Short-term Operational Impacts of Wind Generation on the Puget Sound Energy Power System

Phase 2 Studies

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Section 1 - Executive Summary

1.1 The PSE Wind Phase 2 Project Scope

While the body of literature surrounding wind generation development is fairly voluminous, it has only been in the last couple of years that coordinated attempts have been made to identify and quantify the short-term operational impacts of large-scale wind farms on utility power systems. As part of PSE's overall effort in evaluating wind resources, Golden Energy Services (Golden) was asked in mid-2003 to assist PSE personnel in the evaluation of the short-term operating impacts of wind generation on the PSE power system.

A report titled Short-term Operational Impacts of Wind Generation on the Puget Sound Energy Power System (also known as the Phase 1 Report) was presented to PSE on August 22, 2003. This report provided an evaluation of the short-term operational characteristics of wind generation specifically for the PSE power system. In December 2003, PSE proposed that Golden perform additional wind generation related analysis work in order to: 1) expand upon the results of the previously completed Phase 1 studies, and 2) to develop information that would assist PSE in evaluating wind resource bids. The additional wind generation analysis to be performed by Golden and selected PSE staff were termed the PSE Wind Phase 2 studies.

This Phase 2 Report provides a description of the analysis work performed by Golden and PSE subsequent to the completion of the Phase 1 Project. Specifically, Golden analyzed the following four operational impacts categories in the Phase 2 studies: 1) PSE Regulation impacts, 2) PSE Operating Reserve impacts, 3) PSE Hour-Ahead impacts, and 4) PSE Day-Ahead impacts. Since portions of the Phase 2 Project Scope build upon work completed during the Phase 1 studies, important conclusions from the Phase 1 studies are also at times referenced in the Phase 2 report.

For the purpose of evaluating short-term operating impacts of wind generation on the PSE power system, Golden and PSE utilized actual wind generation data from an operating wind project located in the Columbia River Basin. Golden and PSE also utilized simulated wind generation data that was developed in the Phase 1 studies for a wind project located near Ellensburg, Washington.

1.2 Summary Description of the Phase 2 Report

Sections 2 and 3 contain a description of the Phase 2 Project Scope, along with Golden's general approach to the Project. These sections also provide a description of how the Phase 2 analysis expands upon the work previously conducted under Phase 1.

Section 4 presents summary information regarding the observed wind generation data that was developed for the Phase 2 Study. This section is intended to provide a high level review of the operating characteristics of an operating Northwest wind project.

Section 5 provides details on the construction of three separate data sets for an operating Northwest wind farm. This data was subsequently used to develop Hour-Ahead and Day-Ahead wind forecast error probability tables.

The impacts of wind generation on PSE system regulation requirements are presented in Section 6. Section 7 quantifies the impacts of wind generation on PSE's operating reserve requirements.

Section 8 contains an overview and brief summary of three separate modeling methodologies that were evaluated in order to determine the Hour-Ahead and Day-Ahead wind integration impacts for the PSE system. Each of these three models in discussed separately in Sections 9-10.

Section 9 describes the Standard Options modeling approach. Section 9 provides details on the Mid-C Flex Model while Section 10 discusses the Virtual Storage Model.

Section 11 provides an in depth analysis of Hour-Ahead cost impacts associated with wind generation on the PSE system while Section 12 provides a similar evaluation for Day-Ahead cost impacts.

Section 13 provides an overall summary of all four short-term cost impact categories for wind farm capacities ranging in size from 25 MW to 450 MW. The PSE Phase 2 results are also compared to the Phase 1 results, and also against five other similar studies performed for other utility systems. Overall conclusions for the Phase 2 studies are presented in Section 14.

1.3 Summary of PSE Short-term Wind Generation Integration Costs

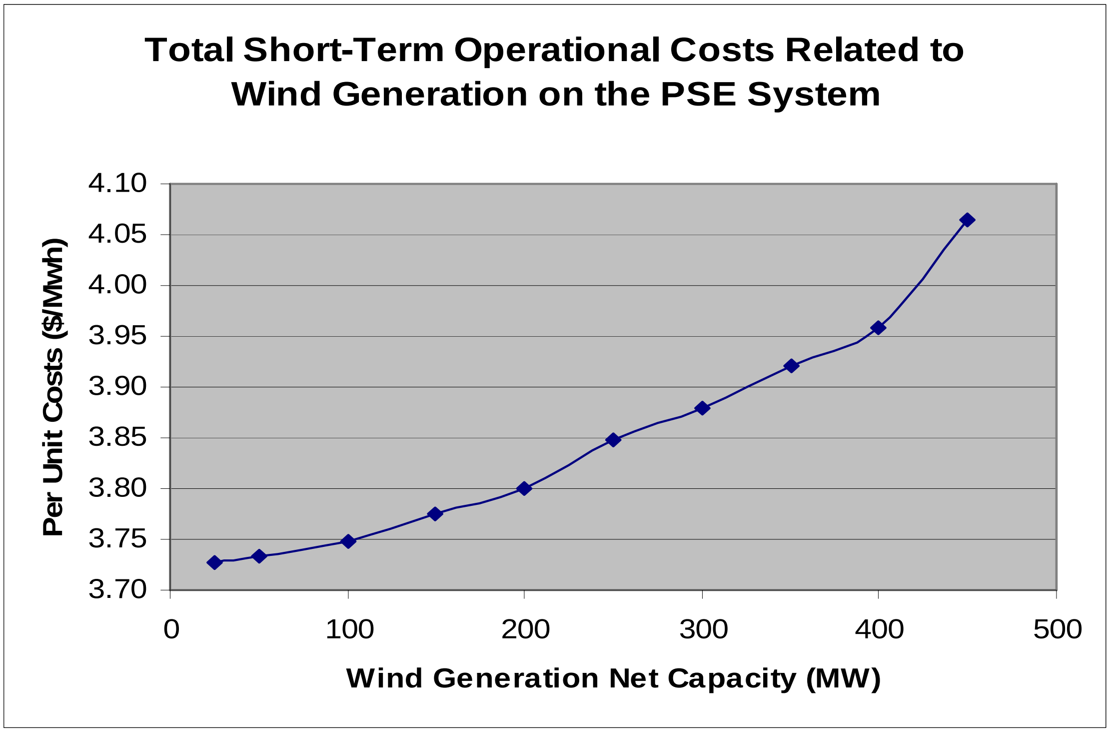
The table shown below presents the impacts on the PSE power system of the four identified short-term wind impacts categories:

Table 1.3 - Summary of Short-Term Operational Impacts due to the Addition of Varying Amounts of Wind Generation on the PSE System

Wind Generation Net Capacity (MW)	Regulation ($/Mwh)	Operating Reserves ($/Mwh)	Hour-Ahead Costs ($/Mwh)	Day-Ahead Costs ($/Mwh)	Total Costs ($/Mwh)
25	0.16	0.00	2.72	0.84	3.73
50	0.16	0.00	2.73	0.84	3.73
100	0.16	0.00	2.75	0.84	3.75
150	0.16	0.00	2.78	0.84	3.77
200	0.16	0.00	2.81	0.83	3.80
250	0.16	0.00	2.85	0.84	3.85
300	0.16	0.00	2.89	0.83	3.88
350	0.16	0.00	2.93	0.83	3.92
400	0.16	0.00	2.97	0.82	3.96
450	0.16	0.00	3.01	0.89	4.06

Chart 1.3 shows the trend in per unit total operational costs as a function of wind generation net capacity on the PSE system:

Chart 1.3



As can be seen from Table 1.3 and Chart 1.3, the addition of 150 MW of net wind capacity to the PSE system would be expected to result in additional short-term operational costs of approximately $3.77/Mwh on an annual average basis. This cost rises to $4.06/Mwh for 450 MW net capacity of wind generation.

1.4 Sensitivity of Results

In addition to the scaling studies performed to analyze the impacts of varying wind generation amounts, Golden also performed a cost sensitivity study for the 150 MW wind capacity case. Table 1.4 below presents the results of this sensitivity study; figures shown in bold type indicate the recommended baseline results previously reported in Table 1.3.

Table 1.4
Cost Sensitivity Results for 150 MW Net Capacity Wind Generation

Impacts Category	Low Side of Cost Range ($/Mwh)	Recommended Cost ($/Mwh)	High Side of Cost Range ($/Mwh)
Regulation	0.01	**0.16**	0.19
Operating Reserves	0.00	**0.00**	0.00
Hour-Ahead	0.98	**2.78**	3.25
Day-Ahead	0.75	**0.84**	1.96
Total	1.74	**3.77**	5.40

1.5 Summary Comparison of Phase 2 versus Phase 1 Results

Table 1.5 below presents a summarized cost comparison of the four short-term wind related impacts categories that were analyzed in both the PSE Phase 1 and Phase 2 studies, referenced to a common wind generation amount of 136.4 MW net capacity:

Table 1.5
Comparison of Phase 1 and Phase 2 Study Results – 136.4 MW Net Wind Capacity

Impacts Category	PSE Phase 1 Study Results ($/Mwh)	PSE Phase 2 Study Results ($/Mwh)
Regulation	0.16	0.16
Operating Reserves	0.00	0.00
Hour-Ahead	1.54	2.77
Day-Ahead	2.24	0.84
Total	3.94	3.77

1.6 The PSE Phase 2 Costs versus Other Reported Results

In November, 2003, UWIG released a technical paper entitled Wind Power Impacts on Electric-Power-System Operating Costs – Summary and Perspective on Work Done to Date. This paper summarized the results of six studies conducted by other entities that focused on quantifying the short-term operational impacts of integrating wind generation into large utility systems. All of the six studies except one (the so called Hirst study) evaluated Regulation, Hour-Ahead ("load following") and Day-Ahead ("unit commitment") impacts. While these impact categories match up fairly well with the impacts analyzed in the PSE Phase 2 studies, it should be noted that the results of the five UWIG reported studies (excluding Hirst) may not be directly comparable to each other or the PSE Phase 2 results since all of the studies used differing wind penetration levels.

A comparison of the five UWIG reported studies (excluding Hirst) and the PSE Phase 2 study does, however, provide some useful information as to the probable *range* of short-term wind integration costs. Table 1.6 below shows such a summary:

Table 1.6 - Short-Term Operational Costs of Wind Generation
On Large Utility Power Systems

Study	Wind Penetration Level (Percent of Peak Load)	Total Short-Term Operational Costs ($/Mwh)
PSE Phase 2 (150 MW Case)	**3.3**	**3.77**
UWIG/XCEL	3.5	1.85
Pacificorp	20.0	5.50
BPA	7.0	1.47-2.27
We Energies I	4.0	1.90
We Energies II	29.0	2.92

Section 2 - The PSE Wind Phase 2 Project Scope and Purpose

2.1 Introduction

On November 13, 2003, Puget Sound Energy (PSE) issued an RFP for the potential acquisition of wind-based resources. Among the alternatives under consideration by PSE is the purchase of "green" wholesale power from other utilities/marketers, or the purchase of wind generation directly from a wind farm developer. In the first case, ancillary services related to wind generation (including but not limited to regulation, operating reserves and generation following/balancing) would likely be included in the wholesale product purchased by PSE. However, if PSE elects to purchase wind generation directly from a site located within or connected to its load control area, PSE would be responsible for providing, and absorbing the cost of, these ancillary services.

In order for PSE to evaluate the relative economics of purchasing wholesale wind energy from other utilities (where many if not all of the ancillary services would be included in the purchase price) versus interconnecting a wind farm to its own control area (where PSE would self-provide ancillaries or purchase the ancillaries separately from the raw wind power output), PSE needs to determine both the magnitude and cost of ancillary services associated with wind generation.

2.2 Recap of the Wind Phase 1 Project Scope and Results

In mid-2003, Golden Energy Services (Golden) was asked to assist PSE personnel in the evaluation of the short-term operating impacts of wind generation on the PSE power system. Golden was not asked to review specific wind generation proposals but rather was directed by PSE to help generally define and quantify the operational impacts of wind generation for the PSE power portfolio.

A decision potentially facing PSE is whether PSE would prefer to have purchased wind generation integrated directly into its own control area, or whether it would be more desirable (from either an operational or economic perspective) to have the generation integrated into another control area. A major goal of the Phase 1 studies was to develop data and information that would assist PSE in evaluating the overall merits of each of these cases.

Golden presented the Wind Phase 1 findings to PSE on August 22, 2003 in a report titled <u>Short-Term Operational Impacts of Wind Generation on the Puget Sound Energy Power System (herein referred to as the Phase 1 Report)</u>. This report contained a quantitative analysis of wind generation for four separate short-term operational impact categories: 1) Regulation, 2) Operating Reserves, 3) Intra-Hour (i.e. Hour-Ahead) balancing, and 4) Day-Ahead balancing.

The analysis of Intra-Hour and Day-Ahead impacts relied primarily on the wind generation output of a simulated 154.5 MW gross capacity (136.4 MW net capacity) wind farm located in the area of Ellensburg, Washington. The simulated wind generation series was based upon a potential future wind farm consisting of 103, 1.5 MW GE Model 1.5sl wind turbines with a total gross installed capacity of 154.5 MW. This figure represented an approximate 3.3% wind penetration rate based on a PSE winter peak load of 4500 MW.

The Phase 1 Report computed $/Mwh impacts for each of the four defined impact categories, based on the interconnection of a 136.4 MW (net capacity) wind farm to the PSE control area. A summary of the cost impacts derived in the Phase 1 studies is provided below:

Table 2.2
Summary of Wind Generation Related Short-Term Operational Impacts On the PSE Power System - Phase 1 Study Results

Short-Term Impacts Category	Annual Average Cost ($/Mwh)
Regulation	0.16
Operating Reserves	0.00
Intra-Hourly (Hour-Ahead)	1.54
Day-Ahead	2.24
Total Short-Term Impacts	3.94

2.3 <u>The PSE Wind Phase 2 Project Scope</u>

Upon the completion of the Wind Phase 1 studies in August 2003, both PSE and Golden recognized that further research in some targeted areas would be beneficial in providing additional useful information regarding short-term wind resource integration costs and effects.

In December 2003, PSE asked Golden to perform additional wind generation studies to refine and expand upon the work that was completed as part of the Phase 1 studies. In Particular, Golden was directed by PSE to perform the following tasks as part of the Phase 2 Project scope:

> <u>Refine Operational Cost Estimates for Hour-Ahead and Day-Ahead Impacts</u>
> Considerable effort was directed in the Phase 1 studies towards identifying and quantifying the short-term generation balancing requirements of wind generation, both on an Hour-Ahead and Day-Ahead basis. Two areas that were specifically identified by PSE and Golden for further study included the following:
>
> > <u>Refinement of a Short-term Dispatch Model for the PSE system</u>
> > The Phase 1 studies utilized a simplified PSE operations model approach to value wind generation variations. PSE and Golden felt that the development of a more sophisticated model might be beneficial in

providing improved operational cost estimates regarding wind generation variations.

Development of Options-Based Valuation Techniques
The Phase 1 studies utilized a simplified off-peak/on-peak wholesale price differential approach in valuing Hour-Ahead and Day-Ahead operational costs associated with wind generation variability. A key goal of the Phase 2 studies was to consider the applicability of option valuation techniques in evaluating the costs of short-term wind generation variations.

Develop Factors to Allow for Easy Comparison of Different Wind Products
Pursuant to the schedule released as part of PSE's November 2003 Wind RFP, PSE expected that it would receive offers for wind generation products in January, 2004. It was also believed that prospective bidders would likely offer differently tailored wind products. A goal of the Phase 2 Project was therefore to develop and present the study results in a fashion that would enable PSE personnel to evaluate different wind RFP bids using a standardized set of cost adjustment factors.

Incorporate Newly Available Wind Generation Data
At the time the Phase 1 studies were being completed, PSE had very little actual wind generation data available that was suitable for conducting short-term operational studies. PSE had begun purchasing a wind generation product in April 2003, however only approximately two months of actual wind generation data were available at the time the Phase 1 studies were being completed. For the Phase 2 studies, a primary goal was to incorporate detailed real-time wind generation data that was just becoming available to PSE, and to use this information to augment the simulated wind generation data series developed as part of Phase 1.

Perform Wind Farm Capacity Scaling Studies
The Phase 1 studies assumed a static wind farm size of 154.5 MW gross capacity (136.5 MW net capacity after losses). A stated goal of the Phase 2 studies was therefore to investigate scaling impacts; how the per unit short-term operational costs for the PSE system might vary according to installed wind generation capacity.

Utilize Dynamic Wind Forecasting Techniques
The Phase 1 studies computed wind generation forecast error (for both the Hour-Ahead and Day-Ahead time frames) over an 11 ½ month period. In valuing forecast error, the average Hour-Ahead and Day-Ahead errors over the entire 11 ½ month period were utilized. It was recognized in the Phase 1 studies that a more preferable method of valuing wind generation forecasting error would be to utilize a dynamic "bandwidth" type forecast whereby the Hour-Ahead and Day-Ahead forecasts were based on a set of forecast errors determined for specific wind forecast ranges.

2.4 Short-Term Wind Impacts Categories

The Phase 1 studies identified four separate short-term operational impact categories. At the onset of the Phase 2 studies, Golden first evaluated the appropriateness of these same four impact categories and whether any modifications and/or additions were warranted. Golden concluded that these same four impact categories, as further described below, were still appropriate for use in the Phase 2 studies:

Regulating Reserves (Regulation)
The impacts of very short-term (i.e. seconds to minutes) variations in wind generation was assessed for the PSE system. Wind generation variations in this timeframe could cause PSE to carry additional regulating reserves in order to maintain short-term load/resource balance and conform to NERC/WECC reliability criteria.

Operating Reserves in Addition to Regulation
In addition to maintaining adequate regulating reserves, PSE is also required by NERC/WECC performance standards to maintain an additional operating reserve amount. Since it is not possible to "carry" operating reserves related to on-line wind generation capacity on the wind units themselves (since wind generation is non-dispatchable), the impacts of carrying wind related operating reserves on other PSE resources was examined.

Hour-Ahead Wind Generation Variability
Since the standard Northwest scheduling increment is one clock hour in length, forecasted wind generation will be prescheduled at a flat MW level for an entire hour. Wind generation, however, is variable within the schedule hour; therefore there is a need for other resources to provide intra-hourly "generation following" in order to offset the changes in wind generation.

Preschedule (i.e. Day-Ahead) Wind Generation Variability
This time period stretches from the end of the Hour-Ahead period through the end of the preschedule period, which in most cases (except for weekends and holidays) is through hour ending 2400 on the following day. Impacts associated with potential variations of wind generation output versus the original prescheduled hourly amounts was analyzed and quantified.

The results of the Phase 1 studies (as was previously summarized in Table 2.2) determined that the short-term wind related operational costs for the Regulation and Operating Reserve impacts categories were very small in relation to the Hour-Ahead and Day-Ahead costs. Golden determined that the per unit costs derived in the Phase 1 studies remained valid and no further study work was required in these areas as part of the Phase 2 Project Scope. However, for the sake of completeness, a brief discussion of Regulation and Operating Reserve impacts based upon the Phase 1 study work are included in this report as well.

Section 3 - Golden's Approach to the PSE Phase 2 Project

3.1 Golden's General Approach

While the body of literature surrounding wind generation development is fairly voluminous, it has only been in the last couple of years that coordinated attempts have been made to identify and quantify the short-term operational impacts of large-scale wind farms on utility power systems. Recently, the members of the Utility Wind Interest Group (UWIG) identified that their highest priority concern was a better understanding of wind generation's short-term operational impacts. The result of the UWIG initiative, as well as other research sponsored by organizations such as the National Renewable Energy Laboratory (NREL), has been a number of studies initiated in the last 2-3 years aimed specifically at providing more information on the short-term impacts of large wind farm development.

Golden's approach in quantifying short-term operating impacts for the PSE system involved implementing the following two-step approach:

1) Determine the MW magnitude and potential range of predefined wind related short-term operating characteristic for the PSE power system, given the unique attributes of PSE's system, and
2) Determine probable economic values or costs associated with the MW values determined in No. 1 above.

Golden also desired to avoid "re-inventing the wheel" but rather rely, in part, on existing data and/or research in determining the approximate short-term operating impacts on the PSE power system. In some areas, most notably the analysis of Regulation impacts, research and data from other recent studies provided useful conclusions that would be expected to be reasonably valid for PSE's system. In other areas, however, the existing body of research did not adequately address issues that are relevant to PSE's specific situation including: 1) the impacts of hydro generation, 2) Northwest site specific wind characteristics, and 3) the consideration of lost option value.

Golden also utilized the body of work performed in the Phase 1 studies to help "target" the additional Phase 2 efforts into the specific areas that were expected to provide the most useful new information, such as incorporating dynamic wind generation forecasting techniques. Conversely, the Phase 1 studies concluded that Regulation and Operating Reserve costs associated with wind generation were relatively low; therefore the Phase 2 studies did not focus on these impact categories but rather adopted the results of the Phase 1 report (with some minor updates).

Finally, Golden has taken care to set up the Phase 2 studies from the perspective of how PSE's System Operators and Power Traders would actually make short-term operating decisions in real life. This includes grounding the studies on the same timeframes that System Operators and Traders have to deal in when making operational decisions and also not assuming any “perfect foresight” regarding Hour-Ahead or Day-Ahead wind generation forecasts.

3.2 PSE Power Portfolio Assumptions

The operational cost impacts of wind generation on a particular utility’s power portfolio are very sensitive to the amount of installed wind capacity relative to the amount of flexible resources available to the utility to manage wind generation variability. In particular for PSE, the amount of available Mid-Columbia hydro (Mid-C) generation flexibility relative to total installed wind generation is a key cost determinate. Wind farm sizes ranging from 25 MW up to 450 MW were then evaluated and operational costs computed that incorporated PSE’s current maximum Mid-C capacity figure.

It is recognized that PSE’s power portfolio will likely undergo changes in the years to come as PSE embarks on a program to: 1) meet expected future retail load growth via new dedicated firm resources, and 2) replace long-term power purchase agreements that have recently terminated. Also, the amount of PSE’s future Mid-C capacity may change from present levels as the current long-term Mid-C purchase agreement come up for renewal. The results of the Phase 2 studies are referenced to PSE’s current amount of contracted Mid-C capacity; to the extent that PSE’s has less Mid-C capacity in the future, it would generally be expected that the per unit operational costs associated with wind generation would be somewhat higher than what is presented herein.

3.3 Potential Impacts of RTO Implementation

As noted in Section 3.2 above, Golden has primarily studied the PSE power portfolio as it is currently situated including the incorporation of general industry scheduling/operating conventions that are presently in place. It is possible, however, that the electric industry in the Northwest may be restructured in the future to include a Regional Transmission Organization (RTO). Under such a restructuring, the manner in which PSE would operate its power portfolio could change, as could even PSE’s status as a control area operator.

Due to the current uncertainty surrounding the formation of a Northwest RTO (to be known as Grid West), Golden has not attempted to analyze the short-term operational impacts of integrating wind generation under a Grid West operated Northwest grid.

3.4 Study Assumptions and Base Data

It was the general intent of Golden and PSE personnel to utilize the datasets assembled for the Phase 1 Project as much as possible for the Phase 2 Project. It was also recognized, however, that some new real-time Northwest wind generation data had become available following the completion of the Phase 1 studies. It was therefore Golden and PSE’s intent to utilize the Phase 1 datasets and report conclusions where applicable, but also to augment and expand upon the Phase 1 data where updated information was available.

A prerequisite to evaluating the short-term operational and economic impacts of wind generation on the PSE power system is the availability of a very short time increment wind generation data series. In particular, the evaluation in Hour-Ahead wind effects requires a wind generation time series that is on a time increment of one hour or less in duration.

Since PSE currently does not have any wind generation interconnected to its control area, the Phase 1 studies relied heavily upon a set of wind generation time series that were synthesized from Ellensburg area wind speed data. Golden constructed an 11 ½ month continuous wind generation dataset from 10-minute increment wind speed data measured at six different locations near Ellensburg. The resulting 10-minute increment wind generation time series was then utilized to compute Hour-Ahead and Day-Ahead wind variability for a representative 136.4 MW net capacity Northwest regional wind farm. Additional information regarding the Ellensburg area wind speed data and the mechanisms used to create the 10-minute increment wind generation time series are detailed in Section 6 of the Phase 1 Report.

On April 1, 2003, PSE began taking delivery of a 25 MW (net peak capacity) wind generation product from an operating wind farm located in the Columbia River Basin (hereafter referred to as the CRB Project). This wind product was designated as an "hour-ahead" firm product, meaning that the seller would establish a delivery schedule for the next preschedule hour and that the seller (not PSE) would absorb any variation in actual wind generation that occurred during that same hour.

The seller also provided PSE with a non-binding Day-Ahead wind generation estimate, as well as after-the-fact actual wind generation quantities on a 10-minute increment basis. PSE would therefore have available from the CRB Project wind generation amounts on three different time frames: 1) real-time (i.e. 10-minute increment), 2) Hour-Ahead schedules, and 3) Day-Ahead schedules.

The Phase 2 wind studies relied primarily on the above referenced CRB Project wind generation data for the purpose of evaluating probable wind forecast variations. However, since this data was only available for an eight month period (April–November 2003) at the time the Phase 2 studies were being performed, the previously assembled 10-minute increment Ellensburg based wind generation dataset was also utilized such that a full 12-month wind generation dataset could be analyzed.

PSE specific Regulation impacts were primarily developed based on the reported results from other operating wind farms and relevant technical papers published by "independent" third party sources such as NREL. Also, as is more fully described in Section 6, Regulation impacts are not very significant, so an in depth technical analysis specifically for the PSE system would probably not be warranted especially given the lack of "hard" data.

Section 4 – Columbia River Basin Project Wind Generation Summary

4.1 Overview and Summary of the CRB Project Wind Data

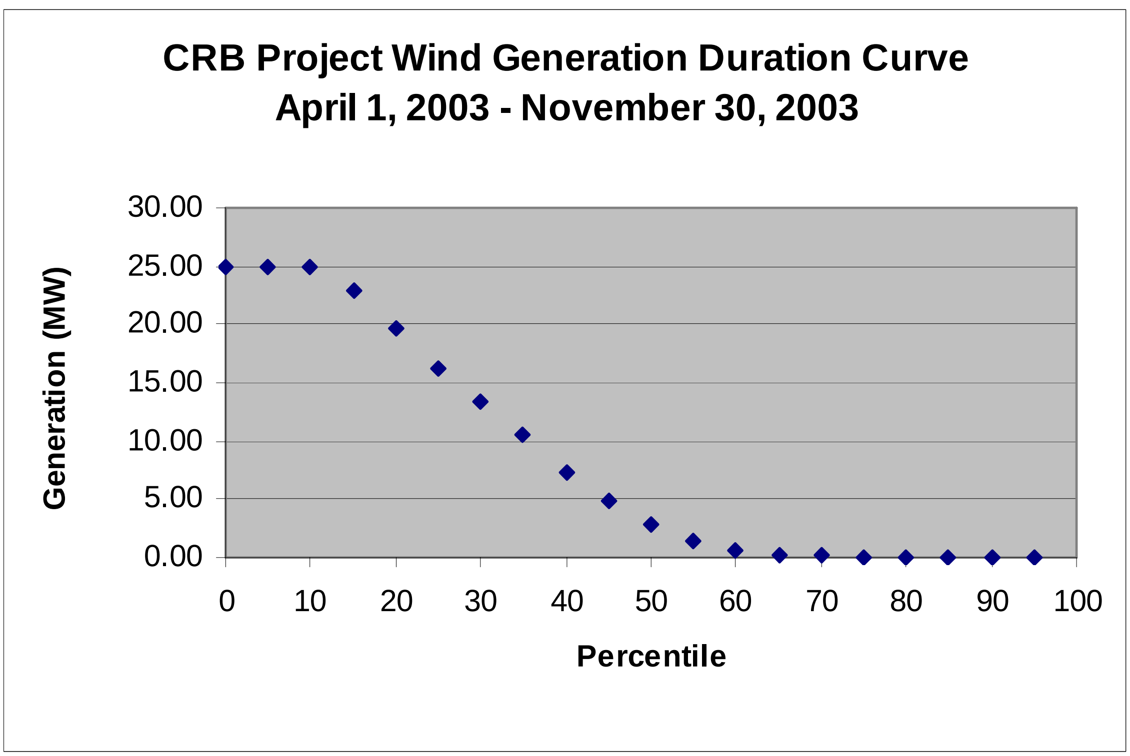
Following the methodologies more fully described in Section 5, Golden assembled a wind generation time series based on 10-minute increment actual generation readings for the period April 1, 2003 – November 30, 2003 from the CRB Project. This generation dataset is referenced to a 25 MW pro-rated portion of the CRB Project's overall capacity. Some useful general observations and statistics on this wind generation dataset are presented in Table 4.1 below:

Table 4.1
CRB Project Wind Farm Generation Summary (25 MW Prorated Share)

	April 1, 2003 - November 30, 2003
Net Capacity (MW)	25.00
Average Actual Wind Generation (25 MW Share, aMW)	8.13
Average Capacity Factor (Percent)	32.5%

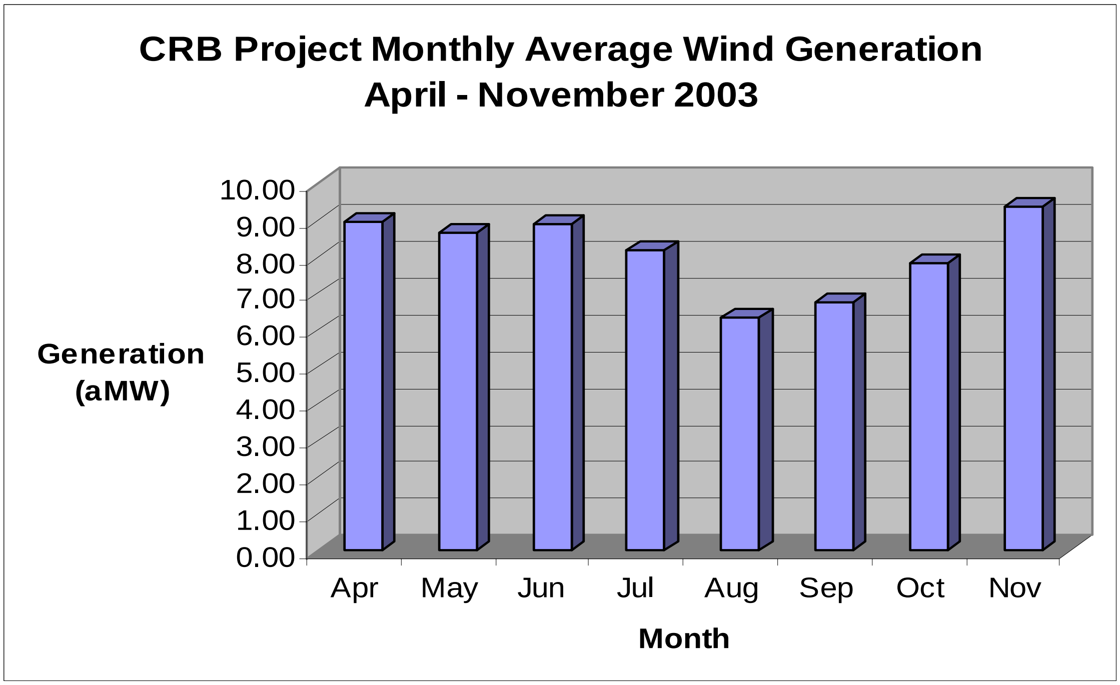
Figure 4.1a below shows a wind generation duration graph for the CRB Project, based on eight months of actual 10-minute increment generation data:

Figure 4.1a



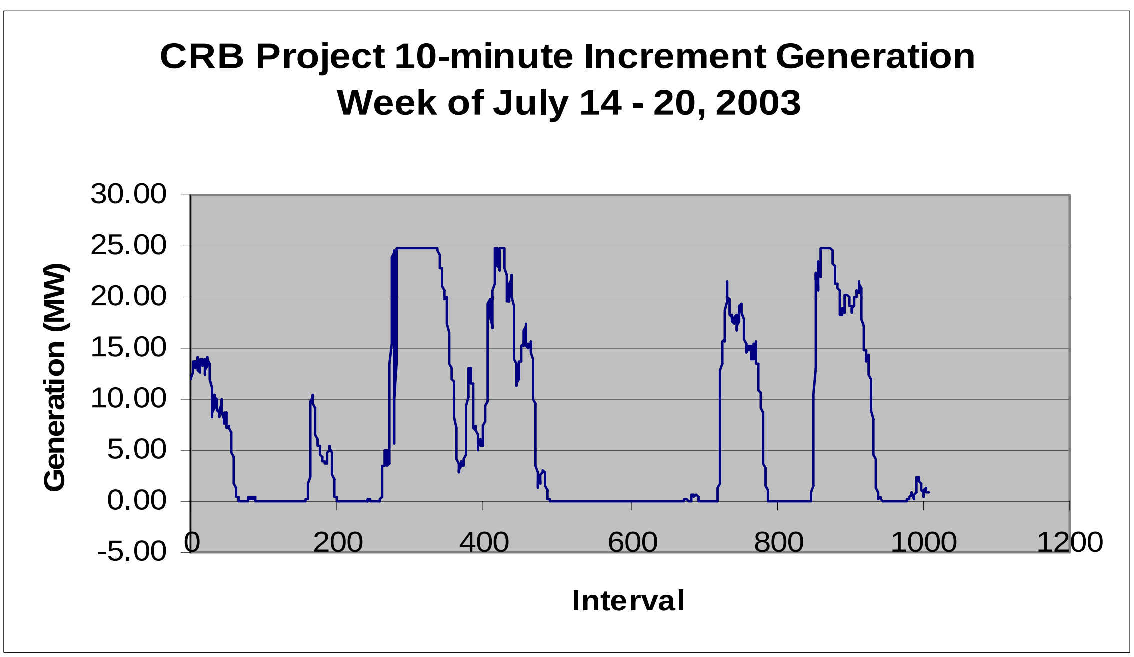
The 10-minute increment generation amounts were also averaged to produce monthly generation amounts, as is shown in Figure 4.1b below:

Figure 4.1b



Finally, Figure 4.1c below illustrates the potential short-term variations in generation at the CRB Project site for a typical one-week period:

Figure 4.1c



Section 5 - Development of the Columbia River Basin Project Wind Generation/Wind Forecast Data

5.1 Wind Generation Data Utilized in the Phase 1 Studies

As has been previously stated, one impediment to performing wind generation studies on the PSE power system is the lack of historical wind generation data. In order to perform wind integration studies specifically referenced to the PSE power system, the Phase 1 studies relied upon an 11 ½ month simulated record of 10-minute increment wind generation amounts. Complete details regarding the derivation of the Ellensburg simulated wind generation data series is outlined in Section 6 of the Phase 1 report.

One drawback of the simulated Ellensburg wind generation data is that there were no historical wind generation forecasts available for inspection. The Phase 1 studies therefore relied upon standard persistence forecasting techniques to develop a series of simulated Hour-Ahead wind generation forecasts. A similar technique was employed to produce simulated Day-Ahead wind generation forecasts with the addition of an assumed forecast error reduction factor.

5.2 Use of the CRB Project Wind Generation Data

One of the stated goals of the Phase 2 studies was to augment the use of the simulated Ellensburg area data with actual "real-life" wind generation data. Specifically, PSE began receiving wind generation data from the CRB Project beginning in April, 2003. Golden therefore decided to utilize this wind generation dataset for the Phase 2 studies to the extent practical, and to use the previously derived Ellensburg wind generation data to fill in any gaps (such as the four winter months where the CRB Project data was not yet available).

Pursuant to PSE's wind generation purchase agreement, PSE had the following wind generation data available, referenced to a 25 MW maximum capacity figure:

1) After-the-fact 10-minute increment actual generation amounts
2) A firm wind generation schedule for the upcoming schedule hour
3) An estimated Day-Ahead wind generation schedule for each hour of the next day

Using the above referenced data, PSE could compute actual Hour-Ahead and Day-Ahead wind forecast errors based upon an operating Northwest wind farm, rather than relying upon simulated persistence based forecasts as was done in the Phase 1 studies.

5.3 Development of the CRB Project Wind Generation Datasets

Pursuant to the terms of PSE's wind purchase agreement, the following CRB Project wind generation data was available to PSE:

Actual 10-Minute Increment Data

At the time the Phase 2 studies were being set up in December 2003, PSE had 10-minute actual wind generation data available for the period April – November 2003. In some cases, the raw 10-minute data files supplied by the seller contained missing intervals and/or spurious data values. Golden examined all of the actual generation data and where necessary, filled in missing intervals and replaced erroneous data points utilizing linear interpolation techniques.

Hour-Ahead Firm Wind Generation Schedules

The seller communicated to PSE the amount of wind generation that it was going to deliver to PSE during the next hour at least 35 minutes prior to the start of that hour. Once the Hour-Ahead schedule was communicated to PSE, the seller delivered the agreed upon Hour-Ahead amount regardless of what the actual wind generation was within that hour.

Day-Ahead Wind Generation Estimates

The seller also provided PSE with non-binding, Day-Ahead estimates of hourly wind generation amounts. These estimates were provided to PSE prior to 10:00 AM on the day before delivery.

5.4 Interrelation of the 10-minute, Hour-Ahead and Day-Ahead CRB Project Data

In analyzing the above referenced wind generation data, it was readily apparent that the Day-Ahead estimates and the Hour-Ahead delivery amounts had a consistent low side bias; in all eight months studied, the monthly average of the Day-Ahead and Hour-Ahead forecasts were both much lower than the monthly average of the actual 10-minute increment generation.

The following table summarizes the monthly averages of the CRB Project wind data for the period April 2003–November 2003:

Table 5.4
Comparison of PSE CRB Project Wind Generation Quantities

Month	PSE-CRB Project Actual Wind Generation (aMW)	PSE-CRB Project Hour-Ahead Wind Forecast (aMW)	PSE-CRB Project Day-Ahead Wind Forecast (aMW)
April-03	8.99	7.75	4.04
May-03	8.65	6.74	2.35
June-03	8.91	7.08	3.46
July-03	8.21	5.97	2.25
August-03	6.36	5.18	2.34
September-03	6.76	5.05	2.84
October-03	7.83	5.71	4.52
November-03	9.38	7.17	6.31

5.5 Adjustments to the CRB Project Hour-Ahead and Day-Ahead Data

As can be seen in Table 5.4 above**,** the Hour-Ahead forecasts for the period April 2003–November 2003 averaged 22% lower than the associated actual generation. The Day-Ahead forecasts for the same period averaged 57% less than the associated actual generation. Golden therefore determined that it was prudent to modify the initial Hour-Ahead and Day-Ahead forecasts to remove their inherent low side bias. This was done by employing the following process:

1) For the Day-Ahead forecast, the total monthly wind generation was computed and compared to the total monthly actual wind generation
2) The monthly ratio of actual generation to Day-Ahead forecast generation was computed
3) Each non-zero hourly Day-Ahead forecast was increased by the monthly ratio computed in step No. 3 above
4) Each adjusted hourly Day-Ahead forecast was limited to 25 MW
5) A second iteration of steps No, 1-4 was performed to re-allocate any hourly reductions made due to the application of the 25 MW hourly limit, with the exception that all hours were adjusted upwards.
6) Day-Ahead forecasts were also adjusted as described in steps 1-5 above.

5.6 Development of CRB Project Wind Forecast Error Tables

One of the goals of the Phase 2 studies was to employ a more sophisticated dynamic wind forecasting technique when determining the amount of PSE system flexibility required to manage wind generation variability. Utilizing the adjusted forecast values as determined in Section 5.5, Golden and PSE computed a series of wind forecast error tables assuming confidence intervals ranging from 50% confidence to 99% confidence. Separate forecast error values were computed for potential increases in wind generation (i.e. over-generation) and potential decreases in wind generation (i.e. under-generation).

Table 5.6a shows the forecast error tables for the adjusted CRB Project Hour-Ahead forecasts versus actual CRB Project wind generation:

Table 5.6a
Hour-Ahead Adjusted CRB Project Wind Generation Forecast Errors
April 2003-November 2003

	95% Confidence		75% Confidence		50% Confidence	
Forecast Range (MW)	Under Generation Error (MW)	Over Generation Error (MW)	Under Generation Error (MW)	Over Generation Error (MW)	Under Generation Error (MW)	Over Generation Error (MW)
0.00 - 5.00	1.58	8.69	0.93	5.00	0.48	2.44
5.01 - 10.00	6.76	12.84	4.65	8.45	3.19	5.40
10.01 - 15.00	10.33	10.97	6.97	7.33	4.63	4.80
15.01 - 20.00	13.26	8.27	8.69	5.72	5.52	3.94
20.01 - 25.00	11.82	3.62	6.79	2.48	3.28	1.69

For instance, table 5.6a indicates that when CRB Project wind generation is forecasted for the next hour to be a value X where X is between 0 and 5.00 MW, there is a 95% probability that the actual wind generation average for that hour will be between a minimum of X-1.58 MW (limited by zero) and a maximum X+8.69 MW.

Table 5.6b shows the forecast error tables for the adjusted CRB Project Day-Ahead forecasts versus actual CRB Project wind generation:

Table 5.6b
Day-Ahead Adjusted CRB Project Wind Generation Forecast Errors
April 2003-November 2003

	95% Confidence		75% Confidence		50% Confidence	
Forecast Range (MW)	Under Generation Error (MW)	Over Generation Error (MW)	Under Generation Error (MW)	Over Generation Error (MW)	Under Generation Error (MW)	Over Generation Error (MW)
0.00 - 5.00	3.45	21.29	2.55	14.21	1.93	9.29
5.01 - 10.00	9.09	19.78	6.80	13.91	5.22	9.83
10.01 - 15.00	14.48	14.20	10.51	10.05	7.75	7.17
15.01 - 20.00	18.92	10.00	13.47	7.49	9.68	5.66
20.01 - 25.00	21.08	4.40	13.06	3.03	7.48	2.09

5.7 <u>Development of Full Year Wind Generation/Forecast Data Series</u>

A shortcoming of the CRB Project data is that only eight months of wind generation data and forecasts were available at the time the Phase 2 studies were being completed in December 2003 and January 2004. From the Phase 1 studies, it was known that the wind generation load factor in the Ellensburg area was significantly lower in the winter months than during other times of the year; it therefore was desirable to construct a full 12 month wind dataset such that full annual cost figures could be evaluated.

Golden therefore decided to combine the CRB Project and Ellensburg area data as follows in order to produce one integrated set of wind generation and forecast data:

- The hourly average of the 10-Minute increment simulated Ellensburg actual wind generation amounts were utilized as a proxy for PSE wind generation. This data is referenced to a maximum net generating capacity of 136.4 MW.

- The Hour-Ahead and Day-Ahead wind forecast error tables computed from the adjusted CRB Project data were applied to the hourly Ellensburg wind generation amounts in order to compute the probable range of wind generation for each hour. Since the CRB Project error tables were referenced to a maximum net generating capacity of 25 MW, the individual entries in the error tables were multiplied by the ratio of 136.4/25.0 in order to produce adjusted error tables that were referenced to a maximum net capacity of 136.4 MW.

Section 6 - Regulation Impacts due to Wind Generation on the PSE System

6.1 Summary of Regulation Impacts Determined in the Phase 1 Studies

Regulating reserves are very short time-frame (i.e. several seconds to several minute) reserves that are maintained by control area operators in order to: 1) balance rapidly fluctuating control area loads and resources, 2) maintain scheduled power transfers between different control areas, and 3) maintain system frequency within a narrow bandwidth around 60 hz. The second-to-second and minute-to-minute load fluctuations of end use electric customers are largely uncorrelated and are therefore essentially random in nature.

Section 7 of the Phase 1 report contained a comprehensive analysis of the Regulation impacts associated with wind generation on the PSE control area. Due to the lack of data for Northwest wind farms, the conclusions of the Phase 1 studies relied on several technical papers that reported on the results of detailed Regulation studies conducted with actual operating data from two existing Midwest wind farms (Lake Benton and Storm Lake). The Phase 1 Report concluded that Regulation impacts for the PSE system would be expected to be very small, and that based on the available Ellensburg area wind data, the costs of managing Regulation impacts associated with wind generation on the PSE control area would be approximately $0.16/Mwh. Also, based on the analysis of the Phase 1 report, a 154.5 MW gross capacity wind farm would require only an additional 1.0 MW of regulating margin on the PSE control area system.

6.2 Regulation Impacts in the Phase 2 Studies

Between the time that Golden performed the Phase 1 studies (summer 2003) and was setting up the Phase 2 studies (December 2003), no new data regarding regulation impacts of wind generation on the PSE control area became available. While PSE did receive some operational data from the CRB Project, PSE did not receive any data on a short enough time frame to evaluate Regulation impacts (plus the CRB Project is not interconnected to the PSE control area).

Also, during the approximate six month period between the Phase 1 and the Phase 2 studies, no new technical literature was released that contradicted the previously reported results of wind related Regulation impacts on the Lake Benton and Storm Lake wind farms. These observations, combined with the fact that the Phase 1 studies concluded that Regulation impacts of wind generation was likely very small for the PSE system, lead Golden to conclude that additional detailed work to quantify Regulation impacts was not warranted in the Phase 2 studies. Therefore, the Phase 2 study adopts the results of the Phase 1 study regarding the Regulation impacts of wind generation on the PSE system.

Section 7 - Operating Reserve Impacts due to Wind Generation on the PSE System

7.1 Summary of Operating Reserve Impacts Determined in the Phase 1 Studies

Section 9 of the Phase 1 report contained a detailed analysis of the effects of wind generation on PSE's Operating Reserve requirements. At the time the Phase 1 studies were being completed in the summer of 2003, the Northwest Power Pool (NWPP) had not yet determined the appropriate amount of Operating Reserves to be maintained for wind resources. The Phase 1 studies were therefore based on Golden's opinion that the likely "worse case" scenario was that the NWPP would treat wind resources similar to non-hydro resources and therefore require that Operating Reserves be calculated based on 7% of the on-line wind generation amount.

The Phase 1 report concluded that PSE's Operating Reserve requirement would not be appreciably changed by the addition of 136.4 MW (net capacity) of wind generation on the PSE system. The Phase 1 report noted that based on the Ellensburg area wind data, the average expected operating reserve impact was only 0.4 MW and that the maximum possible Operating Reserve impact was +/- 2.7 MW. Golden therefore concluded that the addition of 136.4 MW of wind generation to the current PSE power portfolio would have an insignificant impact on PSE's operating reserve requirements.

7.2 Updated NWPP Operating Reserve Policies

In January 2004, the NWPP implemented two revisions to its Operating Reserve policies that have a bearing on wind related resources. First, effective January 1, 2004, Operating Reserves associated with wind generation are computed based on 5% of the on-line wind generation amount. Second, effective February 20, 2004, the largest single contingency requirement was dropped from the determination of the minimum Operating Reserve amount.

7.3 Summary of Operating Reserve Impacts Determined in the Phase 2 Studies

Neither of the changes noted in Section 7.2 has an appreciable impact on PSE regarding the amount of Operating Reserves to be maintained for wind generation. The addition of any new generation resources on the PSE system (no matter what the fuel source or generation type) would result in the requirement for PSE to carry additional Operating Reserves pursuant to the NWPP's 5%/7% calculation. The addition of wind generation in the PSE control area would, in itself, not increase PSE's Operating Reserve requirement relative to the addition of a non-wind resource.

Based upon the results of the Phase 1 studies and taking into account the NWPP's updated Operating Reserve criteria, Golden's concludes that PSE's wind-related Operating Reserve costs would remain negligible (i.e. $0.00/Mwh) for wind farm sizes up to at least 450 MW, given PSE's current Mid-C maximum capacity amount.

Section 8
Discussion of the Phase 2 Methodologies Utilized to Evaluate Hour-Ahead and Day-Ahead Wind Impacts on the PSE System

8.1 Overview of the Phase 1 Hour-Ahead and Day-Ahead Study Methodologies

The Phase 1 studies primarily employed a simplified hydro storage/release model for the purpose of determining Hour-Ahead and Day-Ahead operational impacts of wind generation. While this model had a number of strong points (simplicity, results consistent with operational experience), it was recognized that some improvements could be made. In particular, Golden felt that "hard" operating constraints on the PSE system, such as maximum and minimum Mid-C generation levels, were not being fully considered in the simplified Phase 1 model. While these constraints were not expected to have a major influence for 136.4 MW of net wind generation capacity on the PSE system (the amount evaluated in the Phase 1 studies), it was anticipated that as the wind generation amount was increased that these types of real life operational constraints would come into play more and more often. Also, it was contemplated that the inclusion of option valuation techniques might provide a more comprehensive measure of the operational flexibility costs associated with managing wind generation variability.

8.2 Overview of the Phase 2 Hour-Ahead and Day-Ahead Study Methodologies

For the Phase 2 studies, Golden and PSE jointly decided to evaluate the following three methodologies for valuing the Hour-Ahead and Day-Ahead operational impacts of wind generation on the PSE system:

1. An options based model utilizing standard option valuation techniques (termed the Standard Options Model). Under this concept, the magnitude of the physical power options required to manage short-term wind generation variations would be determined and then valued pursuant to the Black-Scholes options pricing methodology.

2. An enhanced operations-based hydro routing model (ultimately termed the Mid-C Flex Model). Under this concept, Golden and PSE would build upon the Phase 1 work and would attempt to incorporate more real-life operational constraints into the subject models. This approach also included the potential development of an hourly (or shorter) least cost dispatch model for the PSE system. A detailed assessment of the Mid-C Flex model is discussed in Section 9.

3. A modified options-based model (termed the Virtual Storage Model). Under this concept, a "virtual" hydro pondage account would be defined and dedicated to managing short-term wind generation variations based on a pre-defined set of Mid-C based operating constraints. The value of the virtual hydro storage account would then be assessed utilizing the Black-Scholes methodology. A detailed assessment of the Virtual Storage model is discussed in Section 10.

8.3 Summary of Hour-Ahead and Day-Ahead Study Methodology Results

Each of the three aforementioned modeling concepts was fully evaluated as part of the Phase 2 studies. High level results of these investigations are summarized below:

Standard Options Model

Upon further investigation, Golden and PSE determined that the Standard Options Methodology resulted in an "overkill" situation and that the computed Hour-Ahead and Day-Ahead wind integration costs using this method were significantly higher than would be reasonably expected. This methodology was therefore dropped from final consideration.

Mid-C Flex Model/Least Cost Dispatch Model

The development of a full-blown hourly least cost dispatch model for the PSE system was ultimately abandoned as: 1) not being feasible within the project timeline, and 2) being too heavily dependant upon subjective input assumptions. The PSE dispatch model concept was therefore replaced with a more conceptual Mid-C operational-based storage/release model. Golden and PSE felt that this model was successful in incorporating several key physical Mid-C operating constraints. The Mid-C Flex model yielded overall results that were generally in line with published results for other utility systems.

Virtual Storage Model

The Virtual Storage Model yielded general results reasonably in line with published wind studies for other utilities. While this model incorporates superior valuation techniques, PSE and Golden recognized that it does not incorporate physical PSE operating constraints as well as the Mid-C Flex Model.

8.4 Overall Hour-Ahead/Day-Ahead Model Summary

Upon review of preliminary modeling results, PSE and Golden felt that a "blending" of the Mid-C Flex methodology and the Virtual Storage methodology would yield the optimal results. In this fashion, physical PSE operating constraints and sophisticated options valuation techniques could both be incorporated into the assessment of Hour-Ahead and Day-Ahead wind integration costs. The Hour-Ahead and Day-Ahead cost results presented in Sections 11-13 of this report therefore utilize a 50/50 blending of the individual results of the Mid-C Flex and the Virtual Storage models.

Section 9 - PSE Mid-C Flex Model

9.1 Overview

A key component in determining the short-term operational and cost impacts of wind generation on a utility's power system is the development of an analytical tool to quantify and measure how wind generation interacts with other system resources. This can especially be a daunting task in the case where the wind resources have not yet been integrated into the subject utility's system since many of the operational impacts are very much a function of the specific characteristics of the subject utility's power portfolio.

In the Phase 1 studies, a simplified Mid-C pondage/storage model was utilized to determine the amount of Mid-C flexibility that was required to manage wind generation variability on the PSE system. While this model was fairly simple to implement and yielded reasonable results (as compared to similar studies performed on other utility systems), Golden and PSE felt that some improvements could be made, especially in the area of more accurately modeling PSE's operational constraints.

9.2 The Mid-C Flex Model Approach

Upon abandoning the development of an hourly PSE LCD model (see Section 8.3), Golden pursued an approach of fine tuning the methodology originally developed in the Phase 1 studies. That approach used the concept that most wind generation deviations would be managed by PSE's share of the Mid-C plants. Golden decided to utilize the same basic approach in the Phase 2 studies, with additional enhancements regarding the size of the wind generation additions and a more detailed incorporation of the Mid-C plants' operating constraints.

The Mid-C Flex model was based on several general resource management goals that PSE personnel attempt to implement as a part their ongoing resource optimization activities. For instance, inflows to the Mid-C plants are generally heavily reshaped to minimize generation amounts during the off-peak hours and maximum generation during the on-peak hours. This operation must be done pursuant to: 1) minimum Mid-C generation constraints, 2) maximum Mid-C generation constraints, and 3) other constraints such as environmental and/or recreational requirements.

Some of the key operational constraints and resource strategies incorporated into the Mid-C Flex model are highlighted below:

> Mid-C Minimum and Maximum Generation Constraints
>
> In most cases, the Mid-C minimum is the controlling constraint during off-peak hours and the Mid-C maximum is the controlling constraint during on-peak hours. With the addition of variable wind generation to the PSE power portfolio, the two main conditions that need to be actively managed (and that may result in incremental operational costs) are as follows:

1. For off-peak hours, the potential that wind generation could *increase* within the hour (above the Hour-Ahead forecasted amount) could result in PSE hitting its Mid-C minimum generation constraint within the hour.

2. For on-peak hours, the potential that wind generation could *decrease* within the hour (below the Hour-Ahead forecasted amount) could result in PSE hitting its Mid-C maximum generation constraint within the hour.

In both of the above cases, PSE's Traders and System Operators need to preschedule the Mid-C generation in such a manner as to be able to counteract the *forecasted* wind variations within the next schedule hour.

The Mid-C Flex model determines on which specific hours PSE would need to increase and decrease scheduled Mid-C generation in order to manage the wind resource and keep the Mid-C within its allowable minimum and maximum generation constraints.

<u>Forced Off-Peak Sales and Forced On-Peak Capacity Purchases</u>
Since the Mid-C minimum is the controlling constraint during off-peak hours, PSE would need to schedule its Mid-C generation at a somewhat higher level than what it would do in the absence of wind generation. This operation is driven by the probability that actual wind generation could be higher than the forecasted amount. Increasing the loading on the Mid-C units during off-peak hours would typically be accomplished by PSE selling additional energy into the off-peak wholesale markets.

Since the Mid-C maximum is the controlling constraint during on-peak hours, PSE would need to schedule its Mid-C generation at a somewhat lower level than what it would do in the absence of wind generation on the specific hours that PSE is in danger of hitting its Mid-C maximum constraint. This operation (which would necessitate an incremental PSE energy purchase) is driven by the probability that actual wind generation could be lower than the forecasted amount.

<u>Daily Water Balance</u>
While PSE can actively shift Mid-C generation in time by implementing short-term fills and releases from its pondage accounts, PSE cannot change the overall amount of water that is flowing into the Mid-C complex. If PSE generates an incremental additional amount of power from the Mid-C during off-peak hours, it will need to generate the same increment less power from the Mid-C during some other future hours. The model compensates for water balance by forcing each day's total PSE Mid-C generation to be the same in both the pre and post wind cases.

Dual Constraint Limitations

During some high flow periods, it is possible that PSE's Mid-C loading gets "squeezed" by both the minimum and maximum constraints on the same hour. In this situation, PSE does not physically have enough Mid-C flexibility to manage the expected wind generation variations within the hour no matter what "corrective" actions PSE may take (such as buying or selling power in advance of the next hour). If this situation occurs (identified as a "dual constraint" hour in the model), PSE must utilize some other means to manage the wind variability. The frequency of occurrence of dual constraint hours is therefore an important metric regarding whether PSE's power portfolio has enough Mid-C capacity to physically manage wind generation variability in the Hour-Ahead and Day-Ahead timeframes.

9.3 Mid-C Flex Model Base Data and assumptions

Some of the key input data and related assumptions used in the Mid-C model are briefly described below:

Base (pre-wind) Hourly Mid-C Generation Series

PSE's actual hourly Mid-C generation for the period January 1 – December 11, 2003 was utilized for this purpose. This Mid-C generation dataset contains a good mixture of low, medium and high flow days, therefore it is considered to be more or less "normal". It is possible that the overall results of the Mid-C Flex model could be somewhat different (as compared to the results presented herein) for either a specific very dry, or a very wet water year.

Mid-C Maximum Generation Constraint

PSE's maximum gross Mid-C generation capacity as of January, 2004 was utilized in the model. It was assumed that PSE maintained 100% of its Operating Reserve requirements on the Mid-C units. The model was configured such that the maximum Mid-C constraint could be modified to reflect: 1) a different PSE Mid-C maximum gross capacity or, 2) a different Operating Reserve treatment.

Mid-C Minimum Generation Constraint

PSE's minimum Mid-C generating constraint is highly variable in nature and is closely tied to real-time river operations. The model assumes that PSE managed (prior to the acquisition of wind power) its Mid-C generation to the minimum level possible on all off-peak hours in order to maximize off-peak/on-peak economic load factoring operations.

Hourly Mid-C Wholesale Power Prices

Actual hourly Mid-C power prices for the period January 1 – December 31, 2003 (as reported by Dow Jones) were used to compute the dollar impacts of Hour-Ahead and Day-Ahead wind variations. Specifically, the Mid-C Flex model used hourly prices to value the incremental PSE purchases and PSE sales required to manage short-term wind generation variations.

Section 10 – Virtual Storage Model

10.1 Overview

The use of a Standard Options methodology for evaluating wind variation impacts, while promising in concept, was determined to exhibit a number of drawbacks. Golden and PSE, however, felt that the use of an options valuation technique might still be promising given a revised framework. The Virtual Storage methodology uses the concept of a virtual hydro storage account in a virtual pond. The virtual pond is assumed to be a sub-set of PSE's actual Mid-C pondage rights that is effectively "set aside" to manage wind generation variability. The value of the virtual pond is then determined by computing the option value associated with PSE's operational ability to store and deliver power into and out of the virtual pond account, subject to the pre-defined limits.

10.2 Short-term Option Value of the PSE Power Portfolio

The current PSE power portfolio contains a significant amount of short-term operational flexibility, particularly from the Mid-C plants. Another way to view this flexibility is from the perspective of option value: PSE has the right, but not the obligation, to generate power at any particular time. This generation option right, coupled with PSE's pondage capabilities, allows PSE to shift power into higher value periods, or into periods where increased (or decreased) generation is required to meet system load/resource needs.

This portfolio option value is heavily utilized by PSE (in conjunction with short-term wholesale market purchases and sales) to minimize PSE's overall net power costs on a long-term basis. Even if events happen exactly as forecasted for a particular time period (such as variable wind generation), there is always a level of uncertainty in the outcome that has to be managed, in advance and in real-time, by PSE's System Operators and Traders. The optionality inherent in the PSE power portfolio therefore has significant value in that it allows PSE to manage such uncertain events while minimizing overall operational costs.

10.3 Virtual Storage Model Principles and Assumptions

Instead of modeling PSE's entire Mid-C physical generation/pondage operations (which is done in part in the Mid-C Flex model), the Virtual Pond method assumes that a portion of PSE's overall Mid-C pondage rights are dedicated to managing wind generation variability. The Virtual Storage methodology computes the amount of hydro storage flexibility that is required to integrate wind generation into the PSE portfolio, and then values this flexibility and capacity using option valuation techniques.

The Virtual Pond has a "neutral" storage point of 0 Mwh; energy can be stored into the account (thereby creating a positive balance) or drafted out of the account (creating a negative balance). For each hour of the day, wind generation uncertainty is computed utilizing a user defined confidence interval (discussed in more detail in Sections 11 and

12). These wind forecast uncertainties are then used to determine hourly generating and storage constraints. The maximum amount of storage flexibility required (i.e. the maximum allowed positive and negative balances of the Virtual Pond) was determined from the CRB Project wind generation forecast error tables previously discussed in Section 5.6.

One of the key inputs to the Virtual Storage model is the frequency in which the storage account is effectively "reset" back to a neutral zero balance. This feature is necessary to isolate short-term storage operations required to manage Hour-Ahead and Day-Ahead wind variations from longer-term storage operations that off-set large wind imbalances within a given month. While such longer-term imbalance effects are also important in evaluating wind generation impacts, they are outside the bounds of the impacts to be studied in the Phase 2 studies.

Given the aforementioned general principles, the model calculates a storage value via a linear program that optimizes revenues given actual hourly Mid-C power prices for a one year historical period. This model uses a base wind generation net capacity of 25 MW, and all of the pre-defined Virtual Storage limitations, constraints and assumptions are referenced to this particular wind generation capacity. Wind forecast error confidence intervals of between 50% and 99% were also evaluated.

10.4 <u>Virtual Storage Model Results</u>

Numerous Virtual Storage model runs were set up and conducted by PSE staff in order to test the validity of concept and to evaluate differing sets of input parameters. The Virtual Storage model yielded results that were judged by Golden and PSE to be more reasonable than the Standard Options methodology. Preliminary results from the Virtual Storage model for Hour-Ahead and Day-Ahead wind generation cost impacts were also in line with other publicly available wind integration studies.

The preliminary results for the Virtual Storage model were also somewhat higher than the comparable results for the Mid-C Flex model; this outcome was, however, somewhat expected given that the Mid-C Flex model does not include a full option value treatment.

While exhibiting some clear advantages over the Standard Options methodology, one drawback of the Virtual Storage methodology is that the model itself cannot determine the appropriate limits to place on the operation of the Virtual Pond. Since the definition of the appropriate Virtual Pond limits and constraints becomes progressively more subjective as wind generation capacity is scaled up above 25 MW, the Virtual Storage model is not as well suited as the Mid-C Flex model for the purpose of evaluating wind capacity scaling effects. Also, the option valuation inherent in the Virtual Storage model assumes as infinite market size: for instance the per unit option value of an 100 Mwh virtual pond would therefore be the same as for a 1,000 Mwh virtual pond.

Section 11 – Evaluation of PSE Hour-Ahead Wind Generation Impacts

11.1 The Evaluation of Hour-Ahead Impacts in the Phase 1 Studies

The setup and approach of the Hour-Ahead impacts analysis in the Phase 1 studies were driven in part by the availability and form of the wind speed data available at the time. As has been previously referenced, Golden obtained approximately one year's worth of 10-minute increment wind speed data for six sites located near Ellensburg. Since no actual short-term wind generation forecasts existed for the Ellensburg recording sites, the Phase 1 studies employed a 2 hour delay persistence technique to forecast the next hour's wind generation.

Hour-Ahead forecast errors were computed and an 11 ½ month average error was determined for both the over-forecast and under-forecast cases. These average over and under forecast errors were then combined with a simplified Mid-C storage/release algorithm to compute the amount of Mid-C flexibility that was required to be set aside to manage wind generation deviations. Finally, the amount of Mid-C flexibility dedicated to managing wind variations was valued by applying a multi-year average price differential between on-peak and off-peak hours. Section 8 of the Phase 1 Report contains an in depth discussion of how the original Hour-Ahead studies were set up and performed.

11.2 The Evaluation of Hour-Ahead Impacts in the Phase 2 Studies

During the initial set up of the Phase 2 studies, five key areas were identified as exhibiting the potential to improve upon the Phase 1 results:

1. Utilize Hour-Ahead forecasts and actual wind generation from an operating Northwest wind farm (Discussed in Sections 4 and 5)
2. Replace the static average forecast error approach with a dynamic forecast error approach (Discussed in Section 5)
3. Develop, if practical, a 10-minute or hourly increment dispatch model for the PSE system to enable a more detailed analysis of PSE system operation impacts (Discussed in Section 8.3)
4. Employ options-based techniques to value wind generation variations (Discussed in Section 10)
5. Perform "scaling" studies to evaluate Hour-Ahead impacts for wind farm capacities ranging up to 450 MW (Discussed in this Section 11)

11.3 Common Phase 1/Phase 2 Study Conventions and Methodologies

The Phase 2 Hour-Ahead studies employed some of the basic conventions and assumptions that were also utilized in the Phase 1 studies. For instance in order to evaluate Hour-Ahead wind generation variations, it is important to understand the timeframe on which System Operators and Traders make real-time operating and/or marketing decisions. Outside of certain transactions with the California ISO, energy transfers between control areas in the Northwest (including wholesale purchases, sales and exchanges) are scheduled on a clock hour basis. Energy transfers are scheduled at a uniform delivery rate for the entire hour.

Control area operators and merchant personnel generally agree to scheduled energy transactions at least 30 minutes prior to the beginning of the next scheduling hour. This means that the System Operator/Trader will have to make forecasts of certain operating conditions (such as retail load levels and generation output) up to 1 ½ hours into the future, based on the information that is available at that moment. PSE's System Operators and Traders will also be required to develop an hourly wind generation forecast on this same timeframe.

11.4 Use of CRB Project Hour-Ahead Wind Generation Forecasts

For the Phase 2 studies, Golden and PSE had available a set of actual Hour-Ahead wind schedules from the aforementioned CRB Project. As was previously discussed in Section 5, upon analysis of the CRB Project wind generation data Golden identified that the Hour-Ahead wind schedules exhibited a consistent low-side bias when compared to the actual after-the-fact wind generation. The CRB Project Hour-Ahead schedules were therefore adjusted by Golden to remove this bias. Golden utilized the adjusted CRB Project data for the purpose of computing Hour-Ahead wind forecasts as opposed to computing persistence based forecasts (as was done in the Phase 1 studies).

11.5 Determining the Hour-Ahead Wind Forecast Confidence Interval

The CRB Project wind forecast analysis models were specifically designed to allow for the use of differing confidence intervals. For instance, use of a 95% confidence interval would indicate that the difference between the Hour-Ahead wind forecast and the actual hourly average wind generation for that same hour would be expected to be within the indicated range 95% of the time.

Golden and PSE ran a series of Hour-Ahead wind forecast sensitivity studies employing confidence intervals ranging from 50% to 99%. In choosing which confidence interval to use as the recommended level, PSE and Golden considered several factors regarding how PSE's Traders and System Operators actually make operating decisions and how power is traded in the real-time marketplace.

While the Pacific Northwest has a very active Hour-Ahead power market, there is virtually no within-the-hour market. Within-the-hour purchases and sales are generally limited to those transactions that are initiated by unforeseeable real-time events such as a generating unit trip, transmission line outage, or a sudden curtailment of another scheduled transaction. Because the within-the-hour market is so illiquid, Traders and System Operators generally do not want to be in the position of *having to* enter into a within-the-hour transaction; one will usually pay a premium (which can be significant) for a within-the-hour transaction versus an hour ahead prescheduled purchase or sale.

Traders and System Operators do not want to manage intra-hourly wind variability with within-the-hour transactions. In fact, due to implementation considerations and lack of a liquid market, *it may not even be possible to enter into certain desired intra-hourly transactions.* Because of the lack of a viable within-the-hour wholesale market, the premium that PSE would likely have to pay for within-the-hour transactions (relative to Hour-Ahead prescheduled transactions), and the potential for PSE to hit hard operating constraints within the hour, PSE and Golden agreed that a confidence interval of 95% was appropriate for use in evaluating Hour-Ahead wind generation impacts.

11.6 Wind Generation Hour-Ahead Scaling Impacts

The Phase 1 study results were based on the integration of a 154.5 MW (136.4 net output) wind farm on the PSE power system. The Hour-Ahead operational impacts and related costs that were computed pursuant to that study were therefore based on a single, static wind farm size.

One of the goals of the Phase 2 studies was to investigate Hour-Ahead operational impacts on the PSE system as the size of the installed wind generation was varied. While no hard wind farm size constraints were originally dictated for the Phase 2 studies, PSE staff and Golden agreed to evaluate total wind generation levels ranging from 25 MW (net capacity) to 450 MW (net capacity).

The Ellensburg Area wind generation data and the associated Hour-Ahead CRB Project forecast error tables (ratioed up to 136.4 MW net capacity) were used as the base case for the scaling studies. All of this data is referenced to a 136.4 MW net capacity wind generation level. When evaluating wind farm sizes smaller than, or greater than 136.4 MW, the wind generation data series and the base forecast error tables were then adjusted based on the ratio of the wind generation capacity being evaluated divided by 136.4 MW. Impacts were computed for each wind capacity level using a constant 95% forecast confidence interval.

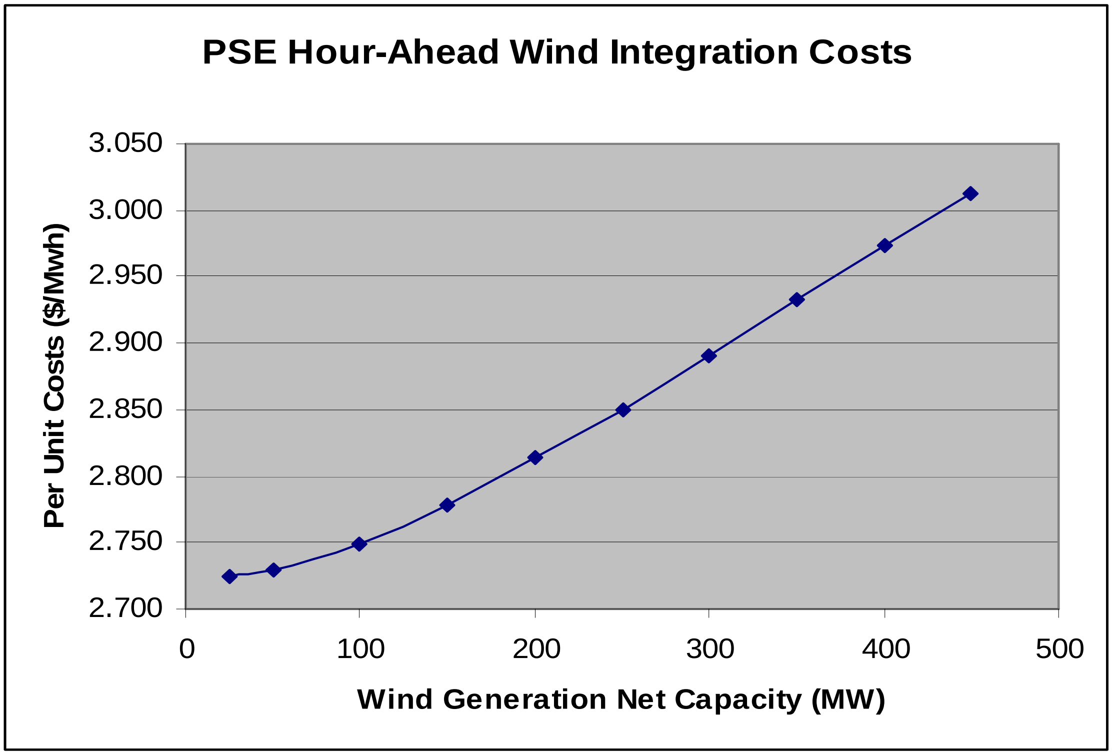
The Mid-C Flex model was specifically designed to accommodate varying amounts total installed wind generation. In order to produce a family of per unit Hour-Ahead cost impacts, a series of model runs were made whereby the wind generation net capacity was increased from a minimum of 25 MW to a maximum of 450 MW.

11.7 Summary Results of the Hour-Ahead Studies

Both the Mid-C Flex model and the Virtual Storage model were run to determine Hour-Ahead impacts for wind generation net capacities ranging from 25 MW to 450 MW. These model runs used an Hour-Ahead wind generation forecast confidence interval of 95% and also utilized the specific modeling constraints and assumptions previously described in Sections 9 and 10.

Results of the Hour-Ahead scaling studies are summarized in the following chart:

Chart 11.7



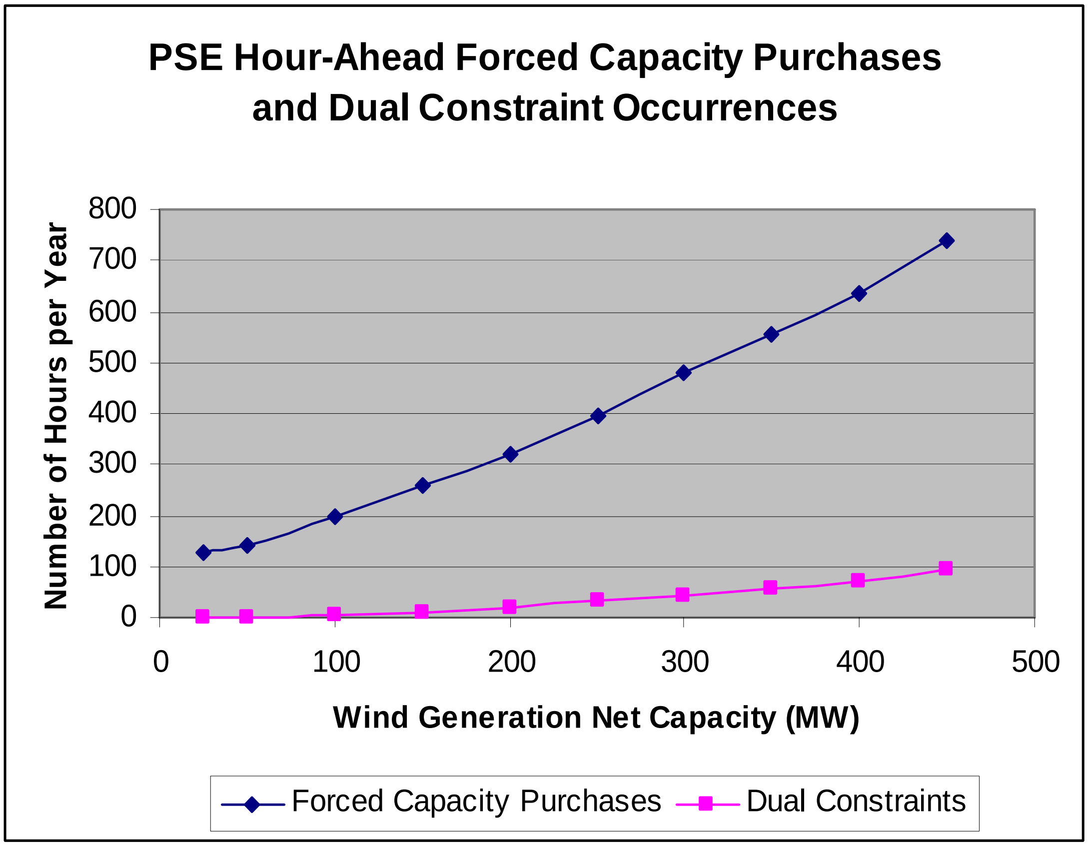
The per unit Hour-Ahead costs range from a low of $2.72/Mwh for the 25 MW wind capacity case to a high of $3.01/Mwh for the 450 MW wind capacity case. It should be noted that there is a moderate exponential trend in the per unit Hour-Ahead costs as wind generation capacity is increased: this feature is due primarily to the fact that the number of hours on which PSE is forced to purchase capacity in order to stay below its maximum Mid-C generating constraint also increases exponentially as wind generation capacity is increased.

11.8 Forced Capacity Purchases and Dual Constraint Hours

As was discussed in Section 9, the Mid-C Flex model computes two important operational metrics for the PSE system: 1) the number of hours that PSE is required to purchase capacity in order to keep its Mid-C loading below its maximum generating constraint, and 2) the number of hours that PSE encounters dual constraint problems (i.e. when the MW difference between the Mid-C maximum and minimum constraints is less than the total forecasted wind generation variation range).

Chart 11.8 below shows the frequency of occurrence of forced capacity purchase hours and dual constraint hours for wind generation capacities ranging from 25 MW to 450 MW:

Chart 11.8



As can be seen from Chart 11.8, the number of hours that PSE would be required to purchase capacity in the Hour-Ahead markets in order to keep its Mid-C loading below its maximum generating constraint ranges from 126 hours/year for the 25 MW case up to 738 hours/year for the 450 MW case. This is equivalent to a 1.4% occurrence rate for the 25 MW case and an 8.4% occurrence rate for the 450 MW case.

As can also be seen from Chart 11.8, the number of occurrences of dual constraint hours is relatively small under the conditions studied. The number of dual constraint hours ranges from 1 hour/year for the 25 MW case up to 95 hours/year for the 450 MW case. This is equivalent to a 0.01% occurrence rate for the 25 MW case and a 1.1% occurrence rate for the 450 MW case. In a high streamflow year, it would be expected that the occurrence of dual constraint hours would be higher than what is presented here.

The Mid-C Flex model does not attempt to value the occurrences of dual constraint hours; since dual constraints occurrences were fairly small in the Phase 2 studies, Golden would not expect that the overall Hour-Ahead wind integration costs would be appreciably impacted by excluding dual constraint related costs (under the conditions studied). However, if PSE's overall Mid-C capacity were to be significantly reduced from its current level, a valuation of dual constraint impacts would be required in order to accurately evaluate PSE's overall Hour-Ahead wind integration costs.

Section 12 – Evaluation of PSE Day-Ahead Wind Generation Impacts

12.1 The Evaluation of Day-Ahead Impacts in the Phase 1 Studies

Like the evaluation of Hour-Ahead effects in the Phase 1 studies, the setup and approach of the Phase 1 Day-Ahead analysis was driven in part by the availability and form of the available wind speed data. The analysis was conducted in a similar fashion as for the Hour-Ahead studies, with the primary exception that Day-Ahead versus actual generation forecast errors were utilized.

Since the general accuracy of a persistence type wind forecast decreases rapidly for forecasts beyond roughly six hours into the future, it was assumed in the Phase 1 study that PSE's Traders would also have access to specialized meteorological forecasting tools for the purposes of developing Day-Ahead wind generation forecasts. As a proxy for such an undeveloped meteorological forecasting tool, Golden utilized a 2 day delay persistence forecasting model with an assumed 20% forecast error improvement adjustment.

12.2 The Evaluation of Day-Ahead Impacts in the Phase 2 Studies

All of the Phase 2 study goals that were mentioned in Section 11.2 regarding the evaluation of Hour-Ahead impacts also apply to the evaluation of Day-Ahead impacts. For measuring Day-Ahead effects, Golden and PSE desired to utilize the available Day-Ahead wind generation preschedules for the CRB Project.

12.3 Common Phase 1/Phase 2 Study Conventions and Methodologies

The Phase 2 Day-Ahead studies expanded upon some of the basic conventions and assumptions that were also utilized in the Phase 1 studies. Day-Ahead load forecasts, resource commitment schedules and scheduled energy transfers between control areas in the Northwest (including wholesale purchases, sales and exchanges) for a given 24 hour day are generally established prior to approximately 0700 on the preceding work day. For example, most energy transactions for HE 0100 – HE 2400 on a Tuesday would usually be established by approximately 0700 on the preceding Monday morning. Since PSE's Traders generally need to commit to scheduled power transactions early each workday morning (for delivery the following preschedule day), the Traders also need to develop Day-Ahead forecasts of PSE generator output on this same general timeframe.

12.4 Use of CRB Project Day-Ahead Wind Generation Forecasts

For the Phase 2 studies, Golden and PSE had available a set of actual Day-Ahead wind schedules from the CRB Project. As was previously discussed in Section 5, upon analysis of the available wind generation data Golden identified that the CRB Project Day-Ahead wind schedules exhibited a consistent low-side bias when compared to the actual after-the-fact wind generation. The CRB Project Day-Ahead schedules were therefore adjusted by Golden to remove this bias.

Golden utilized the adjusted CRB Project data for the purpose of computing Day-Ahead wind forecasts as opposed to computing persistence based forecasts (as was done in the Phase 1 studies). Even though the adjusted Day-Ahead preschedules were not "firm" (the seller had the right to change the Day-Ahead prescheduled amounts up to 35 minutes prior to the start of the delivery hour), Golden and PSE felt that the adjusted Day-Ahead wind schedules represented the "best available" forecast of the CRB Project's next day wind generation.

12.5 <u>Determining the Day-Ahead Wind Forecast Confidence Interval</u>

Golden and PSE ran a series of Day-Ahead wind forecast sensitivity studies employing confidence intervals ranging from 50% to 99%. In choosing which confidence interval to use as the recommended level, PSE and Golden considered several factors regarding how PSE's Traders and System Operators actually make operating decisions and how power is traded in the real-time marketplace.

The Pacific Northwest has historically had, and is expected to continue to have, an active and liquid hourly power market. From an implementation and timing perspective, it is therefore possible for utilities such as PSE to reasonably off-set at least some variations in Day-Ahead schedules in the real-time hourly markets. This situation is in contrast to the Hour-Ahead case (discussed in Section 11.5) where deviations in Hour-Ahead schedules generally cannot be off-set by within-the-hour transactions. Due to the existence of a liquid real-time hourly market, using a high Day-Ahead wind generation confidence interval (such as 95%) to compute Day-Ahead wind integration costs would probably overstate the costs involved.

For instance, capacity purchased on a Day-Ahead basis by PSE to keep prescheduled Mid-C loading below its maximum generation constraint can, in some cases, be re-sold back into the real-time hourly markets if it is not needed on an Hour-Ahead basis. This type of operation is made possible due to the availability of an updated Hour-Ahead wind generation forecast, which would be expected to be more accurate than the Day-Ahead forecast. The Mid-C Flex model was configured to compare the Day-Ahead forced capacity purchases and off-peak energy sales to what would be expected to be needed for the next schedule hour, utilizing the updated Hour-Ahead wind generation forecasts. If PSE had effectively over-purchased peaking capacity in the Day-Ahead market, the capacity not needed to manage the next hour's forecasted wind generation was resold back into the market.

Because of the existence of a viable real-time Hour-Ahead wholesale market and the ability of PSE to enter into incremental hourly transactions to off-set Day-Ahead wind generation forecast errors, PSE and Golden agreed that a confidence interval of 75% was appropriate for use in evaluating Day-Ahead wind generation impacts.

12.6 Wind Generation Day-Ahead Scaling Impacts

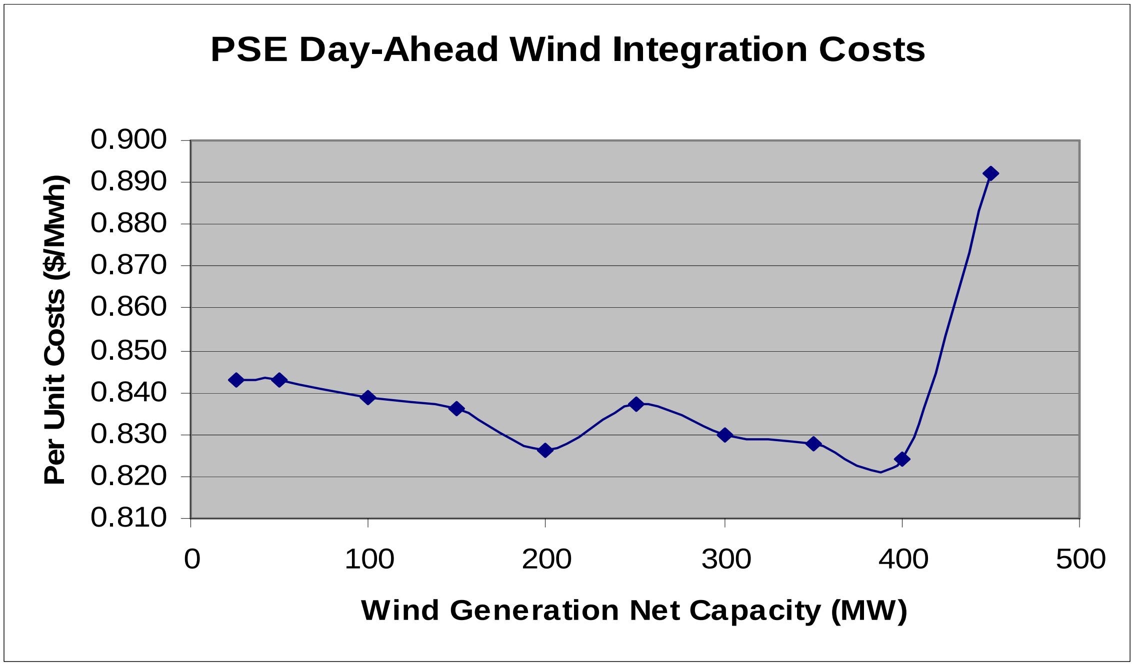
One of the goals of the Phase 2 studies was to investigate Day-Ahead operational impacts on the PSE system as the size of installed wind generation was varied. Day-Ahead impacts were therefore analyzed for wind amounts ranging from 25 MW (net capacity) to 450 MW (net capacity).

The Ellensburg wind generation data and the associated CRB Project Day-Ahead forecast error tables were used as the base case for the scaling studies. All of this data was referenced to a 136.4 MW net capacity wind generation level. When evaluating wind farm sizes smaller than, or greater than 136.4 MW, the base forecast error tables were then adjusted based on the ratio of the wind generation amount being evaluated divided by 136.4 MW. Impacts were computed for each wind generation level using a constant 75% forecast confidence interval. In order to produce a family of per unit Day-Ahead cost impacts, a series of model runs were made whereby the wind generation net capacity was increased from a minimum of 25 MW to a maximum of 450 MW.

12.7 Summary Results of the Day-Ahead Studies

Both the Mid-C Flex model and the Virtual Storage model were run to determine Day-Ahead impacts for wind generation net capacities ranging from 25 MW to 450 MW. These model runs used an Hour-Ahead wind generation forecast confidence interval of 75% and also utilized the specific modeling constraints and assumptions described in Sections 10 and 11. *Day-Ahead Costs that are in addition to the previously reported Hour-Ahead costs are summarized below:*

Chart 12.7



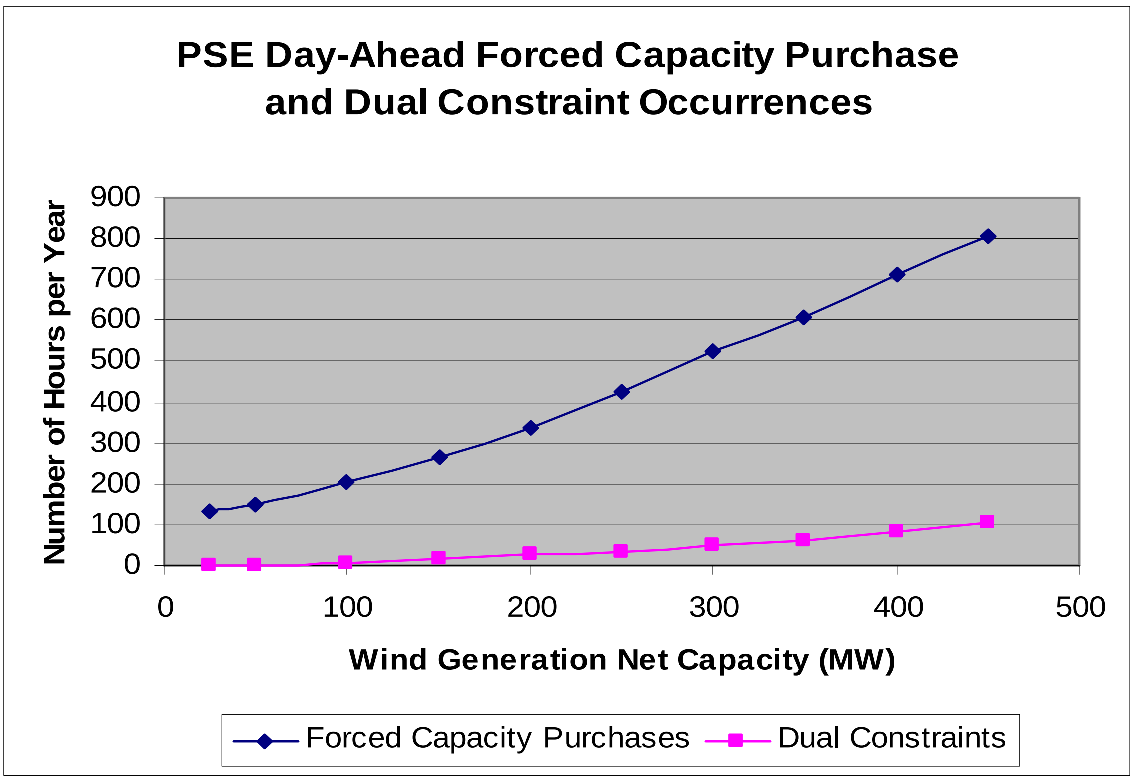
While the trend-line of the above graph appears at first glance to be somewhat "lumpy", it should be noted that the vertical scale of this graph is extremely compressed, with per unit costs varying only by +/- $0.01/Mwh over a generation range of 25 MW to 400MW.

12.8 Forced Capacity Purchases and Dual Constraint Hours

Forced capacity purchase hours and dual constraint hours were previously discussed in Section 11.8 regarding Hour-Ahead effects. For Day-Ahead effects, these issues are somewhat less critical cost drivers since PSE has the opportunity to modify generation levels and power purchase and sales schedules in the hourly real-time markets. So while the Day-Ahead preschedules may indicate forced capacity purchases and/or dual constraint problems for the upcoming delivery day, PSE may not actually be forced to modify a Day-Ahead operation in order to manage these events.

Day-Ahead indicated forced capacity purchase occurrences and indicated Day-Ahead dual constraint occurrences are shown below in Chart 12.8:

Chart 12.8



As was the case with Hour-Ahead impacts, Day-Ahead dual constraint hours are not a significant cost driver given the current amount of PSE's Mid-C flexibility relative to the wind generation capacities studied. The costs of managing Day-Ahead dual constraint hours could, however, be a more significant issue if PSE's Mid-C capacity were to be reduced from current levels.

Section 13 - Summary of PSE Short-term Wind Generation Integration Costs

13.1 Summary of Results

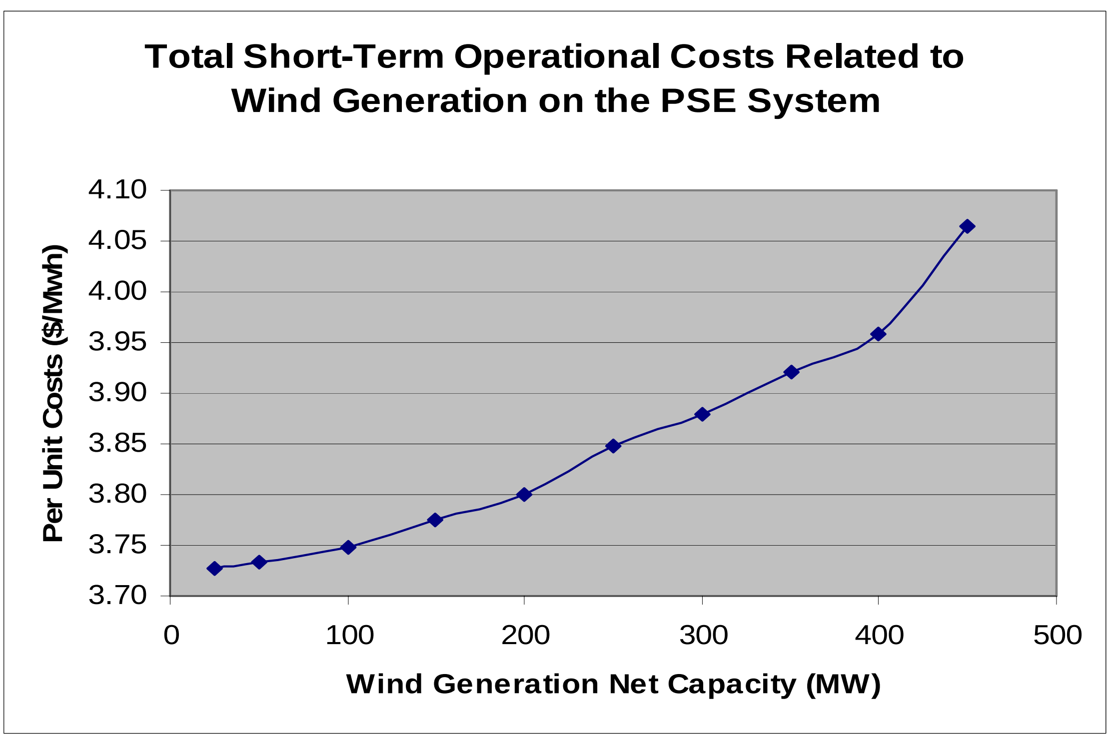
Table 13.1 below presents overall results for the four categories of short-term wind generation impacts analyzed individually in Sections 6, 7, 11 & 12 of this report:

Table 13.1 - Summary of Probable Short-Term Operational Impacts due to the Addition of Varying Amounts of Wind Generation on the PSE System

Wind Generation Net Capacity (MW)	Regulation ($/Mwh)	Operating Reserves ($/Mwh)	Hour-Ahead Costs ($/Mwh)	Day-Ahead Costs ($/Mwh)	Total Costs ($/Mwh)
25	0.16	0.00	2.72	0.84	3.73
50	0.16	0.00	2.73	0.84	3.73
100	0.16	0.00	2.75	0.84	3.75
150	0.16	0.00	2.78	0.84	3.77
200	0.16	0.00	2.81	0.83	3.80
250	0.16	0.00	2.85	0.84	3.85
300	0.16	0.00	2.89	0.83	3.88
350	0.16	0.00	2.93	0.83	3.92
400	0.16	0.00	2.97	0.82	3.96
450	0.16	0.00	3.01	0.89	4.06

Chart 13.1 shows the trend in per unit total operational costs as a function of wind generation net capacity:

Chart 13.1



13.2 <u>Sensitivity of Results</u>

In addition to the scaling studies performed to analyze the impacts of varying wind generation amounts, Golden also performed a cost sensitivity study for the 150 MW wind capacity case. Table 13.2 below presents the results of this sensitivity study; the figures shown in bold type indicate the recommended baseline results previously reported in Table 13.1.

Table 13.2
Cost Sensitivity Results for 150 MW Net Capacity Wind Generation

Impacts Category	Low Side of Cost Range ($/Mwh)	Recommended Cost ($/Mwh)	High Side of Cost Range ($/Mwh)
Regulation	0.01	**0.16**	0.19
Operating Reserves	0.00	**0.00**	0.00
Hour-Ahead	0.98	**2.78**	3.25
Day-Ahead	0.75	**0.84**	1.96
Total	1.74	**3.77**	5.40

For Regulation cost impacts, the low side of the indicated range was determined from the results of the Hudson and Kirby study (a regulating reserve increase of 0.22%) and the high side of the indicated range was determined from the results of the UWIG/Xcel study (a regulating reserve increase of 3.5%). For Hour-Ahead cost impacts, the low side of the indicated range was determined using a 50% confidence interval and the high side of the range was determined using a 99% confidence interval. The indicated low and high points for the Day-Ahead cost impacts were determined in a similar fashion as for the Hour-Ahead low and high points.

13.3 <u>Comparison of Phase 2 versus Phase 1 Results</u>

Table 13.3 below shows a summary cost comparison of the four short-term wind related impacts categories analyzed in both the Phase 1 and Phase 2 studies, referenced to a common wind generation amount of 136.4 MW net capacity:

Table 13.3
Comparison of Phase 1 and Phase 2 Study Results – 136.4 MW Net Wind Capacity

Impacts Category	Phase 1 Study Results ($/Mwh)	Phase 2 Study Results ($/Mwh)
Regulation	0.16	0.16
Operating Reserves	0.00	0.00
Hour-Ahead	1.54	2.77
Day-Ahead	2.24	0.84
Total	3.94	3.77

Two broad trends are evident in comparing the Phase 1 and Phase 2 results:

- The sum total cost impact for all four categories as determined in the Phase 2 studies is slightly, but not radically, lower than the total cost determined in the Phase 1 studies.

- The relative magnitude of the Hour-Ahead and Day-Ahead costs has shifted between the Phase 1 and Phase 2 studies, even though the sum total cost remain largely unchanged. This result is due to the incorporation of more sophisticated Hour-Ahead and Day-Ahead wind forecast confidence intervals in the Phase 2 studies.

13.4 The PSE Phase 2 Costs versus Other Reported Results

In November, 2003, UWIG released a technical paper entitled Wind Power Impacts on Electric-Power-System Operating Costs – Summary and Perspective on Work Done to Date. This paper summarized the results of six studies conducted by other entities that focused on quantifying the short-term operational impacts of integrating wind generation into large utility systems. All of the six studies except one (the so called Hirst study) evaluated Regulation, Hour-Ahead ("load following") and Day-Ahead ("unit commitment") impacts.

The results of the five UWIG reported studies (excluding Hirst) may not be directly comparable to each other or the PSE Phase 2 results since all of the studies used differing wind penetration levels. A comparison of the five UWIG reported studies and the PSE Phase 2 study does, however, provide some useful information as to the probable *range* of short-term wind integration costs. Table 13.4 below shows such a summary:

Table 13.4 - Short-Term Operational Costs of Wind Generation On Large Utility Power Systems

Study	Wind Penetration Level (Percent of Peak Load)	Total Short-Term Operational Costs ($/Mwh)
PSE Phase 2 (150 MW Case)	**3.3**	**3.77**
UWIG/XCEL	3.5	1.85
Pacificorp	20.0	5.50
BPA	7.0	1.47-2.27
We Energies I	4.0	1.90
We Energies II	29.0	2.92

As can be seen from Table 13.4, there is a fairly wide range of per unit cost impacts as determined in the six comparative studies. Some of the reasons for these cost differences include: 1) differing wind penetration levels, 1) differing uses of forecast versus actual wind generation quantities, 3) differing treatment of capacity and/or option value, 4) differing market price and fuel price assumptions and 5) differing power portfolio resource operating characteristics/constraints.

Section 14 – Conclusions

14.1 Summary

This report has described the data sources, computational methodologies, and results developed by Golden and PSE to identify and quantify the impacts of adding wind generation into the PSE power portfolio. Specifically, Golden and PSE analyzed the impact of adding 25 MW to 450 MW of wind generation capacity to the PSE system. The analysis was based primarily on: 1) eight months of actual wind generation and wind generation forecast data derived from the CRB, and 2) an 11 ½ month record of simulated wind generation and wind generation forecasts for a future wind farm assumed to be located near Ellensburg, Washington.

Golden and PSE jointly developed two separate analytical tools to evaluate the Hour-Ahead and Day-Ahead operational impacts of wind generation on the PSE system. The first analytical model (termed the Mid-C Flex model) was based on general PSE Mid-C operating practices and incorporated a number of real-life operating constraints. The second model (termed the Virtual Storage model) utilized a virtual storage pond concept and employed sophisticated options valuation methodologies. The results of both models were then combined to produce the overall results presented in this Report.

The MW and dollar cost impacts presented herein represent reasonable, mid-point evaluations given the selected input data and stated assumptions. In particular, the confidence intervals chosen to evaluate wind forecast error impacts are believed to strike a fair balance between PSE's general desire for operational certainty versus minimizing the costs of managing wind generation variations.

The results presented are valid for the range of wind generation amounts studied, assuming PSE's current amount of Mid-C capacity. Should PSE's Mid-C generating capacity be reduced in the future, or should the amount of wind generation added to the PSE system exceed 450 MW, it would generally be expected that the per-unit operational costs of integrating wind resource onto the PSE system would be somewhat greater than what is presented herein. Additional sensitivity studies would be required to quantify these types of impacts.

Finally, as mentioned in the initial discussion of the Project Scope, there are several wind related impacts that Golden/PSE did not analyze as part of this Phase 2 study. These other issues include transmission impacts, seasonal resource planning concerns and wind generation winter capacity ratings. The 10-minute increment wind generation datasets assembled by Golden from the CRB Project data and the Ellensburg area datasets originally developed in the Phase 1 studies should be of use to PSE personnel examining these other wind related topics.

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