least Cost Plan pending before Colorado PUC, is modeling wind power at 2.75¢ per KWh in 2006 (including the PTC), another indication that the current cost of wind power is in the range of 4.75¢ per KWh.

Finally, the DOE's Wind Energy Program Multi-Year Technical Plan estimates that generation in Class 4 wind regimes costs at about 4.3-5.0 cents/KWh currently.

The terminal cost of 3.5¢ per KWh is also likely to be conservative. The Department of Energy's goal for Low Wind Speed Technology costs is 3.0¢ per KWh in 2012, a much more optimistic goal that the assumption made in this report. The 3.5¢ per KWh assumption used in this report is equivalent to a capital investment of approximately $750 per installed kilowatt at a 40% capacity factor, values that appear to be easily achievable by 2023 given current progress in wind technology.

Wind Capacity Factor: We assume a 35% capacity factor in 2004 increasing to 40% for new wind projects in 2023. The 35% value at the beginning of the analytical period is commonly used to characterize wind projects built in Wind Class 4 areas today. The 40% capacity factor at the end of the twenty-year period reflects the fact that wind regimes are becoming increasingly better characterized, and that blade, rotor and generator design continue to improve.

Wind Integration Costs: The addition of intermittent resources can cause a utility to incur operational costs to integrate such a resource into it system. This report assumes a wind integration cost of $2.50 per MWh for up to 800 MW on any system. This value is based on testimony by Public Service Company of Colorado that was accepted by the Colorado Public Utilities Commission in a recent order. Recent research by Xcel Energy reportedly concludes that $2.00/MWh represents the integration costs in Minnesota over a range of wind capacity additions.

Other research in Wisconsin and Michigan estimates integration costs in the range of $2.00 to $3.00 per MWh. Thus, the value used this report is in range of current values. For wind generation added to a single system in excess of 800 MW, we use the higher value of $4.00 per MWh for the integration costs of the incremental generation.

Incremental Transmission Costs: The addition of any generating resource likely adds transmission costs to a system. Thus, for example, Public Service Company of Colorado estimates it must spend $134 million to build new transmission facilities from Pueblo to the Denver metro area to accommodate its proposed 750 MW addition to the Comanche coal plant in Pueblo.

On the other hand, the transmission system serves multiple purposes – not simply to connect single power plants to the grid. Transmission capacity increases system reliability, allows the utility to undertake power exchanges, and can be used by subsequent new generation. It is appropriate to consider a portion of the incremental transmission costs when estimating the cost of adding wind resources, but not appropriate to add the full incremental cost unless similar additions are made for all other generation resources.

To model the cost of wind generation added in Colorado, this report assumes an incremental transmission cost of $4.20 per MWh is appropriate. We did not add transmission costs to the calculation of the avoided cost of the production of the combined cycle plant that wind is assumed to displace.

The value of $4.20/MWh was developed based on the experience of Public Service Company with the Colorado Green project in Lamar and on the Minnesota Public Utilities Commission's recent decision in an Xcel Energy case. In the Minnesota case, transmission capacity was approved that will enable the utility to add 825 MW of wind generation. This value also agrees with the differential transmission costs assigned to wind production by EIA in its *2004 Annual Energy Outlook*.

The Production Tax Credit

Beginning in 1992, Congress approved a Production Tax Credit (PTC) of 1.5¢ per KWh for electricity produced from a renewable resource project in the first ten years of the project life. The PTC was indexed for inflation, so that its 2003 value was approximately 1.8¢ per KWh.

The original PTC expired in 1999 and was extended (retroactively with no break) through 2003.   Congress did not act on a comprehensive energy bill in 2003, with the result that the PTC has again expired. Legislation has been introduced to extend the PTC through 2006 and most observers expect the PTC to be reestablished.

The 2003 PTC has an after-tax value of 1.8¢ per KWh produced in 2004 dollars. Assuming that a firm faces a 36% marginal federal tax rate, this means that the PTC has a pre-tax value of 2.8¢ per KWh for energy produced in the first ten years of a project. Levelized over the project's depreciation life, this pre-tax number is equivalent (on a net present value basis) to 2.0¢ per KWh value for all energy produced for 20 years. It is this value – 2.0¢ per KWh for 20 years – that was used in this report.

At 2.0¢ per KWh, the PTC is obviously very important to an analysis of the rate impact of an RES. Since the status of the PTC is not known with certainty, this report includes analyses conducted under different assumptions about status of the PTC.

THE COST OF SOLAR ENERGY IN COLORADO

Amendment 37 requires that affected utilities fulfill their renewable energy standard with at least 4% of the renewable energy coming from solar resources. Further, at least half of this solar energy must come from facilities located at the customer's location, often called "distributed generation."

Electricity from solar energy is generated mainly in one of two ways: 1) photovoltaic (PV) cells which convert sunlight directly into electric current and 2) solar-thermal generation in which sunlight is concentrated by reflectors and used to power a generator. This first technology is more suitable to smaller, distributed projects; the second technology is more suited to larger, centralized generation facilities.

This report makes three assumptions about the way in which the state's utilities meet the solar requirement of Amendment 37:

- We assume that the municipal and rural electric utilities exercise their option to adopt RES requirements that are substantially similar to the requirements of the ballot measure. Under this provision of the ballot measure, the municipal utilities and the REAs may "self-certify" their compliance and will not be required to meet the solar energy requirements of the ballot measure.[2]

- We assume that the remaining utilities, Public Service Company and Aquila, meet their solar requirements in least-cost fashion by purchasing half the required solar power from a central station solar facility and half through rebates to residential and commercial customers who install distributed generation.

- Finally, we assume that the utilities have access to a state-level or region-level renewable energy certificate (REC) market. RECs are tradable financial instruments that solar RECs may be bought or sold. A full discussion of this assumption follows on page 34 below.

As we shall see below, the first assumption about self-certification is reasonable in view of the higher cost of solar energy, which is likely to induce some utilities to opt out of that requirement. Similarly, the assumption that the remaining utilities meet half their solar requirement through central station generation has an evident economic rationale: even though the customer pays for a portion of the cost of distributed solar generation, its

[2] The ballot measure also permits a rural electric utility or a municipal utility to exempt itself entirely from the RES if a majority of customers vote to make the utility exempt. While we assume these companies will "self-certify," we do not assume that any utility votes to exempt itself entirely.

cost to the utility is higher than the cost of central station solar generation.   Finally, it is very likely that a region-wide REC market, now being developed by the Western Governors' Association, will be enabled in 2005, in advance of the first deadline in the Colorado RES.

Colorado's Solar Resources

Many would say that the familiar slogan "'Tis a privilege to live in Colorado," is justified by the state's sunny climate. Viewing the "insolation map" of the United States, we see that Colorado occupies an enviable spot in the western United States, making the state a candidate for the future development of electricity generated from solar energy resources.

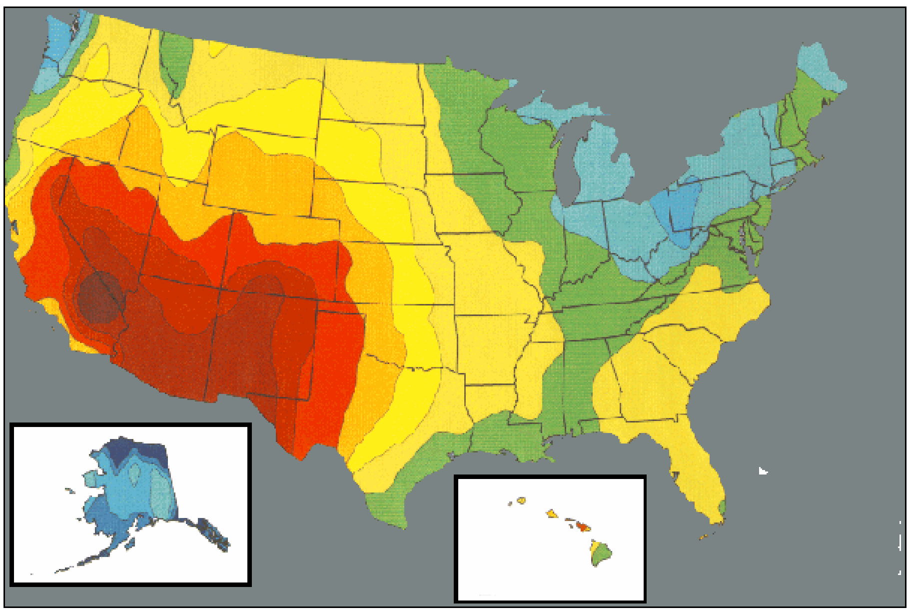


Figure 19 – Average U.S. Daily Solar Radiation 1961-1990

Source: National Renewable Energy Laboratory

While Colorado's climate may provide the raw material, whether a state is suitable for solar electric development depends on several other factors, including

- Relative timing of system peak and incidence of solar radiation
- Air conditioning load
- Relative size of summer and winter loads
- Utility retail and wholesale prices
- State tax policies

A major solar energy developer, PowerLight Corporation, rates Colorado as "Suitable" for solar energy systems, as shown in this map from the company's website:

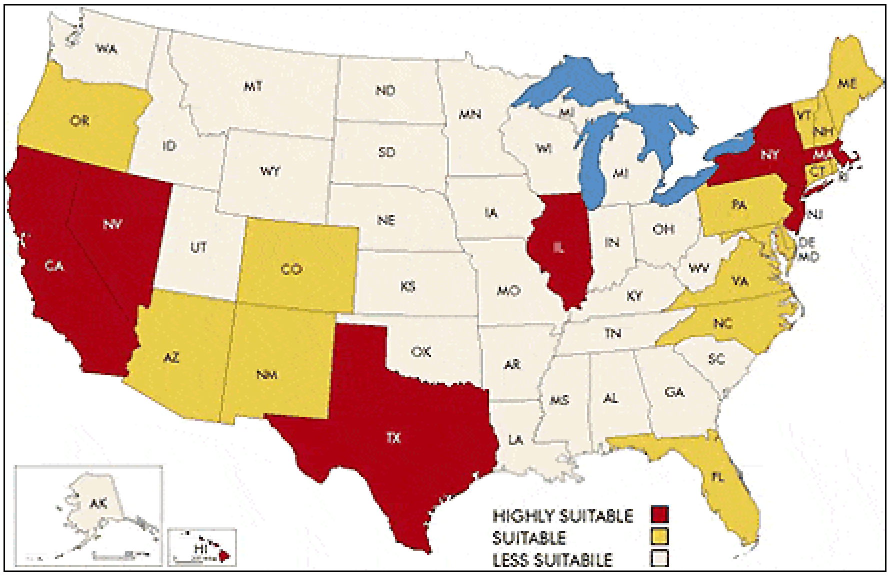


Figure 20 – Relative Suitability of States to Solar PV Development

Source: PowerLight Corporation

Central Station Solar Generation

Electric generation using solar radiation as a power source in a relatively large installation (e.g., 50 MW) is accomplished mainly through one of three technologies:

- **Parabolic trough technology** in which a transfer medium is heated by solar radiation concentrated by trough-shaped parabolic reflectors;
- **Tower generators** in which solar radiation is concentrated by mirrors on the ground focused on a single receptor site at the top of a tower;
- **Rankine or Stirling engine technology** in which mirrors are arrayed in a parabolic dish-shaped configuration and concentrate solar radiation on an engine that converts heat into mechanical energy.

While the costs of central station solar generation are falling, they are still considerably more expensive – by a factor of three or more – than conventional generation using natural gas-fired turbines. Central station solar has the advantage, though, of having output that is concentrated during electric system peak. Solar plants are also no more difficult to site than conventional plants, so that no special consideration needs to be made to accommodate their transmission requirements.

For this report, we assume that half of the affected utilities' solar renewable requirement is fulfilled through central station solar generation. Cost assumptions are taken from a recent report conducted for the National Renewable Energy Laboratory by Sargent and Lundy, LLC. We assume that the 2004 cost per KWh of central station solar is 14¢ per KWh, declining *linearly* to 5.5¢ per KWh by 2020. This appears to be a conservative assumption since the Sargent and Lundy study identifies solar technologies with costs that start lower, decline faster and terminate lower than the assumption used in this report. Moreover, Sargent and Lundy described its own independent assessment as being conservative.

The following chart summarizes the Sargent and Lundy results for Tower and Parabolic Trough technologies:

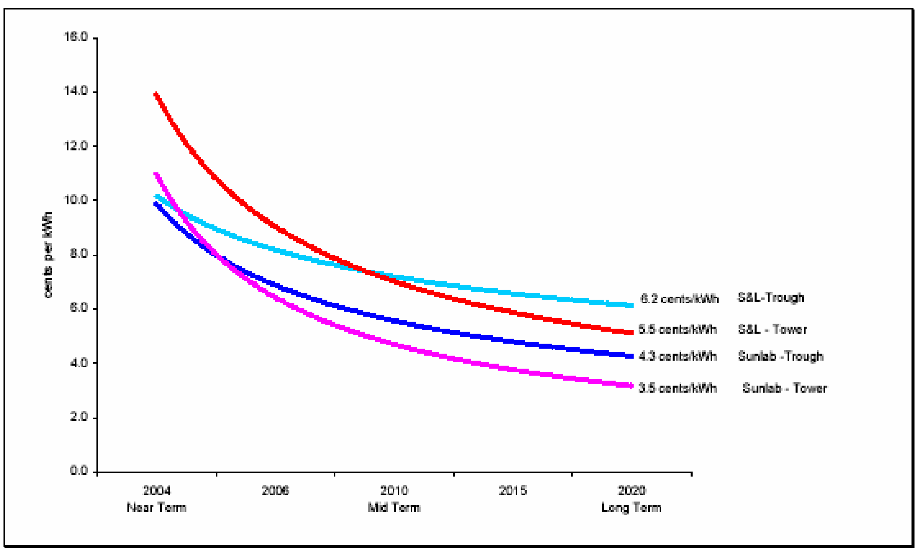


Figure 21 – Future Costs of Tower and Trough Solar Generation

Source: National Renewable Energy Laboratory

Distributed Solar Generation

Solar radiation can be converted directly to an electric current using photovoltaic (PV) technology. Wafers of thin films of semiconductor material such as silicon or gallium arsenide are arranged into familiar PV panels, connected to each other and then exposed to sunlight.

The resulting direct-current electricity is processed by an inverter that converts DC current to AC current at the appropriate voltage and frequency. If the installation is grid-connected, the PV output is simply integrated into the electric grid. If the system is not grid-connected, batteries may be used to make electricity available at times when the system is not generating.

Photovoltaic systems are suited for “distributed” applications near the point of electric consumption, as opposed to centralized utility-scale applications. PV systems are usually modest in size, ranging from a few watts (highway warning signs) to a few kilowatts (residential rooftops) to a few megawatts (large commercial installations).

When integrated into a utility system, distributed PV has the merit of producing electricity during the heat of the day, when a utility’s demand (and its cost) is the highest. And, although electricity from PV is intermittent, its performance tends to be correlated to utility system demand: the source is present during sunny peak periods and is diminished when the utility’s load is lower (during cloudy periods).

The following chart shows the relative hourly output each month for a flat panel PV system installed in Pueblo, Colorado. As can be seen from the chart, daytime output is relatively constant year-round, slightly higher in the months May to October.

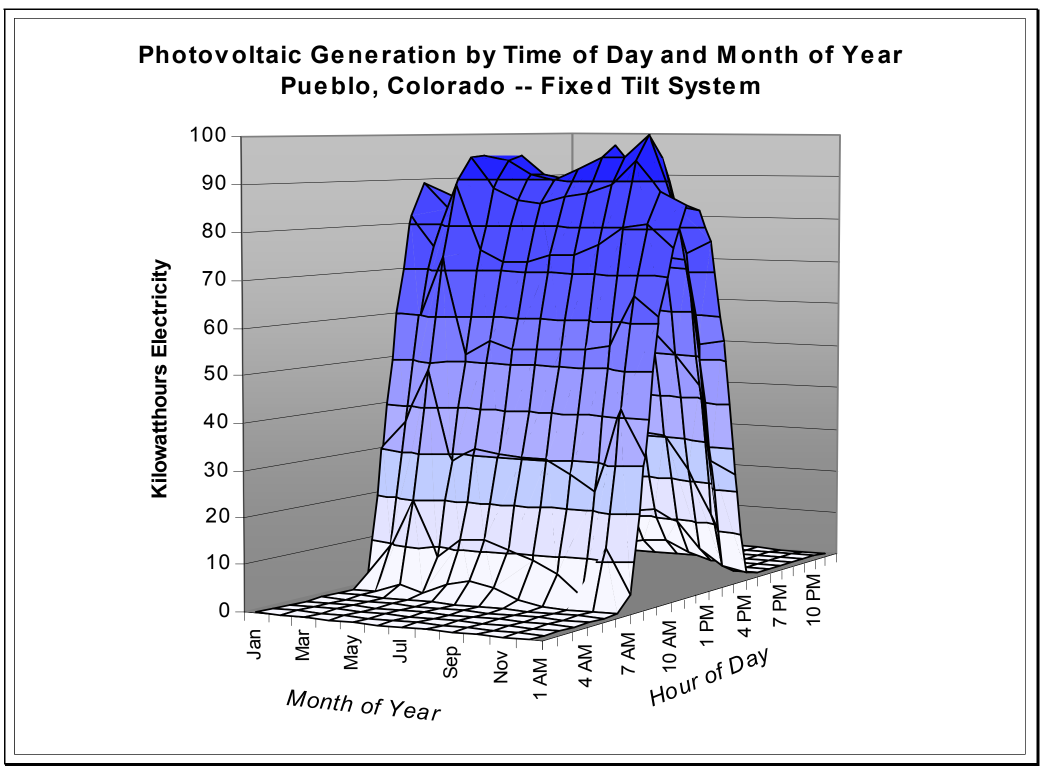


Figure 22 – Characterization of PV Capacity in Pueblo

Data Source: PVGrid, PowerLight

Estimating the Cost of Distributed Solar Generation

To estimate the cost of distributed solar generation, two methods were employed in this report: a 1) a top-down" method in which cost estimates of Renewable Energy Credits (RECs)[3] were used to calculate the cost to utilities of subsidizing customer installation of distributed solar generation; and 2) a "bottom-up" approach in which the utility was modeled making rebates to customers for installing distributed solar systems and then recovering the rebates through the utility rate making process. The annual costs of distributed solar generation developed using these two approaches were averaged to arrive at an estimate used in the modeling.

The main assumptions in the "top-down" case are that solar RECs are priced at $300/MWh in 2006 and decline at the rate of 5% per year to a base price of $150 by the end of the study period. These cost estimates are conservative in the sense that they are at the top end of the range of estimate of costs for photovoltaic power usually encountered and do not include offsets such as distribution and transmission line savings, avoided line losses and the hedge value of solar generation, discussed later.

Amendment 37 requires utilities to offer rebates of at least $2 per watt toward the cost of distributed solar installations. In this report, the rebates were modeled to be large enough to induce residential and commercial customers to install solar PV generation, but not less than $2 per watt; the costs of the rebates were treated as utility capital investments, allowed to earn the utility's authorized return on rate base and recovered from all retail customers.

The Capacity Value of Solar and Wind Generation

Solar generation, either central station or distributed, is an intermittent resource. Wind obviously varies in speed and density, even at class 4 wind sites. Similarly, the "fuel" for solar generation is available only during a portion of daylight hours; even then, cloudy conditions can diminish or eliminate solar generation. Nevertheless, both solar energy and wind energy has a capacity value to utilities.

It turns out that the capacity value for solar energy is often larger than a corresponding wind facility with the same nameplate power rating. To see why, recognize that solar production is highly correlated with a utility's peak load. The most likely time for a solar facility to reach its peak operating capacity is during the hottest hours of a summer day – precisely when a utility reaches its system peak. While clouds may reduce the output of a solar installation, the same weather system that brings clouds could reduce temperatures and lessen the cooling load of an electric utility.

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[3] A discussion of Renewable Energy Credits follows later in this chapter.

Solar production can thus be viewed much like a gas combustion turbine peaking unit: running run only intermittently – during peak demand periods. Of course, while the correlation between solar generation and peak load may be significant, it is not perfect. In some cases, developers pair solar generation with firming capacity in the form of a combustion turbine or contracts for ancillary service from another energy provider.

In contrast, the production from wind resources is not correlated with system load. This means that wind generation has a lower capacity value to the utility than solar production, even if a wind resource has a higher capacity factor. To be concrete, a typical wind farm may produce 35% of its theoretic maximum output over time, while a solar facility that produces electricity five hours per day will have a capacity factor no larger than 21%. Yet the solar facility may well be more valuable to the utility system (have a greater capacity value) because it is more predictably available during peak periods.

Renewable industry analysts use the term "effective load carrying capacity" (ELCC) to describe the capacity value associated with intermittent resources. Research at the National Renewable Energy Laboratory, using load data from Public Service Company of Colorado and 56 other utilities across the nation, shows that the ELCC for solar generation in Colorado is about 60% of the nameplate value of the unit. It is even higher in other western states where the correlation between system peak and solar peak is more nearly perfect. In this report, we use this NREL estimate to calculate the capacity value of solar generation. The ELCC for a wind resource will be much lower, approximately equal to its average capacity – its capacity factor times the facility's nameplate capacity.

Renewable Energy Credits

The proposed Colorado RES provides that the Colorado Public Utilities Commission adopt rules that establish

> …a system of tradable renewable energy credits that may be used by a qualifying retail utility to comply with this standard. The Commission shall also analyze the effectiveness of utilizing any regional system of renewable energy credits in existence at the time of its rulemaking process and determine if the system is governed by rules that are consistent with the rules established for this article.

Electricity generated from renewable sources can be thought of as having two distinct properties -- the underlying electricity and the associated "non-energy" attributes. "Renewable energy credits" or "certificates" (RECs) represent a contractual right to these non-energy attributes associated with a specific amount of generation. One REC represents one megawatt-hour of renewable energy generation.

The value of a REC derives from the fact that some utilities in a market are subject to renewable energy standards. A utility will be able, for example, to satisfy the Colorado RES requirement that it "generate, or cause to be generated, electricity from eligible renewable energy resources" by purchasing RECs, typically from renewable energy producers.

RECs thus become a type of currency in which the cost and price of renewable energy can be stated; RECs also provide a short-hand means to describe the requirements of an RES. Using this parlance, a utility under the Colorado RES (or any RES) is required to obtain a specified number of RECs. These certificates can be obtained either by building renewable generation facilities, purchasing renewable energy from another provider, paying customers to install renewable facilities or, if there is a tradable REC market, purchasing RECs from a market participant with RECs to sell.

The price of RECs will be determined in the marketplace, but will be closely related to the cost premium associated with a specific set of renewable generation technologies. When a REC is priced near this value, buyers and sellers are nearly indifferent to the build-or-buy decision: a utility can build a renewable facility, internalizing the cost premium of the resource or purchase a REC from another entity, externalize the premium. The producer of renewable energy can sell the energy and the associated RECs outright to a single buyer or it can sell RECs in one market and its renewable energy at market prices in the electricity market.

RECs are traded in several regional markets and are being tracked by Evolution Markets, LLC (evomarkets.com). Here is an excerpt from the Company's web page on which it reports bid, ask and last trade prices of Renewable Energy Certificates:

Monthly Market Update

REC Markets
August 2004

Compliance RECs

CT CLASS I CERTIFICATES

TERM	BID	OFFER	LAST	DATE
2004	$40.00	$45.00	$42.50	07/12/04
2005	$37.00	$45.00	$36.50	05/19/04
2006	$37.00	$45.00	$36.50	05/19/04

Maine / CT CLASS II CERTIFICATES

TERM	BID	OFFER	LAST	DATE
2004	$0.50	$0.70	$0.65	07/21/04
2005	$0.50	$0.90	$0.70	08/31/04
2006	$0.50	--	$0.65	03/ -- /04

MA "NEW" CERTIFICATES

TERM	BID	OFFER	LAST	DATE
2004	$45.00	$50.00	$49.25	07/19/04
2005	$40.00	$48.00	$46.00	08/16/04

TEXAS RECs

TERM	BID	OFFER	LAST	DATE
2003	$11.25	$12.00	$11.00	08/16/04
2004	$11.50	$12.50	$11.50	08/18/04

NJ CLASS I

TERM*	BID	OFFER	LAST	DATE
RY 05	$6.00	$7.00	$7.50	08/--/04
RY 06	$6.00	$8.00	$6.50	12/31/03
RY 07	$7.00	--	$6.00	7/31/03

NJ CLASS II

TERM*	BID	OFFER	LAST	DATE
RY 05	$4.00	$4.25	$4.35	08/--/04
RY 06	$4.15	$4.25	$4.35	03/ -- /04
RY 07	$4.25	$5.00	$4.35	11/21/03

NJ SOLAR

TERM*	BID	OFFER	LAST	DATE
RY 05	$125.00	$200.00	$175.00	07/--/04
RY 06	$125.00	$200.00	--	--
RY 07	$125.00	$200.00	--	--

*Note: In accordance with the new NJ RPS rules, the NJ RECs market is now based on "reporting years" ("RY"). The reporting year runs June 1 - May 31, and generation from any time during the RY can be used to meet that year's compliance obligations. The RY is referred to by the calendar year in which it ends - therefore, the RY that runs from June 1, 2004 to May 31, 2005 is referred to as "RY 2005".

Figure 23 – Reported Prices for Renewable Energy Credits, August 2004

Source: Evolution Markets, LLC

The August 2004 Evolution REC Markets report demonstrates several important points. First, the price of a REC reflects a small premium for the option value captured in the financial instrument. For that reason, the price of certificates associated with a specific technology will always be positive, even when the cost of the resource is lower than fossil-fueled generation. We can see from the table that the price of RECs for Class II resources in Connecticut (waste-to-energy plants, hydroelectric generation) are small but positive (~$0.60/MWh) even though those are proven technologies that compete successfully with coal and gas-fired thermal generation without a price premium.

Second, it is also important to note that solar RECs will constitute a separate market from RECs associated with technologies such as wind and biomass, which are very nearly cost competitive today. For example, in the New Jersey REC market, general RECs were trading in the range of $4 to $7 per MWh in August 2004 while Solar RECs in the same state last traded at $175 per MWh.

Anticipating the need for a REC market in the western United States, the Western Governors' Association (WGA) has spearheaded a move to create such a market. In conjunction with the California Energy Commission and the Western Regional Air Partnership, WGA is working toward the creation of WREGIS, the Western Regional Energy Generation Information System. WREGIS is scheduled to become operational in 2005 and should enable a REC market in the region.

This report assumes that RECs will be available in the region and will be used by some utilities to meet their obligations under Amendment 37 to acquire a fraction of their energy from renewable resources. At the present time, the Platte River Power Authority is purchasing RECs from the Pleasant Valley wind facility in Wyoming to supply the City of Fort Collins with energy produced by 20 MW of wind capacity.

To estimate the cost of complying with the Colorado RES using RECs, we assume that the cost of a REC equals the price premium of wind generation (if any) plus an option premium of $2.00 per MWh. This produces a 2004 REC price of $10.00 per MWh for general RECs. For solar RECs, we assumed an initial price of $300 per MWh, declining to $150 per MWh in 2023 (see the discussion on page 33 above).

THE FUTURE COST OF ELECTRICITY FROM FOSSIL FUELS

Production Costs of Coal and Natural Gas Plants

In Colorado, the most likely traditional power sources for meeting growth in electric demand are fossil-fueled plants powered by coal or natural gas. Colorado's utilities will acquire such power by either constructing the capacity themselves or purchasing the power in the market. The utilities will answer the "build or buy" question in a decision that balances the availability of capital, assessment of risk, environmental considerations and other factors.

But whether the companies build or buy, the cost of the power will be driven by the familiar components of utility generation costs: capital costs, operating costs and fuel costs. Purchased power is subject to the additional influence of market pressures, with prices responding to market demand.

For this report, we assume that the "avoided cost" facing the utilities is the cost of power produced by an advanced combined cycle natural gas plant. Plants of this design are the preferred choice of third-party power producers given their lower capital costs. During the past decade, natural gas plants provided two-thirds of new capacity in Colorado.

The per-kilowatt-hour costs of an advanced coal plant and an advanced combined cycle gas turbine plant are projected to be relatively close, as demonstrated by the following table, which shows the most recent estimates of the Department of Energy. The values in this table were not used in this report, but are presented here as a check on the costs developed in the model used here.

	2010		2025	
Costs	**Advanced coal**	**Advanced combined cycle**	**Advanced coal**	**Advanced combined cycle**
	2002 mills per kilowatt-hour			
Capital	33.77	12.46	33.62	12.33
Fixed	4.58	1.36	4.58	1.36
Variable	11.69	32.95	11.74	37.91
Incremental transmission	3.38	2.89	3.26	2.78
Total	**53.43**	**49.65**	**53.20**	**54.38**

Figure 24 – Cost of New Coal and Gas Generation

Source: *2004 Energy Outlook,* Energy Information Administration (EIA)

Each technology has its advantages and disadvantages. As can be seen, coal plants have a significantly higher capital cost, but lower variable operating costs, due mainly to the relatively lower cost of coal. Gas plants are cheaper and faster to build but have significantly higher operating costs due to the higher cost of natural gas per kilowatt-hour produced.

These two types of plant differ in other characteristics, including fuel conversion efficiency (heat rates), emissions, water use, etc. But the bottom line is that per-KWh costs are similar under current projections for coal and gas prices. It is reasonable to assume that the avoided cost faced by Colorado utilities is the cost of an advanced combined cycle gas plant.

Model Assumptions

Capital Costs: For this report, we assume that the marginal plant is an advanced combined cycle gas plant with a capital cost of $608/KW that remains constant (in real terms) over the study period.

Heat Rate: We assume a heat rate of 7000 BTU/KWh, improving continuously to 6300 BTU/KWh in 2024.

Capacity Factor: We assume a capacity factor of 85% in 2004 improving continuously to 90% in 2023.

Fuel Cost: For the base case cost of natural gas, we used the most recent projections by the Department of Energy, contained in the *Annual Energy Outlook 2004*, for natural gas delivered to utility generators in the Western region. This is the same index described by Xcel Energy in its current Least Cost Plan pending before the Colorado Public Utilities Commission, Docket No. 04A-214E.

As discussed *infra*, we also established an alternate High Gas Cost case and an alternate Low Gas Cost case in which future gas costs were adjusted up and down from the current DOE estimate by about 15%, with the difference phased in over 10 years. Finally, we created a Spike Gas Cost scenario to measure the hedge value of renewable resources in the portfolio. See the discussion of these alternative Gas Cost cases below.

Operation and Maintenance Costs: Variable O&M Expenses are assumed to be 3.1 mills/KWh, remaining constant (in real terms) over the study period.

The combination of these assumptions yields the series of costs for gas-fired electric generation shown in the following chart.

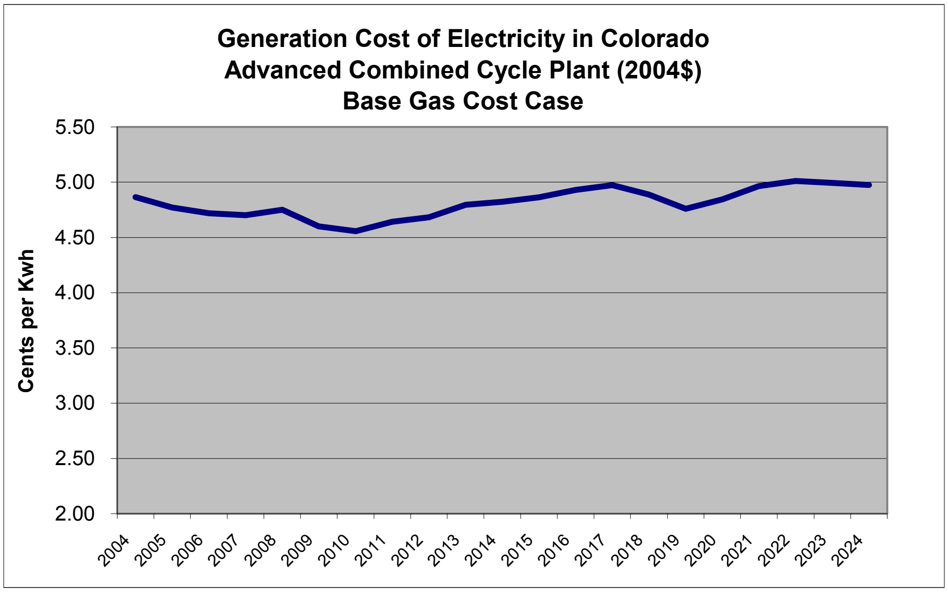

Figure 25 – Per KWh Cost of Combined Cycle Generation, 2005-2024

The Future Cost of Natural Gas

One of the more vexing challenges facing an analyst of the U.S. utility industry is making assumptions about the future price of natural gas. This premium fuel has become the fuel of choice of non-utility electric generators. In Colorado, the use of natural gas as a generator fuel grew by 498% from 1993 to 2002, an annual growth rate of 22%. During the same period, the energy produced using coal in Colorado increased only 15%, about 1.6% each year from 1993 to 2002. In short, the cost of natural gas has become an important determinant of generation costs and the price of electricity in western markets.

For the base case estimate in this report, we adopt the current projections to 2025 developed provided by the Department of Energy for gas prices delivered to electric generators in the west region. Here is a graph showing actual wellhead natural gas prices to 2003 together with DOE's estimates from 2004 to 2025.

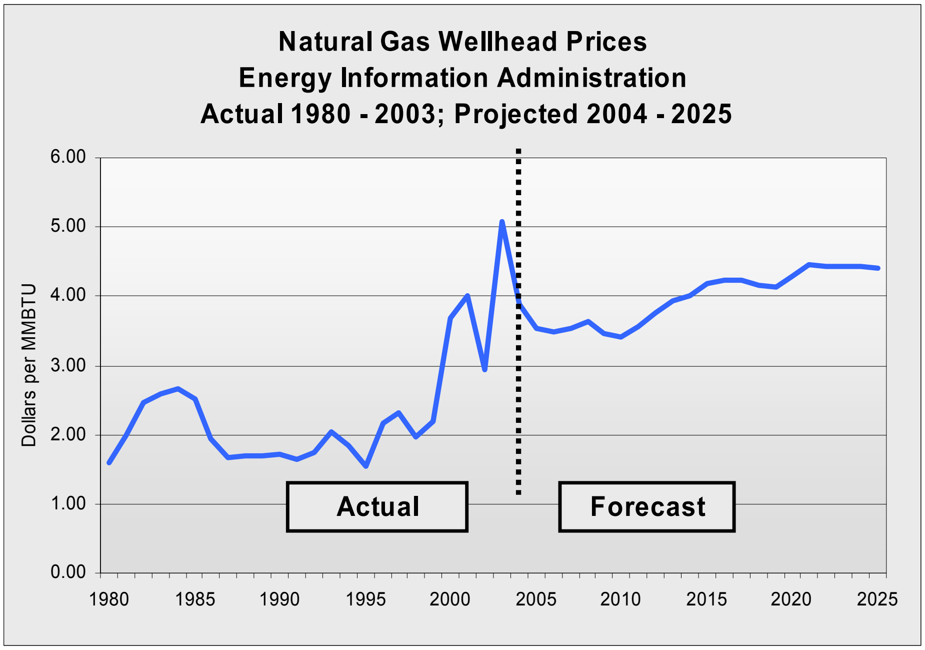

Figure 26 – Actual and Forecast Natural Gas Wellhead Prices

There are two important observations about DOE's estimates of future natural gas prices:

- Each year for the past ten years, the DOE estimate of natural gas prices has superseded the previous year's estimate by *increasing* the estimate of future prices; and
- For the past five years, DOE's estimate has shown a downward bias when compared to commodity futures prices. The bias is between $0.40 and $0.60 per MMBTU when current DOE forecasts are compared to the nearest-in-time futures contracts.

Due to this observed downward bias in DOE's estimates and in order to test the sensitivity of the model results to changes in natural gas prices, we created "High Gas Cost" and "Low Gas Cost" scenarios (depicted in the following chart) in which prices for natural gas are assumed to differ by $0.75/MMBTU from DOE's forecast of prices delivered to the Mountain region.

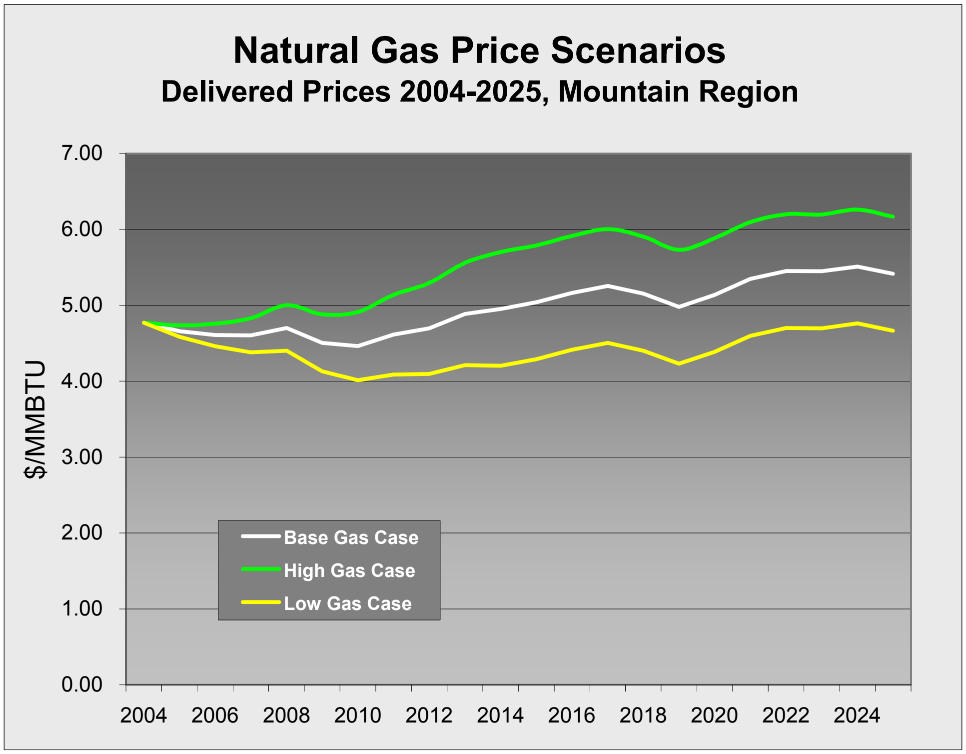

Figure 27 – Natural Gas Price Scenarios: Base, High and Low Cases

RATE IMPACT OF AN RES IN COLORADO

We are now able to estimate the impact that an RES mandate would have on retail electric rates in Colorado for each of the affected utilities. We begin with a detailed examination of the impact on Xcel Energy, which accounts for 71% of the retail energy subject to the RES in 2005. Xcel is subject to both the general RES requirement and the solar energy requirement. The method is to calculate the impact of general RES requirement and the solar requirement separately and combine them for the net impact on rates of the utility.

Following the calculation of the impact on Xcel Energy, we estimate the impact on the other fourteen utilities that will be eventually subject to the RES.

As mentioned previously, we model the non-solar RES requirement assuming wind energy was used to fulfill the requirement. The relative cost of wind power compared to fossil fueled generation is dependent on the choice of input factors. We distinguish nine cases, differing on the assumptions about the future price of natural gas and the status of the federal Production Tax Credit. Later we will attach probabilities to these scenarios and produce an expected value of the rate impact of the RES.

Nine Scenarios

Scenario	Gas Price Assumption	PTC Assumption
Scenario 1A	Base Gas Cost	No PTC Extension
Scenario 1B	Base Gas Cost	PTC to 12/31/2006
Scenario 1C	Base Gas Cost	PTC to 12/31/2009
Scenario 2A	High Gas Cost	No PTC Extension
Scenario 2B	High Gas Cost	PTC to 12/31/2006
Scenario 2C	High Gas Cost	PTC to 12/31/2009
Scenario 3A	Low Gas Cost	No PTC Extension
Scenario 3B	Low Gas Cost	PTC to 12/31/2006
Scenario 3C	Low Gas Cost	PTC to 12/31/2009

Figure 28 – Nine RES Cost Scenarios

The first three cases assume the accuracy of the Energy Information Administration's estimate of delivered natural gas prices for the twenty-year period 2005-2024.

Scenario 1A: Assume base gas costs; assume that the Production Tax Credit (PTC) is not extended following its expiration on December 31, 2003.

Scenario 1B: Assume base gas costs; assume that the Production Tax Credit (PTC) is extended retroactively from December 31, 2003 to December 31, 2006.

Scenario 1C: Assume base gas costs; assume that the Production Tax Credit (PTC) is extended retroactively from December 31, 2003 to December 31, 2009.

The next three cases assume higher gas costs by removing the observed downward bias of the EIA gas price projections.

Scenario 2A: Assume high gas costs; assume that the Production Tax Credit (PTC) is not extended following its expiration on December 31, 2003.

Scenario 2B: Assume high gas costs; assume that the Production Tax Credit (PTC) is extended retroactively from December 31, 2003 to December 31, 2006.

Scenario 2C Assume high costs; assume that the Production Tax Credit (PTC) is extended retroactively from December 31, 2003 to December 31, 2009.

The last three cases assume gas prices are lower than forecast by approximately 15%, with the discount phased in over ten years.

Scenario 3A: Assume low gas costs; assume that the Production Tax Credit (PTC) is not extended following its expiration on December 31, 2003.

Scenario 3B: Assume low gas costs; assume that the Production Tax Credit (PTC) is extended retroactively from December 31, 2003 to December 31, 2006.

Scenario 3C Assume low costs; assume that the Production Tax Credit (PTC) is extended retroactively from December 31, 2003 to December 31, 2009.

The relative cost of wind generation, compared to generation provided by a combined cycle gas plant, and representing 96% of the RES requirement, is calculated separately for each of the scenarios. The cost of acquiring 2% of the RES requirement fulfilled by central station solar power is added to each of the cases. Finally, the cost of acquiring 2% of the RES requirement fulfilled by distributed solar generation (photovoltaic installations) is added to the total.

As described earlier, the cost of photovoltaic energy is calculated as the average of the "top-down" and the "bottom-up" methods. These methods estimate the relative cost of distributed solar energy, compared to gas generation, assuming the Base Gas Cost case. Similarly, the estimate of the relative value of central station solar generation is based on the Base Gas Cost case.

Summary of Effects by Scenario

The following table summarizes the effects of the RES on retail electric rates for Xcel Energy for each of the nine scenarios just described. The results reflect the combination of the solar and non-solar requirements for Xcel.

Referring to Figure 29, the scenario description is shown in table Column A, the (nominal) 20-year total change in Xcel's revenue requirement is shown in Column B, followed by the discounted net present value of the annual effects in Column C. A positive number indicates higher revenue requirement; a negative number signifies a reduction in the revenues required by Xcel.

The next three columns show the monthly bill impact for the average residential customer of Xcel Energy in Colorado. Column D states the average monthly bill change over the 20-year period 2005-2024. A negative number signifies a reduction in the monthly bill.

Columns E and F report the range in changes in the monthly bills over the twenty year period. Thus, for example, under the assumptions of Scenario 1A, Column D shows the average residential bill will increase by an average of 36 cents per month. The largest monthly increase would be 44 cents per month (Column E); the smallest change in the bill would be an increase of 3 cents per month (Column F) in some months during the twenty year period 2005-2024.

Rate Impact of Colorado RPS for 2005-2024: Nine Scenarios

		Xcel Total 20 Year Effect		*Impact on Average Residential Monthly Bill*		
Scenario	**Senario Description**	Nominal	NPV	Overall	Range	
	Col A	Col B	Col C	Col D	Col E	Col F
1A	*Base Gas Case, No PTC*	390,461,630	147,905,158	0.36	0.44	0.03
1B	*Base Gas Case, PTC to 2006*	24,709,183	(1,944,066)	0.02	0.13	(0.19)
1C	*Base Gas Case, PTC to 2010*	(146,287,190)	(43,740,649)	(0.14)	0.04	(0.26)
2A	*High Gas Case, No PTC*	245,618,715	105,278,688	0.23	0.36	0.03
2B	*High Gas Case, PTC to 2006*	(120,133,732)	(44,570,536)	(0.11)	0.03	(0.21)
2C	*High Gas Case, PTC to 2010*	(291,130,104)	(86,367,119)	(0.27)	0.03	(0.45)
3A	*Low Gas Case, No PTC*	535,304,544	190,531,628	0.50	0.63	0.03
3B	*Low Gas Case, PTC to 2006*	169,552,097	40,682,404	0.16	0.32	(0.16)
3C	*Low Gas Case, PTC to 2010*	(1,444,275)	(1,114,180)	(0.00)	0.16	(0.16)

Figure 29 – Xcel Rate Impact Summary

Probability of the Scenarios

Rather than present a single point estimate from among the outcomes from the scenarios presented above, we will calculate an "expected value" of the nine scenarios by assigning probabilities to each of the nine cases. Given the Department of Energy's track record in estimating future natural gas costs, it is reasonable to assume that the probability of the Base Gas scenario occurring is 50%, that the probability of the Low Gas Cost scenario occurring is 20% and that the probability that the High Gas Cost case will occur is 30%.

Regarding the Production Tax Credit, it appears likely that Congress will extend the PTC for renewable energy. To compute an expected value of the cases, it is reasonable to assign a 70% probability that the PTC will be extended for three years to 2007; a 20% that the PTC will be extended six years (possibly in two stages) to 2010; and a 10% probability that the PTC will not be extended at all.

Assigning a probability of 70% of extending the PTC through 2006 has less effect on the result than might be predicted: we can assume that, as has occurred in past periods, utilities and wind developers will accelerate acquisition of wind resources in order to take advantage of a PTC if it were scheduled to expire. In other words, the assumption of an extension through, say, 2009 might have the same effect as an extension through 2006. In view of this effect, this report adjusts the rate of acquisition of renewable resources based on the assumed timing of expiration of the PTC.

Under this assignment of probabilities to the two main variables, here is the likelihood of each of the nine scenarios occurring:

Scenario Probabilities		
Scenario 1A:	Base Gas, No PTC	5%
Scenario 1B:	Base Gas, PTC to 2006	35%
Scenario 1C:	Base Gas, PTC to 2010	10%
Scenario 2A:	High Gas, No PTC	3%
Scenario 2B:	High Gas, PTC to 2006	21%
Scenario 2C:	High Gas, PTC to 2010	6%
Scenario 3A:	Low Gas, No PTC	2%
Scenario 3B:	Low Gas, PTC to 2006	14%
Scenario 3C:	Low Gas, PTC to 2010	4%

Figure 30 – Scenario Probabilities

Rate Impact for Xcel Energy

Using these probability weightings, we derive the expected value of the costs and benefits of renewable acquisition (assumed to be 96% wind energy, 2% central solar, 2% distributed solar). The result for Xcel is detailed in the table in Figure 32 below. Here are three selected results:

- It is likely that the Renewable Energy Standard will increase the revenue requirement of Xcel Energy slightly over the 20-year period 2005-2024. The expected value of the increase is approximately $12.6 million in 2004 dollars. This translates to an increase for the average residential customer of about 1 cent per month.
- This near-zero expected value is the result of the offset of $335 million of solar generation costs by a similar amount of savings from wind generation. The following chart shows the year-to-year changes in average residential monthly bills in the expected value case:

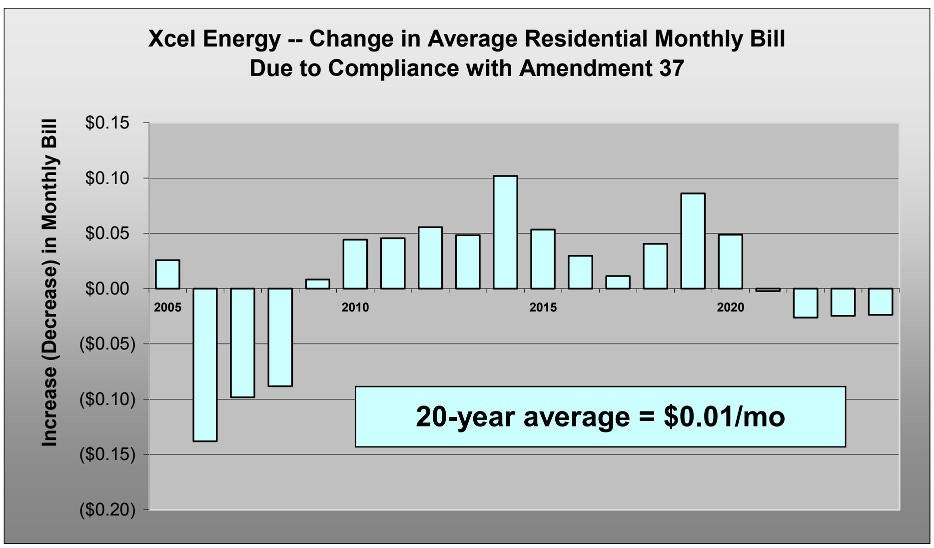

Figure 31 – Xcel Energy, Change in Average Residential Bills

- Under less likely assumptions, the RES will decrease the Xcel's required revenues by $291 million during the 20 years, reducing average residential electric bills by 27 cents per month.

- Under much less likely assumptions, the RES will increase Xcel's required revenues by $535 million during the period 2005-2024, increasing average residential electric bills by 50 cents per month.

Rate Impact for Other Colorado Utilities

The rate impact of the Renewable Energy Standard on consumers on the companies other than Xcel will vary somewhat from utility to utility depending on several factors:

- Whether the utility is subject to the solar energy requirements of Amendment 37;
- The degree to which the utility's power supply contracts allow it to obtain resources from another source;
- The fuel source used by the utility or its supplier at the margin for power generation;
- The level of existing renewable energy use at the utility;
- The strategy employed by the utility to meet the RES requirements;
- The average number of kilowatt-hours used by customers on the system.

We now present a discussion of the assumptions used to estimate the impact of the RES on each of the additional fourteen utilities subject to the requirements of Amendment 37.

Following this utility-specific discussion, the table on page 50 summarizes the impact on each utility's costs over the twenty year period 2005-2024. The table also contains an estimate of the impact on the monthly bill of the utility's average residential customer.

When estimating the cost of complying with the RES for these fourteen utilities, we employed one of four models, depending on the utility's circumstances:

- The expected value of costs and benefits of acquiring wind energy from the same model used for Xcel Energy, applied to the loads and growth of the utility;
- The costs of fulfilling the RES requirement by purchasing RECs. The price of the RECs is given by the cost premium associated with wind generation in Scenario 1A (Base Gas Cost, No PTC), if any, plus an option value of $2.00 per MWh.
- Flow-through of costs and benefits experienced by the utility's wholesale provider;
- A combination of these strategies.

City of Colorado Springs Utilities

Colorado Springs Utilities (CSU) is the state's second largest utility and will be required by the RES to acquire more than 10,000 gigawatt-hours (GWh) of renewable energy over 20 years. We assume that CSU exercises its option to adopt its own RES and will be exempt from the solar energy requirement of Amendment 37.

If CSU meets its RES using wind energy purchases beginning in 2006, residential rates will be lower by an average of 33 cents per month and the utility's revenue requirement will be lower by a total of $63.6 million over 20 years. If Colorado Springs Utilities fulfills its entire RES requirement by purchasing Renewable Energy Certificates (RECs), rates for the average residential customers would rise by an average of about 14 cents per month. A combination of the two strategies would yield residential rates that are lower by about 9 cents per month over the 20-year study period.

Intermountain REA

Intermountain REA is the state's third largest utility and is a full-requirements customer of Public Service Company of Colorado. This means that IREA will share in the costs and benefits of renewable energy obtained or produced by Public Service Company. We assume that IREA will exercise the option to exempt itself from the solar energy requirement by the self-certification option in the amendment.

Under these assumptions, the most likely outcome for IREA consumers is a reduction of energy costs of 45 cents per month for the average residential customer. This equates to wholesale power costs that are lower by a cumulative $24.6 million over the twenty years 2005-2024.

Other REAs

Holy Cross Electric Association and Yampa Valley Electric Association and are also full-requirements customers of PSCo. Assuming these cooperatives exempt themselves from the solar requirement by self-certification, the most likely outcome for Holy Cross is a reduction in energy costs of 48 cents per month for the average residential customer, a total savings to the utility of $14.1 million over twenty years. Similar results occur for Yampa Valley.

United Power, Mountain View Electric Association, La Plata Electric Association, Poudre Valley REA, Delta Montrose Electric Association and San Isabel Electric Association are all full requirements customers of TriState Generation and Transmission Cooperative. We assume that these distribution coops will exempt themselves from the solar requirement and that the RES is satisfied by renewable resources that are no more costly than wind power.

It is difficult to assess the impact of wind purchases on TriState, since the majority of TriState members are not subject to the RES. Therefore, for modeling purposes we assume that these six coops meet their RES obligations by purchasing Renewable Energy Certificates in the regional REC market. This is a conservative estimate and is likely to be more costly than a strategy that involves TriState purchasing wind power directly. With these assumptions, the impact of Amendment 37 on residential customer of these coops will average 19 cents per month, although that amount could be mitigated, depending upon TriState's strategy. Details for each coop are found in the table on page 50.

Aquila, Inc.

Aquila is an investor-owned utility that serves retail customers in southern Colorado. Aquila is a partial requirements customer of Public Service Company. As such, Aquila will share in the costs and benefits incurred by PSCo as it complies with the RES. The balance of Aquila's non-solar requirements can be met with Renewable Energy Credits associated with the company's wind farm in western Kansas.

We assume that Aquila will meet the solar requirement of Amendment 37 in a similar fashion to Public Service Company – 50% from central station solar generation and 50% from distributed generation. With these assumptions, the average monthly bills of Aquila's residential customers are estimated to increase by 1 cent per month due to compliance with Amendment 37.

City of Fort Collins

In 2003 the City of Fort Collins adopted an Energy Plan that calls for the city to acquire renewable resources equivalent to 15% of the utility's load in 2017. This is a more aggressive schedule than the Colorado RES contained in Amendment 37. Therefore we assume that the City of Fort Collins will self-certify compliance with Amendment 37 through its existing RES. We do not include Fort Collins in this analysis since any rate impact, up or down, will be due to the pre-existing Energy Plan, and not Amendment 37. That said, the experience of Fort Collins should be similar to that of the cities of Longmont and Loveland which are discussed below.

Cities of Longmont and Loveland

Longmont and Loveland purchase their power from the Platte River Power Authority (PRPA), which operates wind turbines in Wyoming and purchases Renewable Energy Certificates (RECs) from another Wyoming wind farm. We assume that Longmont and Loveland will exempt themselves from the solar requirement and satisfy the RES through PRPA with a strategy that combines wind acquisition and REC purchase. Under these assumptions, residential monthly bills are expected to decrease slightly: 9 cents per month for Longmont and 14 cents per month for Loveland consumers.

The following table summarizes the impacts for all of the utilities that are likely to become subject to the RES during the period 2005-2024:

Impact of the Colorado Renewable Energy Standard Proposed in Amendment 37

Impact on 20-Year Utility Revenue Requirements, by Utility
Impact on Monthly Residential Bills, by Utility

		Residential Monthly Bill Impact			
Utility Name	***20-Year Impact on Total Retail Revenues***	***20 Year Average***	***Max in Any Year***	***Min in Any Year***	***Notes***
Public Service Company	12,600,861	0.01	0.15	(0.19)	A, B
City of Colorado Springs					
REC Strategy	29,730,597	0.14	0.28	0.11	C, J
Wind Purchase Strategy	(63,560,352)	(0.33)	(0.24)	(0.42)	D, J
Combination Strategy	(16,914,877)	(0.09)	0.02	(0.16)	E, J
Intermountain REA	(24,561,694)	(0.45)	(0.30)	(0.54)	F, J
Aquila	542,366	0.01	0.08	(0.22)	B, G
City of Fort Collins	-	-	-	-	H, J
Holy Cross Electric Association	(14,124,008)	(0.48)	(0.35)	(0.61)	F, J
United Power	5,587,924	0.21	0.40	0.15	I, C, J
City of Longmont	(2,864,165)	(0.09)	0.04	(0.15)	E, J
Mountain View Electric Association	3,752,289	0.20	0.39	0.15	I, C, J
La Plata Electric Association	6,088,597	0.15	0.29	0.11	I, C, J
Poudre Valley REA	4,733,765	0.22	0.41	0.16	I, C, J
Delta Montrose Electric Association	3,164,594	0.17	0.39	0.00	I, C, J
Yampa Valley Electric Association	(7,116,752)	(0.39)	(0.28)	(0.50)	F, J
City of Loveland	(1,889,240)	(0.14)	(0.06)	(0.21)	E, J
San Isabel Electric Association	56,656	0.10	0.10	0.00	I,C, J
Total State	**(14,028,808)**				

Notes:

A -- Uses Expected Value Assumptions for Natural Gas Prices and Status of Production Tax Credit
B -- Solar Requirement Met 50% Central Station, 50% Distributed Resources
C -- Assumes RES Met By Purchase of Renewable Energy Certificates (RECs)
D -- Assumes RES Met With Wind Purchases Beginning 2006
E -- Assumes Combination Strategy; 50% RECs, 50% Wind Purchases
F -- PSCo Full Requirements Customer; PSCo effect passed through wholesale rates
G -- PSCo Partial Requirements Customer; PSCo effect passed through wholesale rates
H -- Adheres to Own Renewable Energy Standard
I -- TriState Member; Options Limited by Power Purchase Agreement
J -- Assumes Self-Certification with No Solar Requirement

Figure 32 – Summary of RES Impact by Utility

Statewide Impact

Combining the results in the table in Figure 32 across utilities, we see that the aggregate state-wide effect of the RES will be to lower collective utility costs by $14.0 million over the period 2005-2024. This is a near-negligible amount, translating into a reduction of about one cent per month for a residential customer using 750 KWh per month.

The effect on bills of commercial and industrial customers would similarly be modest. A large commercial customer with a 2 megawatt demand and a 60% capacity factor would have a normal monthly bill of about $52,000. The RES would decrease such a bill by about $10.80.

Renewable Energy as a Hedge for Natural Gas Prices

As mentioned previously, the wellhead price of natural gas has generally increased over the past 25 years, with wide fluctuations observed, especially in the past ten years. In 2003, for example, a spike sent wellhead prices up 72% over 2002 levels.

The estimates of future natural gas costs made by the Department of Energy suggest that prices will trend upward relatively smoothly over the next twenty years. (See the chart on the left in Figure 33 below) Of course, the DOE estimates do not project price spikes, since these are, by definition, not knowable future events.

Since some renewable resources (e.g., wind and solar) have essentially zero "fuel" costs, these resources can serve as a hedge or insurance against price spikes such as those observed in 2000 and 2003. While it is not possible to predict price spikes, it is possible to model the mitigation of their impact, assuming that the utility's supply portfolio contains a given level of renewable energy resources with zero fuel cost.

The economy is replete with examples of hedges against price fluctuation. Individuals assign a value to predictability in prices: consumers will often select fixed-rate options even when a market-rate or variable-rate option might be advantageous, simply to reduce the risk of price fluctuations. Similarly, firms often hedge their risk by purchasing various types of financial options. Importantly, these options are valuable even if they do not "pay off" in the sense of actually functioning in the case of fluctuations.

While it may be difficult to obtain a precise value of the hedge when applied to renewable electric energy resources, we can simulate the "pay off" value of renewables as a hedge by assuming that natural gas prices take unexpected spikes in the future.

The chart on the left of Figure 33 shows the most recent estimates of future natural gas prices published by the Energy Information Administration in its *Annual Energy Outlook*

2004. The chart on the right of Figure 33 illustrates the effect of two hypothetical price spikes in 2010 and 2017, and in the "shoulder" years of 2011 and 2018. From inspection of the chart, these price spikes are seen to be plausible, even if they are not predicable.

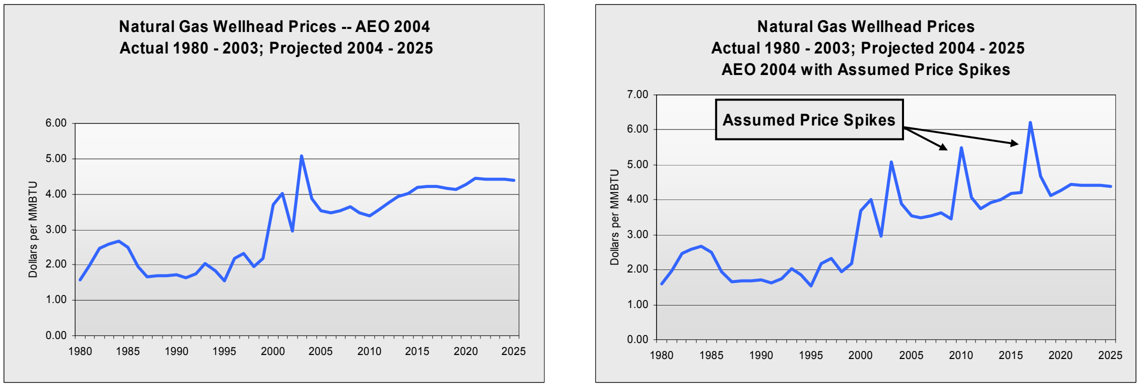

Figure 33 – Natural Gas Price Spike Assumptions

To illustrate the hedge value of the proposed Renewable Energy Standard, we calculated the difference between the cost of renewable generation and gas turbine generation under the Base Gas Cost case (the chart on the left) and then made the same calculation using the gas prices shown in the Spike Gas Cost case (chart on the right). The difference of these two results represents the marginal value of the renewable resources under the assumption of the hypothetical price spikes.

The results are striking. Under the gas price assumptions illustrated in the graph above, the presence of wind resources on the Xcel system at the level required by the RES would save Colorado consumers $26 million and $44 million during the two years of the assumed price spike. This equates to monthly savings of $ 0.46 and $ 0.67 for residential customers during those two years. These savings are in addition to any other costs or benefits of the RES identified earlier.

Of course, the hedge value for commercial and industrial customers would be much larger. For example, a commercial customer with a 500 KW demand and 60% load factor would save about $223 per month in a year in which natural gas prices spiked as illustrated in this example.

OTHER EFFECTS OF AN RES IN COLORADO

Water Use

Thermal electric generating plants such as coal-fired and gas-fired generators use a large amount of water in the production process. The water used in electricity production can be permanently lost to the state (*consumptive use)* or it can be withdrawn and replaced, usually with a temperature differential (which can have environmental consequences in some cases). Focusing on the consumptive use of water in generation plants, that use is approximately 250 gallons per MWh for gas plants and 490 gallons per MWh for coal plants.

By displacing the need for a portion of new gas-fired or coal-fired generation, some renewable energy sources can reduce the consumptive use of water in generation. For example, energy produced using wind turbines requires no water. Other renewable resources, e.g. co-firing biomass, require water for cooling and will not have this impact.

The following tables illustrate the water savings due to the proposed Colorado RES assuming that renewable resources such as wind or solar (which do not require water for consumptive use) displace electric generation using natural gas or coal.

Impact of RES on Consumptive Water Use
RES Displacing Natural Gas Generation

Total Impact 2005-2024		
MWh	Gallons Saved	Acre-Feet Saved
84,904,806	21,226,201,572	65,164

Average Annual Impact 2005-2024		
MWh	Gallons Saved	Acre-Feet Saved
4,245,240	1,061,310,079	3,258

Impact of RES on Consumptive Water Use
RES Displacing Coal Generation

Total Impact 2005-2024		
MWh	Gallons Saved	Acre-Feet Saved
84,904,806	41,603,355,080	127,722

Average Annual Impact 2005-2024		
MWh	Gallons Saved	Acre-Feet Saved
4,245,240	2,080,167,754	6,386

Figure 34 – Impact of RES on Consumptive Water Use

If renewable generation replaces natural gas generation only, the water savings would be approximately 65,000 acre-feet of water over twenty years. If renewable generation displaces coal-based electric generation, 127,000 acre-feet of water would be saved. To put these numbers in perspective, 127,000 acre-feet of water is equal to half the capacity of Dillon Reservoir.

Air Quality Effects

If the Renewable Energy Standard were met with near-zero-emissions energy sources such as wind or solar resources, there would be a substantial positive impact on Colorado air quality and a reduction in greenhouse gas emissions.

In modeling the rate impact of the RES, this report assumed that the RES resources would displace generation from natural gas-fired turbine generators. While these remain the most likely avoided capacity installations or purchases, actual system operations may include displacement of some coal generation, depending on the system considerations at the time. Obviously, the emissions profile of gas and coal as fuel sources differ considerably.

Focusing on carbon dioxide emissions, and assuming the avoided capacity is a combined cycle natural gas plant, we calculate that the avoided CO_2 emissions are approximately 32 million tons over 20 years. The corresponding value of avoided carbon dioxide emissions if coal-fired production is displaced is 81 million tons of CO_2.

It is beyond the scope of this report to estimate the reduction in emissions of sulphur oxides (SO_x), nitrogen oxides (NO_x), and mercury, since the level of these pollutants will depend upon the quality of fuels and the mix of coal and gas generation actually displaced by renewable resources. In general, though, the RES would be expected to reduce emissions of these pollutants. Over the next 20 years, the RES will require new renewable resources to supply at least 79 million MWh of electricity, about 7.0% of all the electricity sold in the state during that period.

Rural Economic Development Opportunities

Another effect of developing renewable power (especially wind generation) cited by its advocates is the impact on rural communities. Because wind resources are typically found outside of densely populated areas, there is a natural connection between renewable resources and the economies of rural areas. The economic impact has two facets:

- Increased revenues for local governments from an increased tax base;
- Income for rural landowners from leasing land to wind site developers.

The National Conference of State Legislatures released a briefing paper in January 2004, *Tax and Landowner Revenue from Wind Projects* that discusses these aspects of wind power and rural economies. NCSL quotes data that shows that landowners are receiving between $750 and $4000 per wind turbine per year in payments for the use of their land.

The NCSL report includes numerous anecdotal examples of county governments and school districts across the country collecting substantial revenues from wind projects. In some cases, the counties are receiving payments in lieu of taxes for tax-exempt projects.

Finally, Western Resource Advocates reports that the addition of a wind farm similar to the Lamar wind farm would increase the tax base of many eastern Colorado counties by percentages ranging from 20% to 50%. Thus, the RES requirements could prove very valuable to rural counties: one scenario for satisfying the 2015 RES is with the output of nine wind farms, each 200 megawatts in size.

CONCLUSIONS

It is reasonable to ask about the impact on utility bills of the Renewable Energy Standard proposed in Amendment 37. While renewable energy initiatives usually enjoy broad public support, consumers might well react negatively if the RES caused electric rates to rise significantly.

This report concludes that the impact on consumer rates of the proposed Renewable Energy Standard in Colorado will likely be very small. While rates may rise slightly for some customers, they will fall for others. The most likely outcome will be to leave state-wide electric rates virtually unchanged.

The expected impact of the RES on the monthly bill of an average residential customer of a Colorado utility subject to the RES is reduction of one cent in monthly electric bills during the twenty year period 2005-2024.

In addition to the likely neutral impact on rates, this report identifies two other impacts of a Renewable Energy Standard: the impact on Colorado's rural economies and a reduction in emissions from the state's power plants.

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