Report Addendum

Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio

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Section 1 OVERVIEW

The objective of this study is to assess the costs that Idaho Power will incur in modifying its operations at the Hells Canyon Complex for “integrating” or incorporating wind energy onto its system. The intermittent and unpredictable nature of wind generation requires a utility to have generating resources available which can increase or decrease generation on short notice in order to keep the interconnected power system balanced. While hydroelectric power plants are well suited for performing this function, there are operational impacts and costs associated with operating Idaho Power’s hydroelectric plants in a manner that maintains reliability and facilitates integration of energy from wind generation facilities.

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), Idaho Power is required to offer independent developers a power purchase contract based on a standard avoided cost rate for a qualifying facility with an output of 10 aMW or less. Due largely to federal tax incentives and favorable PURPA rates, a large number of wind project developers came to Idaho Power in 2005 requesting PURPA contracts. Because of uncertainty in integrating this large volume of wind generation on its system, Idaho Power sought temporary relief from PURPA requirements until the impact of wind integration could be more fully studied. The Idaho Public Utilities Commission (IPUC) granted this relief by temporarily reducing the PURPA cap of 10 aMW to 100 kW for PURPA wind projects.

Variability and uncertainty are the two attributes of wind generation that underlie most of the concerns related to power system operations and reliability. In day-ahead planning, for either conventional unit commitment or offering generation into an energy market, forecasts of the demand for the next day will drive the process. In real-time operations, the output of generating resources must be continually adjusted to match the ever-changing demand pattern. The inherent variability and uncertainty of wind generation may complicate the ability of matching these generating resources to loads. Adding wind resources may also increase the challenge of meeting demand at the lowest cost while maintaining system reliability.

The primary focus of this study has been to determine how the real-time operation of Idaho Power’s Hells Canyon Complex would be impacted by the addition of significant amounts of wind generation. Previous wind integration studies (of large amounts of wind generation) have shown that the impacts of wind generation uncertainty and variability on the bulk power system are primarily economic, and manifested in increased system costs. These costs are a consequence of the additional controllable generation capacity that must be allocated to manage the incremental variability of the Balancing Authority area due to wind generation, and the increased uncertainty that must be dealt with in operations planning.

Following the completion of the original report in February 2007, which resulted in an integration cost of $10.72 per MWh, Idaho Power conducted a public workshop on March 15, 2007 to formally present the results of the study and to solicit feedback from representatives from the wind industry, environmental groups, customer groups and governmental and regulatory entities. At this workshop, a list of 18 items consisting of questions, concerns and requests was developed for Idaho Power to address.

On June 20, 2007, a second workshop was held to address questions and concerns raised in the first workshop and to present updated modeling results based on suggestions from the first workshop. The updated modeling resulted in a wind integration cost of $7.92 per MWh. This addendum to Idaho Power's original wind integration study addresses the issues discussed at both workshops and presents modeling results which were updated as a result of the workshops. Section 2 contains a brief summary of the methodology used to conduct the study followed by a summary of the issues raised at the public workshops in Section 3. Section 4 presents the work done since the completion of the original report regarding the determination of reserve requirements as well as the results of sensitivity analyses. Lastly, Section 5 presents updated study results.

Section 2 STUDY METHODOLOGY

While there is no formal or rigorous definition, “integration cost” is the term used to describe the economic impact of wind generation variability and uncertainty on the utility company charged with accepting and delivering that energy. The term applies to the operational time frame, which comprises the real-time management of conventional generating units and the short-term planning for demand over the coming day or days. As evaluated in this study, the term does not include costs related to transmission upgrades required to deliver wind generation to serve load or for off system sales.

A chronological operations simulation methodology has become the de-facto standard analytical approach for wind integration studies. This framework utilizes synchronized hourly load and wind generation patterns, and mimics the scheduling and real-time operation activities for the company or area of interest. For this study, Idaho Power used the Synexus Global *Vista* Decision Support System™ (*Vista* DSS) to assess the impacts of wind generation on the real-time operation of its system.

Vista DSS is a hydro optimization model that simulates the operating characteristics of Idaho Power’s system. The model has detailed generating unit definitions, a simplified bus level transmission architecture and hourly inputs for hydro inflows, loads, electricity prices, reserve requirements and energy contracts. This software is capable of optimizing generation scheduling for the Hells Canyon Complex, while observing hydraulic, transmission, and regulatory constraints. The generation scheduling computed by *Vista* DSS for the Hells Canyon hydro facilities includes generation from other Idaho Power resources as well as off-system market transactions.

Seasonal water conditions play a critical role in Idaho Power’s ability to utilize its fleet of hydroelectric resources. Because of this, three different water condition years were modeled for this study: 1998 (a good water year), 2000 (a normal water year), and 2005 (a poor water year). In addition to varying water conditions, the amount of wind generation on Idaho Power’s system, or “penetration level,” was modeled in the original study for four different cases: 300 MW, 600 MW, 900 MW, and 1,200 MW. The 1,200 MW penetration level was removed from consideration for the updated analysis presented in this report addendum.

The study evaluates the changes in operations and the resulting cost that wind variability and uncertainty introduce into Idaho Power’s system at the varying levels of wind penetration for each of the three water years modeled. Two *Vista* DSS runs were needed to evaluate each wind penetration level for each water condition. The first run (flat wind case) modeled wind generation in flat blocks to simulate a predictable resource. The second run (variable wind case) modeled the same amount of wind generation with its inherent unpredictability and variability. The difference between the values of these model runs is the basis of determining the cost to integrate wind.

In the original analysis, the flat wind case wind generation was calculated as the average wind energy for a day and was determined by summing 24-hours of wind generation and dividing by 24. This average energy is then applied to each hour during that day resulting in a 24-hour flat block of energy, which removes the variability of wind for that day. The second run incorporates the actual (hourly variable) wind output and the required additional regulating reserves necessary to maintain a consistent level of system control performance. In the updated analysis, the flat wind case was revised such that the daily wind generation was separated into two flat blocks, one for heavy-load hours and one for light-load hours.

The wind integration cost per MWh is calculated as the difference between the dollar value of the total annual generation from the flat wind case run valued at market and that of the total annual generation from the actual wind run also valued at market, divided by the total wind energy produced during the year in MWh. This process was completed for each wind penetration level and water year which resulted in a total of six *Vista* DSS model simulations per wind penetration level to complete the analysis.

In order to understand to how Idaho Power calculated the cost of wind integration, it was important to first review the methodology of the study. Further details regarding study methodology can be found in Section 2 of the original report. Section 3 of this addendum presents the questions raised at the March 15, 2007 public workshop along with Idaho Power's responses which were presented at the second workshop on June 20, 2007.

Section 3 PUBLIC WORKSHOPS

Idaho Power Company completed its original wind study report in February 2007. Following the submittal of the report, the Idaho Public Utilities Commission asked Idaho Power to conduct a public workshop to present the results and to explain the methodology used to conduct the study. The workshop took place on March 15, 2007 and was attended by representatives from the wind industry, environmental groups, customer groups, and governmental and regulatory entities.

The first workshop resulted in the following list of items (grouped by topic) for Idaho Power to consider with regard to the study methodology and observations concerning the results of the study. The items that were deemed actionable were analyzed and incorporated in updated *Vista* DSS modeling. Following this additional work, a second public workshop was held on June 20, 2007 to present the updated results. The complete list of items developed at the first workshop and a brief description of actions taken are shown below:

Wind Modeling

1. WindLogics should address concerns regarding west to east diversity of wind modeling (re: Idaho National Lab (INL) wind data).

   - WindLogics reviewed the wind data used in Idaho Power's study and compared it with data provided by INL. The INL and WindLogic data were sampled from significantly different heights. This difference made a direct comparison difficult; however there appears to be good similarity of tracking storm fronts and synoptic patterns. The review of the wind data does not invalidate it as a reasonable basis for determining wind generation characteristics over the three year study period. Additional information on simulating Idaho wind resources can be found in the original study on pages 20 – 21.

7. The capacity factors used in the modeling appear to be low. Would going to a different power curve reduce variability?

   - EnerNex has evaluated the wind data using a turbine curve for the GE 1.5 MW SL and the results showed an even lower capacity factor than the Vestas V82 used in the study. It appears the Vestas V82 turbine works well with the wind resource found in southern Idaho. Table 1 compares the two machines as they are modeled with the wind simulation profiles.

Table 1. Wind machine capacity factor comparison

		Vestas V82		GE 1.5 SL	
Year	Nameplate (MW)	Total Annual Wind Energy (GWh)	Capacity Factor	Total Annual Wind Energy (GWh)	Capacity Factor
1998	300	673	25.6%	656	25.0%
	600	1,549	29.5%	1,514	28.8%
	900	2,265	28.7%	2,211	28.0%
	1,200	3,007	28.6%	2,935	27.9%
2000	300	702	26.7%	686	26.0%
	600	1,585	30.2%	1,550	29.4%
	900	2,286	29.0%	2,232	28.2%
	1,200	3,013	28.7%	2,941	27.9%
2005	300	617	23.5%	601	22.9%
	600	1,450	27.6%	1,414	26.9%
	900	2,140	27.1%	2,085	26.4%
	1,200	2,835	27.0%	2,764	26.3%

8. Idaho Power needs to review the data behind wind variability and scaling issues.

   - Scaling issues were primarily related to the increase from the 900 MW to 1,200 MW penetration level. Because the 1,200 MW penetration level was shown to be beyond Idaho Power’s ability to integrate, the 1,200 MW penetration level was dropped from further consideration in the updated analysis. Therefore, the scaling of wind data is no longer an issue in the updated analysis. Item 12 also contains additional information on turbine scaling issues.

12. Can the analysis be re-run at the 300 MW penetration level to account for the recently approved wind contract being in eastern Oregon rather than southern Idaho?

   - The wind data has been updated to reflect the recently approved Elkhorn Valley wind contract (101 MW) in northeastern Oregon.

   - In the original study, the Cotterel site was included in the 300 MW penetration level as 102 MW taken from 6 extraction points. These points were moved to the Elkhorn Valley site and condensed into 5 extraction points.

   - Idaho Power also took this opportunity to remove scaling as much as possible between the penetration levels. This was accomplished by redistributing the Cotterel generation at the 600 MW penetration level to 5 sites. An additional 24 MW site was added at the 900 MW penetration level. These changes enabled a reduction in scaling by reconfiguring the build out, however 3 MW of scaling remained at one site between the 300 and 600 MW scenarios. Table 2 below (Table 5 in the original study) has been updated to reflect these changes.

Table 2. Assignment of extraction points to wind generation scenarios

Relative to Borah	Near/Name	Site	Area West to East	300 MW	600 MW	900 MW	1200 MW
West	Fossil Gulch	1	3.0	10.5	10.5	10.5	10.5
West	Tuana Gulch	2	3.0	10.5	10.5	10.5	10.5
West	Pilgrim Stage	3	3.0	10.5	10.5	10.5	10.5
West	Thousand Springs	4	3.0	10.5	10.5	10.5	10.5
West	Oregon Trails	5	3.0	10.5	10.5	10.5	10.5
West	Salmon Falls	6	3.0	21	21	21	21
West	Notch Butte	7	3.5	18	18	18	18
East	Milner Dam	8	5.0	18	18	18	18
East	Burley Butte	9	5.0	18	18	18	18
East	Golden Valley	10	5.0	10.5	10.5	10.5	10.5
East	Lava Beds	11	7.5	10.5	10.5	10.5	10.5
East	Ammon	12	9.0				
East	Ammon	13	9.0				
East	Parker	14	9.5				
East	Parker	15	9.5				
East	Ammon	16	9.0				
East	Ammon	17	9.0				
East	Ammon	18	9.0				
East	Ammon	19	9.0				
East	Ammon	20	9.0				
East	Ammon	21	9.0				
East	Basalt	22	8.0				24
East	Basalt	23	8.0				24
East	Basalt	24	8.0				24
East	Basalt	25	8.0				
East	Basalt	26	8.0				
East	Basalt	27	8.0				
East	Rockland	28	7.0			18	30
East	Rockland	29	7.0			18	30
East	Rockland	30	7.0			18	30
East	Rockland	31	7.0			18	30
East	Rockland	32	7.0			18	30
East	Rockland	33	7.0			18	30
East	Rockland	34	7.0			18	30
East	Rockland	35	7.0			18	30
East	Cotterel	36	6.0	**0**	21	21	33
East	Cotterel	37	6.0	**0**	21	21	33
East	Cotterel	38	6.0	**0**	21	21	33
East	Cotterel	39	6.0	**0**	21	21	33
East	Cotterel	40	6.0	**0**	24	24	33

Relative to Borah	Near/Name	Site	Area West to East	300 MW	600 MW	900 MW	1200 MW
East	Cotterel	41	6.0	**0**	0	24	33
West	Magic Mt	42	4.0		21	21	21
West	Magic Mt	43	4.0		21	21	21
West	Salmon Falls	44	4.0		21	21	21
West	Salmon Falls	45	4.0		21	21	21
West	Salmon Falls	46	4.0		21	21	21
West	Glenns Ferry	47	2.0		21	21	21
West	Glenns Ferry	48	2.0		21	21	21
West	Glenns Ferry	49	2.0		21	21	21
West	Glenns Ferry	50	2.0		21	21	21
West	Mt Home	51	1.0			18	21
West	Mt Home	52	1.0			18	21
West	Mt Home	53	1.0			18	21
West	Mt Home	54	1.0			18	21
West	Mt Home	55	1.0			18	21
East	Geiger 1	56	10.0				
East	Geiger 2	57	10.0				
East	Geiger 3	58	10.0				
East	Geiger 4	59	10.0				
East	Schwendiman Farms	60	9.5				
East	Windy Pass	61	7.8			10.5	10.5
West	Tennessee Mt	62	0.3				10.5
West	Glenns Ferry	63	2.0			10.5	10.5
West	Glenns Ferry	64	2.0			10.5	10.5
West	Glenns Ferry	65	2.0			10.5	10.5
West	Magic Wind	66	2.0	21	21	21	21
West	Cassia Gulch	67	2.0	18	18	18	18
West	Cassia Farm	68	2.0	10.5	10.5	10.5	10.5
West	Glenns Ferry	69	2.0				10.5
West	Glenns Ferry	70	2.0				10.5
West	Glenns Ferry	71	2.0				10.5
West	Glenns Ferry	72	2.0				10.5
Oregon	Elkhorn Valley	O-1	0.1	**21**	21	21	21
Oregon	Elkhorn Valley	O-2	0.1	**21**	21	21	21
Oregon	Elkhorn Valley	O-3	0.1	**21**	21	21	21
Oregon	Elkhorn Valley	O-4	0.1	**21**	21	21	21
Oregon	Elkhorn Valley	O-5	0.1	**18**	21	21	21
Not included in totals above							
Montana	*Horse Shoe Bend*	*M-1*	*11.0*	*9*	*9*	*9*	*9*
Montana	*Arrow Rock*	*M-2 Flat*	*11.0*	*19.5*	*19.5*	*19.5*	*19.5*

Combustion Turbines & Coal

3. Can Idaho Power utilize existing natural gas-fired combustion peaking facilities (CTs) to provide reserves and load following capability more economically than using the hydro system?

   - An independent analysis evaluated operations using several historic gas price scenarios and shapes against several historic electricity pricing scenarios. The plant under normal system operating and market conditions is generally run about 400 hours per year. The simulation evaluated running the plant for all 8,760 hours in 2005. The economics of running the existing Bennett Mountain simple cycle combustion turbine to provide 10-minute regulation at the 300 MW penetration level for year 2005 was modeled using Microsoft Excel.

   - The model results using the existing Bennett Mountain project to provide regulating reserves proved to be more costly than using the Hells Canyon Complex. The high heat rate of the plant makes the operation uneconomical during most hours of the year and therefore more costly than using the hydro system to provide reserves.

14. Can Idaho Power include the new Evander Andrews unit when investigating the use of combustion units to integrate wind?

   - The new simple cycle peaking plant will have the same operating characteristic of the existing plant described in #3. The regulation benefit of the plant when it is running is limited as it would be available only for reg-down reserves during heavy load hours during which time there is plenty of reg-down reserve available on the hydro units.

18. Run just a combustion turbine analysis (possibly using Aurora).

   - See #3 & #14.

6. Can Idaho Power modulate its coal-fired projects in order to integrate wind?

   - Idaho Power theoretically could modulate the Jim Bridger and Boardman coal-fired plants to a certain degree in order to integrate wind into its system. However, because of the low variable operating cost of these facilities, it only makes economic sense to use these resources for reg-down capability during light load hours when market prices are low and generation from the hydro system is reduced and less able to provide reg-down regulating reserves. The updated analysis includes a sensitivity case with 48 MW of reg-down reserve capability assumed from the Jim Bridger Power Plant. It is emphasized that the use of the Jim Bridger plant for this purpose is a pronounced departure from current operating practice, and is expected to be problematic considering Idaho Power's position as a non-operating partner at its jointly owned coal-fired resources. Idaho Power's coal-fired resources are typically fully dispatched and operated in a manner that minimizes thermal fluctuations and cycling. Thermal cycling increases the maintenance cost and decreases the reliability of coal-fired units. In addition, Idaho Power is not the operating partner at these facilities and a change in operations would need to be coordinated and agreed to by the operating partner. Therefore, the Company is reluctant to agree to a long-term integration cost which assumes deployment of its coal-fired resources in this manner.

- The purpose of the wind integration study was to determine the operational impacts arising from integrating wind generation, under the baseline assumption that Idaho Power's current system of generating resources, the wholesale energy market with which it interacts, and the general operating practices currently followed would be used to conduct the study.
  Idaho Power has acknowledged that as experience is gained in operating its system with greater amounts of wind generation and potential cooperative agreements between control areas are developed, a future analysis of the impact of wind generation may indicate a lower cost of integration. However, Idaho Power feels it would be imprudent to determine the current cost of integrating wind generation into its system based on the speculation of future operating conditions.

Regulating Reserves

9. Does the study double-count regulation requirements?

   - In the original study, Idaho Power assumed that regulating reserve was necessary to cover variability in high-resolution load and wind data along with instantaneous 10-minute load and wind data. These two sources of variability were combined through a root-mean-square operation, not a straight arithmetic addition. Idaho Power recognizes that the instantaneous 10-minute data may include a portion of the variability present in the high-resolution data, and consequently regulating reserves calculated from both time series may reflect double-counting. The use of smoothed (e.g. averaged) 10-minute data would rectify this situation. However, smoothed 10-minute data for wind generation were not available for the study. While the double-counting likely has a small overall effect, Idaho Power elected to consider only the 10-minute instantaneous data in regulating reserve calculations for its updated analysis, removing from consideration variability in the high-resolution data.

10. Idaho Power needs to investigate using an "all reg-down" methodology as proposed by Renewable Northwest Project.

- An all reg-down methodology of maintaining reserves was considered, but was not analyzed because Idaho Power is not prepared to commit to such a significant departure from current operating practices at this time. The asymmetric methodology used in the modeling (described in Section 4 in the discussion on revised regulating reserve requirements) is a more realistic depiction of how Idaho Power will operate using wind forecasts to maximize the hydro operational revenue.

2. What additional reserves does Idaho Power carry to maintain a CPS2 compliance level of 98%?

   - As discussed in the two public workshops, the assumed level of CPS2 compliance is a factor in the estimation of regulating reserve requirements. For its study of wind integration, Idaho Power has assumed a 98% CPS2 compliance level. Because of FERC Standard of Conduct regulations, discussions with personnel from the Company's transmission group for the purpose of quantifying the extra reserve necessary to maintain 98% compliance versus a lower level of compliance are not permitted. However, it is possible to use the methodology for estimating reserve requirements described in Section 4 of this addendum report to calculate the additional reserve imposed in the study as a result of the assumed compliance level. It is understood that relaxed compliance assumptions would reduce the estimated regulating reserve requirement for both wind study cases – the flat wind case where regulating reserve is based on analysis of load data alone, and the actual wind case where the reserve level is calculated from analysis of load data and wind data – although the reduction for the flat wind case is expected to be smaller than that for the actual wind case.

     Using the study methodology for calculating regulating reserve and an alternative compliance level of 95%, the 98% compliance level requires an additional 17 MW of regulating reserve for the flat wind case in the study. For the actual wind case at the 600 MW wind penetration level, an additional 29 MW of regulating reserve is imposed because of the 98% compliance level. While it was not estimated, it is expected that the disparity in the additional reserve between the flat wind and actual wind cases (12 MW at the 600 MW wind penetration level) would be less for the 300 MW penetration level and greater for the 900 MW scenario. It is emphasized that these estimates have relevance only with respect to the reserve levels as imposed in the study, and should not be considered to represent actual reserve relationships as applied in practice.

17. Can Idaho Power calculate the reg-down component of reserves? What about spilling wind? What about the impacts of using a 20-minute ahead forecast?

- Yes, the reg-down component of reserves can be calculated. The updated study results are based on separate (asymmetric) reg-down and reg-up reserve levels. Furthermore, the asymmetric reserve levels are defined dynamically as functions of load and wind level. That is, given a forecast load of X MW and a forecast wind of Y MW, functions have been derived to estimate the amount of reg-up/reg-down associated with each of the load and wind forecasts. These amounts are added together through a root-sum-square operation to yield a total reg-up/reg-down. This approach is considered a practical way to consider the problem of wind integration from the perspective of scheduling real-time operations. In the original study, a single, static, bi-directional, regulating margin was used for each year.

- Because of the timing issues involved in the scheduling of real-time operations in an hourly market, the use of a 20-minute ahead forecast is considered impractical. In practice, generation schedulers would be unable to derive benefit from such a forecast with regard to relying on the market to make adjustments.

- Spilling or controlling the up ramp of wind generation is an option for integrating wind generation. This option is based on an economic decision depending on the cost of the wind generation vs. the cost associated with either purchasing or carrying additional reserves on Idaho Power's system. Controlling the up ramp or curtailing wind generation was not factored into any of the regulation reserve scenarios analyzed. Winds down ramps are not controllable from the wind turbine side of the interconnection and would have no effect on reg-up reserve requirements.

- Further discussion of methods used to estimate regulating reserves is provided in Section 4 of this addendum.

<u>General Questions</u>

16. The flat wind HL/LL bias should be removed from the model.

    - In the flat wind or base case, actual wind generation was originally input as a flat block for the entire day. To address this concern, in the updated model actual wind generation has been separated into two flat blocks, one for heavy-load hours and one for light-load hours.

5. Moving wind remotely has built in a very high transaction cost. This needs to be investigated.

    - This question demonstrated some confusion in how *Vista* DSS treated the wind generation under the flat versus variable scenarios. The total wind energy is equal between scenarios on a daily basis. The available water was shaped to maximize the economics of the hydro generation subject to regulating reserve constraints. Any transaction cost differential between the flat and variable wind cases is due to the differing reserve constraints and timing of generation subject to the economic optimization algorithm in *Vista* DSS.

- In evaluating the purchase or sale of electricity outside of Idaho Power's Control Area, an average transmission "wheeling" expense of $5 per MWh was used in the *Vista* DSS model. The *Vista* DSS model accounts for this expense when making economic decisions to optimize operation of the system. This transmission expense applies to any market purchase or sale (not just wind generation) and is always a factor when considering the economics of making purchases or sales in the market.

13. Can a further breakdown of the costs associated with the $10.72 be shown in regards to the amount attributed to the hour-ahead forecast, the wind forecast error, reserves and transmission costs (delta between flat and variable case)?

    - The $10.72 cost figure has been highly processed which makes stratifying the components difficult and highly subjective. The $10.72 is a synthesis of model results from three years, interpolated to a 472 MW penetration level which is then applied to a PURPA contract price. The clearest way to think about the components of the cost is what contributes to the reserve requirements. The reserve requirements changed based on the changed variability between cases. For the workshop this equates to an hour ahead forecast error evaluated on a 10 minute time step which was used to construct a 98 percentile confidence interval formula adjusted seasonally to derive the hourly up and down regulation reserves modeled in *Vista* DSS for each of the three years. The fast fluctuation component was ignored in setting hourly reserves.

11. Market prices from year 2000 should not have been used due to market anomalies. Idaho Power needs to investigate other pricing alternatives.

    - To address this concern, 2006 market prices were used in the updated analysis for all study years.

4. Can Idaho Power utilize the regional markets to integrate wind more economically?

    - Yes, but there are limitations. The utilization of hourly regional markets is an integral part of operating Idaho Power's system. The initial study results included the utilization of both the east side market and the west side (Pacific Northwest) hourly markets to the degree transmission capacity was available to either import or export energy. Further review of the model results uncovered an exaggerated arbitrage opportunity that had an adverse impact on the results of the original study. The modeling of the regional markets was modified by setting the east side prices equal to the west side prices in order to eliminate arbitrage opportunities. The arbitrage effects were the result of large price differentials between the Mid-C and the Palo Verde markets. The perfect foreknowledge in *Vista* DSS allowed the model to take advantage of this arbitrage situation in an excessive manner. The modeling in the updated analysis removed the arbitrage opportunity by setting the prices at Mid-C levels for both markets. All other market assumptions remained unchanged in the updated analysis.

- The within hour regulating requirements, which were the focus of the study, are not available for support in the hourly market structure in which Idaho Power operates. The western electricity market operates on an hourly basis which means power is transacted in whole hour blocks and within-hour products are not available.

15. Investigate "what-if's" associated with expanding the size of the control area.

    - Utilities across the Northwest are investigating the impacts of integrating wind generation and ways of working together that would lessen the impact of the variable and intermittent nature of wind generation. Members of the Northern Tier Transmission Group (NTTG) along with British Columbia Transmission Company (BCTC) have developed and implemented an ACE Diversity Interchange (ADI) pilot program. The program pools Area Control Error (ACE) to take advantage of control error diversity (momentary imbalances of generation and load). This project and others like it will undoubtedly be developed in the future, however the focus of Idaho Power's study is to estimate the current cost of integrating wind generation. Idaho Power acknowledges the results will change over time as additional experience is gained and programs like ADI are implemented.

In this section, Idaho Power has attempted to address the questions raised at the first public workshop. These questions were the basis for additional work completed between the first and second workshops. Section 4 provides a more detailed explanation of the work completed in regards to the determination of reserve requirements. In addition, Section 4 presents the results of two sensitivity analyses performed as a result of issues raised at the first workshop.

Section 4 REVISED ANALYSIS AND IMPACTS

REVISED REGULATING RESERVE REQUIREMENTS

Since completing the original study, Idaho Power has incorporated substantive changes to its approach for estimating regulating reserve requirements. Because regulating reserve requirements are the basis for determining the cost of integrating wind, the revised estimation techniques warrant further discussion. In general, the revisions to the estimation process are related to the simulation of hour-ahead forecasts for system load and wind generation, and the ability of the *Vista* DSS model to impose regulating reserve requirements dynamically and asymmetrically.

As discussed previously in this addendum report, regulating reserve requirements in the original study were input to *Vista* DSS at a constant and bi-directional level. In this approach, the amount of regulating reserve the model was forced to carry was independent of system load and level of wind production. The reserve level carried was determined simply by calculating the amount of bi-directional regulating reserve covering 98% of the variability in both load and load net wind. In the revised approach discussed here, the regulating reserve level for a given hour is determined as a direct function of the projected load and wind generation for that hour. This results in decreased regulating reserve requirements, and consequently lower wind integration costs. A detailed description of the previous method used to calculate reserve requirements can be found in Section 6 of the original study report. A discussion of the revised process developed in work leading up to the June 20, 2007 public workshop follows.

LOAD REG-UP / REG-DOWN

The first step in the investigation was to develop a process for representing system regulating reserve requirements associated with variability and uncertainty in load alone. The objective is to estimate the amount of regulating reserve needed to cover deviations in 10-minute instantaneous measurements of load from hourly average load as forecast on an hour-ahead basis. This is based on the premise that the hour-ahead forecast load dictates the generation scheduling (and market activity) for the next operating hour, and deviations from that forecast load must be managed by increasing or decreasing the output of other generating units. Deviations from the hour-ahead load forecast occur because (i) the 10-minute instantaneous load data are variable, and (ii) the hour-ahead forecast is in error. That is, even if the load forecast is exactly correct as evaluated on an hourly average basis, deviations occur simply because the instantaneous load varies above and below the observed average during the course of an operating hour. Conversely, even if instantaneous load somehow remains constant during the course of an operating hour, deviations occur unless the load forecast is exactly correct.

To mimic load forecast error, a random error was applied to each hourly average load. For example, consider an hour for which the six 10-minute instantaneous load readings average to 2,000 MW. If the randomly selected error for the hour is -1.00%, then the hour-ahead forecast hourly average load is considered to be 1,980 MW. The randomly selected errors follow a normal distribution having a mean of 0.0%, standard deviation of 1.3%, and an average absolute error of 1.0%. The distribution of the 8,760 errors used for calendar year 2005 is shown in Figure 1 below.

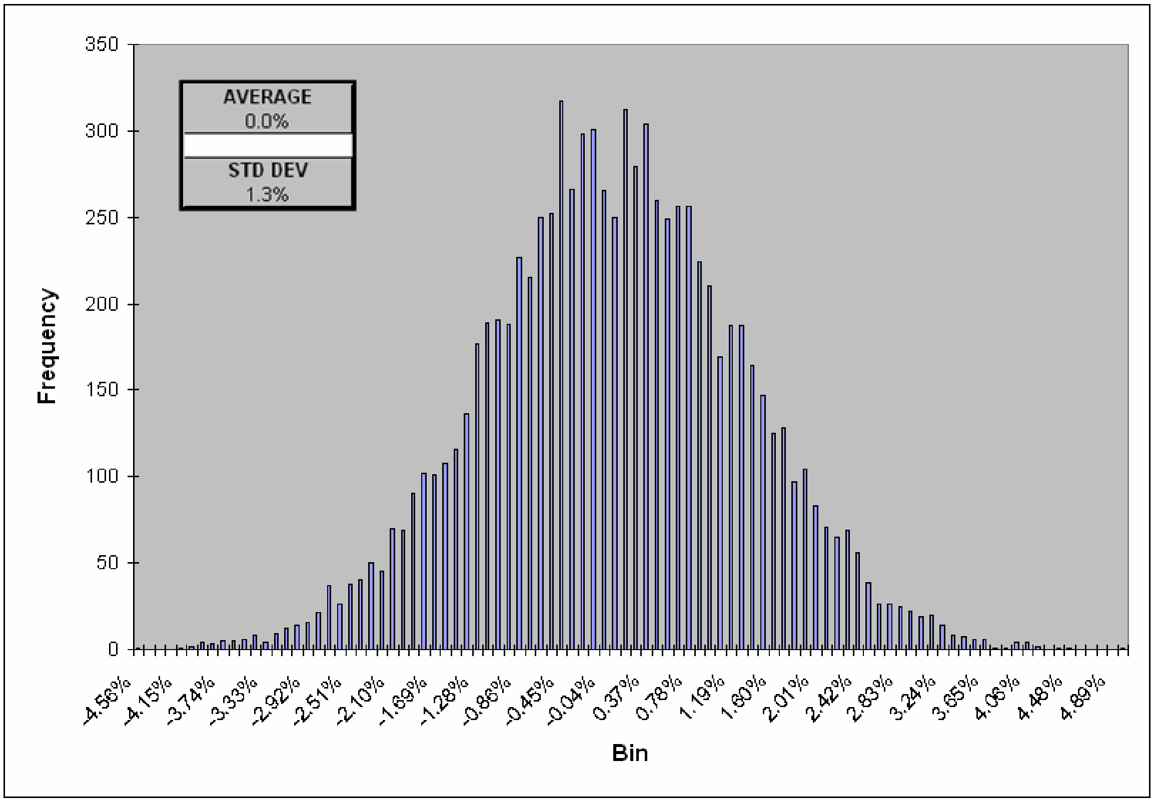

Figure 1. Distribution of errors for hour-ahead forecast load

Taking into account the variability in the 10-minute load measurements and the error in the hour-ahead load forecast, Idaho Power must schedule resources with an expectation of how much higher or lower system load might be during the actual operating hour relative to forecast hourly average system load. Using calendar year 2005 load data, an hourly time series representing the hour-ahead load forecast was devised using the process described above for calculating forecast load. The actual 10-minute load data were then compared to the hourly forecast loads. The data were binned according to the forecast load, resulting in the curves shown in Figure 2.

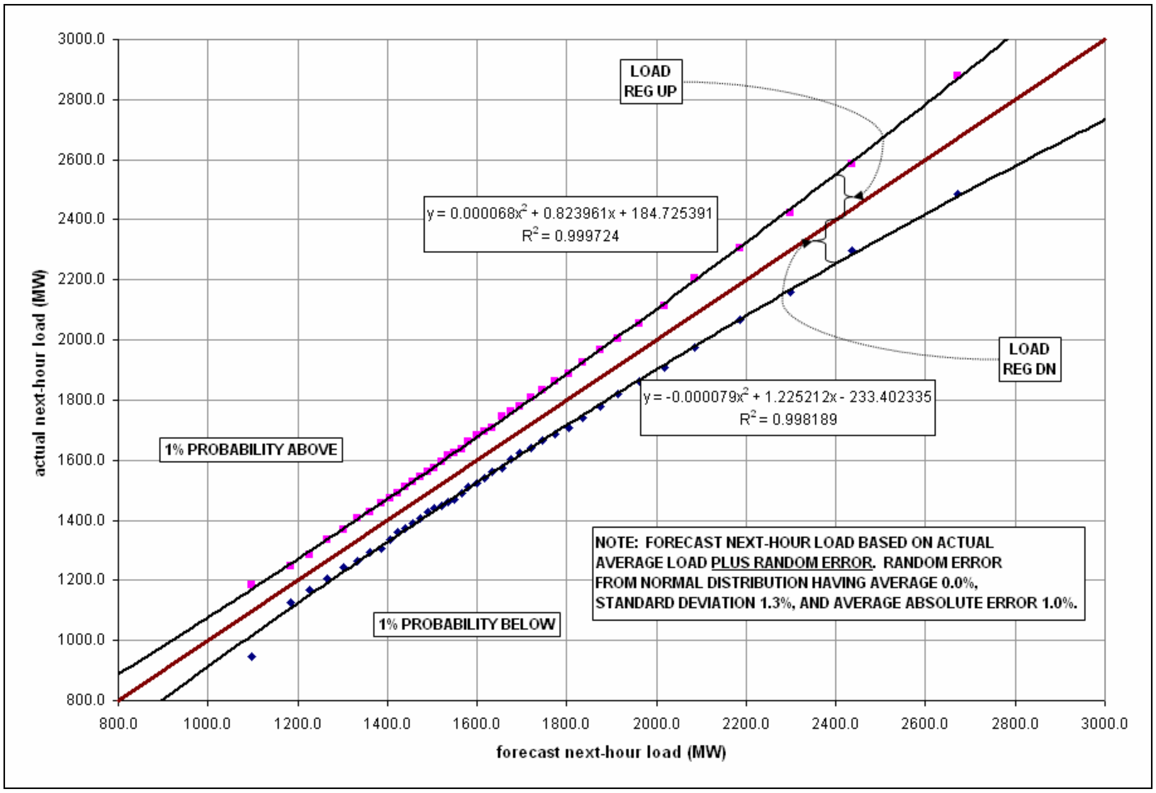

Figure 2. Actual operating hour load vs. forecast hour-ahead load

Based on a simple empirical analysis of the data, the probability of observing a 10-minute system load measurement exceeding the upper fitted line above is 1%. Similarly, the probability of a 10-minute system load measurement less than the lower fitted line is 1%. For example, given an hour-ahead load forecast of 2,400 MW, there is a 1% probability of observing a 10-minute load measurement exceeding 2,554 MW and a 1% probability of observing a 10-minute load less than 2,252 MW. In other words, the power system dispatcher can have 98% confidence that the system load (at least as measured at 10-minute intervals) will remain between 2,252 MW and 2,554 MW. Therefore (neglecting any interaction with wind), to assure CPS2 compliance of 98%, Idaho Power should allow for 154 MW of reg-up reserve to cover possible upward movement in load (relative to forecast load) and 148 MW of reg-down reserve to cover possible downward movement in load. It is important to note that this explanation has yet to consider the L_{10} band. That is, the above-noted 154 MW of reg-up reserve was derived based on the assumption that generation/load imbalances need to be reconciled to a balanced position. However, CPS2 regulations require only that imbalances are reduced to within a utility's L_{10} level, which for Idaho Power is 38.52 MW. Consideration of the L_{10} level will be discussed in a later step.

WIND REG-UP / REG-DOWN

In this case, the objective is to estimate how much regulating reserve is needed to cover deviations in 10-minute instantaneous measurements of wind generation versus hourly average wind generation as forecast on an hour-ahead basis. As with load, deviations from the forecast wind generation must be managed by increasing or decreasing the output of other generating units. Also similar to load, deviations between instantaneous wind generation observed during the course of an operating hour and the associated hour-ahead hourly average wind generation forecast come about for two reasons:

i.) the instantaneous wind generation during the course of the operating hour varies above and below the hourly average, and

ii.) the hour-ahead hourly average wind forecast is in error.

With regard to wind generation, an hour-ahead forecasting process can be simulated through the use of an autoregressive time-series model expressing hourly average wind generation for an operating hour as a function of the six 10-minute readings occurring 65, 75, 85, 95, 105, & 115 minutes prior to the start of the operating hour (e.g. wind generation forecast for 9:00-10:00 is a function of instantaneous wind at 7:55, 7:45, 7:35, 7:25, 7:15, & 7:05). The hour-ahead wind forecasting utilized in the study was further refined through the derivation of season-specific forecast models (i.e. separate winter, spring, summer, and fall forecast models). The autoregressive forecast technique is a marked improvement over the persistence forecast used in the original analysis (February 2007 report), where the hourly average wind generation was forecast to persist from the wind generation occurring at 65 minutes prior to the start of the operating hour.

The fundamental question for the power system dispatcher is similar to the load alone case – given an hourly average wind forecast, how much higher or lower might system wind generation be during the actual operating hour? Using calendar year 2005 wind data, the following curves were derived. It should be noted that Figure 3 is provided for illustration purposes only. The actual seasonal hour-ahead wind forecast models differed slightly from the example presented below:

> *Given an hour-ahead wind forecast of 300 MW, there is a 1% probability of observing a 10-minute wind measurement exceeding 428 MW and a 1% probability of observing a 10-minute wind measurement less than 162 MW. In other words, Idaho Power can have 98% confidence that the wind generation (at least as measured at 10-minute intervals) will remain between 162 MW and 428 MW. Therefore, to assure CPS2 compliance of 98%, Idaho Power should allow for 138 MW of reg-up reserve to cover possible downward movement in wind generation (relative to forecast wind) and 128 MW of reg-down reserve to cover possible upward movement in wind generation. Consideration of the* L_{10} *band, which is essentially the extent to which loads and resources can be out of balance*

without constituting a control performance violation, will be reserved for the following discussion on total regulating reserve requirement.

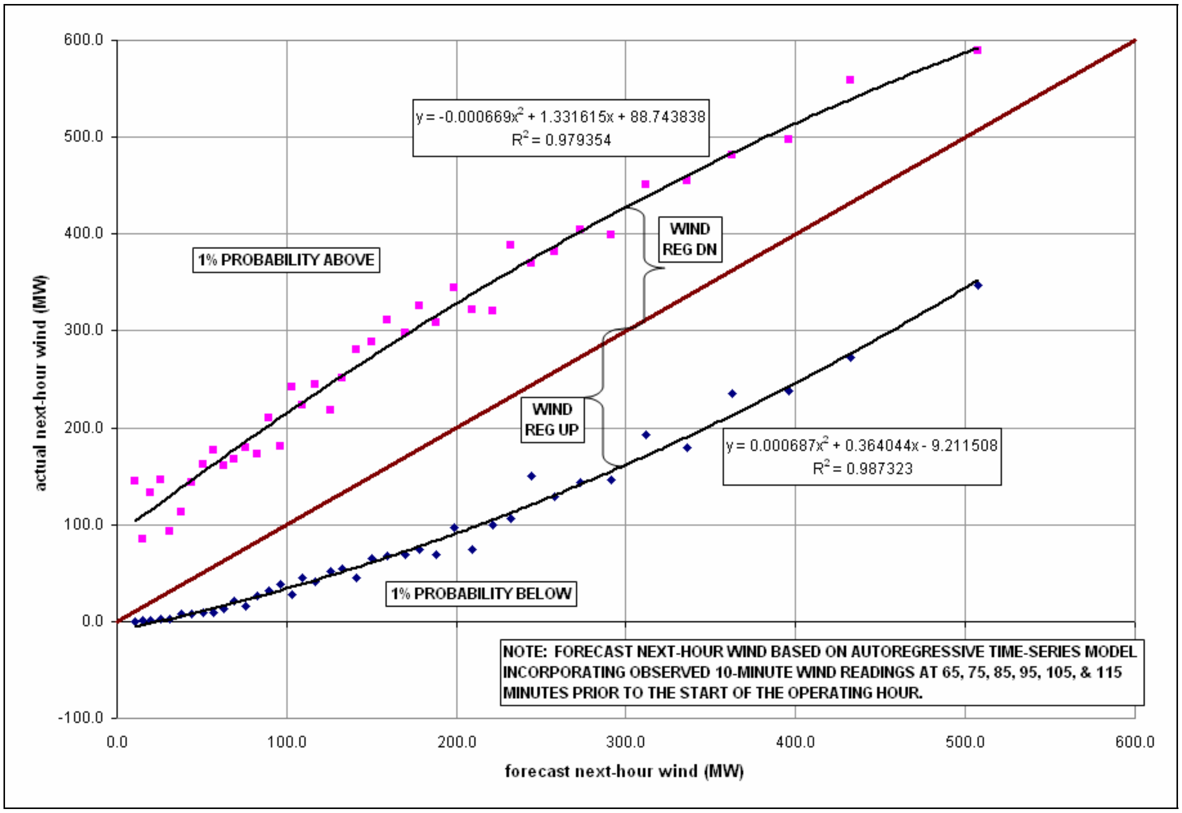

Figure 3. Actual operating hour wind vs. forecast hour-ahead wind

TOTAL REG-UP / REG-DOWN

In typical real-time operations, load and wind generation share the characteristic of being largely outside the control of the electrical load serving entity. Other factors in the load/resource balance are either dispatchable or highly predictable in the time frame of real-time operations. For example, generation at a run-of-river hydroelectric plant on an hour-ahead basis is very predictable, barring unforeseen outages related to equipment failure.

Because of the similarity between load and wind with respect to real-time operations, it is useful to couple their separate regulation components into a single total regulating reserve level. It is understood that because of interaction between load and wind, a straight arithmetic sum of the separate components results in reserve levels that are inappropriately high. Using the examples given in each section, the load forecast of 2,400 MW requires 154 MW of reg-up reserve and the wind forecast of 300 MW requires 138 MW of reg-up reserve. It would likely be excessively conservative for a system to carry reserve equal to the sum of these components (292 MW). For modeling purposes, Idaho Power combined the components through a root-sum-square operation. Using the same example, the total reg-up reserve calculated in this manner would equal:

$$\text{Total Reg-up} = \text{SQRT}\left[(154\ \text{MW})^2 + (138\ \text{MW})^2\right] = 207\ \text{MW}$$

At this point, the L_{10} band can be applied, resulting in a reg-up reserve requirement of 168 MW (207 MW – 38.52 MW). This process can be followed to generate an hourly regulating reserve time-series for each study year and wind penetration level that is a dynamic and asymmetric function of hour-ahead forecast load and wind. Table 3 provides average regulating reserve levels calculated by the above described process, where the load reg-up reserve and load reg-down reserve columns are averages for the load alone (flat wind) cases and the load net wind columns are for the root-sum-square combined load and wind.

Table 3. Average levels of regulating reserve by wind penetration level

Wind Penetration Level (MW)	Load Reg-up (MW)	Load Reg-down (MW)	Load Net Wind Reg-up (MW)	Load Net Wind Reg-down (MW)
300	51.4	49.8	66.8	74.8
600	51.4	49.8	87.4	104.3
900	51.4	49.8	109.4	140.3

REVISED MODEL INPUTS

As part of its continuing study of wind integration following the March 15, 2007 public workshop, Idaho Power recognized six primary modeling revisions expected to improve the accuracy of the study results. The incorporation of these changes produced an overall decline in the estimated cost to integrate wind generation. In this section, the individual revisions and their associated cost impact are described. It is emphasized that interdependence between the modeling revisions make it difficult to isolate the cost impact attributable to an individual modification, consequently the cost impacts presented in this section should be considered approximate. The estimated cost impacts can be considered indicative of the effect of the utilized modeling revisions in a relative sense. A summary of the *Vista* DSS modeling changes used in the updated wind integration cost determination are summarized below:

1. In the original study, wholesale electricity markets to the west and east of Idaho Power's system were respectively assigned historical observed prices reported for the Mid-Columbia (Mid-C) and Palo Verde (PV) electricity markets. Price differences between these two markets caused the *Vista* DSS model to consistently take advantage of arbitrage opportunities across Idaho Power's system. While in practice these opportunities do occur on occasion, review of the modeling results indicated that *Vista* DSS's arbitrage activity was far too frequent

and preferential to the flat wind case. Therefore, the arbitrage opportunity was removed by replacing the PV price data for the wholesale market to the east with Mid-C prices. Thus, the two markets available to the model contained equivalent price data, thereby removing the arbitrage opportunity across Idaho Power's system. The elimination of this arbitrage opportunity had a significant impact and resulted in a reduction of the wind integration cost of approximately $1.00/MWh.

2. In the original study, regulating reserves were imposed by the *Vista* DSS model at a constant and bi-directional level. Since completion of the original study, Synexus Global has incorporated the ability to input asymmetric reserve requirements into the model. This new feature coupled with the ability to specify dynamic reserves on an hourly basis has allowed the assignment of varying levels of reg-up and reg-down regulating reserves on an hourly basis. These reserve levels are considered to more realistically simulate the connection between reserve obligation and load/wind conditions than the constant, bi-directional reserves used in the original study. The impact of this change was also significant and reduced the wind integration cost by approximately $1.00/MWh.

3. As discussed in Section 3 of this addendum report, it was suggested in the workshop process that the reserve estimation methodology of the original study "double-counted" the amount of necessary reserves. To remove the potential for double-counting, Idaho Power excluded high-resolution load and wind data from the reserve estimation process, and instead based its estimates on the amount of reserve necessary to cover variability solely in the instantaneous 10-minute data for load and wind. This change had a small impact and reduced the wind integration cost by approximately $0.10/MWh.

4. In the original study, the flat wind case was constructed such that wind generation was input at constant levels by day. The 24 hourly wind generation levels were set equal to each other, and equal to the average generation for the day. However, because average light load generation in the synthetic wind time series exceeded heavy load, the value of the flat wind case was favorably biased prior to consideration of any effects related to wind integration. To remove this bias, the design of the flat wind case was modified such that wind generation was separated into flat blocks for both heavy load and light load hours. This change resulted in lowering the wind integration cost by approximately $0.25/MWh.

5. The distribution of wind projects used to model the 300 MW penetration level was updated to reflect selection of the Elkhorn Valley Wind Project (Horizon) in northeastern Oregon in Idaho Power's recently concluded wind RFP. The 300 MW penetration level was amended to include the Elkhorn Valley project and to move the southern Idaho Cotterel site to higher penetration levels. Overall, 100 MW from the Elkhorn project was added to the 300 MW scenario and 100 MW from the Cotterel site was removed. In addition, the sizes of several individual extraction points were adjusted to address scaling issues between the

300, 600 and 900 MW penetration levels. This change provided a greater diversification of the wind resource and resulted in a reduction in the wind integration cost of approximately $0.20/MWh.

6. The wind forecasting methodology used in the model was improved by utilizing a seasonal, autoregressive method rather than a persistence forecast taken at 65 minutes before the hour. This change reduced the wind integration cost by approximately $0.25/MWh.

SENSITIVITY RUNS

In addition to the modifications mentioned above, Idaho Power performed additional *Vista* DSS simulations for the purpose of exploring the sensitivity of the results to two issues raised at the public workshops: 1) the use of actual Mid-C market prices as recorded for the three study years, and 2) using the Jim Bridger coal-fired generating facility for reg-down reserves.

The selection of these factors for sensitivity testing is a product of the workshop process, where considerable discussion was focused on the market price assumptions used in the *Vista* DSS modeling and the practicality of providing regulating reserve with resources other than the Hells Canyon Complex. These sensitivity results are considered exploratory, and are not included in Section 5. The updated study results provided in Section 5 are based on a feasible modification of current operating practices for Idaho Power's generating resources.

MARKET PRICE ASSUMPTIONS

In the updated work since the completion of the original study, Idaho Power selected Mid-C prices recorded for calendar year 2006 for modeling. The use of actual prices in the original study received considerable attention at the workshops, particularly with regard to calendar year 2000 prices. As a consequence, it was decided for the updated work to input prices observed for calendar year 2006 for all three study years. The following table provides the results of the sensitivity test in which the actual market prices observed in the three study years were restored, with all other modeling revisions discussed in this section implemented. The results of this analysis are presented in Table 4 and Figure 4.

Table 4. Modeling results as a percentage of market prices using actual market prices and no Bridger coal plant for regulating reserves

Study Year	300MW	600MW	900MW	AVG Market Price
1998	14.3%	14.1%	19.5%	$27.61
2000	5.8%	11.0%	17.2%	$132.17
2005	6.1%	10.6%	15.0%	$58.19
Average	8.7%	11.9%	17.2%	
PURPA Wind Contract:	$62.40	$62.40	$62.40	
Wind Integration Cost:	$5.43	$7.41	$10.75	
Adjusted PURPA Wind Contract:	$56.97	$54.99	$51.65	
Interpolated Wind Integration Cost at 492 MW:		$6.70		

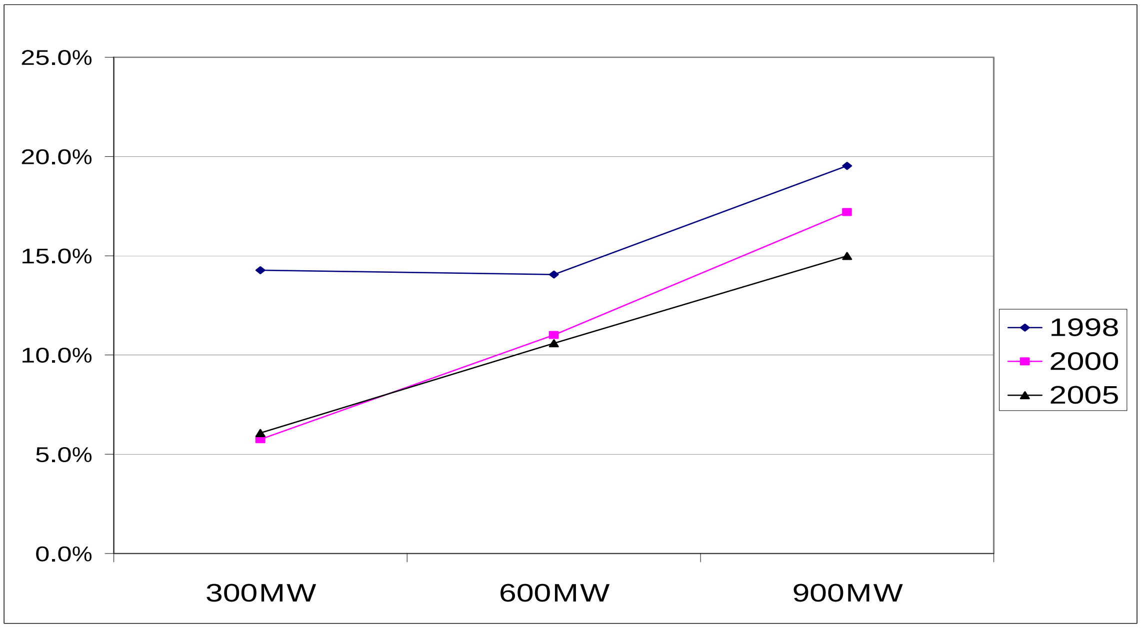

Figure 4. Modeling results as a percentage of market prices using actual market prices and no Bridger coal plant for regulating reserves

JIM BRIDGER REGULATING RESERVE

The second sensitivity analysis illustrates the impact of using thermal units to provide reg-down reserves. To incorporate the reg-down capability assumed to be provided by Jim Bridger, the thermal units were not actually modeled providing reserves; rather the reserve requirement was reduced on the Hells Canyon Complex. It is important to note that cycling these units would result in increased maintenance costs which are difficult to quantify and are not included in the results presented in Table 5 and Figure 5. Additional discussion of the use of Jim Bridger for this purpose is included in response to item 6 in

Section 3 of this addendum report. All other modeling revisions discussed previously in this section were implemented for this analysis.

Table 5. Modeling results using 2006 market prices and the Bridger coal plant for regulating reserves

Study Year	300MW	600MW	900MW	AVG 2006 Price
1998	21.9%	19.4%	22.9%	$44.44
2000	-0.8%	4.9%	12.1%	$44.44
2005	2.8%	6.1%	11.2%	$44.44
Average	8.0%	10.1%	15.4%	
PURPA Wind Contract:	$62.40	$62.40	$62.40	
Wind Integration Cost:	$4.98	$6.33	$9.60	
Adjusted PURPA Wind Contract:	$57.42	$56.07	$52.80	
Interpolated Wind Integration Cost at 492 MW:		$5.84		

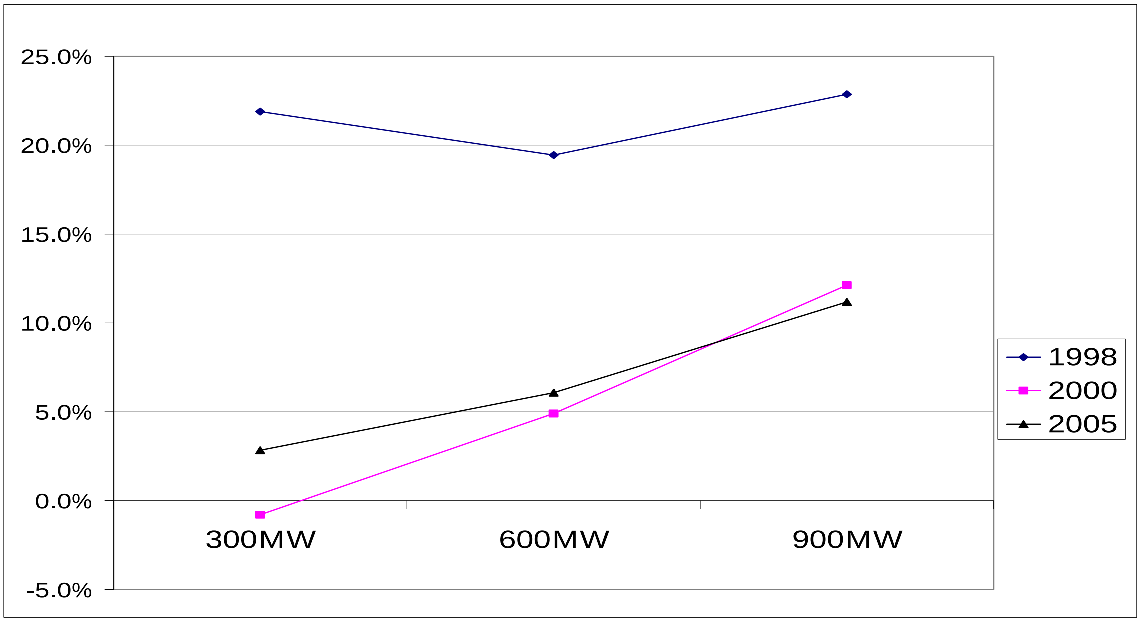

Figure 5. Modeling results using 2006 market prices and the Bridger coal plant for regulating reserves

The determination of required regulating reserves is a major component of Idaho Power's wind integration study and this section has provided details of the work completed in the time since the original study was published. Section 5 presents the updated study results in regards to the cost of integrating wind generation on Idaho Power's system.

Section 5 UPDATED STUDY RESULTS

In the updated study, Idaho Power incorporated the six primary modeling revisions described in the previous section to derive a new estimated cost to integrate wind generation. Table 6 and Figure 6 below show the results of the updated analysis and integration costs by study year as a percentage of 2006 market prices. Table 6 also summarizes the average wind integration cost by penetration level.

Table 6. Updated modeling results as a percentage of 2006 market prices without use of the Bridger coal plant for regulating reserves

Study Year	300MW	600MW	900MW	AVG 2006 Price
1998	15.1%	15.7%	18.1%	$44.44
2000	7.4%	11.2%	12.4%	$44.44
2005	5.0%	17.1%	14.5%	$44.44
Average	9.2%	14.7%	15.0%	
PURPA Wind Contract:	$62.40	$62.40	$62.40	
Wind Integration Cost:	$5.72	$9.15	$9.35	
Adjusted PURPA Wind Contract:	$56.68	$53.25	$53.05	

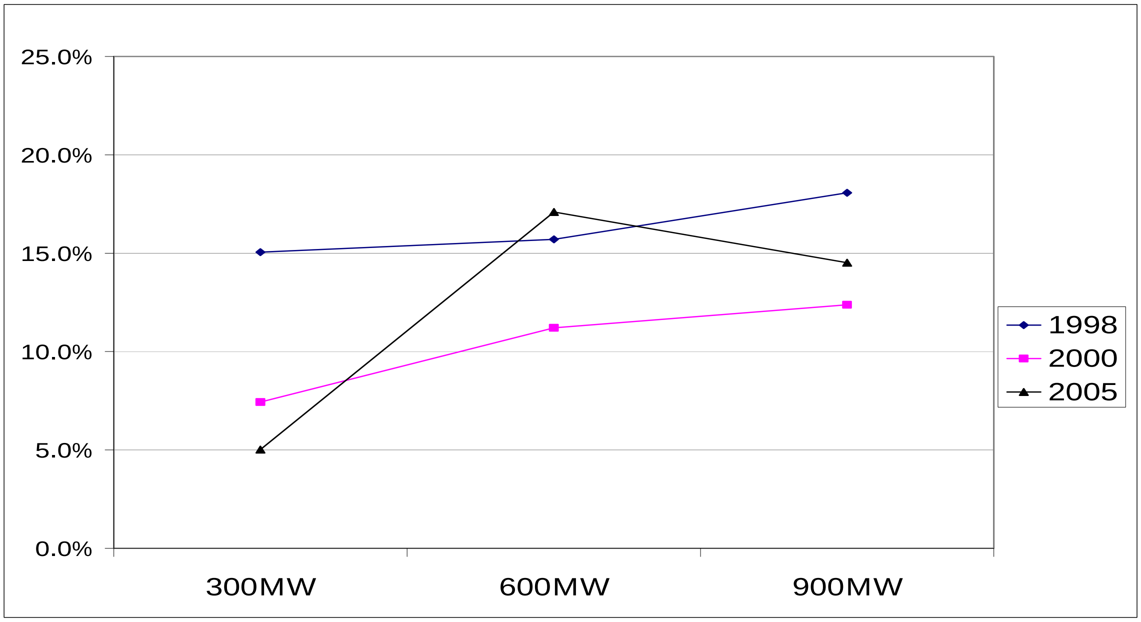

Figure 6. Updated study results as a percentage of 2006 market prices without use of the Bridger coal plant for regulating reserves

Figure 7 shows Idaho Power's estimate of the cost it will incur (in \$/MWh) to accommodate wind generation for a range of penetration levels for both the initial and updated studies. Study results suggest that as wind penetration levels increase, the resulting reserve requirements at higher wind penetration levels will ultimately overwhelm the current system's reserve capacity. Idaho Power believes that given current technology and market structure, the upper limit on the amount of wind generation that can be integrated on its current system lies between 600 and 900 MW. At the time the original study was completed, Idaho Power had signed contracts or commitments to develop 384 MW of wind generation. It should be noted that 600 MW of wind generation corresponds to a penetration level of approximately 19% (according to the convention of expressing penetration level as percentage of peak system load), which is an ambitious level of development by current standards.

To arrive at a single cost estimate to account for system impacts due to wind integration, Idaho Power proposed using the estimated cost at the midpoint of wind development between the current committed level of 384 MW and 600 MW utilizing current PURPA rates to convert from percent of market to a dollar amount. In the original study, the cost at this midpoint level (492 MW) was estimated via a 3rd order line fitted to the original study results. This cost (\$10.72/MWh) is illustrated in Figure 7 below. In the updated study, the cost at this midpoint level (492 MW) is estimated via linear interpolation between the updated study results at 300MW and 600MW. This process results in a wind integration cost of \$7.92/MWh and is also illustrated in Figure 7 below.

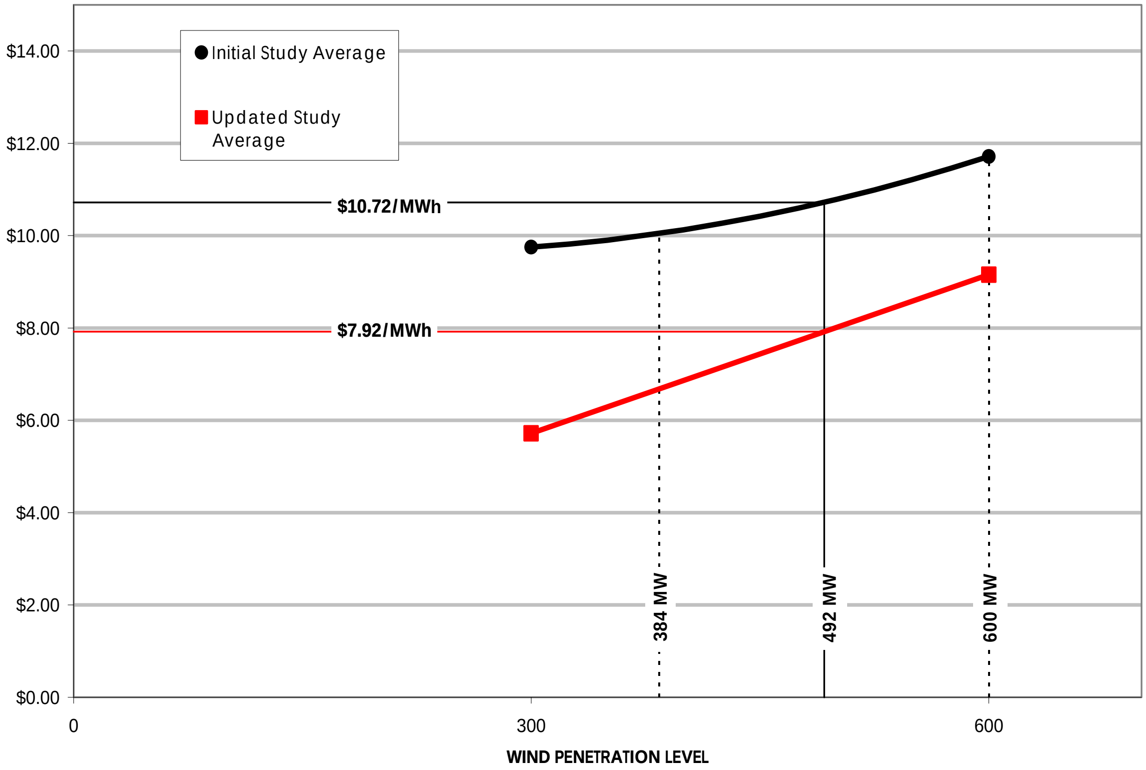

Figure 7. Idaho Power's updated cost estimate (in \$/MWh) for wind integration

Idaho Power supports society's desire to have future energy supplies that come from clean, renewable energy sources. Renewable, emission-free electricity production has been a part of our company's history for over 90 years and wind power will be an important part of continuing that legacy. One thing is for certain – the cost of wind integration will change over time. Regional wind integration efforts, improvements in wind forecasting, regulatory changes and actual "hands-on" experience will all have an impact on the cost of integrating wind energy. In recognition of this fact, Idaho Power will continue to evaluate wind integration costs as model assumptions change and new and improved study methods are developed.