Attachment 2.12-1

Final Report:

Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment for

Public Service Company of Colorado

Prepared for
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TECHNICAL REVIEW COMMITTEE

The following individuals comprised a technical review committee (TRC) for this project. The TRC was kept apprised of the approach, methodology, and assumptions for the analysis described in this report, and provided valuable comments, suggestions, and guidance at several critical junctures from project commencement to conclusion.

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Executive Summary

Background

Public Service Company of Colorado (PSCo) will add approximately 700 Megawatts (MW) of wind power to its system by 2015 in accordance with its approved 2007 Colorado Resource Plan which included the 2009 All-Source Solicitation (Colorado Public Utilities Commission (CPUC) Decision Nos. C08-0929 and C09-1257). With this incremental 700 MW of wind capacity, PSCo will have approximately 1,934 MW of nameplate wind generation capacity on its system.

Wind power results in additional system costs that are not captured and reflected in traditional resource planning models. These additional "hidden" costs are often referred to as integration costs. Those integration costs associated with wind variability and wind forecast uncertainty have been previously analyzed, quantified and documented. Other wind integration costs, such as those relating to coal plant cycling, wind curtailment, and electricity trading opportunity costs have been identified but not quantified.

The purpose of this study is to define and quantify the integration costs directly associated with 1) cycling[1] baseload coal generator output as a result of wind generation levels 2) curtailing wind generation at times to avoid certain excessive system bottoming events. PSCo intends to incorporate all wind integration costs into its resource planning and selection processes to ensure that wind generation is compared equitably with the other resource technologies.

Two levels of nameplate wind capacity, 2 and 3 Gigawatts (GW) by 2020, were evaluated as part of this study. In addition to identifying and analyzing the cycling and curtailment integration costs noted above, through this study PSCo seeks to establish the appropriate coal plant operating protocol for system operations.

Summary and Conclusions

The study evaluated two coal plant cycling protocols. The first protocol (referred to as 'Curtail') involves cycling coal plants down to their economic minimum generation levels (shallow cycle) to accommodate wind and curtailing wind in excess of the level needed to meet system load. The second protocol (referred to as 'Deep Cycle') involves cycling coal plants down to their lower emergency minimum levels (deep cycle) to accommodate wind and curtailing wind in excess of the level needed to meet system load. While the analysis identified no significant difference in the cost of each protocol, there are advantages and disadvantages to each. The Deep Cycle protocol maximizes wind output while minimizing coal burn and associated CO_2 emissions. This protocol may result in reduced system reliability as a result of routinely operating baseload coal units down to their emergency minimum loading levels, a condition which increases the wear and tear on these units possibly resulting in more coal unit outages. In contrast, the

[1] The term "cycling" in this document refers to variations in the electric output of coal units from their maximum output to their minimum output (while being synchronized to the grid). Shutting down a coal plant to accommodate wind was determined to be uneconomic.

Curtail protocol results in slightly less wind generation than the Deep Cycle protocol but avoids deep cycling the coal units and the potential downside of reduced system reliability that may occur under a Deep Cycle protocol. For this reason, the Curtail protocol is being recommended as the preferred operational protocol for the PSCo system in the near term given no distinct cost advantage to either protocol.

Table 1: Summary of Scenario Results from 2011 to 2025 (2010 Present Value)

Scenario	Installed Wind	Cycling Protocol	Cycling Cost Component ($Million)	Curtailment Cost Component ($/Million)	Total Levelized Annual Cost ($Million)	Total Levelized Cost ($/MWh)
1	2GW	Curtail	$3.6	$1.2	$4.82	$0.77
2	2GW	Deep Cycle	$5.1	$0.1	$5.21	$0.83
3	3GW	Curtail	$5.0	$3.3	$8.30	$1.03
4	3GW	Deep Cycle	$8.2	$0.6	$8.75	$1.08

This study determined that the cycling and curtailment costs associated with 2GW of wind are $0.77/MWh. Average cycling and curtailment costs in the 3GW scenario are about $0.25/MWh higher than the 2GW scenarios.

The incremental integration costs associated with 1 GW of nameplate wind additions[2] on top of the 2GW level are higher than those in Table 1 (which are average costs for the entire 2GW and 3GW of wind) because the additional 1 GW of wind causes an increase in both the depth and frequency of coal unit cycles. As a result, incremental cycling costs in Table 2 are forecast to be just over $2/MWh (present value in 2010) on a levelized basis. Increasing integration costs demonstrate that the costs of the incremental 1GW tranche of wind required to reach 3GW are greater on a $/MWh basis than those of the first 2GW of installed wind. These cycling related integration costs will be considered, along with the previously identified wind integration costs that address wind variability and wind forecast uncertainty, when evaluating the expected costs of wind additions beyond 2GW.

Table 2: Incremental Cost of 1GW of Wind 2011 to 2025 (2010 Present Value)

Installed Wind	Cycling Protocol	Cycling Cost Component ($Million)	Curtailment Cost Component ($/Million)	Total Levelized Annual Cost ($Million)	Total Levelized Cost ($/MWh)
+ 1GW	Curtail	$1.8	$2.7	$4.46	$2.18
+ 1GW	Deep Cycle	$3.9	$0.7	$4.54	$2.22

The results produced by this study are dependent on the various assumptions that are detailed throughout this report. Changes to the load forecast, wind profile and system resource mix among others will impact the results. The study team intends to update the

[2] For the purposes of this study, the 3 GW scenario was derived by adding 200 MW of nameplate wind capacity annually to the 2 GW scenario for five years beginning in 2016 to reach a total of 3 GW by the year 2020.

analysis as needed to ensure the assumptions used are consistent with those used in future resource planning processes. The mix of generation resources used in this study is consistent with the Company's anticipated resource portfolio following the implementation of the Company's approved Colorado Clean Air-Clean Jobs Act (CACJA) plan.

Introduction

Nameplate wind capacity in the Public Service Company of Colorado (PSCo) service territory has increased from 283 Megawatts (MW) in 2006 to 1,234 MW in 2010. In a recent decision, the Colorado Public Utilities Commission (CPUC) approved the addition of approximately 700 MW of wind power by 2015.[3] Installing this additional wind capacity, will push the nameplate wind capacity on the PSCo system to approximately 1,934 MWs.

Wind generation results in additional system costs that are not captured or reflected in traditional resource planning models. These "hidden" costs are called integration costs. Some integration costs have been previously defined and documented. For example, in recent years PSCo analyzed the costs associated with wind generation uncertainty and variability for three different levels of wind, 722 MW, 1,038 MW, and 1,400 MW[4,5] Other wind integration costs, such as power plant cycling costs, curtailment and electricity trading opportunity costs, have been identified, but merited more study.[6]

This objective of this study is to define and quantify the integration costs directly associated with 1) cycling baseload coal generator output as a result of wind generation levels 2) curtailing wind generation at times to avoid certain excessive system bottoming events. PSCo intends to include the wind integration costs that are not explicitly captured in the Company's planning models, including the coal cycling costs identified in this study, in its resource planning and selection processes to ensure that wind generation is compared equitably with other resource technologies. It is important to note that wind curtailments and their costs are captured in the Company's planning models and are included in this study to highlight the total costs associated with system bottoming events and to allow for the evaluation of two distinct cycling protocols.

Two levels of nameplate wind capacity, 2 and 3 Gigawatts (GW) by 2020, were evaluated as part of this study. In addition to identifying and analyzing the cycling and curtailment integration costs noted above, through this study PSCo seeks to establish the appropriate coal plant operating protocol for system operations.

This study report begins by describing the limitations of traditional resource planning models used by PSCo. Cycling costs and curtailment costs are described separately followed by an explanation of how they interact. The study methodology is briefly described. Results from the scenarios evaluated are presented and conclusions follow. Appendices detailing assumptions, methodology and other data are included.

[3] Colorado Public Utilities Commission. November 6, 2009. In the Matter of the Application of Public Service Company of Colorado for Approval of its 2007 Colorado Resource Plan: Decision No. C09-1257. http://www.dora.state.co.us/puc/DocketsDecisions/decisions/2009/C09-1257_07A-447E.doc. pg 12.
[4] Zavadil, R M. May 22, 2006. Wind Integration Study for Public Service of Colorado. pg 12.
[5] Zavadil, R M, Jack King. July 20, 2007. Wind Integration Study for Public Service of Colorado Addendum: Detailed Analysis of 20% Wind Penetration. pg 12.
[6] Ibid pg 11.

Limitations of Resource Planning Models

To date wind induced cycling costs have not been considered in PSCo's planning models or planning process. As the level of wind energy on the PSCo system increases, however, the cost impacts of both unit cycling and wind curtailments will increase thus warranting their consideration in future planning decisions. PSCo uses two commercially available computer models for both near term production cost forecasts and long-term resource planning purposes. These models, and their limitations, are described below.

The first model, Strategist, is a capacity expansion model. Strategist determines the most cost-effective mix of generation resources that can be integrated with an electric utility's existing system to serve future customer demand for electricity. Strategist ranks each feasible combination of resources, i.e. those that include sufficient capacity to meet the target reserve margin, according to user-established objective functions, e.g. minimization of revenue requirements or minimization of average rates. PSCo used Strategist to evaluate the least-cost mix of resources in its last three resource plans and it will continue to be the primary tool used for resource planning studies.

The second model is the ProSym® production cost model. ProSym is a least-cost, chronological dispatch-and-commit model that simulates generation and contractual assets to meet the load obligations. ProSym allows PSCo to forecast the future production costs of serving its forecast load. In addition to the load forecast, inputs include generating unit characteristics and operating parameters, committed purchases and sales, fuel prices, transmission area constraints, and electricity market prices.

One of the key aspects of studying the effects of wind induced cycling on PSCo's coal-fired units is estimating the number of cycling events that are directly attributable to wind. While the ProSym and Strategist models capture the reduction in coal generation due to wind, the models do not have the ability to track and report the number of times a coal unit is cycled as a result of wind generation or assign a cost for each cycle. As a result, cycling costs can not be input into the models for purposes of determining overall coal plant cycling costs and these costs are not considered as part of the production cost optimization within the models.

One of the consequences of this is that operational strategies that may reduce cycling costs, such as alternative unit commitment and economic dispatch schedules that take the cycling costs into account are not considered in the production cost models. A full accounting of these cycling costs in the commitment and dispatch simulations may result in fewer, and/or shallower, coal unit cycles. Future work could more fully address this issue when modeling tools are able to capture these costs.

As a result of these resource planning models' limitations, PSCo developed a spreadsheet model to analyze and quantify coal-plant cycling and wind curtailment costs. This model forecasts the number of wind-induced coal plant cycles for a given nameplate level of wind and estimates the total curtailed wind energy under two dispatch protocols. The estimated number of coal plant cycles are multiplied by a per cycle cost developed in a separate study by an independent industry expert to produce a total cost of cycling.

Separately, the estimated curtailed wind energy is multiplied by a curtailed energy rate to produce the total cost of wind curtailments.

This modeling approach can be applied to all resources that are expected to increase coal-cycling and wind energy curtailment – not just wind resources. New low cost resources or baseload resources can increase cycling costs for the existing coal fleet as well. For example, a low cost flat power purchase schedule can displace the current baseload generation fleet, forcing it to cycle more. While this report only addresses costs associated with wind induced coal cycling and wind curtailments, this modeling approach may be used to evaluate similar costs of other energy resources.

Coal Plant Cycling Costs

Cycling is the operation of thermal electric generators at varying load levels, including on/off and low load variations, in response to system load requirements.[7] Some PSCo generators (mostly natural gas-fired power plants and pumped hydro units) were designed for cyclical operation in order to follow, or balance, variations in load. In contrast, the PSCo coal-fired generating units were principally designed for baseload, or full output, non-varying, operation. PSCo is diversifying its portfolio of resources by including intermittent energy sources, such as wind facilities. The inclusion of greater levels of variable energy sources has forced a movement from the design operation of the coal-fired generating units and the increased cycling induced plant wear has increased the costs of operating the system.

Wind energy has zero fuel costs which lowers its incremental dispatch cost. In hours of low system load and high wind output, generators that were otherwise operated as baseload units are now being required to reduce their output, or cycle, to allow wind energy to serve load and, thereby, minimize overall system costs and emissions. With an ever larger wind portfolio, the depth and frequency of cyclical operation of baseload units will increase and affect more and more generators. Coal-fired units that have historically been base loaded will be required to turn-down to their minimum capacity, or possibly turn off entirely. These cycling evolutions will be occurring more rapidly and more frequently with greater levels of wind generation.

Any plant cycling causes component wear[8] and tear[9] costs. When a thermal generator is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through large thermal and pressure stresses. Eventually, these stresses cause component failures, driving maintenance costs up. In low load operation, the pressure and temperatures

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[7] Grimsrud, G Paul, Steven A Lefton. May 1995. Economics of Cycling 101: What Do You Need to Know About Cycling Costs and Why?. Pg 2.

[8] Wear refers to the ordinary mechanisms (accelerated by cycling) by which components reach the end of their "natural" lives. Such mechanisms are creep, thermal-fatigue, erosion, corrosion, etc.

[9] Tear relates to the accelerated life consumption brought on by episodes of off-normal operation such as periods of poor fuel quality, poor control of combustion conditions, poor water chemistry etc. Tear of components can be caused even during baseload operation, although the propensity is generally greater for off-normal conditions during some cycling modes. EPRI GS-7219 Cycling of Fossil-Fueled Power Plants Volume 6 page 3-4

fluctuate in pipes and tubes causing fatigue[10] and, ultimately, pre-mature failure. Fatigue further erodes the designed stress tolerances of full output operation, or creep tolerance. This creep-fatigue interaction is one of the most important phenomena contributing to component failure.[11] Thus, wind induced cycling costs of PSCo's coal-fired fleet is an additional "hidden" cost of integrating wind generation onto the system. It is appropriate to determine this additional wind integration cost and appropriately burden incremental wind power with this cost in future resource planning efforts.

Cycling is defined in two general ways. An *on/off cycle* is the shutdown and restart of a unit. A *load follow cycle* refers to a change in generation from maximum capacity to a lower load or minimum capacity and back to maximum. On/off cycles are further divided into hot, warm, and cold starts referring to the number of hours the unit is off-line. In a hot cycle, the coal-fired unit is off-line less than 24 hours; a warm cycle 24 to 120 hours; and a cold cycle greater than 120 hours with actual times dependent on the design of the specific unit.

Load follow cycles are further divided into shallow or deep cycles depending on the depth of the load follow, i.e. the MW level to which the plant was turned down. A shallow load follow reduces generation to the economic minimum level. The economic minimum is the lowest level of net production that a generating unit can maintain continuously under normal system conditions. The economic minimum is determined on a unit by unit basis while considering the unit design, minimum boiler outlet temperature to minimize corrosion and allow proper operation of emission control equipment, turbine outlet steam conditions, unit stability, minimum mills in service and similar operating items. A deep load follow reduces generation to the emergency minimum level - or to the lowest theoretical minimum level of operation where the unit is safe, stable, and environmentally compliant.

Cycling damage is a result of the cumulative effect of multiple load follow and on/off cycles over time. Types of cycles listed from lowest to highest cost are as follows: Automatic Generation Control (AGC) regulation, shallow load follow, deep load follow, hot on/off, warm on/off and finally the most expensive being cold on/off cycles. Coal units are not identical in their ability to cycle or in the cost that would be incurred in shallow or deep cycling. This study took into account the differences in cycling costs, along with other variable costs, on a unit-by-unit basis. The results are reported based on the average cycling cost per MWh of wind generation.

For purposes of this study, on/off cycling of coal units was **not** considered as a viable operating practice to accommodate wind generation on the PSCo system due to the high cost per cycle (see Appendix A for a more detailed description). Costs associated with AGC cycles for frequency regulation were also excluded from this study. AGC cycle costs are small when compared with other types of cycles due to the low temperature

[10] Fatigue is the progressive and localized structural damage that occurs when a material is subjected to cyclic loading.
[11] Grimsrud, G Paul, Steven A Lefton. May 1995. Economics of Cycling 101: What Do You Need to Know About Cycling Costs and Why? Pg 2.

variation incurred during the small changes in output and were therefore excluded from the analysis. As a result, this study examined only load following cycles (both shallow and deep cycles).

Wind Curtailment Costs

As an alternative to cycling coal-fired generators, system operators can choose to reduce or curtail the amount of wind energy being generated on the system. While this action can avoid additional cycling and cycling costs, curtailing wind generation results in its own set of costs including payments for the value of lost Production Tax Credits (PTC) in instances where wind is purchased under a power purchase agreement (PPA). [12] Other costs of curtailment include fossil fuel costs (mostly coal), potential carbon mitigation costs, and Renewable Energy Credit (REC) opportunity costs.

The fossil fuel component of wind curtailment costs is estimated using the fuel cost of the fossil unit(s) that would have been turned down in lieu of curtailment. In addition, when wind is curtailed in lieu of reducing coal generation, a portion of the environmental attributes of wind generation were not realized - CO_2 was emitted, fossil fuel costs were incurred, and the value of any REC is lost.

Cycling and Wind Curtailment – An Integrated Approach

PSCo believes that the costs of curtailing wind facility output and the cost of cycling of baseload units should be analyzed in an integrated manner to arrive at the best solution for the purpose of resource planning decisions and in developing appropriate system operating protocols.

Under current PSCo system operating protocols, shallow load following is pursued first (since the ability of PSCo coal-fired generators to reliably reach their emergency minimums is uncertain) followed by curtailment of wind output if needed. Full shutdown of coal-fired generators is a reliability risk because the facility may be unable to be restarted and available for the daily peak due to long minimum down times, slow startup ramp from off-line to full load and the possibility of equipment failures due to the shutdown.

Determining total cycling costs is not only useful for resource planning and crafting operating strategies, but also for estimating the potential impacts of coal unit modifications that could either increase or decrease the load following capability of the units or the impacts of unit retirement. Investments can be made to improve a coal unit's flexibility such as: lowering the economic minimum, enabling emergency minimums to be reliably achieved, and mitigating wear and tear costs due to a unit start. Targeted retirements of inflexible units may have system-wide benefits to the entire coal fleet and the wind portfolio. Additionally, the value of increased flexibility on wind units themselves, through AGC regulation of wind plants, can be quantified by evaluating the

[12] Exceptions include transmission emergencies or curtailments resulting from wind farm issues outside the control of PSCo. In addition, two wind farm PPAs have curtailed energy allowances, capped at 14 Gigawatt-hours (GWh) of wind energy annually.

reduction in wind curtailments as a result of targeted curtailment vs. curtailment of large blocks of wind. Benefits of these investments can be quantified in terms of the avoided curtailment and/or reduced cycling costs that could be realized.

Summary of Study Methodology

For purposes of this study, total cycling costs were considered to contain a plant cycling component and a wind curtailment component. To determine the plant cycling cost component it was necessary to 1) estimate the number of coal unit cycles that were directly attributable to a given level of wind generation on the PSCo system and 2) determine the cost per coal unit cycle. To estimate the number of coal unit cycles attributable to wind, a spreadsheet model was developed that utilized a forecast of load before and after the addition of a user specified level of wind generation to estimate the frequency and intensity of cycles. To determine the cost per coal unit cycle, PSCo retained APTECH Engineering Inc. in the fall of 2008[13] to analyze cycling costs for PSCo's Pawnee station. The Pawnee study results were extrapolated to other PSCo coal-fired generating units using previous APTECH study work.[14]

Wind generation curtailment costs were calculated based on existing coal price forecasts, REC price forecasts and CO_2 emissions cost forecasts. Separately, system load and wind energy scenarios were determined.

In the model resources are stacked by operating cost to meet forecast load and the number of cycles, by unit, was estimated. Plant cycling costs are costs per cycle developed by APTECH multiplied by the number of cycles estimated with the model. Wind curtailment costs were then determined and added to the plant cycling costs to calculate the total costs. These costs are calculated twice, under a scenario with wind and a control scenario excluding wind to remove cycling and curtailment costs that would have occurred due to reductions in demand alone. The cost difference between the wind scenario and the control scenario represents the cycling and curtailment cost attributable to the level of wind evaluated. A more detailed description of the model is included in Appendix A.

The spreadsheet model did not explicitly address the effect of wind uncertainty and variability on overall cycling and curtailment costs. Operators historically have and, in the future, will curtail wind energy during extreme up and down ramp events. Wind energy will be curtailed prior to reaching the absolute system bottom to maintain a cushion against inherent uncertainty and variability. The model did not account for these reasonable, yet difficult to model, scenarios since the model assumes perfect foresight regarding the wind portfolio and load. In addition, costs associated with the fast ramp rate of these extreme events are beyond the scope of this study; ramp rates are limited to current economic planning parameters within the model.

[13] Agan, Dwight; Besuner, Philip; Grimsrud, G Paul; Lefton Steven A; APTECH Engineering Services; Cost of Cycling Analysis for Pawnee Station Unit 1 Phase 1: Top-Down analysis; November 2008.
[14] APTECH Engineering Services, Inc.; Total Cost of Cycling Fossil Power Plants: Phase 2, January 1997 (PSCo Source Data: 1985-1994).

It is important to note that the study attempts to quantify the costs associated with cycling coal plants for a specific system configuration. The methodology presented in this paper is not a cost optimization methodology. This study does not attempt to minimize costs while considering potential changes to the system that could mitigate coal cycling and curtailment costs such as unit modifications to increase flexibility or unit retirements.

In addition, some factors that could influence total costs were beyond the scope of this document. Changes in emissions (SO_2 and NOx) that occur to accommodate wind due to a reduced coal burn or coal units operating at suboptimal generating levels were not considered in this study.

Study Scope

The study looks at two levels of installed wind on the PSCo system. The 2GW case represents the approximate level of wind PSCo expects to have on the system by 2013 after the acquisition of new wind approved in the 2007 CRP and 2009 All-Source Solicitation. A 3GW scenario was also studied to understand the cost of adding an incremental 1GW of wind to the PSCo system by the year 2020. The study period includes the years 2011 through 2025. Analysis of these two levels of installed wind will provide a better understanding of costs that can be anticipated given the current level of committed wind as well as costs for wind generation additions for use in future resource planning decisions.

Coal unit cycling costs were calculated for each level of installed wind under two cycling protocols: 1) load follow coal units sequentially down to the economic minimum (shallow load follow) then curtail wind as needed, and 2) load follow with all coal units down to the economic minimum, then continue to reduce unit output to emergency minimums (deep load follow), then curtail wind as needed.

Protocol 1 – Referred to as the "*Curtail*" Protocol

All PSCo coal units are dispatched to follow changes in net load, where the net load is the obligation load minus wind generation. Each coal unit would be cycled down to its economic minimum before any wind generation is curtailed. If the net load decreased below the aggregate coal fleet economic minimum capacity, curtailment of wind would be required to effectively increase the net load back to the economic minimum capacity. This protocol limits all coal units to shallow load follow cycling only.

Protocol 2 - Referred to as the "*Deep Cycle*" Protocol

As in the Curtail protocol, all coal units would be ramped down as far as their economic minimums to follow reductions in net load. Rather than curtail wind at this point if net load falls further, one or more coal units would be called upon to deep cycle. Wind curtailments may still be required if net load falls below the aggregate coal fleet minimum deep cycle level. This protocol essentially swaps wind curtailment costs for deep cycling costs on coal units.

It is important to note that shallow cycling and some wind curtailment costs may be incurred in both protocols. The primary cost difference between protocols comes from deep cycling costs vs. curtailment costs.

The study is intended to forecast only the total cost of cycling baseload coal units and does not address the costs of cycling natural gas units or the effect of wind on system stability/reliability. Gas units also have cycling costs associated with load following but were not explicitly studied for this analysis.

Discussion of Results

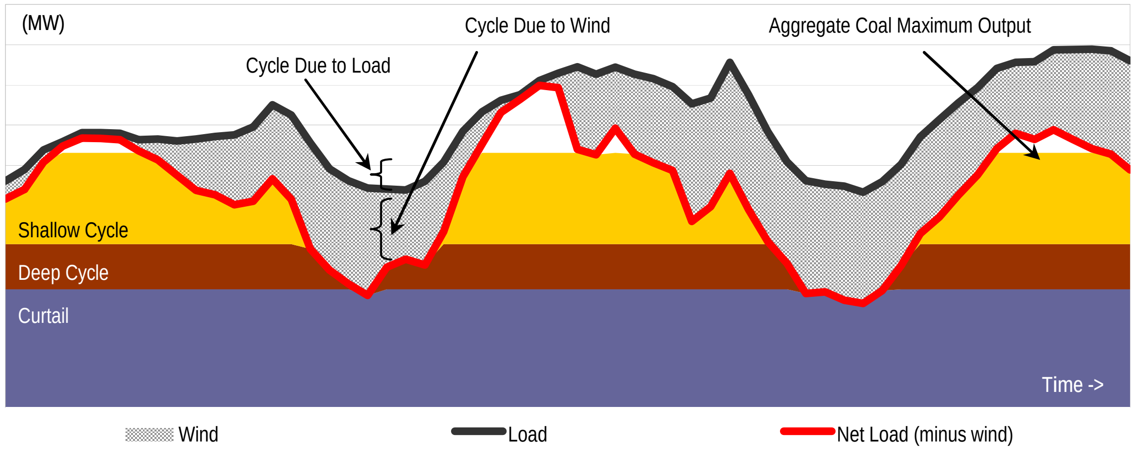
By evaluating various levels of wind penetration on the PSCo system and how costs change over time the study identified two key results: 1) the relationship between total cycling costs and wind penetration is not linear, 2) for a fixed level of wind, cycling costs are forecast to generally decline over time which highlights the importance of life-cycle analysis of cycling costs.[15]

The first result is that cycling costs do not change linearly with changes in wind penetration. When the amount of wind on the system is insufficient to push the net load below the aggregate baseload maximum, additional wind generation has little or no effect on increasing baseload unit cycling. However, once the wind capacity is equal to or greater than the difference between minimum obligation load and the aggregate baseload maximum, the cycling effect from incremental additions of wind increases sharply.

Figure 1 illustrates this effect. Small levels of wind generation have little or no effect on coal cycling – net load remains above the aggregate baseload coal maximum output level. As wind generation increases, net load pushes down into the coal stack which requires coal units to cycle down to balance system load with generation. Larger levels of wind penetration increase the size of the wind wedge (the shaded area between the load and net load lines) in the chart which increases the size, intensity and frequency of cycling events.

[15] Whether cycling costs rise or fall over time is a function of the specific characteristics of the electric system being examined. For the PSCo system, the decline in costs were largely driven by the assumptions of future load growth, coal unit retirements and reductions in must take power purchases.

Figure 1: Impact of Wind on Coal Unit Cycling Illustration

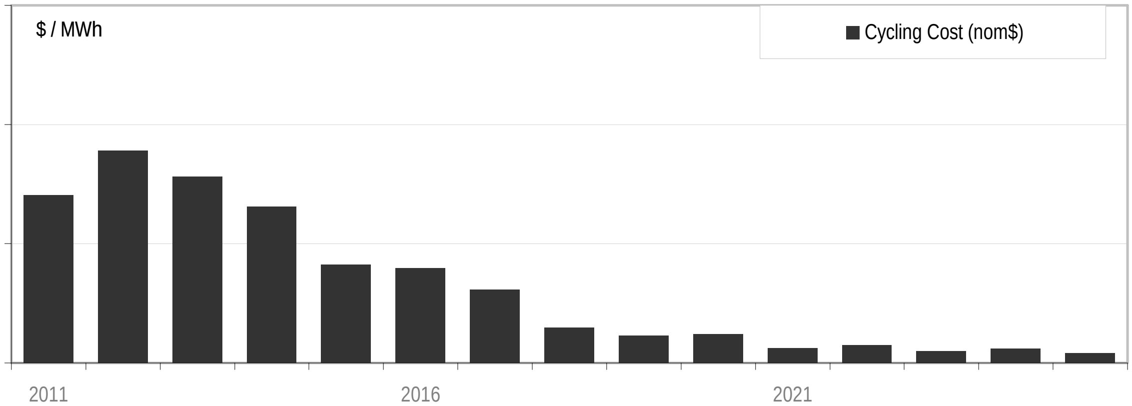


The second key result is that with a fixed amount of wind on the PSCo system, there is expected to be downward pressure on cycling and curtailment costs over time. With all else equal, an incremental quantity of wind has the largest impact on cycling costs in the year of installation with costs decreasing thereafter assuming:

1) System loads (both on and off peak) grow over time and
2) Baseload unit retirements and must-take contract expirations are replaced with more flexible resources.

These two assumptions, which are representative of the PSCo system, result in higher minimum loads, lower system minimum generation levels and lower system baseload maximum generation levels over time. These factors tend to mitigate the effects of a fixed amount of wind on baseload unit cycling as the gap between minimum system load and baseload maximum increases (Figure 2). Referring back to Figure 1, one can visualize that an increase in load (black line) with the same quantity of wind will pull the net load up through the coal stack and reduce the intensity and frequency of cycling events. Conversely a reduction in the aggregate coal maximum generation would move the coal generation stack below the net load (red line) more often. Higher net loads and lower aggregate coal generation both move the net load away from the baseload cycling range (yellow band in Figure 1) although more flexible units higher in the generation stack still cycle to match the increased variability of the net load caused by wind. Figure 2 illustrates the decrease in cycling costs.

Figure 2: Illustration of Decreasing Cycling Costs



The non-linear relationship between the level of wind generation and the number of coal unit cycles, coupled with the expectation of fewer cycles over time (due to load growth and changes in the generation supply mix) and the long life of wind generation resources, all indicate that cycling costs be analyzed on a life cycle basis rather than a single point in time. For purposes of this study, both the number of coal plant cycles and the cost of wind generation curtailments were calculated for each year of the 15-year study period and then levelized (levelized cost is the fixed annual payment that is equivalent to the present value of the annual cost streams). Although a single resource plan was used for this study, that resource plan included known changes to the generation mix as well as forecasts of future load growth. The coal unit retirements included as part of CACJA and the expected load growth both have the affect of reducing cycling and curtailment costs.

Overview of Results

Results presented below are based on assumptions that are current as of the Spring of 2011 (load forecasts, generation resource mix including known changes and fuel and curtailment cost assumptions) and are intended to show the scale of cycling costs for the PSCo system. Importantly, the model and results will be refreshed with updated information prior to incorporation into future resource planning analyses. Table 3 shows the levelized cost of the four primary scenarios (figures 2-5 show the annual detail for each scenario).

Table 3: Summary of Scenario Results from 2011 to 2025 (2010 Present Value)

Scenario	Installed Wind	Cycling Protocol	Cycling Cost Component ($Million)	Curtailment Cost Component ($/Million)	Total Levelized Annual Cost ($Million)	Total Levelized Cost ($/MWh)
1	2GW	Curtail	$3.6	$1.2	$4.82	$0.77
2	2GW	Deep Cycle	$5.1	$0.1	$5.21	$0.83
3	3GW	Curtail	$5.0	$3.3	$8.30	$1.03
4	3GW	Deep Cycle	$8.2	$0.6	$8.75	$1.08

Costs are forecast to be $0.77/MWh for the 2GW scenario and $1.03/MWh for the 3GW scenario. These average costs apply to the entire quantity of wind generated in each scenario.

2GW Installed Wind Scenario

This scenario represents the cumulative level of wind that PSCo expects to reach by 2013 as a result of its 2007 Resource Plan approved by the CPUC. The costs are relatively low for the first 2GW of wind on the PSCo system. Levelized costs for both protocols, Curtail and Deep Cycle, are similar ($0.77 vs. $0.83/MWh) which suggests that factors other than cost (see Table 4) should be considered when choosing the best protocol.

Table 4: Qualitative Factors for Differentiating Protocols

Protocol	Pros	Cons
Curtail	• Impacts are more certain • Costs are easily quantified	• Less wind energy delivered • Higher CO_2 emissions • Possibly higher CO_2 price risk
Deep Cycle	• More wind energy • Lower CO_2 emissions • Possibly lower CO_2 price risk	• Unpredictable timing of cash expenditures – costs are modeled in the year of accrual • Uncertain impact of operating at emergency minimums – unknown operating regime, risk of understating deep cycle costs, increased risk of latent damage causing future forced outages and derates and reduced system reliability

PSCo system operators currently operate the system consistent with a Curtail protocol, although at current wind levels of approximately 1,200 MW, wind is infrequently curtailed due to system bottoming situations. This Curtail protocol is being followed when PSCo experiences a system bottoming situation due to the uncertainty of the effects that operating coal units at emergency minimums will have on the units and system reliability over time. Increased component damage, outages and unit trips are expected while operating at an emergency minimum level.

The last tranche of wind capacity additions in the 2GW scenario are operational in 2013. As noted above, annual costs decrease from this point forward as load growth gradually raises the minimum net load which has the effect of reducing the frequency and depth of system bottoming occurrences. Figures 2 and 3 clearly show the declining annual costs once the maximum level of installed wind capacity for the scenario is reached.

Figure 3: Scenario Results – 2GW of Wind, Curtail Protocol

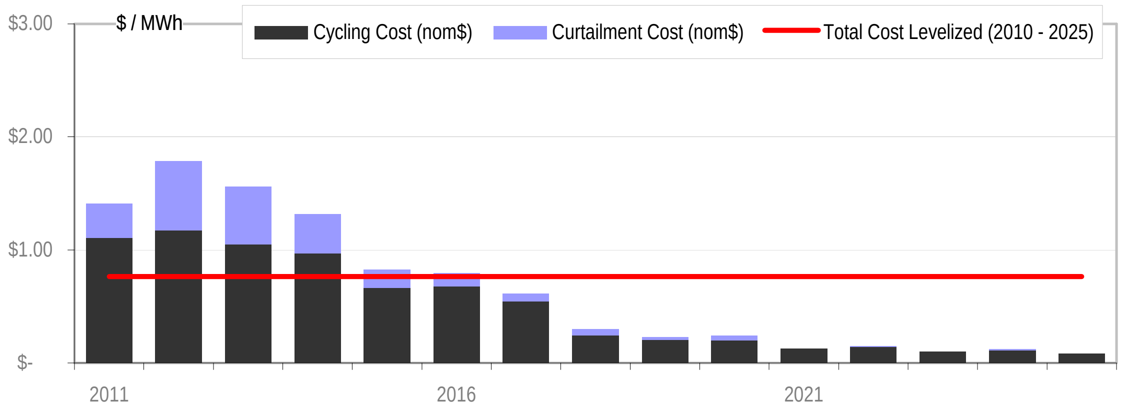
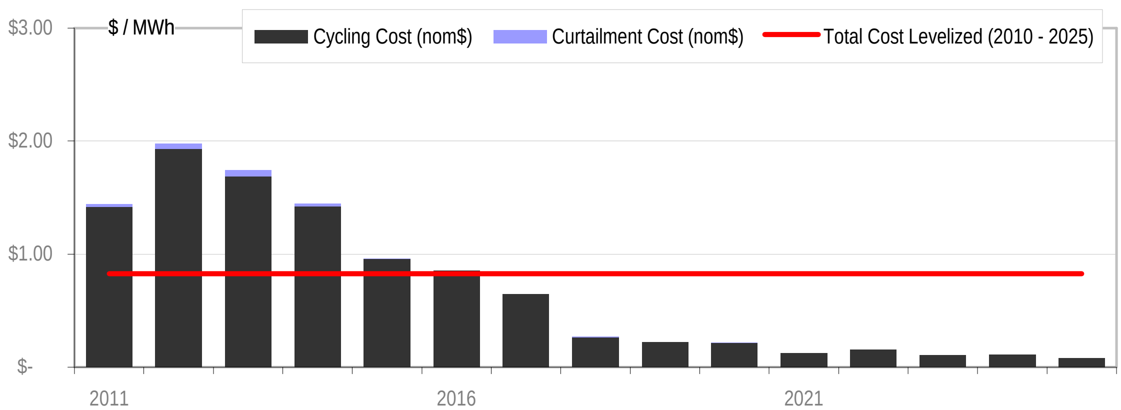


Figure 4: Scenario Results – 2GW of Wind, Deep Cycle Protocol



3GW Installed Wind Scenario

This scenario adds 200 MW of wind annually beginning in 2016 to the 2GW scenario for a cumulative total of 3GW by 2020. These wind additions elevate costs through most the study period (Figures 4 and 5) compared to the 2GW scenario where costs began declining in 2014. In this scenario, the last tranche of wind capacity is added in 2020 after which costs begin to decline. Generation from 3GW of wind pushes through the shallow cycling range much more frequently than the 2GW scenario which leads to a pronounced increase in costs.

Average cycling and curtailment costs in the 3GW scenario increase compared with the 2GW scenario. The levelized costs of $1.03/MWh and $1.08/MWh for the Curtail and Deep Cycle protocols, respectively, are about $0.25/MWh higher than the 2GW. The increasing average cost highlights the fact that the incremental costs of the additional 1GW tranche of wind required to bring installed wind from 2GW to 3GW are greater than those of the first 2GW of installed wind (see discussion below).

Figure 5: Scenario Results – 3GW of Wind, Curtail Protocol

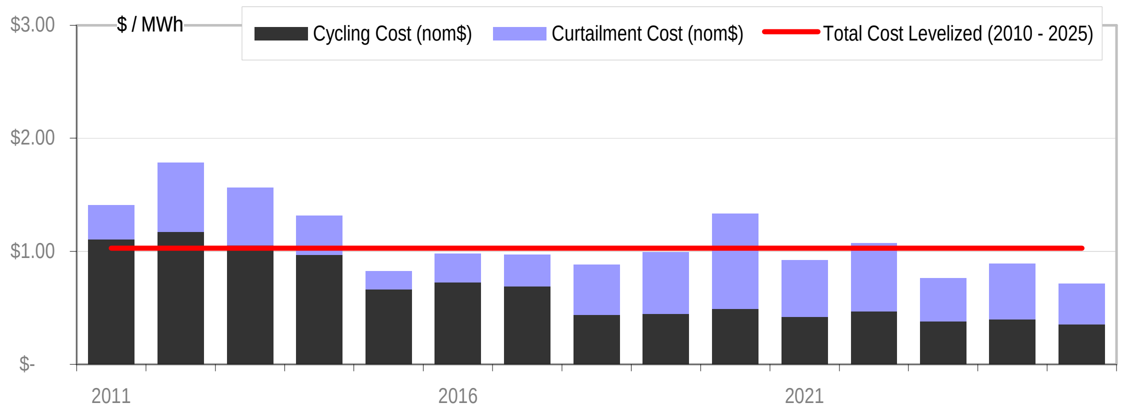
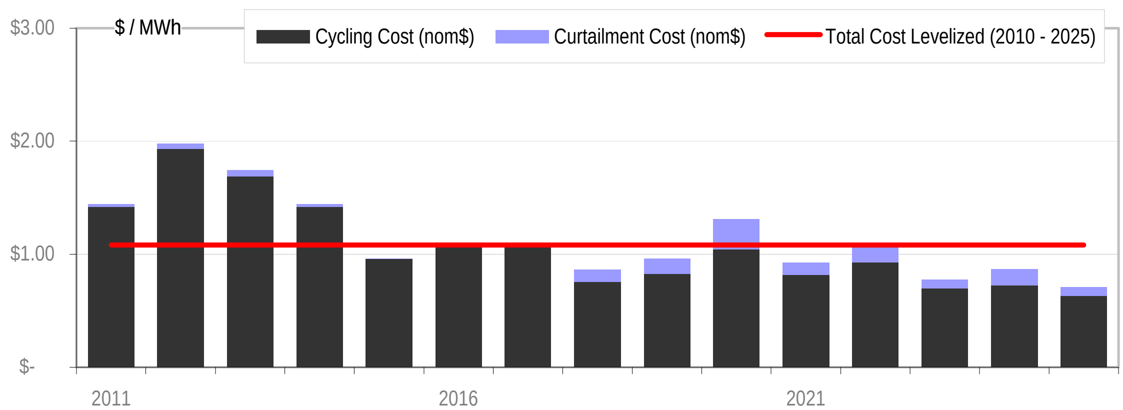


Figure 6: Scenario Results – 3GW of Wind, Deep Cycle Protocol



Incremental 1GW of Installed Wind

The total cycling costs incurred for the incremental 1GW of wind (wind required to reach 3GW) represent costs that would be used in the next resource evaluation process. As noted above, incremental wind induced coal unit cycling and curtailment costs are increasing as installed wind capacity increases. Table 5 shows the incremental cost associated increasing the level of wind from 2GW to 3GW.

Table 5: Incremental Cost of 1GW of Wind 2011 to 2025 (2010 Present Value)

Installed Wind	Cycling Protocol	Cycling Cost Component ($Million)	Curtailment Cost Component ($/Million)	Total Levelized Annual Cost ($Million)	Total Levelized Cost ($/MWh)
+ 1GW	Curtail	$1.8	$2.7	$4.46	$2.18
+ 1GW	Deep Cycle	$3.9	$0.7	$4.54	$2.22

The levelized incremental cost of going from 2GW to 3GW of wind on the PSCo system is higher than the average cost of the first 2GW due to increases in both the frequency of cycling events and the depth of the cycling events (refer to cycling illustration in Figure 1). Average cycling and curtailment costs for the incremental 1GW are forecast to be $2.18/MWh for the Curtail protocol of which $0.86/MWh are cycling costs and $1.32/MWh are associated with curtailments costs. The annual detail in Figures 6 and 7 shows that the cost remains relatively flat between $2 and $3/MWh (in nominal dollars) as wind capacity is added from 2016 through 2020 at a rate of 200 MW annually. After 2020, costs gradually decline to $2/MWh (nominal dollars) in 2025.

Figure 7: Scenario Results – Incremental 1GW of Wind, Curtail Protocol

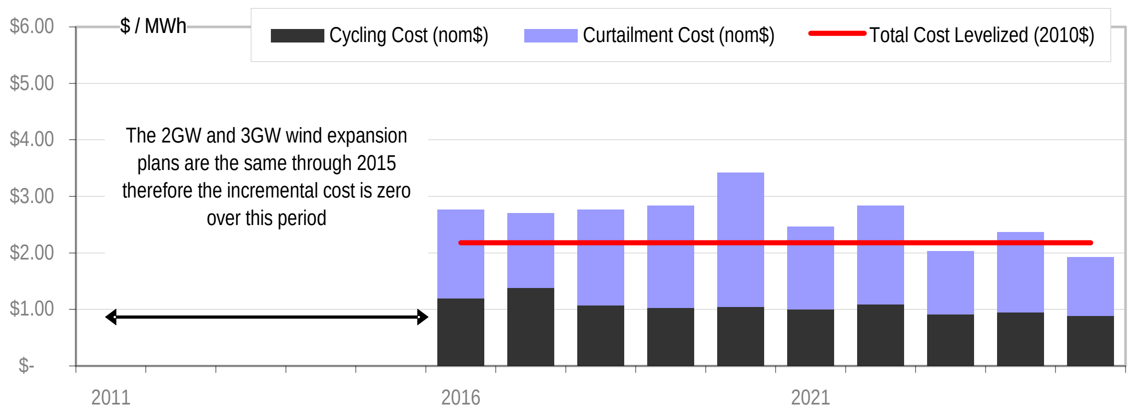
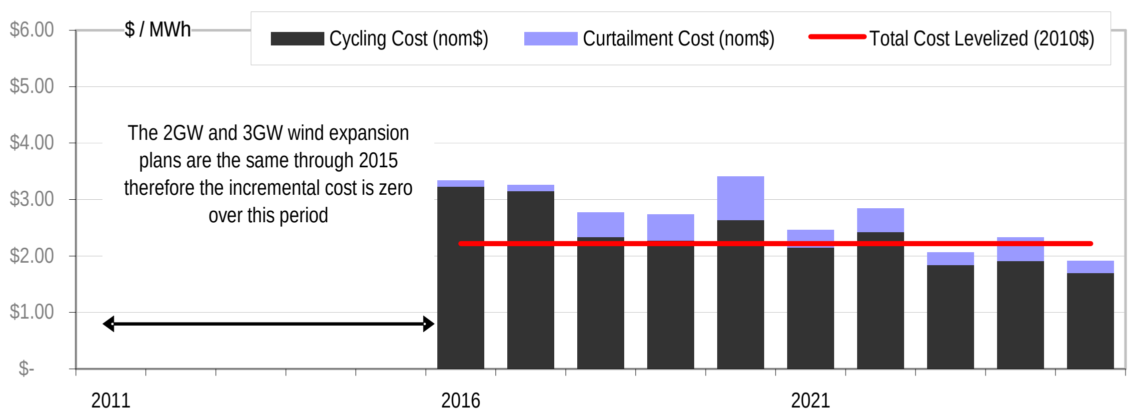


Figure 8: Scenario Results – Incremental 1GW of Wind, Deep Cycle Protocol



Conclusions

PSCo expects to have approximately 2GW of installed wind generation on the system by 2013 when the peak load is forecast to be approximately 6,700 MW, representing a wind penetration level (wind energy as a portion of total load) near 20%. This study determined that the average cycling and curtailment costs associated with this level of wind are forecast to be $0.77/MWh (present value in 2010). Incremental wind additions beyond 2GW increase both the depth of load follows and the frequency of events. As a result, incremental cycling and curtailment costs are increasing and are forecast to be $2.18/MWh on a levelized basis although cycling costs are only $0.86/MWh of the total. When evaluating the expected costs of wind additions beyond 2GW it is important to consider the cycling related costs in *addition* to previously identified wind integration costs that address wind generation variability and uncertainty.

Both operating protocols (Deep Cycle and Curtail) show increasing costs for the next incremental 1GW of installed wind. With no significant difference in the cost of the two protocols, the Curtail protocol is recommended as the preferred operational protocol in the near term. This is primarily due to qualitative factors including the uncertainty of the effects on the baseload units and system reliability due to operating these units at emergency minimums. Curtailment costs are the largest cost component for the Curtail protocol and are driven by future CO_2 and REC price assumptions, both of which are based on best estimates of potential regulatory environments and requirements.

The results in this study are dependent on both the existing generation portfolio as well as assumptions about how that portfolio might change over time. The study does not account for cycling cost mitigation opportunities that might be available as a result of modifications to the resource portfolio such as additional coal unit retirements, baseload unit modifications or the addition of more flexible power supply resources. The study is based on a fixed generation mix including known changes over time. Cycling costs and curtailment costs should be considered when evaluating future portfolio modifications.

Appendix A – Assumptions and Methodology

This study estimated wind induced cycling costs for two plant cycling protocols (Curtail and Deep Cycle) as well as for two levels of installed nameplate wind capacity (2GW and 3GW). The total wind induced cycling costs are the sum of the plant cycling component and the wind curtailment component. The study determined cycling costs and curtailment costs as follows:

Plant Cycling Component Calculation

This study used current resource expansion plans, unit operating characteristics, load forecasts and cost per cycle metrics to estimate wind induced cycling costs using a method that applies a cost per cycle to the forecast number of wind induced cycles to determine annual wind induced cycling costs.

Plant cycling costs are the number of wind induced cycles multiplied by the cost per cycle where cycles are one of two types 1) shallow cycle or 2) deep cycle. The costs are calculated on an annual basis and divided by the associated MWh of annual wind generation resulting in a dollar per Megawatt-hour metric for ease of discussion and consistency with how wind integration costs have been presented in previous studies.

Types of Cycles

Cycling is generally defined as the operation of thermal electric generators at varying load levels, including turning units on/off, in response to system requirements. Some PSCo generators such as small natural gas-fired power plants and pumped hydro units were designed for cyclical operation to follow, or balance, variations in load. In contrast, the coal-fired fleet was designed for baseload, or full output, non-varying, operation.

Increasing amounts of wind energy on the PSCo system has changed this implied operation of the coal-fired fleet. In hours of low loads and high wind generation, previously baseloaded generators are now required to cycle and reduce their output to maintain economic system balance. With an ever larger wind portfolio, the depth of cyclical operation will affect more and more generators. The coal-fired fleet will be required to ramp down to their minimum capacity, or possibly be required to turn off entirely, more frequently. The previously baseload fleet will cycle deeper and more frequently to balance wind and load.

On/Off Cycling

On/Off Cycles can be divided into hot, warm, and cold cycles with increasing number of hours off-line respectively. Compared with load following cycle, on/off cycles cause more damage to coal units and are therefore the most costly types of cycles based on results from the APTECH study. Hot start costs represent the type of cycle a unit would go through if it were decommitted overnight to lower system minimums and reduce cycling on other units in anticipation of large wind generation events.

The methodology described in this study for calculating cycling costs does not consider on/off cycles as a viable means to balance generation with net load due to both the high cycling cost and the cost associated with the unit being unavailable (more expensive generation could be required) in the event actual wind generation is significantly below forecast. The analysis described briefly below is the basis for this assumption.

The benefits of avoiding curtailments are equal to the cost of a curtailment ($/MWh) multiplied by the curtailed energy (MWh). In order to make an economic decision to shut a unit down, these benefits must outweigh the unit's hot start cost. Hot start costs run into the tens of thousands of dollars and are proportional to the size of the unit. As the size of the unit increases, both hot start costs and potential benefits from avoided curtailments increase.

As an example, decommitting a coal unit with a 100 MW minimum would reduce the system minimum generation level by 100 MW at a cost of over $50,000 for a hot start. Assuming curtailment costs of $60/MWh, a curtailment event of 833 MWh ($50,000 / $60), or 8.3 hours, is required to make the decommit decision better than break-even.

Wind curtailment events in 2013 were classified by depth (MW) and duration (hours) to determine the size of the pool of potentially avoidable curtailment energy (MWh). Six events of the size described above are forecast in 2013 although accurately forecasting these infrequent events for operational purposes would be difficult and the economic benefit small compared to the operational risk incurred by decommitting the unit. Based on this poor risk/reward dynamic, unit decommittment was not considered as an option for balancing generation with net load to accommodate wind generation in this study.

Load Following Cycling

Load following cycles can be divided into two general categories: shallow cycles and deep cycles. Shallow load follow cycles maintain the unit's design temperatures causing far less stress to components and equipment. A shallow load follow cycle reduces output as low as the unit's *economic minimum*, but not below. Deep load follow cycles take the unit to its lowest output level where the unit is still stable, safe and environmentally compliant – called the *emergency minimum*. Running at emergency minimum will increase costs for several reasons:

1) Pulverizers and related machinery necessary to supply the boiler with fuel may have to be stopped and re-started;
2) Temperatures for certain plant components fall below their design specifications causing increased thermal cycle stresses and thermal fatigue damage;
3) Pressure variations and pressure related stresses and fatigue increase;
4) Corrosion fatigue risks increase due to water chemistry changes caused by process changes, i.e. - oxygen ingress, exfoliation transfer;

5) Units are less efficient at emergency minimums (higher heat rates) and, therefore, both fuel usage and CO_2 emissions rates increase;
6) Flue gas temperatures drop toward dew point causing fabric filter bag fouling and equipment corrosion;
7) Air preheater baskets foul;
8) Fuel costs increase per megawatt produced due to need for stabilization fuel and deterioration in heat rate.

Estimating the Number of Cycles

To estimate the number of coal unit cycles attributable to wind, PSCo developed a spreadsheet tool that forecasts cycles based on hourly obligation load, wind generation forecasts and PSCo's baseload unit generation profiles and used this information to estimate the frequency and intensity of cycles. Inputs needed to calculate cycles are as follows:

Load Forecast

The hourly obligation load forecast and wind generation forecasts are based upon historically coincident hourly load and wind profiles from a one year period ending in March 2009 (see "Wind Generation Profile" description below). Using hourly wind and load data from the same historical period ensures that correlations between wind and load due to meteorology are accounted for properly in the modeling. The base year data is scaled to meet the energy and peak load forecasts that are used in PSCo's planning models (ProSym, Strategist), while maintaining the historical hourly load shape. With this method, the correlation between load and wind generation is maintained while the effects of load changes over time are captured.

Generating Unit Characteristics

Unit level detail of baseload and must take units including: unit minimum and maximum output levels, typical outage schedules, expected forced outage rates and planned capacity changes (additions and retirements). The resource mix used in the analysis is the mix ordered in the 2007 CRP and the CACJA proceedings by the Colorado Public Utilities Commission.

Wind Generation Profile

Two sources of wind generation data were considered as a basis for the hourly wind generation profile used in the study:

1) The Western Wind Resource Dataset (WWRD) provided by National Renewable Energy Laboratory (NREL), which is operated by the Alliance for Sustainable Energy, LLC for the U.S. Department of Energy.
    a. SCORE-lite (Statistical Correction to Output from a Record Extension) generation data representing 10-minute modeled wind generation for the years 2004 – 2006 using Vestas V-90 (3MW) turbines.
    b. Locations within the study area were chosen for their proximity to PSCo wind farms.
    c. WWRD datasets are for the years 2004, 2005 and 2006.

2) Historical wind generation data from PSCo wind farms representing 1,060MW of installed capacity. Hourly data from a one year period ending in March 2009 was the most complete consecutive year of data available at the time of the study initiation.

WWRD modeled generation was compared with observed generation data for two PSCo wind farms where historical datasets coincident with WWRD were available. Colorado Green is a 162MW farm located in southern Colorado. Spring Canyon is a 60MW farm located in northern Colorado. Data covering the period from 2004 – 2006 was compared for Colorado Green. The first eleven months of commercial operations in 2006 for Spring Canyon were used. The analysis looked at average monthly capacity factors, monthly histograms of capacity factors and monthly diurnal patterns to determine if the WWRD generation was a reasonable proxy for observed generation. Monthly histograms and the comparison of monthly diurnal patterns are available in Confidential Appendices B and C.

The analysis indicated that WWRD is a reasonable approximation for southern Colorado wind installations. Monthly capacity factors, histograms and diurnal patterns were similar although capacity factors were underestimated by WWRD in the summer months and overestimated in the winter. The comparison of observed and WWRD generation for northern Colorado was not favorable. WWRD significantly underestimated generation across all months, forecast a lower frequency of high generation hours and did not match observed diurnal patterns. Figures 8 and 9 show the average monthly capacity factors for the two wind farms over the periods analyzed.

PSCo has 1,234MW of wind capacity installed on the system in 2010. Of this capacity, approximately 80% is located in northern Colorado and the next 250MW of wind to be installed in 2011 will also be in northern Colorado. Based on WWRD significantly underestimating wind generation in the region where the majority of PSCo's wind capacity is located, historical generation data was selected as the best proxy for future wind profiles for this study.

Two hourly wind profiles, one for northern Colorado and one for southern Colorado, are based on normalized historical generation for the wind farms located in these regions. 237MW in the south and 822MW in the north for the one year period ending in March 2009 which excludes 175MW of northern Colorado wind added in the fourth quarter of 2009. Hourly wind generation forecasts for futures years are based on these profiles and the installed wind for the given year.

Figure 9: Monthly Capacity Factors – Colorado Green (2004 – 2006)

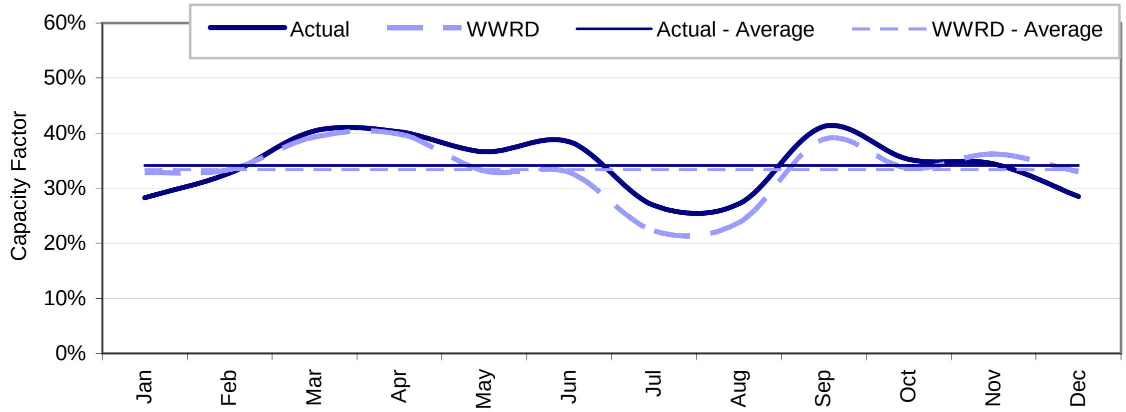
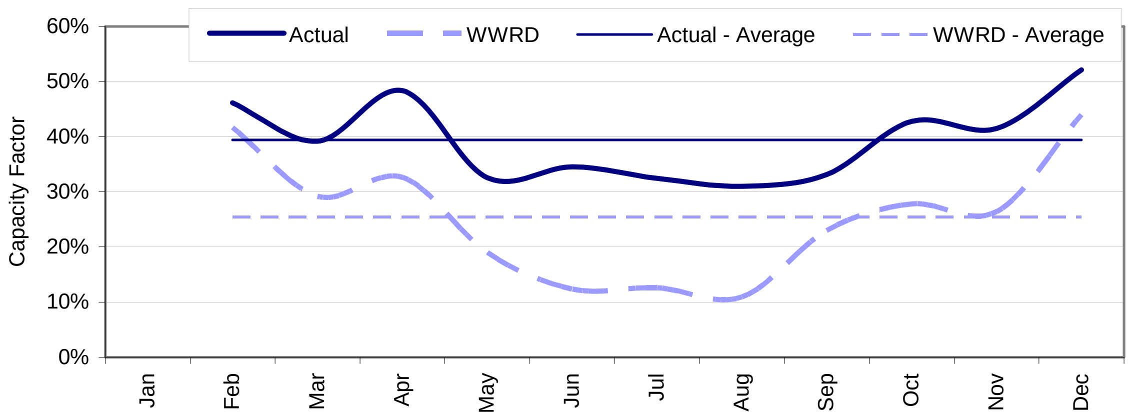


Figure 10: Monthly Capacity Factors – Spring Canyon (2006)



Counting the Cycles

PSCo estimates the number of coal unit load follow cycles (for both shallow cycles and deep cycles) directly attributable to wind generation using the following methodology:

- An hourly net load forecast is created for each year. The net load is the difference between the forecast obligation load and the forecast wind generation.
- For each hour of the year, the net load is compared to the *maximum aggregate* generation capacity of the baseload plants for that hour. If the net load is lower than the maximum aggregate baseload capacity, then it is assumed that one or more baseload units will have to decrease output, or cycle, to follow load. Unit maintenance schedules, scheduled power purchase contracts and estimated forced outages (EFOR) are accounted for in the calculation (EFOR by derating each unit). Therefore the maximum baseload capacity for a given hour is the sum of the expected online units only.
- For each day of the year, the maximum load follow, in MW, is determined based on the hourly calculations above. The model then determines how

many baseload units are required to cycle to balance net load and generation. Annual cycles are the sum of this daily calculation. This method assumes baseload units cycle a maximum of once per day.

These calculations are repeated assuming there is no wind generation on the system, i.e. the net load is equal to obligation load to count cycles that would have occurred absent any wind. The difference between these two cycle counts (with and without wind) is the estimate of the number of cycles attributable to wind.

Calculating the Cost per Cycle

PSCo retained APTECH Engineering Inc. in the fall of 2008 to study cycling costs for PSCo's baseload units. APTECH described its methodology as follows in its study summary:

> The Phase 1 assessment is a top-down analysis using a statistical approach and baseline historical data. In this phase, APTECH determines the relationship between cycling operations (hot starts, warm starts, cold starts, shutdowns, load changes) and costs (capital, operations, maintenance, etc.) using the current plant configuration and historical operations and maintenance costs. Baseline costs can then be established for Pawnee based on pre-wind cycling operations looking back 7 years.

In March 2009, APTECH completed drafts for the Phase 1 study for Pawnee. These costs were extrapolated to the rest of the coal-fired fleet using data from an earlier study[16] which calculated cycling costs for a number of PSCo plants. In the previous study, cycling costs were found to be correlated to plant size. The Phase 1 costs for Pawnee were extrapolated to other coal-fired generating units using the correlation data for the rest of the coal-fired plants. The costs determined for the PSCo plants for the two operating protocols are shown in Confidential Appendix E.

Concerning the confidentiality of the cost per cycle results, APTECH used a proprietary methodology to determine the cost per cycle for PSCo. APTECH's viability is integrally linked to not publicly sharing its study methodologies and its study results. The results of the APTECH study for Pawnee were benchmarked by APTECH with studies of other utility's coal units to confirm the validity of the Pawnee results.

Calculating the Wind Curtailment Cost Component

In addition to load following by baseload units to accommodate wind generation, wind curtailment may be required when the cycling capabilities of the baseload fleet have been maximized. Wind curtailment costs are calculated by multiplying quantity of wind curtailed (MWh) by the cost per MWh of curtailment. The costs

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[16]APTECH Engineering Services, Inc.; Total Cost of Cycling Fossil Power Plants: Phase 2, January 1997 (PSCo Source Data: 1985-1994).

are calculated on an annual basis and divided by the associated MWh of annual wind generation (including curtailed hours) resulting in a dollar per Megawatt-hour metric for ease of discussion and consistency with how wind integration costs have been presented in previous studies.

Forecasting Wind Curtailment MWhs

PSCo estimates the MWhs of curtailed wind generation by determining, for each hour of the year, the quantity of excess wind remaining on the system after all baseload coal units have cycled down to their minimum loads. This quantity of wind must be curtailed to balance load and generation. The calculation is dependent on the operational protocol, Curtail or Deep Cycle.

Per MWh Curtailment Costs

Costs per MWh of curtailed wind are comprised of the following four components:

The Production Tax Credit (PTC)

The PTC uplift payment may be paid to a wind developer when production is curtailed by PSCo. The credit is available for the first 10 years of operations of a wind facility. In the model, it is assumed that the tax credit will be available to wind facilities that begin commercial operations by the end of 2014. The PTC is $22/MWh in 2011 and grows at an assumed inflation rate of 2.5% annually. To make the developer whole, the PTC is grossed-up for taxes using a composite tax rate of 38%. The resulting PTC cost per MWh forecast is shown in Appendix D.

Wind that is curtailed in the model is identified on an hourly basis as ‘PTC wind’ or ‘non-PTC wind’ based on current PSCo wind installations (a wind facility is generally PTC wind for 10 years then moves to non-PTC wind). Only the curtailed PTC wind is used to calculate the total cost of the annual PTC payments.

Avoided Energy Cost

Avoided energy or replacement energy cost is the cost of the coal generation that would have been avoided if not for the wind curtailment. This cost is based on the annual average coal dispatch costs for the PSCo fleet and is shown in Confidential Appendix E. While this method is a simplification and does not explicitly capture the reduced coal plant efficiencies caused by operating at lower output levels when cycling due to wind, it does capture some of these effects of cycling in as much as typical cycles are captured in the dispatch models. Avoided energy costs are multiplied by all curtailed wind MWhs.

CO_2 Emissions Cost

The CO_2 emissions costs are the costs incurred due to the emissions from the energy that replaced the curtailed wind. The weighted average of the emission rates (tons/MWh) of the units online in a given year is used to derive the CO_2 emissions cost. The emission rate is based on historical plant emissions data and the CO_2 cost is \$20/ton beginning in 2018 and escalating at 7% annually. The CO_2 cost per MWh is the emission rate multiplied by the CO_2 cost per ton (Confidential Appendix E)

Renewable Energy Credit Opportunity Cost

The opportunity cost of the Renewable Energy Credit (REC) that was not generated as a result of the curtailment is applied to all curtailed wind. This assumes the REC has value either for compliance or for sale into the market. The forecast REC price is comprised of broker quotes for prices through 2016 and prices thereafter escalated by the inflation rate. (Confidential Appendix E).

Confidential Appendix B – Colorado Green (Southern Colorado) WWRD Modeled vs. Observed Data

Figure 11: Observed Capacity Factor Distribution vs. WWRD (2004 – 2006)

REDACTED

Figure 12: Diurnal Observed Capacity Factor vs. WWRD (2004 – 2006)

REDACTED

Confidential Appendix C – Spring Canyon (Northern Colorado) WWRD Modeled vs. Observed Data

Figure 13: Observed Capacity Factor Distribution vs. WWRD (2006)

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Figure 14: Diurnal Observed Capacity Factor vs. WWRD (2006)

REDACTED

Appendix D – Data Tables

Table 6: Annual PTC Forecast (Nominal $)

Year	Assumed Rate (¢/kWh)	Grossed up for Taxes @ 38% ($/MWh)
2011	2.2	35.49
2012	2.3	37.10
2013	2.3	37.10
2014	2.4	38.72
2015	2.4	38.72
2016	2.5	40.33
2017	2.6	41.94
2018	2.6	41.94
2019	2.7	43.56
2020	2.8	45.17
2021	2.8	45.17
2022	2.9	46.78
2023	3.0	48.39
2024	3.0	48.39
2025	3.1	50.01

Table 7: Annual Results – 2GW Curtail Scenario (Nominal $000)

Year	Curtailed Energy (MWh)	Wind Induced Cycling Cost	Wind Induced Curtailment Costs				Total Wind Induced Cost
			PTC Gross Up	Replace-ment Energy	CO_2	REC	
2011	36,000	$5,438	$445	$706	$0	$324	$6,913
2012	87,700	$6,751	$704	$1,770	$0	$1,052	$10,277
2013	78,800	$6,765	$383	$1,651	$0	$1,281	$10,079
2014	57,800	$6,247	$12	$1,214	$0	$990	$8,462
2015	26,600	$4,293	$0	$555	$0	$472	$5,320
2016	19,350	$4,362	$0	$413	$0	$343	$5,119
2017	11,000	$3,517	$0	$240	$0	$199	$3,956
2018	6,150	$1,566	$0	$110	$137	$114	$1,927
2019	2,600	$1,325	$0	$48	$62	$49	$1,484
2020	4,200	$1,298	$0	$77	$107	$81	$1,562
2021	100	$798	$0	$2	$3	$2	$805
2022	850	$910	$0	$16	$25	$17	$968
2023	200	$633	$0	$4	$6	$4	$646
2024	1,100	$705	$0	$20	$37	$23	$784
2025	0	$527	$0	$0	$0	$0	$527

Table 8: Annual Results – 3GW Curtail Scenario (Nominal $000)

Year	Curtailed Energy (MWh)	Wind Induced Cycling Cost	Wind Induced Curtailment Costs				Total Wind Induced Cost
			PTC Gross Up	Replace-ment Energy	CO_2	REC	
2011	36,000	$5,438	$445	$706	$0	$324	$6,913
2012	87,700	$6,751	$704	$1,770	$0	$1,052	$10,277
2013	78,800	$6,765	$383	$1,651	$0	$1,281	$10,079
2014	57,800	$6,247	$12	$1,214	$0	$990	$8,462
2015	26,600	$4,293	$0	$555	$0	$472	$5,320
2016	46,300	$5,167	$0	$988	$0	$822	$6,977
2017	55,600	$5,371	$0	$1,211	$0	$1,007	$7,589
2018	64,050	$3,721	$0	$1,150	$1,428	$1,183	$7,482
2019	82,050	$4,075	$0	$1,499	$1,957	$1,546	$9,077
2020	130,900	$4,802	$0	$2,393	$3,341	$2,515	$13,052
2021	75,050	$4,137	$0	$1,398	$2,050	$1,471	$9,056
2022	87,200	$4,566	$0	$1,633	$2,548	$1,743	$10,491
2023	54,100	$3,716	$0	$955	$1,692	$1,103	$7,466
2024	67,200	$3,874	$0	$1,201	$2,248	$1,398	$8,721
2025	47,000	$3,480	$0	$825	$1,683	$997	$6,984

Table 9: Annual Results – 2GW Deep Cycle Scenario (Nominal $000)

Year	Curtailed Energy (MWh)	Wind Induced Cycling Cost	Wind Induced Curtailment Costs				Total Wind Induced Cost
			PTC Gross Up	Replace-ment Energy	CO_2	REC	
2011	3,444	$6,958	$17	$68	$0	$31	$7,073
2012	7,346	$11,129	$21	$148	$0	$88	$11,387
2013	9,107	$10,894	$0	$191	$0	$148	$11,233
2014	3,820	$9,162	$0	$80	$0	$65	$9,308
2015	516	$6,191	$0	$11	$0	$9	$6,211
2016	139	$5,514	$0	$3	$0	$2	$5,520
2017	227	$4,175	$0	$5	$0	$4	$4,184
2018	910	$1,676	$0	$16	$20	$17	$1,729
2019	0	$1,422	$0	$0	$0	$0	$1,422
2020	306	$1,379	$0	$6	$8	$6	$1,398
2021	0	$798	$0	$0	$0	$0	$798
2022	0	$1,001	$0	$0	$0	$0	$1,001
2023	0	$679	$0	$0	$0	$0	$679
2024	0	$708	$0	$0	$0	$0	$708
2025	0	$527	$0	$0	$0	$0	$527

Table 10: Annual Results – 3GW Deep Cycle Scenario (Nominal $000)

Year	Curtailed Energy (MWh)	Wind Induced Cycling Cost	Wind Induced Curtailment Costs				Total Wind Induced Cost
			PTC Gross Up	Replace-ment Energy	CO_2	REC	
2011	3,444	$6,958	$17	$68	$0	$31	$7,073
2012	7,346	$11,129	$21	$148	$0	$88	$11,387
2013	9,107	$10,894	$0	$191	$0	$148	$11,233
2014	3,820	$9,162	$0	$80	$0	$65	$9,308
2015	516	$6,191	$0	$11	$0	$9	$6,211
2016	1,926	$7,679	$0	$41	$0	$34	$7,754
2017	3,895	$8,406	$0	$85	$0	$71	$8,562
2018	15,829	$6,379	$0	$284	$353	$292	$7,308
2019	20,421	$7,524	$0	$373	$487	$385	$8,769
2020	41,803	$10,217	$0	$764	$1,067	$803	$12,852
2021	16,104	$8,009	$0	$300	$440	$316	$9,064
2022	20,930	$9,111	$0	$392	$612	$418	$10,533
2023	10,876	$6,855	$0	$192	$340	$222	$7,609
2024	19,607	$7,105	$0	$350	$656	$408	$8,520
2025	10,020	$6,225	$0	$176	$359	$213	$6,973

Appendix E – Confidential Tables and Figures

Figure 15: CONFIDENTIAL APTECH Cost per Cycle Study Results

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Table 11: CONFIDENTIAL - REC & CO_2 Price Assumptions, Coal Dispatch Cost (Nominal $)

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Table 12: CONFIDENTIAL – Unit Operating Ranges and CO_2 Emission Rates

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Table 13: CONFIDENTIAL – Forecast Wind Induced Coal Unit Cycles (2GW Curtail)

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Table 14: CONFIDENTIAL – Forecast Wind Induced Coal Unit Cycles (3GW Curtail)

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Table 15: CONFIDENTIAL – Forecast Wind Induced Coal Unit Cycles (2GW Deep)

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Table 16: CONFIDENTIAL – Forecast Wind Induced Coal Unit Cycles (3GW Deep)

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