Wind on the Public Service Company of Colorado System: Cost Comparison to Natural Gas

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Executive Summary

In the face of rising and volatile natural gas prices and a growing understanding of the wind resources, utilities have expanded the amount of wind generation in their portfolios over the past decade. Public Service Company of Colorado (PSCo) has been no different. In each of its three solicitations since its 1999 all-source solicitation, PSCo has accepted bids for power generation from wind resources. These decisions have benefited ratepayers significantly in terms of both financial and environmental measures.

By comparing these wind projects to the cost of natural gas generation, which wind most often displaces, it is possible to quantify the savings that wind generation has already created and to project the level of additional savings into the future. This study examines the savings that wind generation has produced for the PSCo system in two scenarios:

- a base case that examines the amount of wind that PSCo has agreed to build on its system through its last three resource solicitations (1999, 2004, and 2005); and
- an alternative scenario that proposes the addition of a reasonable amount of incremental wind to the PSCo system in response to each of the three solicitations.

A summary of the two cases examined for each of the resource solicitations:

	1999	2004	2005
Base case (wind bids accepted)	162 MW	60 MW	775 MW
Case 1 (incremental wind)	204 MW	500 MW	1,038 MW

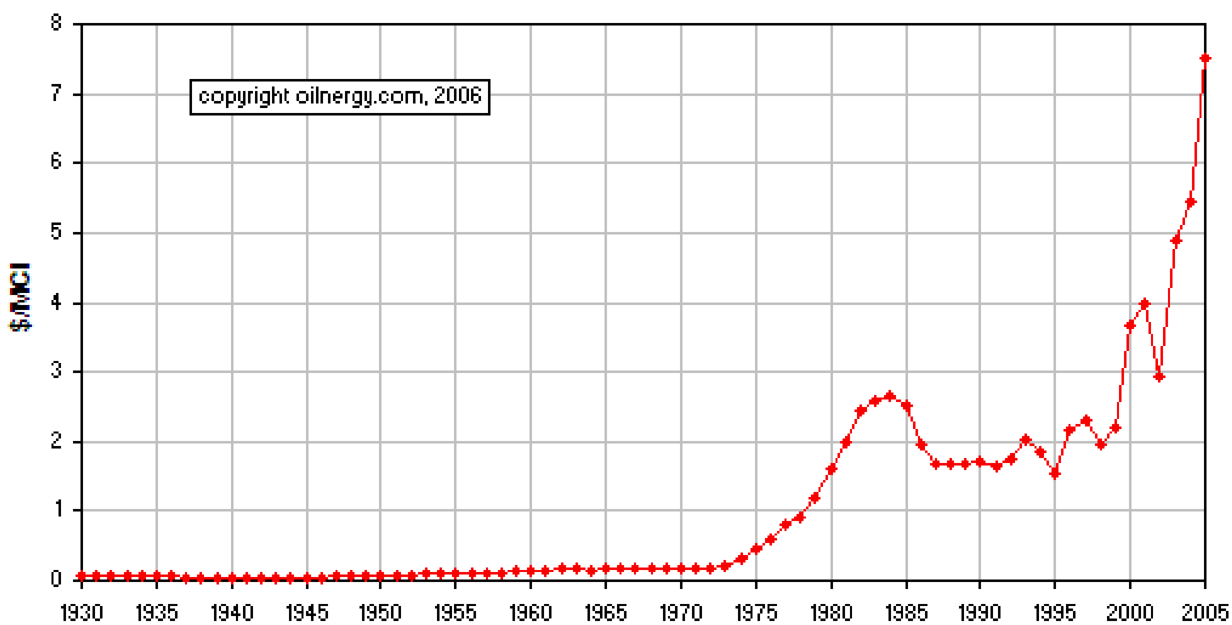
Significant findings from this study include the following:

- The cost savings for wind generation that PSCo has already acquired will produce **more than $251 million in fuel and emissions costs in savings for PSCo ratepayers**.
- Had PSCo decided to acquire additional wind generation, this study calculates that Colorado ratepayers would have saved $438 million over the life of these contracts, an **additional $186 million over the savings that will be achieved based on Xcel's past decisions.**
- **Wind generation will prevent 19.2 million tons of carbon dioxide in the base case; adding the wind generation suggested in this study would further reduce carbon dioxide emissions by 14.7 million tons.**

Introduction

During the past several years, utility regulators around the country have begun to encourage the development of wind in their respective jurisdictions. In part, renewable portfolio standards (RPSs) have driven this development; in other areas, concerns about environmental impacts of electricity generation – both local human health concerns and more global concerns about climate – have contributed as well. More recently, the rising cost and volatile price of fossil fuels have made wind generation a cost-effective source of electricity.

Figure 1. Historic natural gas prices



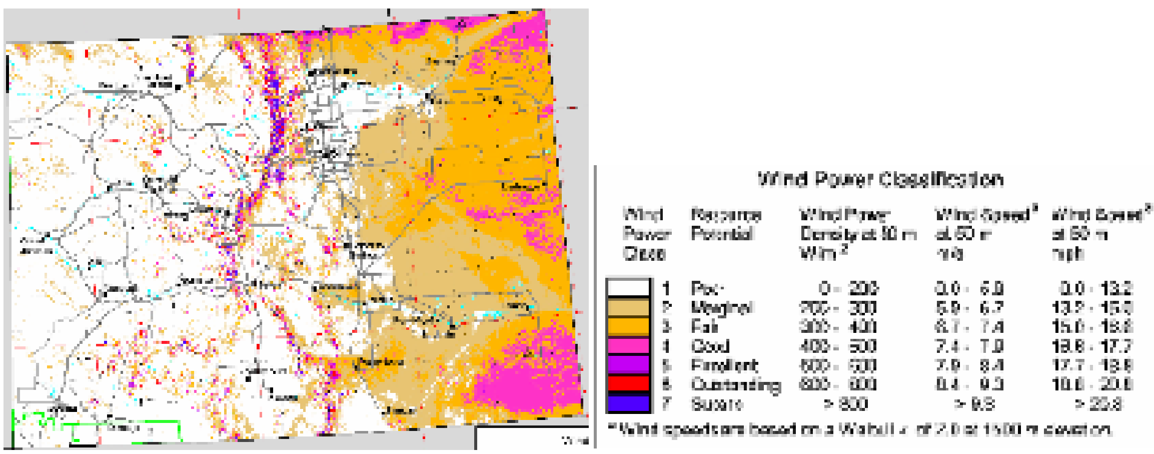
Source: OILENERGY: http://www.oilnergy.com/1gnymex.htm#since30

Natural gas prices remained very low through the late 1980s and the 1990s, stimulating rapid expansion of natural gas power plants. As electricity demand continued to grow during 1999 and in the early years of the new century, however, natural gas prices rose dramatically. (See Figure 1.) Natural gas was no longer a cheap solution to the country's growing need for electricity.

As the need for economic alternative fuels grew stronger, wind developers began to win large-scale generation bids. Decision makers in the utility world grew increasingly familiar with this new technology, beginning to understand how to effectively integrate it into their systems. Along with the increased integration of wind generation came a broader understanding of the actual (rather than perceived) costs and benefits of wind generation. The industry is now beginning to mature, as we see more activity in mergers and acquisitions.

There still remains a significant opportunity to continue to increase the amount of wind generation, especially in the state of Colorado. The state is fortunate to have an abundance of Class III and Class IV wind resources. (See Figure 2.) And, unlike many other wind-rich states, populated areas of Colorado are relatively close to the best wind resources. Both of these factors help to make wind more cost-competitive with conventional technologies.

Figure 2. Colorado wind resources [1]



Despite these advantages, wind has not been as well-received in Colorado as it might have been, costing ratepayers millions of dollars. This paper seeks to examine how much money ratepayers could have saved if the largest utility in the state of Colorado, Public Service Company of Colorado (PSCo), had placed more wind generation in service in each of its last three resource solicitations.

[1] Wind Powering America. March 26, 2004. "Colorado 50 m Wind Power." U.S. Department of Energy Office of Energy Efficiency and Renewable Energy: Wind Powering America. Available: http://www.eere.energy.gov/windandhydro/windpoweringamerica/maps_template.asp?stateab=co [August 7, 2006]

Interwest Energy Alliance requested an estimate of the consumer costs that could have been avoided if PSCo had acquired more wind during the period 1999-2005. In order to do so, a "backcasting" methodology is used; that is, this study will estimate how much additional wind PSCo could have acquired had it been more receptive to wind and then, using reasonable assumptions, assess the savings associated with these foregone wind contracts.

Since assumptions make up the foundation of the model used to assess these savings, some subjectivity is involved. Whenever possible, however, conservative assumptions were made. For example, it is assumed that the power displaced by wind is the most efficient and cleanest alternative, a combined cycle natural gas plant. In practice, wind generation may actually displace older, less efficient peaking plants, which would drive up the cost of the displaced power and, as a result, increase the savings realized by wind generation; this alternative was not modeled.

Further, the combined cycle plant that is modeled is assumed to be more efficient than the only PSCo-owned combined cycle plant – Fort St. Vrain. Heat rate and emissions factors for this plant are publicly available, but the model allowed for the fact that more efficient generation may exist within the PSCo system. Thus, most of the assumptions are a hybrid of the Fort St. Vrain plant and newer combined cycle plants.

Results for the base case for 1999 (Case 1999-B) are fairly similar to PSCo's own published results. In an April 2006 presentation, Xcel's Bill Grant stated that the net benefit of wind on the PSCo system was $4.21 million in 2004 and $9.75 million in 2005.[2] The results of the model prepared for this paper put the 2004 savings within 10 percent of Xcel's estimate and the 2005 savings within 15 percent of Xcel's estimate.

In preparing this report, a significant number of sources were reviewed, including other wind and natural gas cost models, wind integration studies, wind transmission studies, and background on the three PSCo solicitations examined in this report. Several people working in these fields have

[2] Grant, B. April 20, 2006. "Reserve Group and DCS Issues With Wind Generation." Xcel Energy.

also been contacted to provide additional background. To be as clear as possible about the origins of the information in this report, relevant sources are cited throughout the paper.

Background

Beginning with its 1999 all-source request for proposals (RFP), PSCo began incorporating wind into its portfolio of generation resources. Since the 1999 bid, PSCo has released two additional RFPs to which wind could respond: the 2004 renewable energy RFP and the 2005 all-source solicitation. To provide some background for the remainder of the paper, this section will outline the context in which each solicitation took place and the role of wind energy in the process.

1999 All-Source Bid

PSCo's 1999 RFP included requests for several "categories" of bids: demand-side management, renewable energy, and conventional supply-side resources.[3] The renewable energy bid had two components –a quantity of wind generation needed to meet the demands of the company's green pricing program, WindSource, and a separate component for supply-side wind generation. PSCo accepted a bid for 25 MW for a wind farm near Peetz, Colorado, to meet its WindSource requirement. Evaluating and accepting a bid for supply-side renewable generation was more complicated, however.

PSCo's initial modeling efforts, which evaluated renewable bids only as part of larger generation portfolios, showed that natural gas bids would be less expensive than the wind bids. As a result, only natural gas bids were preliminarily accepted. Prior to the Colorado Public Utility Commission (PUC) hearings set to approve PSCo's accepted bids, however, several parties intervened, questioning PSCo's initial natural gas price forecasts. In 2000, gas prices spiked significantly, rendering useless the gas price forecasts that PSCo had employed to select the all-natural gas portfolio. (See Figure 1 in the Introduction.) The intervening parties urged the PUC

[3] Background information about the 1999 RFP was found in a summary about the proceedings prepared for the National Renewable Energy Laboratory (NREL). Lehr, R.L., J. Nielsen, S. Andrews, M. Milligan. September 2001. *Colorado Public Utility Commission's Xcel Wind Decision.* NREL/CP-500-30551. Available: http://www.nrel.gov/docs/fy01osti/30551.pdf [July 28, 2006]

to require PSCo to re-evaluate the bids that better reflected updated gas price projections more reflective of the new circumstances.

In February 2001, the PUC announced its decision to guard against higher future natural gas prices by requiring PSCo to accept a 162-MW wind bid by Enron; the wind facility would be located near Lamar, Colorado. During the time that PSCo was negotiating the contract with Enron Wind, its parent company, Enron, filed for bankruptcy.[4] After GE acquired Enron Wind in May 2002, the project was further delayed until a contract was finally signed in the spring of 2003.[5] The Lamar-based Colorado Green wind project began serving the PSCo system in December 2003.[6]

2004 Renewable Energy Solicitation

The public part of PSCo's 2003 least cost planning process began in April 2004, six months after PSCo requested an extension on its original filing date.[7] In the midst of hearings, PSCo requested an opportunity to issue an RFP for renewable energy prior to the completion of the least cost planning process in order to take advantage of any short-term renewal of the federal production tax credit (PTC), which had expired at the time (August 2004).[8] This early start was intended to enable developers to place in service new wind (or other renewable generation) by the end of 2006, the expected expiration date of a renewed PTC. Had developers been required to wait any longer, PSCo reasoned, they would not have had enough lead time to put the renewable generation in service in time to capture the PTC benefit. This outcome would obviously have discouraged wind generation developers from applying to the all-source solicitation.

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[4] Proctor, C. January 25, 2002. "Enron Bankruptcy Blows Through Colorado." *Denver Business Journal.* Available: http://www.bizjournals.com/denver/stories/2002/01/28/story2.html [July 28, 2006]

[5] Proctor, C. June 13, 2003. "Delays over, wind farm finally ready to produce power." *Denver Business Journal.* Available: http://denver.bizjournals.com/denver/stories/2003/06/16/story6.html?page=3 [July 28, 2006]

[6] EnerNex Corporation. April 2006. *Wind Integration Study Report of Existing and Potential 2003 Least Cost Resource Plan Wind Generation.* Prepared for Xcel Energy, Denver, CO. Available: www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_15056_15473-13518-2_171_258-0,00.html

[7] Xcel Energy. September 25, 2003. "Xcel Energy Asks to Present Power Plan in Spring." Available: http://www.xcelenergy.com [July 28, 2006]

[8] Xcel Energy. August 17, 2004. "Xcel Energy Accepting Renewable Energy Proposals." Available: www.xcelenergy.com [July 31, 2006]

The 2004 Renewable Energy Solicitation requested bids for up to 500 MW of renewable generation. After initially negotiating with three bidders for more than 400 MW of wind generation, PSCo accepted only one bid for 60 MW of wind generation at a second Peetz, Colorado, plant under a 20-year power purchase agreement.

2005 All-Source Solicitation

The 2005 All-Source Solicitation came on the heels of a voter-approved renewable portfolio standard (RPS) in the state of Colorado and of the extension of the PTC through the end of 2005. The RPS required PSCo and other utilities to obtain at least 10 percent of their electricity generation portfolios from renewable sources by 2015.

The first solicitation issued after the completion of the 2004 LCP process, PSCo's February 2005 All-Source Solicitation sought bids for up to a total of 2,500 MW of generation through 2013. When it announced the results of the bidding process, PSCo agreed to acquire up to 775 MW of wind and between 741 MW and 861 MW in natural gas generation in response to this bid. Table 1 provides details about the wind bids accepted.

Table 1. Wind bids accepted in response to 2005 RFP

Project Name	Project Size: Bid	Estimated In-Service Date
Logan	400 MW	July 2007
Colorado Green Expansion	75 MW	October 2007
Cedar Creek	300 MW	December 2007

As of the completion of this paper, it was unclear how much of this generation would actually be built after post-bid negotiation and the construction process.

Scenarios examined

Each solicitation occurred in a unique context, and the scenarios examined for this paper take into account the circumstances surrounding each one. Each solicitation triggers two different nameplate wind capacity cases – one analyzing the amount of wind actually built as a result of the solicitation, and a second case considering the first case *and* additional wind that *could have* been built in response to the solicitation. Table 2 summarizes these cases.

Table 2. Nameplate wind capacity cases (MW)

	1999	2004	2005
Base case	162	60	775
Case 1	204	500	1,038

Although the Lamar plant was the only wind bid in the 1999 solicitation, it is possible that more wind bids would have been submitted had the solicitation been more conducive to the reality of the wind industry. At the time, financial backers uniformly required that the developer have in hand a power purchase agreement prior to the start of construction; at the time, 20-year contracts were the norm. Since the solicitation only requested a 15-year power purchase agreement, it excluded many developers from bidding on the project. The additional 42 MW considered in Case 1999-1 is equivalent to three percent of the 1400 MW for which PSCo sought bids in the 1999 solicitation; the author understands that, during settlement negotiations, PSCo was asked to accept this amount of additional wind generation.[9]

As noted earlier, PSCo initially accepted bids for 500 MW of wind generation in response to the 2004 Renewable Energy RFP; that amount was reduced significantly after negotiation and during construction to a level of 60 MW (Case 2004-B). The 2004-1 case examines how much PSCo ratepayers might have saved had the full 500 MW survived the negotiation and construction phases.

Finally, in addition to the wind bids, PSCo accepted 608 MW of natural gas bids and one of two additional natural gas bids: 133 MW or 253 MW.[10] In total, the range of accepted natural gas nameplate capacity additions in the 2004 RFP is between 741 MW and 861 MW. Assuming that PSCo accepted wind bids with capacity up to 15 percent of its system's anticipated 2007 hourly peak load, it would have accepted another 263 MW of wind, roughly the size of one of the peaking natural gas bids accepted. Combined with the baseline 775 MW, case 2005-1 is modeled

[9] Communication from Ron Lehr, American Wind Energy Association, dated May 22, 2006.
[10] Public Service Company of Colorado. December 2005a.

with 1,038 MW of wind on the system, equivalent to 15 percent of the PSCo system's projected hourly peak load in 2007.[11]

For each of these six cases, two different natural gas price scenarios were explored. A hybrid of the Energy Information Administration's (EIA) *Annual Energy Outlook 2005* (AEO2005) and NYMEX Henry Hub futures prices was used as the reference case. AEO2005's high natural gas price scenario was used for the alternative case. Because of the uncertainty surrounding natural gas prices, these two scenarios are considered equally likely. In total, cost differentials for 12 separate scenarios were calculated as noted in Table 3.

Table 3. Scenarios examined

1999-BR	1999 Base Case – Reference Natural Gas Prices
1999-BH	1999 Base Case – EIA High Natural Gas Prices
1999-1R	1999 Case 1 – Reference Natural Gas Prices
1999-1H	1999 Case 1– EIA High Natural Gas Prices
2004-BR	2004 Base Case – Reference Natural Gas Prices
2004-BH	2004 Base Case – EIA High Natural Gas Prices
2004-1R	2004 Case 1 – Reference Natural Gas Prices
2004-1H	2004 Case 1– EIA High Natural Gas Prices
2005-BR	2005 Base Case – Reference Natural Gas Prices
2005-BH	2005 Base Case – EIA High Natural Gas Prices
2005-1R	2005 Case 1 – Reference Natural Gas Prices
2005-1H	2005 Case 1 – EIA High Natural Gas Prices

[11] EnerNex Corporation. May 1, 2006. *Wind Integration Study for Public Service Company of Colorado*. Prepared for Xcel Energy, Denver, CO. Available: www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_15056_15473-13518-2_171_258-0,00.html

Methodology

In most cases, wind displaces natural gas generation. For this study, the cost of wind in each of the 12 scenarios examined was compared to costs for the same amount of output generated by an existing combined cycle natural gas turbine (CCGT), similar to the one that PSCo owns at Fort St. Vrain. Since the plant is assumed to be operating already, no capital costs are considered, and it is assumed that PSCo has already absorbed costs associated with its capacity value; i.e., the capacity costs are sunk. The only avoidable costs considered for the CCGT are the cost of fuel and emissions fees.

For each scenario, an Excel spreadsheet model was developed to calculate the cost differential between the wind and natural gas generation over the life of the project(s) selected.

Assumptions for both wind and natural gas generation were made in order to perform the calculations. The remainder of this section examines those assumptions.

Assumptions: Wind

IN-SERVICE DATE[12]

Solicitation issued	In-service date	Rationale
1999	December 2003	Colorado Green, the only project built in response to this solicitation, began generating at this time.
2004	January 2006	The only project built in response to the 2004 solicitation went into service at this time.
2005	September 2007	The average date (weighted by nameplate capacity) that PSCo projects the winning bids from the 2005 solicitation to go into service.

CAPACITY FACTOR: 35%

CAPACITY CREDIT: 0%

In its most recent solicitation, PSCo assigned a 10 percent capacity credit to wind.[13] Despite this

[12] EnerNex Corporation. April 2006.

fact, the issue is still hotly contested by both the wind and utility industries. Thus, a conservative approach is taken here, assuming that wind will not fulfill peak load capacity requirements for PSCo.

PROJECT LIFE:

Solicitation issued	Project Life (years)	Rationale
1999	15	Based on the actual duration of the Colorado Green contract.
2004	20	Based on actual duration of the Spring Canyon PPA.[14]
2005	20	Assumed as the industry standard.

Each project is assumed to shut down at the end of its power purchase agreement with PSCo.[15]

UNSUBSIDIZED COST OF WIND:

Solicitation issued	Cost of wind (2006$/MWh)	Rationale
1999	$52	Published cost for Lamar project
2004	$61	Conservative estimate
2005	$61	Conservative estimate

PRODUCTION TAX CREDIT (PTC): The value of the PTC in 2006 ($0.019/kWh) was levelized over the entire life of the project. See Appendix A for details of the calculation.

WIND INTEGRATION COSTS: $0.00351/kWh for 1999, 2004 RFPs; $0.00477/kWh for 2005 RFP In the wind integration report that Xcel released earlier this year, the cost of wind integration varies according to the level of wind penetration. In the 1999 and 2004 scenarios, the level of wind on the system is less than 10 percent, whereas the 2005 scenarios exceed 10 percent but not 15 percent.[16] The corresponding integration costs were applied to each scenario. [17]

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[13] Public Service Company of Colorado. December 2005a. *"Public Version" All Source RFP Bid Evaluation Report.* Xcel Energy. Page 29.
[14] Public Service Company of Colorado. December 2005b. *Annual Progress Report: 2003 PSCo LCP.* Available: http://www.xcelenergy.com/docs/corpcomm/2005COResourcePlanUpdate.pdf [August 4, 2006]
[15] Based on wind development industry standards for strategic planning, per communication with Steve Jones, enXco, July 24, 2006.
[16] Assuming that PSCo's total net capacity is around 7,000 MW, as noted in Public Service Company of Colorado. December 2005b.

INCREMENTAL TRANSMISSION COSTS: $0.0021/kWh

Whenever any type of generation is added to the grid system, it requires the use of a portion of the overall transmission network. When the total amount of generation exceeds the capacity of the transmission system, additional transmission infrastructure must be built. (This is distinct from adding a radial transmission line to serve a specific generating project located away from existing transmission; this latter cost is borne by the developer and included in the unsubsidized cost of wind in this report.)

PSCo's recent transmission study stated, "The PSCo transmission system is able to accommodate the full complement of existing and potential wind generation."[18] For this reason, it is not necessary to assign a large incremental cost of transmission facilities to the new wind generation posited in this report. Indeed, the wind generation accepted in response to the three RFPs was built to accommodate existing transmission infrastructure.

In fact, PSCo itself has not historically included any incremental costs of transmission in its own bid evaluations because of expectations that the wind would be developed in its control areas.[19] Rather than assign a zero value, however, this study uses a value of $2.10/MWh, one-half of the Minnesota-based value used by Binz.[20] This appears to be a reasonable assumption in view of the conclusions of the PSCo transmission study and the relative nearness of wind generation to the PSCo load in Colorado, compared to the Minnesota situation.

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[17] EnerNex Corporation. May 1, 2006.

[18] EnerNex Corporation. April 2006. *Wind Integration Study Report of Existing and Potential 2003 Least Cost Resource Plan Wind Generation.* Prepared for Xcel Energy, Denver, CO. Available: www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_15056_15473-13518-2_171_258-0,00.html

[19] Bolinger, M. and R. Wiser. August 2005. *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans.* Lawrence Berkeley National Laboratory, LBNL-58450. Available: http://eetd.lbl.gov/EA/EMP/reports/58450.pdf [August 16, 2006]

[20] Binz, R. September 2004. *The Impact of the Renewable Energy Standard in Amendment 37 on Electric Rates in Colorado.* Public Policy Consulting, Denver. Available: http://www.rbinz.com/Files/Binz%202004%20Colo%20RES%20Report.pdf [August 17, 2006]

Assumptions: Natural Gas

HISTORIC NATURAL GAS PRICES:

	Historic			
Scenario	2002	2003	2004	2005
Low NG Price Case	$2.54	$4.95	$6.03	$7.85
Base Case	$2.54	$4.95	$6.03	$7.85
High NG Price Case	$2.54	$4.95	$6.03	$7.85

Since PSCo does not make public the prices that it pays for natural gas for electric generation on a monthly basis, annual averages were used; these are contained in PSCo's 10-K reports, which are made public by the Securities and Exchange Commission.[21] The data are published as price paid in the given year; thus, these data were inflated to 2006$.[22]

PROJECTED NATURAL GAS PRICES ($/mcf): [23]

	Projected											
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Reference Case	$7.48	$9.52	$8.93	$8.40	$7.96	$7.56	$7.31	$7.06	$6.81	$6.56	$6.31	$6.06
EIA High Case	$8.41	$7.73	$7.40	$6.78	$6.38	$6.21	$6.22	$6.33	$6.30	$5.77	$5.43	$5.51

	Projected									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Reference Case	$6.06	$6.11	$6.20	$6.23	$6.33	$6.38	$6.54	$6.62	$6.73	$6.88
EIA High Case	$5.67	$5.96	$5.99	$6.11	$6.16	$6.22	$6.34	$6.45	$6.52	$7.40

PSCo's projections for natural gas prices are also not publicly available. However, the sources of the company's projections are publicly known. PSCo uses a combination of the Energy Information Administration's (EIA) *Annual Energy Outlook,* NYMEX Henry Hub futures prices,

[21] Public Service Company of Colorado. 10-K filings for fiscal years ended Dec. 31, 2003, and Dec. 31, 2005. Available: edgar.sec.gov

[22] Adjusted from 2002$, 2003$, 2004$, 2005$ to 2006$ using Bureau of Labor Statistics' (BLS) inflation calculator: http://data.bls.gov/cgi-bin/cpicalc.pl [July 28, 2006]

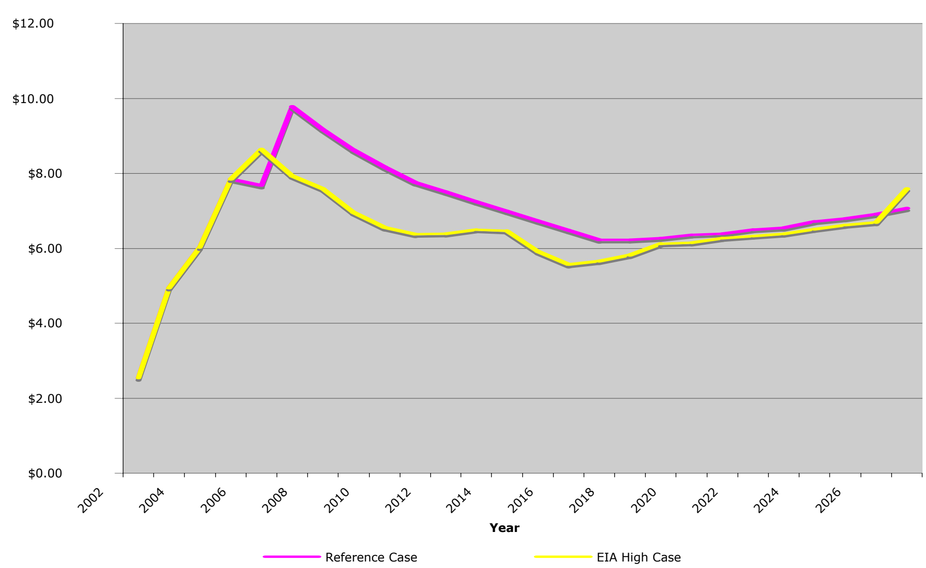
[23] Energy Information Administration. February 2006. *Annual Energy Outlook* 2006 *With Projections to 2030.* Table 13 – high price, reference, low price cases. Figures were reported in 2004$; inflated to 2006$ using conversion rate of 1.0745. See BLS calculator at http://data.bls.gov/cgi-bin/cpicalc.pl

Cambridge Energy Research Associates (CERA), and the PIRA Energy Group.[24] The only two of those sources that are publicly available are used to develop a natural gas projection for the model.

The NYMEX Henry Hub futures trade on a five-year horizon; thus, the data for NYMEX were available for September 2006 through August 2011. During the years when NYMEX price data is available, an annual average is calculated, and this number is used as a proxy for natural gas prices during the years 2006-2011. (A combination of futures prices and actual prices for 2006 is used to calculate the annual average for that year.)

Over the next five years (2012-2017), the difference between the NYMEX futures prices and the EIA's high natural gas price scenario was bridged linearly until the projections use EIA's estimates from 2018-2027. (See Figure 3.) This blended approach is similar to the methods used by several utilities in constructing their own natural gas price forecasts, although this study uses only publicly available projections.[25]

Figure 3. Natural Gas Price Scenarios



[24] Andrews, S. Direct Testimony in response to Colorado Public Utility Commission Docket 04A-325E. Available: http://www.dora.state.co.us////puc/docket_activity/filings/04A-325E/04A-325E_CCNetAndrews.pdf [August 9, 2006]
[25] Bolinger, M. and R. Wiser. August 2005.

Since EIA's recent projections of natural gas prices have consistently underestimated actual prices for near-in years, and since the NYMEX futures prices present more of a real-time estimate of the value of natural gas, this scenario is taken as a best estimate of future natural gas prices.[26]

HEAT RATE: 7,500 BTU/kWh

In general, new CCGT plants are expected to operate at 7,030 BTU/kWh. [27] Fort St. Vrain, which was installed in 1996, produces electricity at the rate of 8,078 BTU/kWh.[28] The 7,500 BTU/kWh estimate assumes that most CCGT plants in the state of Colorado fall between those two points.

EMISSIONS FACTORS FOR COMBINED CYCLE NATURAL GAS:

Tons CO2 / GWh	411
Tons NOx / GWh	0.542

The CO2 emission rate is predicted for new CCGT, which is a conservative estimate; no estimates for a turbine similar to Fort St. Vrain were available. [29]

The NOx emission rate is an average of that expected for new CCGT (0.039 tons/GWh[30]) and that experienced at Fort St. Vrain (1.046 tons/GWh).[31]

Avoidance of other criteria pollutants (e.g., sulfur dioxide, particulate matter, and carbon monoxide) was not included in this report because they were two or more orders of magnitude smaller than these emissions factors. Although these pollutants impact human health at any level, they did not significantly impact the cost of CCGT generation.

[26] *Ibid,* p. 47.
[27] Northwest Power Planning Council. August 8, 2002. *Natural Gas Combined-Cycle Gas Turbine Power Plants."* Prepared for the New Resource Characterization for the Fifth Power Plan. Available: http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf [July 28, 2006]
[28] "TOP PLANTS Supplement." July/August 2005. *POWER Magazine.*
[29] Northwest Power Planning Council. August 8, 2002.
[30] *Ibid.*
[31] "TOP PLANTS Supplement." July/August 2005. *POWER Magazine.*

COST PER TON OF EMISSIONS:

\$ / ton CO2[32]	\$9.00
\$ / ton NOx[33]	\$13.54

PSCo included an adder for future carbon regulation in its 2005 solicitation, which it began applying to generation scenarios in the year 2010. PSCo escalated the carbon adder at its assumed rate of inflation; since this model calculates everything in 2006$, the adder was assumed to be constant throughout the lives of these projects.

The Colorado Department of Public Health and Environment (CDPHE) establishes fees for criteria pollutants (e.g., NOx) in the state of Colorado. PSCo submits regular emissions reports to CDPHE and pays the associated fees. Thus, any power generated using wind facilities that displace CCGT facilities is directly responsible for reducing the cost of generation.

Assumptions: Miscellaneous

CONVERSION FACTOR: 1 mcf natural gas = 1.027 MMBTU[34]

DISCOUNT RATE: 8%

PSCo used a discount rate of 7.82 percent in its 1999 RFP and of 7.38 percent in its 2005 RFP.[35,36] The 8 percent figure is conservative but still near the discount rate that PSCo uses for its own calculations.

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32 Public Service Company of Colorado. December 2005a.

33 Colorado Department of Public Health and Environment. Inventory and Support Unit: Stationary Sources Program. Available: http://www.cdphe.state.co.us/ap/i-n-s.html [July 28, 2006]

34 Energy Information Administration. December 19, 2005. *Natural Gas Annual 2004*. Washington, D.C. See Appendix table B2. Available: http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html [July 28, 2006]

35 Lehr, R.L., et al. September 2001.

36 Public Service Company of Colorado. December 2005a.

Results and Conclusions

Using the assumptions set out in the section above, the model was used to evaluate the relative cost of wind generation compared to CCGT generation. Since all modeling was done in 2006$, results were examined in two settings: total savings in nominal dollars, and a net present value (NPV) of the nominal dollar savings. Results from the model are summarized in Table 4.

Table 4. Cost savings for wind generation, compared to a CCGT plant

	Total Savings	NPV
1999-BR	$ 165,620,365	$ 120,751,025
1999-BH	$ 121,519,503	$ 91,085,780
1999-1R	$ 200,248,148	$ 148,756,227
1999-1H	$ 146,399,114	$ 112,069,282
2004-BR	$ 33,093,913	$ 21,852,907
2004-BH	$ 15,108,108	$ 10,375,940
2004-1R	$ 275,782,606	$ 182,107,558
2004-1H	$ 125,900,899	$ 86,466,163
2005-BR	$ 337,551,295	$ 202,053,920
2005-BH	$ 112,150,970	$ 57,234,174
2005-1R	$ 452,100,961	$ 270,621,895
2005-1H	$ 150,209,945	$ 76,656,868

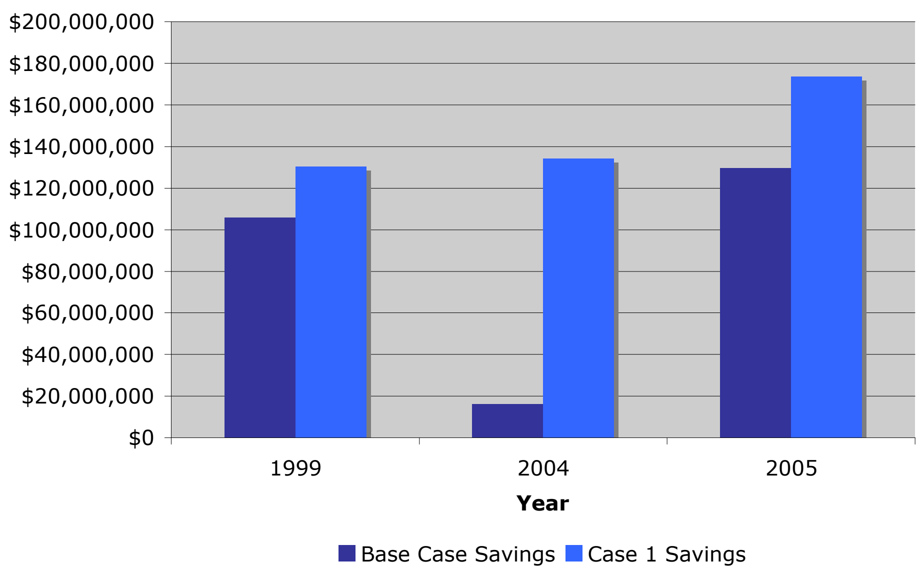
To make sense of all these data, it helps to reduce the number of scenarios examined by creating an expected value for each case (1999-B, 1999-1, etc.). As mentioned earlier, the two natural gas price scenarios are equally likely due to the difficulty in predicting natural gas prices. Thus, assuming a 50 percent probability of the Reference Case and a 50 percent probability of the EIA High Case, an expected level of cost savings for each level of wind is calculated. See Table 5.

Table 5. Expected value of cost savings in each wind case

Solicitation	BASE CASE	CASE 1
1999	$105,918,402	$130,412,754
2004	$16,114,423	$134,286,860
2005	$129,644,047	$173,639,381
TOTAL SAVINGS	$251,676,872	$438,338,996

The cost savings in the base-case scenarios – the ones that represent wind acquisitions that PSCo actually made – are impressive in their own right. Colorado consumers will benefit significantly from these decisions over time; an estimated value of **more than $251 million in fuel and emissions costs alone will be avoided**.[37] Had PSCo decided to acquire the additional wind generation (42 MW in 1999, 440 MW in 2004, and 263 MW in 2005), this study calculates that the total savings would have been $438 million, an **additional $186 million over the savings that will be achieved based on Xcel's past decisions.**

Figure 4. Base Case vs. Case 1 (incremental wind) Savings From Wind Generation



The hypothesis at the beginning of this study was that wind generation would cost less than combined cycle natural gas generation over time and that PSCo had missed several opportunities to reduce costs by choosing natural gas over wind. It appears that this is, indeed, the case. Additionally, there are several factors that could act to increase the cost advantage that wind generation represents:

- a lower actual price that PSCo paid for wind in each contract;

[37] This assumes that PSCo actually acquires all 775 MW of wind generation that were accepted as a result of the 2005 all-source solicitation.

- a higher cost of the actual fuel and technology replaced by wind (e.g., combustion turbine vs. combined cycle, or natural gas vs. petroleum);
- a higher capacity credit assigned to wind;
- the actual integration costs, which might be expected to decrease over time as operators become more familiar with the most effective way to utilize wind generation and as wind prediction techniques improve; and
- the quantification of incremental transmission *benefits* from wind, which may balance out some of the additional costs.

Two other inputs are uncertain to the extent that that their impact could increase or decrease wind's relative advantage over natural gas:
- future natural gas prices, and
- the evolution of greenhouse gas regulation in the U.S.

These last two factors actually provide additional reasons to choose wind over natural gas. Wind generation serves as a hedge against both of these risks. The cost of wind generation is fixed by the up-front capital expenditures, rather than by the marginal cost of fuel, like natural gas generation. Fixed-price wind contracts guarantee a cost of electricity over time, which helps utilities in long-term planning and helps protect ratepayers from spikes in fossil fuel prices.

Additionally, the carbon-free nature of wind generation helps to protect ratepayers against future costs associated with greenhouse gas regulation. Although natural gas is a less carbon-intensive fuel than coal, it still contributes significant levels of greenhouse gases to the atmosphere. **In fact, according to this model, wind generation will prevent 19.2 million tons of carbon dioxide in the base case; adding the wind generation suggested in this study would further reduce carbon dioxide emissions by 14.7 million tons.**

In short, wind generation does display significant cost advantages over combined cycle natural gas generation in the state of Colorado. Current levels of wind are expected to save Colorado ratepayers $250 million over the next 20 years, and placing additional wind generation into service could have saved an additional $186 million.

Appendix A
Levelized Production Tax Credit Calculation

PTC in cents per kwh (2006 dollars)	1.9	Given
Number of years of PTC credits	10	Given
Life of wind facility (years)	20	Assumption (15 in the case of 1999)
Assumed Income Tax Rate	35%	Corporate tax rate
Pretax value of PTC for 10 years	2.92	= 1.9 / (1-0.35)
Discount rate for NPV calculation	8%	Assumption
NPV of pretax value of PTC for 10 years	19.61	NPV of 10 years of 2.92 cents/kWh payments
Levelized pretax value of PTC over project life (cents/kwh)	2.00	Creates the stream of levelized payments over the life of the project

Appendix B: Summary of Assumptions

Assumptions 1999	**1999-B**	**1999-1**
MW wind on the system	162	204
In-Service Date	12 2003	12 2003
Wind capacity factor (for generation, not for system	35%	35%
Unsubsidized cost of wind (per kWh)	$0.052	$0.052
Levelized value of PTC $/kWh (over 15 years)	$0.0229	$0.0229
Wind integration costs	$0.00351	$0.00351
Incremental Transmission costs	$0.00210	$0.00210
Natural Gas (Avoided costs)		
Heat Rate (MMBTU/kWh)	0.0075	0.0075
Emissions Factors for Combined Cycle Natural Gas		
(a) Tons CO2 / GWh	411	411
(b) Tons NOx / GWh	0.542	0.542
(c) Gallons water consumed / GWh	0.25	0.25
Emissions Fees / Adders		
(d) $ / ton CO2	$9.00	$9.00
(e) $ / ton NOx	$13.54	$13.54

Assumptions: 2004

Wind	**2004-B**	**2004-1**
MW wind on the system	60	500
In-Service Date	1 2006	1 2006
Wind capacity factor (for generation, not for system	35%	35%
Unsubsidized cost of wind (per kWh)	$0.061	$0.061
Levelized value of PTC $/kWh (over 20 years)	$0.0200	$0.0200
Wind integration costs	$0.00351	$0.00351
Incremental Transmission costs	$0.00210	$0.00210
Natural Gas (Avoided costs)		
Heat Rate (MMBTU/kWh)	0.0075	0.0075
Emissions Factors for Combined Cycle Natural Gas		
(a) Tons CO2 / GWh	411	411
(b) Tons NOx / GWh	0.542	0.542
(c) Gallons water consumed / GWh	0.25	0.25
Emissions Fees / Adders		
(d) $ / ton CO2	$9.00	$9.00
(e) $ / ton NOx	$13.54	$13.54

Assumptions: 2005

Wind	2005-B	2005-1
MW wind on the system	775	1038
In-Service Date	9 2007	9 2007
Wind capacity factor (for generation, not for system	35%	35%
Unsubsidized cost of wind (per kWh)	$0.061	$0.061
Levelized value of PTC $/kWh (over 20 years)	$0.0200	$0.0200
Wind integration costs	$0.00477	$0.00477
Incremental Transmission costs	$0.00210	$0.00210
Natural Gas (Avoided costs)		
Heat Rate (MMBTU/kWh)	0.0075	0.0075
Emissions Factors for Combined Cycle Natural Gas		
(a) Tons CO2 / GWh	411	411
(b) Tons NOx / GWh	0.542	0.542
(c) Gallons water consumed / GWh	0.25	0.25
Emissions Fees / Adders		
(d) $ / ton CO2	$9.00	$9.00
(e) $ / ton NOx	$13.54	$13.54