EnerNex
CORPORATION

Final Report
Avista Corporation Wind Integration Study

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EXECUTIVE SUMMARY

The variability and uncertainty of wind energy production require that power system operators take measures to manage its delivery. These measures may increase the cost incurred to balance the system and maintain reliability. Over the past nine years, a number of investigations have been conducted by electric utility organizations across the country and around the world to better characterize and quantify the impacts of wind generation on the operation of the grid.

This report documents an analysis conducted by Avista Corporation to quantify the incremental costs to operations associated with integrating wind generation into its control area. Four levels of wind generation were studied: 100 MW, 200 MW, 400 MW, and 600 MW. These generation levels are equivalent to 5% to 30% of control area peak load. EnerNex Corporation of Knoxville, Tennessee was retained by Avista to guide in the construction and application of a methodology which has been used in many of the previous U.S. studies.

Avista's present work builds on analyses completed in 2001/2002. A proprietary Avista System Integration LP Dispatch Model ("Avista LP Model", or "LP Model"), driven by a linear programming engine, optimizes operations with and without wind generation in the utility's system (Figure 1). This hourly LP Model tracks various capabilities (e.g., up and down load following, regulation, energy, storage) of Avista's system to meet system loads at least cost. It contains four modules. The first two optimize hydro generation on a daily basis at the Mid-Columbia and Clark Fork projects, tracking constraints such as maximum and minimum storage and generation levels, and minimum flow. A third creates the hourly pre-schedule, taking daily hydro quantities and allocating them across the highest value hours possible given the remaining system constraints. The pre-schedule LP Model contains day-ahead forecasts of load and wind generation. Purchases and sales made to balance system requirements are carried forward to the real-time module. The real-time module re-optimizes utility resources given the new forecasts for wind and load. It performs tasks similar to the pre-schedule module.

The analysis of wind generation is based on simulating Avista's short-term scheduling and dispatch operations over an extended chronological period. The primary inputs to this simulation process are chronological profiles of system load, wind generation, and market prices for energy purchases and sales. Load and market price data are extracted from archives, but acquiring the wind generation data is much more challenging. Recent studies show that a high-fidelity, long-term, chronological representation of wind generation is the most critical study element. For large wind generation development scenarios, it is very important that the effects of spatial and geographic diversity be neither under- nor over-estimated.

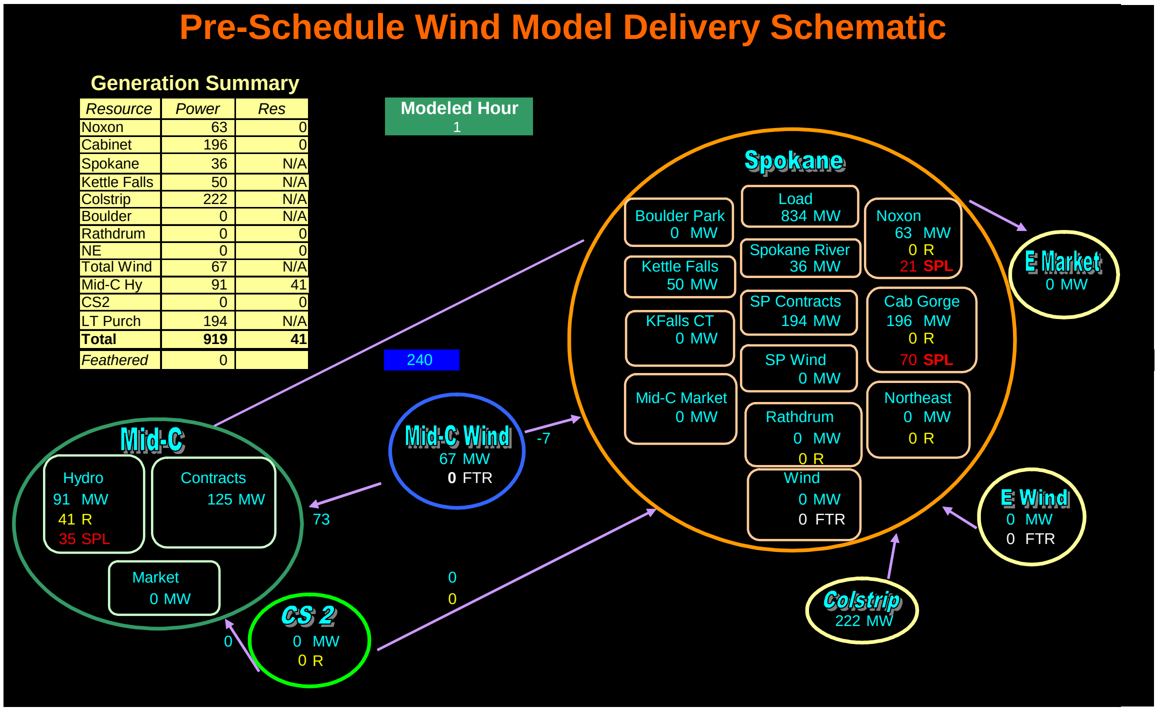

Figure 1: Schematic of Avista LP program – Pre-schedule module

The long-term wind speed data base compiled by Oregon State University's (OSU) Energy Resources Research Laboratory (ERRL) was used as the basis for the chronological wind generation model. Specifically, data from the five historical Bonneville Power Administration (BPA) sites, along with observations from the operating wind plant at Vansycle, were selected as the reference data points. Using methods and algorithms developed in earlier studies, EnerNex utilized the wind speed data to generate high-resolution wind energy production profiles. Annual chronological records of wind generation at 10-minute and hourly resolutions (Figure 2) were used in analysis of wind generation impacts on Avista real-time operations, and were a critical input to the annual dispatch simulations from which integration costs were derived.

Annual capacity factors for the four base wind generation scenarios are documented in Table 1. These capacity factors were adjusted to a consistent 33% in the final calculations of wind integration costs presented later in this study. The portion of Avista load being served by wind generation over each hour of the study year is shown for each scenario in Figure 3.

Table 1: Annual Capacity Factor by Scenario (from LP Model data)

Scenario	Unadjusted Capacity Factor
100 MW	34.0%
200 MW	33.9%
400 MW	30.5%
600 MW	30.5%

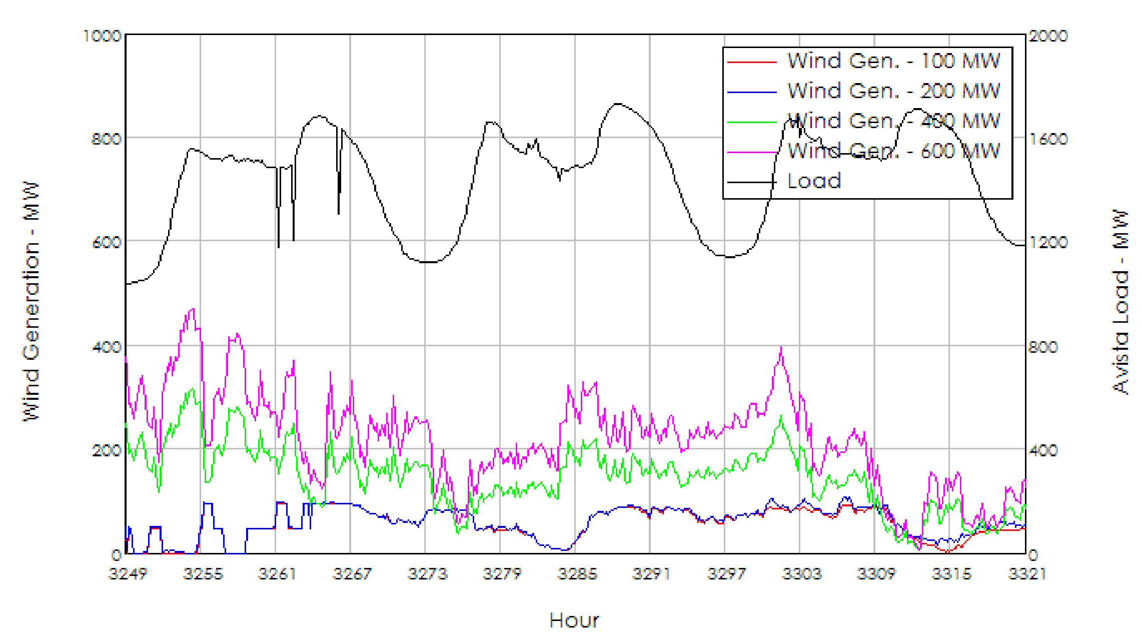

Figure 2: High wind period (3 days) showing load and wind generation by scenario.

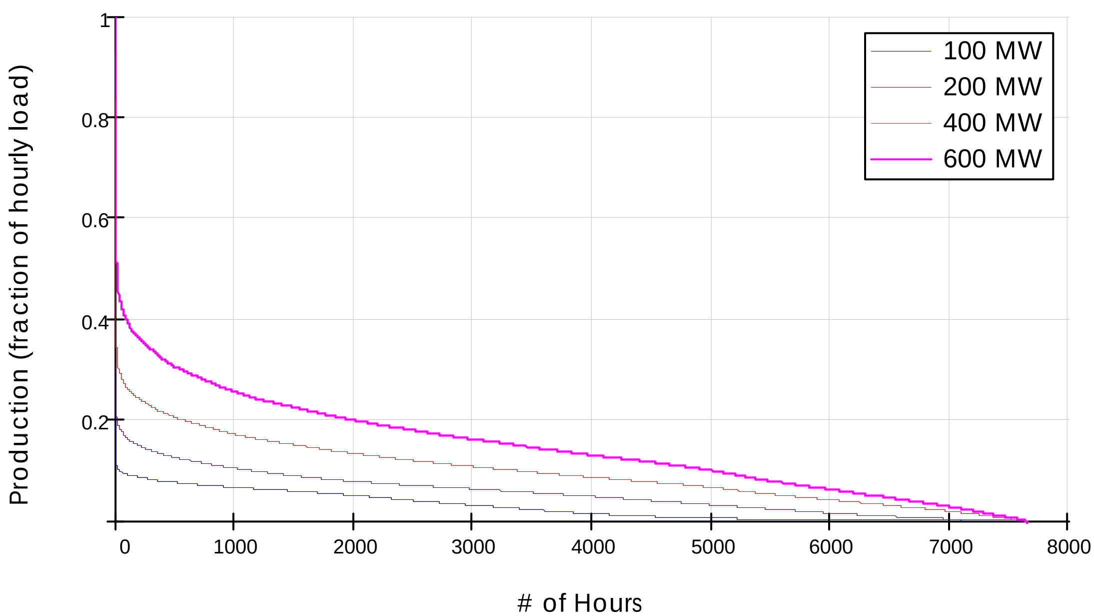

Figure 3: Wind generation "penetration duration" curves for four wind scenarios.

Annual dispatch simulations were conducted using hourly load and wind generation data, as is the norm for these types of studies. Consequently, it was first necessary to assess how wind generation would impact Avista operations inside the hour. Here, generation is continuously adjusted to balance load and obligations for out-of-area transactions. Additionally, generation capacity must be held in reserve to cover sudden losses of other generation or transmission facilities. The variability of wind generation will increase the level of variation already seen and managed by power system operators, so the amount of capacity available to operators to balance the control area is increased. The objective of the intra-hour analysis was to quantify this increase in reserve capacity so that it could be represented in the hourly dispatch simulations.

Various mathematical and statistical analyses were used to quantify these impacts. From high-resolution load and wind generation data, the amount of additional generation capacity needed to manage the system in real time were extracted by applying algorithms used in previous studies and some new approaches developed for specific operating practices prevalent in the Pacific Northwest. Results of the analysis (documented in detail in a later section) are shown in Table 2.

Table 2: Total Reserves for Variability and Schedule Deviations

Case	Average Hourly Flexibility for Variability (+/-)	Average Hourly Flexibility for Variability and Schedule Deviation (+/-)
Load only	20 MW	35.0 MW
100 MW	22.1 MW	38.3 MW
200 MW	24.1 MW	49.5 MW
400 MW	27.9 MW	68.7 MW
600 MW	31.0 MW	103.7 MW

Reserve requirements for load alone and the various levels of wind generation are brought forward as inputs to the dispatch simulations. Because the time step is hourly, the generation movements to balance load inside the hour are not actually simulated directly. Instead, they become constraints on the scheduling and economic dispatch algorithms, and increase costs over the course of the simulation since those capacity amounts cannot be used to serve load or cover out-of-area sales.

While there is no formal definition for "integration cost", in the context of this study and the others performed over the past several years it is the reduction in value of wind energy due to its variability and uncertainty. So, to quantify integration cost, metrics from the simulated scheduling and dispatch of actual wind generation (from the LP Model) are compared to those of a resource that delivers an equivalent amount of energy but has no variability and can be forecast perfectly.

Integration costs for the four base wind generation scenarios are shown in Table 3. It should be noted that integration costs are functions of a large number of factors, and changes to any one of those assumptions could change the results. The results presented here, then, must also be viewed in the context of the assumptions made, the composition of Avista resource portfolio, and the rules and policies by which utilities operating in the Pacific Northwest currently abide.

That said, the results are consistent with findings of a number of studies conducted over the past four years. The 600 MW scenario represents a level of wind generation penetration (30%) at or above the highest level which has been studied in detail by earlier studies.

Table 3: Integration Costs for Base Scenarios (33% capacity factor)

Wind Location	Wind Capacity	System Penetration	Forecast Error	Cost ($/MWh)	Cost (% Mkt)
Columbia Basin	100 MW	5%	15%	$2.75	5.0%
50/50 Mix of CB & MT	200 MW	10%	10%	$6.99	12.7%
Diversified Mix	400 MW	20%	8%	$6.65	12.1%
Diversified Mix	600 MW	30%	8%	$8.84	16.1%

Beyond the results for the base scenarios, the sensitivity of computed integration costs to a number of assumptions was evaluated through additional annual dispatch simulations. A number of observations and conclusions were drawn from these cases; they are reported qualitatively in the following paragraphs, and in the Results section of this report.

HIGHER WIND PENETRATION EQUALS HIGHER INTEGRATION COST

The Avista study confirms what other studies before it have theorized or shown through analysis. Higher wind penetration levels, all other things being equal, increase wind integration costs. To provide a full understanding of wind integration costs, this study ran the LP Model through varying levels of wind penetration, from five percent up to approximately thirty percent. This wide range covers where many systems are today, and pushes the envelope well beyond the 20% level cited as the point below which wind can be accommodated with only modest cost impacts.

INTEGRATION COSTS ARE CORRELATED WITH MARKET PRICES

Capacity opportunity costs are a significant component of wind integration. As prices rise, all things equal, one might expect integration costs to rise as well. Wind resource value, therefore, does not rise equally with the market price, as integration costs consume some of the additional value. Avista used the LP Model to look at two price sensitivities − market prices equal to half of forecasted levels, and twice forecasted levels − and found that market prices and wind integration costs are correlated.

SHORTER-TERM MARKETS CAN REDUCE COST OF VARIABILITY

In this study, the increased short-term uncertainty due to wind generation forecast errors increased the amount of reserve capacity required to operate the system. Much of this is driven by rules that govern short-term exchanges of energy in the Pacific Northwest. Because the “window” for hourly trading closes well in advance of the hour, probable errors in wind generation forecasts become significant.

While improvements in wind generation forecasting can assist, reduction of the lead time for energy transactions would also have an influence. In regions with well-functioning short-term energy markets (some cleared at intervals as short as 5 minutes), variability in demand due to both wind generation and load variability is spread out over a much larger footprint. When the aggregation effects on variability over this larger geographical area are considered, the net effects on system operation can be substantially reduced.

RISING FORECAST ERROR INCREASES INTEGRATION COST

Forecast error affects the overall level of reserve capacity necessary to integrate wind resources. As forecast error rises, so do integration costs. Many participants to the wind integration debate disagree on how accurate wind forecasts, and hence forecast error, are. This study strives to identify an appropriate level of reserves to account for forecast error; the debate will continue. To this end, Avista ran its LP Model under various levels of forecast error, from zero percent, or perfect foresight, to thirty percent.

GEOGRAPHIC DIVERSITY HAS DIRECT INFLUENCE ON INTEGRATION COSTS

Additional generation capacity must be reserved to manage increased control area variability and uncertainty. This capacity is a major component of integration cost. Wind plants concentrated in a small region will exhibit a much higher degree of correlation in their output than plants separated by larger geographic distances.

OPERATIONAL COORDINATION BETWEEN THE CONTROL CENTER AND WIND GENERATORS CAN REDUCE INTEGRATION COSTS

Impacts of wind generation variability and uncertainty on the control area are not evenly distributed over all hours of the year. There can be times where the incremental cost for managing wind generation rise dramatically. In these times, the most economic solution may be to “feather” wind energy via production curtailments.

Section 1

OVERVIEW OF UTILITY SYSTEM OPERATIONS

Interconnected power systems are large and extremely complex machines, consisting of tens of thousands of individual elements. The mechanisms responsible for their control must continually adjust the supply of electric energy to meet the combined and ever-changing electric demand of the system's users. There are a host of constraints and objectives that govern how this is done. For example, the system strives to operate with very high reliability and provide electric energy at the lowest possible cost. The operational limitations of individual network elements–generators, transmission lines, substations – must be honored at all times. The capabilities of each of these elements must be utilized in a fashion to provide the required high levels of performance and reliability at the lowest overall cost.

Operating the power system involves more than adjusting the combined output of supply resources to meet the load. Maintaining reliability and acceptable performance requires operators to:

- Keep the voltage at each node (a point where two or more system elements – lines, transformers, loads, generators, etc. – connect) of the system within prescribed limits;
- Regulate the system frequency (the steady electrical speed at which all generators in the system are rotating) to keep all generating units in synchronism;
- Maintain the system in a state where it is able to withstand and recover from unplanned failures or losses of major elements

Frequency and voltage are the fundamental performance indices for the system. High interconnected power system reliability is a consequence of maintaining the system in a secure state – a state where the loss of any element will not lead to cascading outages of other equipment - at all times.

The electric power system in the United States (contiguous 48 states) is comprised of three interconnected networks: the Eastern Interconnection (most of the states East of the Rocky Mountains), the Western Interconnection (Rocky Mountain States west to the Pacific Ocean), and ERCOT (most of Texas). Within the Eastern and Western interconnections, dozens of individual "control" areas coordinate their activities to maintain reliability and conduct transactions of electric energy with each other. A number of these individual control areas are members of Regional Reliability Organizations (RROs), which oversee and coordinate activities across a number of control areas to maintain the security of the interconnected power system.

A control area consists of generators, loads, and defined and monitored transmission ties to neighboring areas. The Federal Energy Regulatory Commission definition of a control area is:

"An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s); (2) maintain, within the limits of Good Utility Practice, scheduled interchange with other Control Areas; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice."

Each control area must assist the larger interconnection with maintaining frequency at 60 Hz, and balance load, generation, out-of-area purchases and sales on a continuous basis. In addition, a prescribed amount of backup or reserve capacity (generation that is unused but available within a certain amount of time) must be maintained at all times as protection against unplanned failure or outage of equipment.

To accomplish the objectives of minimizing costs and ensuring system performance and reliability over the short term (hours to weeks), the activities that go on in each control area consist of:

- Developing plans and schedules for meeting the forecast load over the coming days, weeks, and possibly months, considering all technical constraints, contractual obligations, and financial objectives;
- Monitoring the operation of the control area in real time and making adjustments when the actual conditions - load levels, status of generating units, etc. - deviate from the forecast.

ANCILLARY SERVICES FOR MAINTAINING POWER SYSTEM RELIABILITY AND SECURITY

The activities and functions necessary for maintaining system performance and reliability and minimizing costs are generally classified as "ancillary services." While there is no universal agreement on the number or specific definition of these services, the following items encompass the range of technical aspects that must be considered for reliable operation of the system:

- Voltage regulation and VAR dispatch – deploying devices capable of generating reactive power to manage voltages at all points in the network;
- Regulation – the process of maintaining system frequency by adjusting certain generating units in response to fast fluctuations in the total system load;
- Load following – moving generation up (in the morning) or down (late in the day) in response to daily load patterns;
- Frequency-responding spinning reserve – maintaining an adequate supply of generating capacity (usually on-line, synchronized to the grid) that is able to quickly respond to the loss of a major transmission network element or generating unit;
- Supplemental Reserve – managing an additional back-up supply of generating capacity that can be brought on line relatively quickly to serve load in case of the unplanned loss of significant operating generation or a major transmission element.

The nature of control area operations in real-time or in planning for the hours and days ahead is such that increased knowledge of what will happen correlates strongly to better strategies for managing the system. Much of this process is already based on predictions of uncertain quantities. Hour-by-hour forecasts of load for the next day or several days are critical inputs to the process of deploying electric generating units and scheduling their operation. While it is recognized that load forecasts for future periods can never be 100% accurate, they nonetheless are the foundation for all of the procedures and processes for operating the power system. Increasingly sophisticated load forecasting techniques and decades of experience in applying this information have done much to lessen the effects of the inherent uncertainty

WHERE DO ANCILLARY SERVICES "COME FROM"?

Meeting the operational objectives for the power system is accomplished through coordinated control of individual generators, the transmission network, and associated auxiliary equipment such as shunt capacitor banks.

How individual plants are deployed and scheduled is primarily a function of economics. Historically, vertically-integrated electric utilities would schedule their generating assets to minimize total production costs for the forecast load while observing any constraints on the operation of the generating units in their fleet. In bulk power markets, competitive bidding either partially or wholly supplants the top-down optimization performed by vertically-integrated utilities. In either case, the economics of unit power production have the primary influence on how a plant is scheduled.

In addition, the entity responsible for the operation of the control area – an individual utility or a regional transmission organization – must manage some generating units to regulate frequency and control power exchanges in real time, to make up discrepancies between actual and forecast loads, and provide adequate reserves to cover an unexpected loss of supply.

The efficiency of thermal generating units typically varies with loading, so for each unit there is a point at which the energy cost is minimized. For large fossil-fired and nuclear generating units, the cost of generation generally declines with increasing loading up to rated output. As a result, economics dictate that these units be "base loaded" for as many hours as possible when in operation.[1] Other factors, such as thermodynamic system time constants or mechanical and thermal stresses may also result in certain units being loaded at fairly constant levels.

Against these operating constraints for certain units, other generating resources are deployed and scheduled to not only produce electric energy but also to provide the flexibility necessary to regulate system frequency, follow the aggregate system load as it trends up in the morning and down late in the day, and provide reserve capacity in the case of a generating unit or tie line failure. Some of these functions are under the auspices of a central, hierarchical control system generally referred to as automatic generation control or AGC. Others involve human intervention by the control area operators. In either case, the generating units participating in the system control activities must:

[1]The term "base loaded" is generally used to describe the operation of large generating units with high capital and operating costs but low fuel costs that are loaded to near maximum capability for most of the hours they are in service. In traditional electric utility system planning, the "base load" is sometimes defined as the minimum hourly system demand over the course of a year.

- Be responsive to commands issued by the control area EMS (energy management system), otherwise known as "being on AGC". Participating in AGC generally requires a specific infrastructure for communications with control center SCADA (System Control and Data Acquisition) system.
- Operate with appropriate "head room" to increase or decrease generation without violating minimum loading limits if commanded by the system operator or energy management system.
- Be able to change their output (move up or down, or "ramp") quickly enough to provide the required system regulation

The EMS is the technical core of modern control areas. It consists of hardware, software, communications, and telemetry to monitor the real-time performance of the control area and make adjustments to generating unit and other network components to achieve operating performance objectives. A number of these adjustments happen very quickly without the intervention of human operators. Others are made in response to decisions by individuals charged with monitoring system performance.

MEASURING POWER SYSTEM CONTROL PERFORMANCE

Control of the interconnected electric power systems in the U.S. is affected by the coordinated actions of over 100 individual control centers. Figure 4 shows the NERC (North American Electric Reliability Council) and the control areas within each region. Within each control area, the supply of electric energy is continuously adjusted to balance the requirements of loads and to maintain scheduled sales or purchases of energy from other control areas.

The primary objective of the individual control centers is to operate the power system to ensure security and reliability. Specific obligations contributing to this objective include:

- Meeting instantaneous demand, Interchange Schedule, Operating Reserve, and reactive resource requirements.
- Providing frequency bias obligations.
- Balancing Net Actual Interchange and Net Scheduled Interchange
- Using tie-line bias control (unless doing so would be adverse to system or interconnection reliability).
- Complying with Control Performance and Disturbance Control Standards
- Repaying its Inadvertent Interchange balance.

It is interesting to note that there is no hierarchical control scheme – each control area follows the same rules, but does not receive signals from a "master" controller charged with the operation of the entire interconnection.

As defined by NERC, the activities and functions traditionally known as ancillary services are called "Interconnected Operations Services (IOS)". Figure 5 illustrates the three sub-categories of IOS. The services shown here are all provided through the scheduling and control of generating resources.

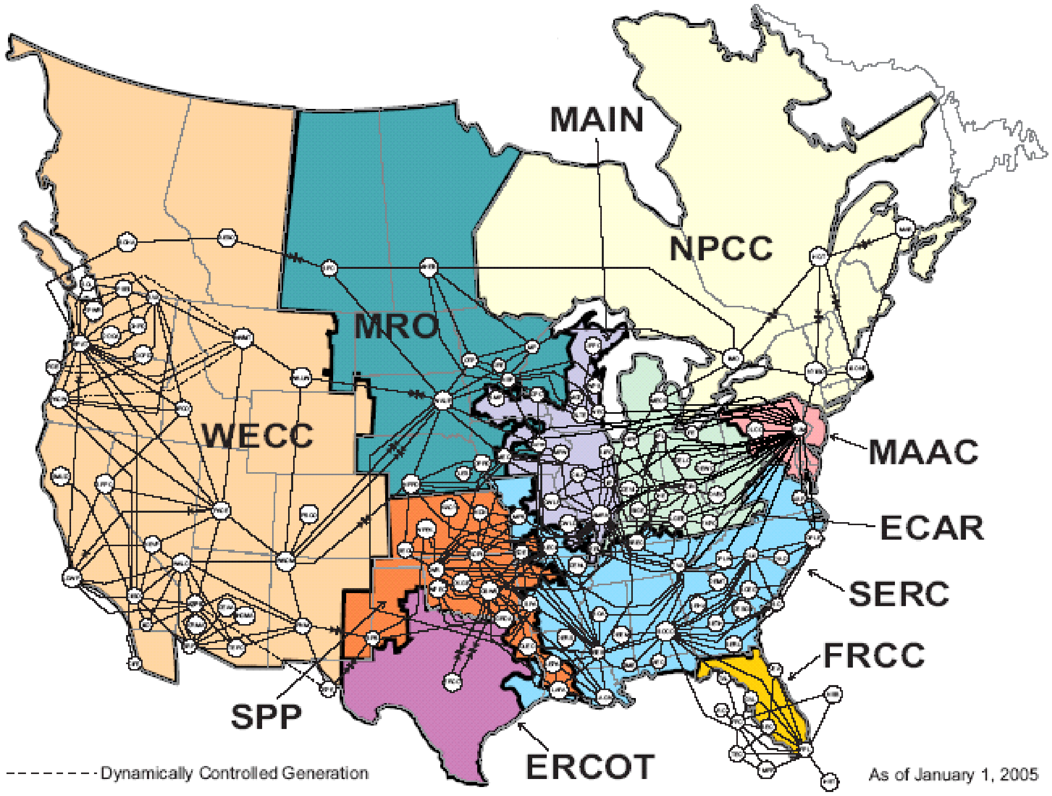

Figure 4: NERC reliability regions and control areas

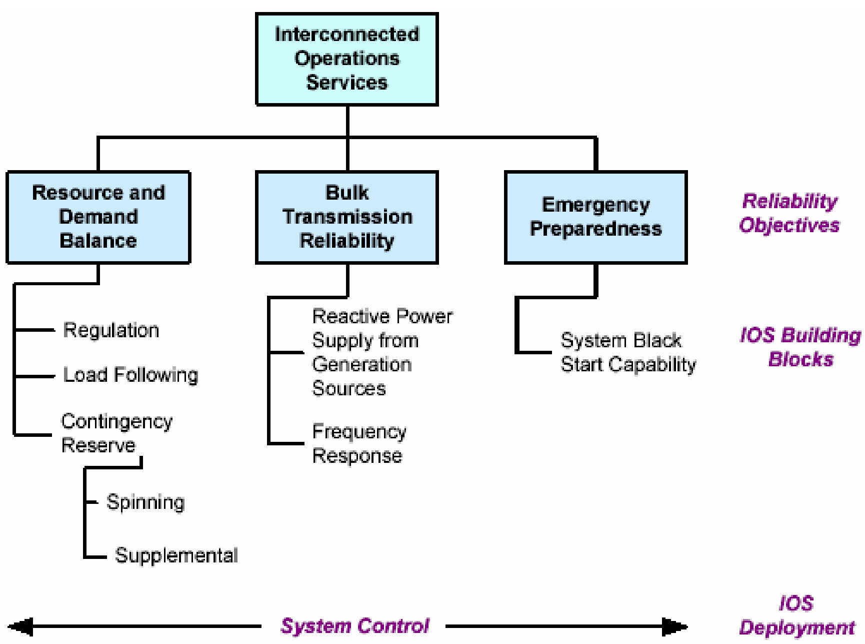

Figure 5: NERC Interconnected Operations Services

The fundamental quantity upon which generation control is based is known as Area Control Error, or ACE.

$$ACE = (NI_A - NI_S) - 10ß (F_A - F_S) - I_{ME}$$

Where

NI_A = the sum of the actual interchange with other control areas

NI_S = the total scheduled interchange with other control areas

β = the control area frequency bias, reflecting the fact that load will change with frequency

F_A = the actual frequency of the interconnection

F_S = the scheduled frequency of the interconnection; this is usually 60 Hz, although there are times when the scheduled frequency is slightly above or below the nominal value to affect what is know as "time error correction"

I_{ME} = metering error, which will be neglected for the purposes of this discussion

ACE is computed automatically by the control area EMS every few seconds. The adequacy of generation adjustments by the control area operators and the EMS are gauged by two metrics that use ACE as an input. The first metric, Control Performance Standard 1 (CPS1), uses ACE values averaged over a 1 minute period. It is a measure of how the control area is helping to support and manage the frequency of the entire interconnection. If the interconnection frequency is low, it signifies that there is more demand than generation (the "machine" is slowing down"). If a particular control area has a negative ACE, it is contributing to this frequency depression. Conversely, if ACE were positive during that period, over-generation in the control area is helping to restore the interconnect frequency.

The CPS1 "score" for control areas is based on performance over a rolling 12-month period. This score must be greater than 100% (an artifact of the equations used to compute the compliance factor). Maintaining adequate capacity on automatic generation control is a major factor in complying with CPS1. On the other hand, very high CPS1 scores can be an indication of over-control, which costs money and is not required.

The second metric is Control Performance Standard 2 (CPS2). It utilizes the average of ten consecutive 1-minute ACE values. Over each ten minute period, the ten-minute average ACE for a control area must be within specific bounds, known as L_{10}. These bounds are unique for each control area and are based generally on system size. 2006 CPS2 bounds for selected control areas in the Western Interconnection are shown in Table 4.

The CPS2 metric is tabulated monthly. To comply with CPS2 requirements, 90% or more of the ten- minute average ACE values must be within the designated L_{10} bounds for the control area. Minimum performance allows 14.4 violations per day. Most control areas keep their CPS2 scores in the mid 90% range.

Table 4: 2006 CPS2 Bounds for some Western Interconnection Control Areas

2006 CPS2 Bounds

	Est. Peak Demand (MW)	Freq. Bias (MW/.1Hz)	Bias/Load (%)	Bias/Total Bias (%)	L10 (MW)	Variable Bias ?
WECC-NWPP						
Alberta Electric System Operator	9,980	-114	1.14	5.57	58.16	
Avista Corp.	2,132	-21.3	1.00	1.04	25.14	
Bonneville Power Administration	9,039	110 - 700**	1.68	7.44	67.22	Variable
British Columbia Transmission Corporation	11,462	114 - 250**	1.03	5.77	59.17	Variable
Idaho Power Company	3,446	-50	1.45	2.44	38.52	
NorthWestern Energy	1,549	-19	1.23	0.93	23.74	
PacifiCorp-East	7,137	-72	1.01	3.52	46.22	
PacifiCorp-West	4,959	-68	1.37	3.32	44.92	
Portland General Electric Company	4,000	-50	1.25	2.44	38.52	
PUD No. 1 of Chelan County	614	-25	4.07	1.22	27.24	
PUD No. 1 of Douglas County	291	-7	2.41	0.34	14.41	
PUD No. 2 of Grant County	550	-25	4.55	1.22	27.24	
Puget Sound Energy	4,934	-50	1.01	2.44	38.52	
Seattle Department of Lighting	1,760	-40	2.27	1.96	34.45	
Sierra Pacific Power Company	1,956	-19.56	1.00	0.96	24.09	
Tacoma Power	973	-18	1.85	0.88	23.11	
Western Area Power Administration - Upper Great Plains West	115	-2	1.74	0.10	7.70	
WECC-NWPP Totals:	**64,897**	**851**	**1.31**	**41.62**		

Source: ftp://www.nerc.com/pub/sys/all_updl/oc/opman/CPS2Bounds_2006.pdf

$$AVG_{10-\text{minute}}(ACE) \le L_{10}$$

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})}\right] * 100$$

Figure 6: NERC CPS2 equations

Control area compliance with NERC performance standards is defined as a combination of CPS1 and CPS2 scores:

- In compliance: CPS1 > 100%, and CPS2 > 90%
- Out of compliance: CPS1 < 100%, or CPS2 < 90%

Maintaining compliance with the NERC control performance standards requires maneuverable generating capacity to be available and controlled or dispatched to compensate for fluctuations in control area demand. How much additional capacity is necessary to maintain compliance as the amount of wind generation in the control area grows is an obvious question. Wind generation exhibits variations over the range of time frames relevant to control performance, at least theoretically, increases the requirement for IOS. Since IOS do not directly generate revenue, dedicating additional capacity for these functions comes at a price to the control area operator.

Operational Planning

Electric utilities use sophisticated strategies and tools for deploying their generating resources to serve load reliably and at the lowest cost. Demand forecasts over the next day to several days are the starting point for optimization processes that determine which resources should be committed to operation, and how they should be scheduled to serve forecast load. The control and reliability needs of the system, along with limitations of the generating units themselves, constrain this optimization problem.

Wind generation variability and uncertainty complicates this problem in various ways:

- Short-term variations in wind generation (minutes to tens of minutes) can necessitate the reservation of additional generating capacity to compensate for excesses or deficiencies in the supply as the system load varies. In general, this reserved capacity cannot be used to serve load.
- Wind generation varies with meteorological patterns. These patterns usually do not align with the daily load patterns. Wind plant production may be low during the late afternoon, when daily load is at its highest, or may be high during the overnight hours when the load is near daily minimums and the value of energy is the lowest.
- Errors in wind generation forecasts can increase the overall uncertainty for unit commitment and scheduling. Since the operations plan is optimized using forecast data, actual load and wind generation that significantly depart from the forecast will cause the plan to be less then optimal, implying that the cost to serve the load will be higher.

Developing plans and schedules involves evaluating a very large number of possibilities for the deployment of generating resources. A major objective here is to utilize the supply resources so that all obligations are met and the total cost to serve the projected load is minimized. With a large number of individual generating units with many different operational characteristics and constraints, and other supply options such as energy purchases from other control areas, software tools must be employed to develop optimal plans and schedules. These tools assist operators in making decisions to "commit" generating units for operation, since many units cannot realistically be stopped or started at will. They are also used to develop schedules for the next day or days that will result in minimum costs if the load forecasts are accurate.

Section 2

WIND INTEGRATION STUDY METHODOLOGY

Avista's present work builds on analyses completed in 2001/2002. A proprietary dispatch LP Model ("Avista LP Model", or LP Model"), driven by a linear programming engine, optimizes operations with and without wind generation in the utility's system. This hourly LP Model tracks various capabilities (e.g., up and down load following, regulation, energy, storage) of Avista's system to meet system loads at least cost. It contains three modules. The first optimizes hydro generation on a daily basis at the Mid-Columbia and Clark Fork projects, tracking constraints such as maximum and minimum storage and generation levels, and minimum flow. A second creates the hourly pre-schedule, taking daily hydro quantities and allocating them across the highest value hours possible given the remaining system constraints. The pre-schedule LP Model contains day-ahead forecasts of load and wind generation. Purchases and sales made to balance system requirements are carried forward to the real-time module. The real-time module re-optimizes utility resources given the new forecasts for wind and load. It performs tasks similar to the pre-schedule module.

The key cost driver is incremental reserves necessary to integrate wind into a utility system. Reserve obligations were calculated by using historical utility data from 2002 through 2004. Specifically, regulation (up to 1 minute), load following (1 minute to one hour), spinning and non-spinning operating reserves, and forecast error are input in the Avista LP Model as constraints on system optimization. In the with-wind cases, reserve quantities are necessary to cover incremental regulation, load following and forecast error. No additional spinning or non-spinning reserves are assumed; these products are tied to system load rather than generation plant operations. This assumption is not the rule today in the Northwest, but this approach will be implemented in the near future.

Incremental regulation and load following reserves are calculated first by identifying levels necessary to meet load variability alone. A second step performs the same analysis but nets wind generation against load when performing the calculations. In each of these analyses, reserve levels ensure a 95% probability of meeting each period's reserve obligation. This level exceeds current CPS1 and CPS2 requirements, whereby control area operators must adhere to a 90% level. Differences between the two analyses (with and without wind) identify the incremental reserve obligations included in the with-wind scenarios.

Incremental regulation reserves necessary to integrate wind were found to be constant across all hours, rising with the level of wind in Avista's control area. Load following obligations varied both with the level of wind in Avista's control area and as hourly wind generation levels changed. Each of these reserve products are met with spinning-capable resources.

Forecast error, a product covered by reserving system capacity, was a significant focus of the Avista study. Two-hour-ahead wind forecasts were compared to actual wind generation levels. Forecast error was calculated at the 95% confidence interval and carried across all hours in the up and down directions. Forecast error is met with spinning-capable resources.

Avista considered various levels of wind from 100 MW to 600 MW, or between 5% and 30% of control area peak demand. Wind resources were evaluated in the Columbia Basin, in Eastern Montana, as a 50%/50% mix of Columbia Basin and Eastern Montana wind, and as a multi-state "diversified" mix with many smaller sites combined. The diversified sites had significantly lower reserve obligations and costs when compared to single basin resources. Wind generation data for the 2002 through 2004 calendar years was obtained from the 10-minute Bonneville Power Administration Long-Term Wind Database of wind speed data. Data limitations required the analysis to focus on the period from August 2002 through July 2003.

STUDY METHODOLOGY

There is no formal or rigorous definition of "integration cost." It is a term used to describe the financial impact of wind generation variability and uncertainty on the control area charged with accepting it. The term applies to the operational time frame, comprising the real-time management of conventional generating units and the short-term planning for demand over the coming day or days.

A chronological operations simulation methodology is the standard analytical approach for wind integration studies. This framework utilizes synchronized hourly load and wind generation patterns. It mimics the scheduling and real-time operation activities for the company or area of interest.

The methodology for the analysis is designed to quantify the costs of wind generation variability and uncertainty in the operational time frame. These costs are assessed by comparing operation costs for managing wind to one where the same amount of energy is delivered by an ideal resource – one that imposes no incremental burden on scheduling or real-time operations.

The ideal resource over the year is represented by a 12X24 shape. For each month a unique 24-hour shape is used for every day. The 24-hour shape was calculated as the average generation delivered during each separate clock hour of each month. The second run incorporates actual–i.e., hourly variable–wind output and the required additional operating reserves necessary to maintain a consistent level of system control performance (CPS1 & CPS2).

Wind integration cost is calculated as the difference between system values from each run The difference between the two runs is divided by the total wind energy produced during the year. This process is completed for each wind penetration level, wind source, and water year, and evaluated scenario.

IMPACTS OF WIND GENERATION WITHIN THE HOUR

The main objective of this study is to determine how the Avista control area would be impacted by the additions of wind generation. An analysis combining Avista load and simulated wind generation data determines the requirements for regulation and load following necessary to maintain system reliability. The findings from the load and wind analysis become inputs to later analytical processes. An LP Model developed by Avista takes these data and simulates the operational changes necessary to provide these capabilities.

The approach for analyzing intra-hour wind generation impacts is based on straightforward mathematical and statistical analyses using ten-minute averages of system load and wind generation. Incremental reserve requirements are determined by comparing various metrics of the load by itself (and the present capacity and capabilities allocated to perform these services) to the combination of load and wind generation.

While the load exhibits a larger trend pattern of steadily increasing over the morning interval and falling in the evening, there is still significant variability in the load by itself. Deviations in wind generation are less patterned than load variability.

Section 3

DEVELOPING THE WIND GENERATION MODEL

The analysis of wind generation is based on simulating Avista's short-term scheduling and dispatch operations over an extended chronological period. The primary inputs to this simulation process are chronological profiles of system load, wind generation, and market prices for energy purchases and sales. Load and market price data are extracted from archives, but acquiring the wind generation data is much more problematic. Recent studies show that a high-fidelity, long-term, chronological representation of wind generation is the most critical study element. For large wind generation development scenarios, it is very important that the effects of spatial and geographic diversity be neither under- nor over-estimated.

The long-term wind speed data base compiled by Oregon State University's (OSU) Energy Resources Research Laboratory (ERRL) was used as the basis for the chronological wind generation model Specifically, data from the five historical Bonneville Power Administration (BPA) sites, along with observations from the operating wind plant at Vansycle, were selected as the reference data points. The historical period of data utilized from each of these sites is shown in Table 5.

Table 5: Measurement Locations and Record Durations from OSU Wind Speed Database utilized for study.

Site Name	First Date	Last Date
Browning Depot, MT	1/29/2002 6:40:00 AM	8/13/2003 2:50:00 AM
Cape Blanco, OR	1/28/2002 4:40:00 PM	9/10/2003 1:50:00 AM
Kennewick, WA	1/29/2002 6:30:00 AM	12/31/2004 11:50:00 PM
Goodnoe Hills, WA	1/29/2002 6:00:00 AM	12/31/2004 11:50:00 PM
Sevenmile Hill, OR	1/29/2002 6:00:00 AM	12/31/2004 11:50:00 PM
Vansycle, OR	8/2/2002 3:20:00 PM	12/31/2004 11:50:00 PM

Wind speed data at each location was transformed into wind energy production at 10-minute intervals using a power curve from a commercially available 2.75 MW wind turbine (NEG 2750). The power curve for this turbine is shown in Figure 7. The selection of power curve is not critical, since the objective is to create a long-term pattern of wind generation. Production over an extended period is a secondary issue.

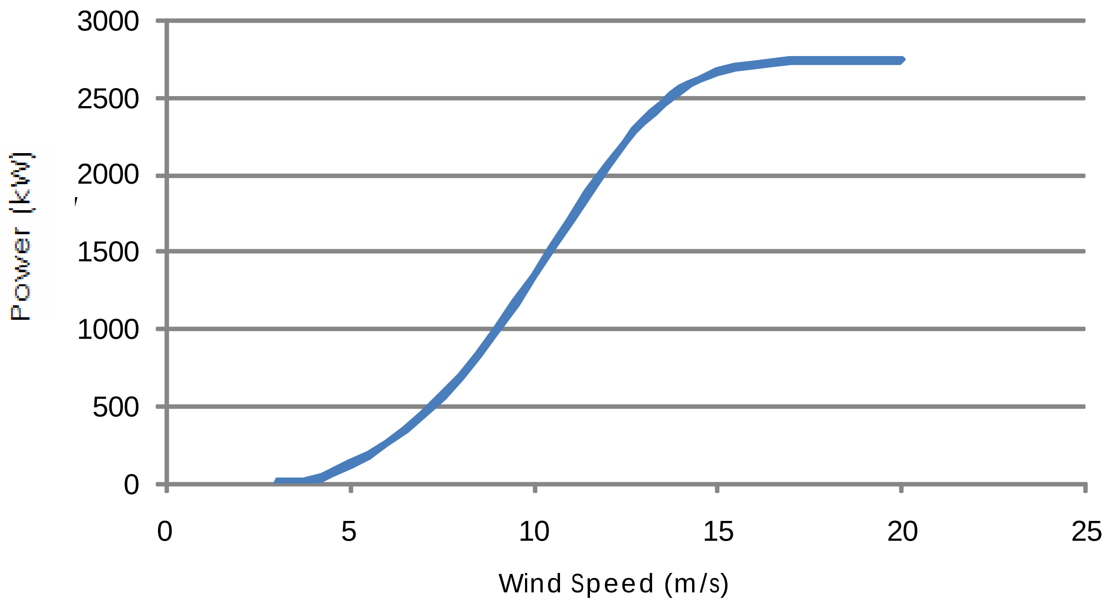

Figure 7: Turbine power curve used in wind speed data conversion

There are a number of factors influencing aggregate production from a collection of wind turbines in a given area. Measurement data collected by the National Renewable Energy Laboratory and others over the past decade provides empirical data on the effect of aggregation and spatial diversity on production variability. As the number of turbines in the collection grows, the aggregate production begins to smooth, first at small time scales (seconds to minutes), then progressively over long spans of time. As the wind production is spread over distinct geographical locations, production can be significantly smoothed over spans of even multiple hours.

With the data used for this study, it is difficult to account for spatial diversity; there is a single observation point of wind speed at each location. Some smoothing is introduced in the algorithm for translation from wind speed to production. This method has been employed, and validated, in previous studies

The net effect of the data limitations is that individual wind generation profiles in this study exhibit more variability than actual wind plants constructed at those locations. To minimize the potential for increased generation variability and its potential for biasing study results, four wind generation scenarios ranging from 100 MW to 600 MW were constructed using wind speed data from the five sites in the OSU database and observations from Vansycle (Table 6 through Table 9).

Table 6: Composition of 100 MW Scenarios

Site Name	Diverse (MW)	Columbia Basin (MW)	Montana (MW)
Browning Depot, MT	25	0	100
Goodnoe Hills	35	0	0
Cape Blanco	10	0	0
Vansycle	10	50	0
Kennewick	10	50	0
Sevenmile	10	0	0

Table 7: Composition of 200 MW Scenarios

Site Name	Diverse (MW)	Columbia Basin (MW)	Montana (MW)
Browning Depot, MT	65	0	200
Goodnoe Hills	75	0	0
Cape Blanco	15	0	0
Vansycle	15	100	0
Kennewick	15	100	0
Sevenmile	15	0	0

Table 8: Composition of 400 MW Scenarios

Site Name	Diverse (MW)	Columbia Basin (MW)	Montana (MW)
Browning Depot, MT	125	0	400
Goodnoe Hills	150	0	0
Cape Blanco	30	0	0
Vansycle	35	200	0
Kennewick	30	200	0
Sevenmile	30	0	0

Table 9: Composition of 600 MW Scenarios

Site Name	Diverse (MW)	Columbia Basin (MW)	Montana (MW)
Browning Depot, MT	195	0	600
Goodnoe Hills	225	0	0
Cape Blanco	45	0	0
Vansycle	45	300	0
Kennewick	45	300	0
Sevenmile	45	0	0

Given the issues related to the exaggerated variability of the LP Model mentioned above, care was taken to reduce the effect on the integration impacts and costs to be calculated later in the project by appropriately selecting the scenarios for each level of wind generation to be studied. For example, a 600 MW scenario from a single location (e.g. Montana) was not considered to be realistic due to the additional variability.

Wind Generation Model Characteristics

The wind generation model consists of ten-minute data for extended chronological periods and is therefore difficult to examine directly. The following charts and graphs are intended to convey certain of these characteristics. Figure 8 and Figure 9 illustrate two three-day periods of Avista load and wind generation from each scenario. The aforementioned issue of higher wind generation variability is apparent during the high wind generation periods, especially for the 600 MW scenario. Compared with the 400 MW scenario which uses the same locations but includes a “build out” of each, some smoothing between these two scenarios would be expected, but is not evident from the plots.

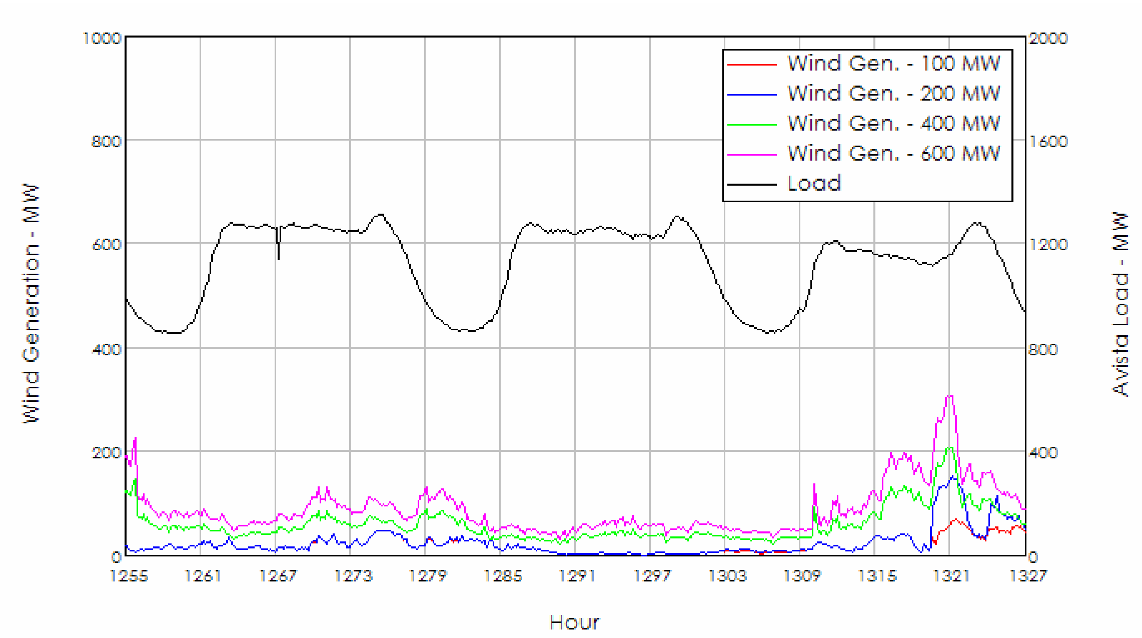

Figure 8: Low wind period (3 days) showing load and wind generation by scenario.

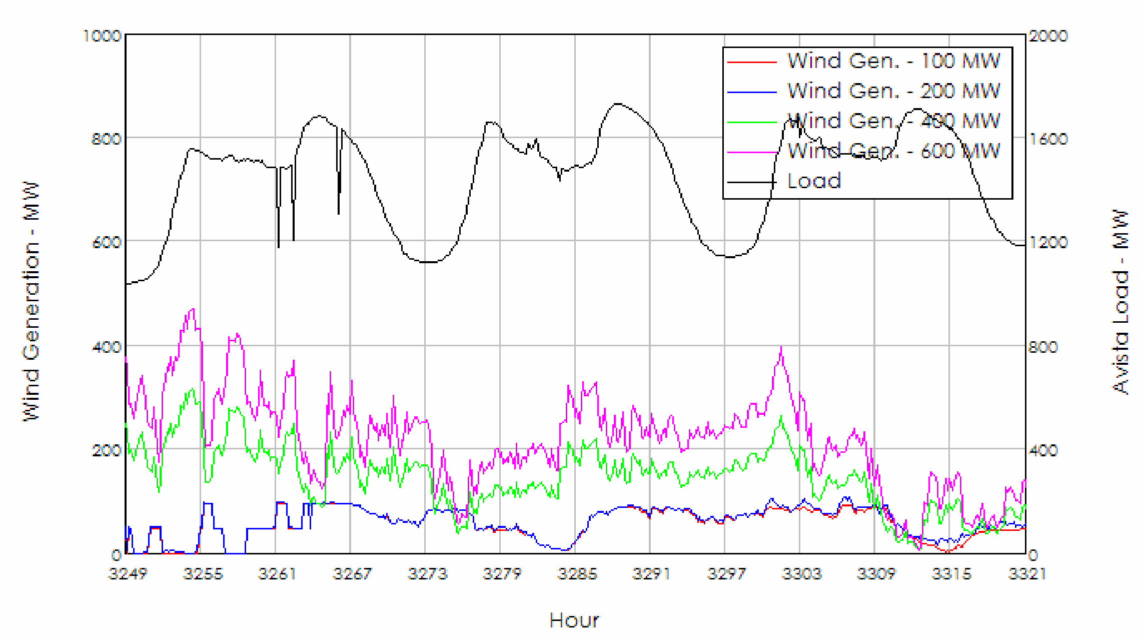

Figure 9: High wind period (3 days) showing load and wind generation by scenario.

Table 12 shows the computed annual capacity factor for each wind generation scenario. Figure 10 through 9 document the hourly production distributions for the four scenarios. Note that as additional sites are added to the mix – i.e. all scenarios except 100 MW – the aggregate production falls short of the nameplate capacity. Production duration curves for the year of data used in this analysis are shown in Figure 14.

Table 10: Annual Capacity Factor by Scenario (from LP Model data)

Scenario	Unadjusted Capacity Factor
100 MW	34.0%
200 MW	33.9%
400 MW	30.5%
600 MW	30.5%

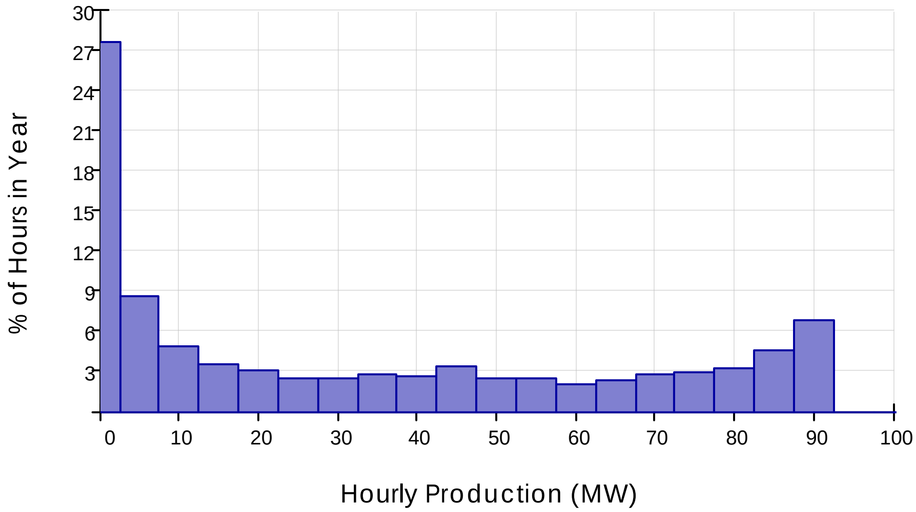

Figure 10: Production distribution for 100 MW scenario.

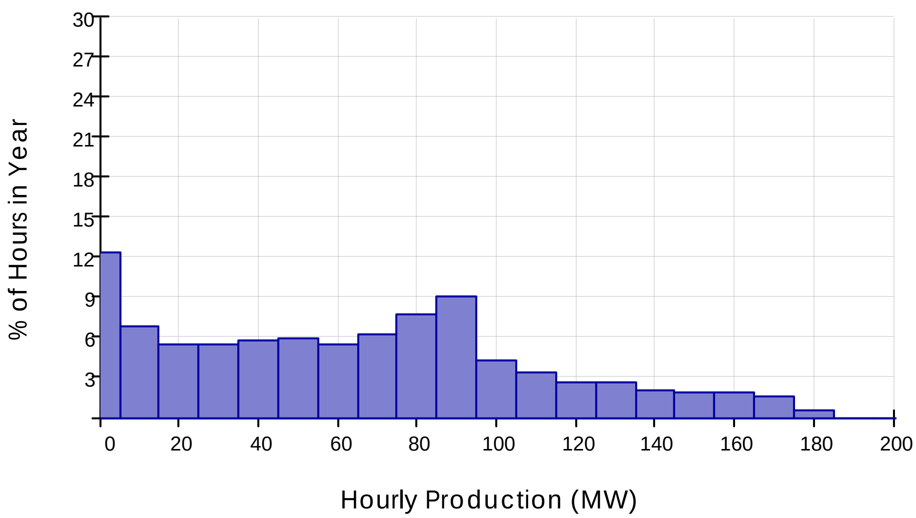

Figure 11: Production distribution for 200 MW scenario.

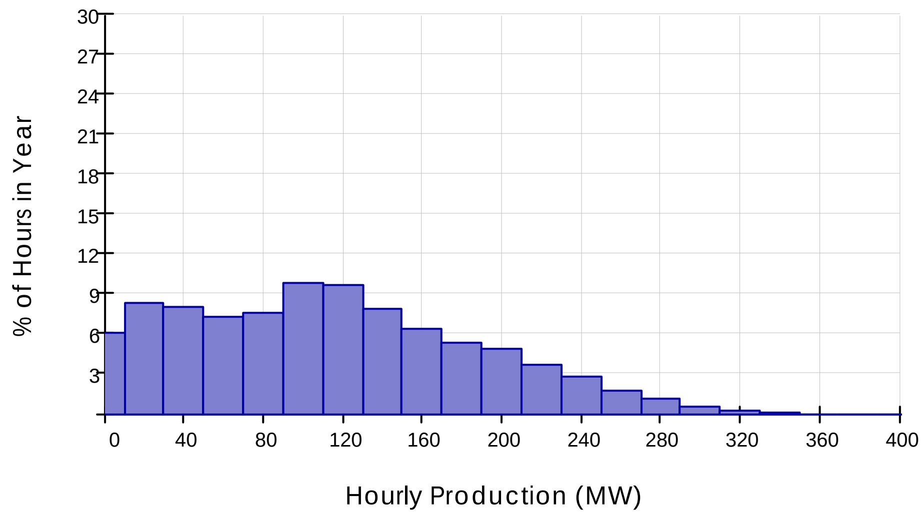

Figure 12: Production distribution for 400 MW scenario.

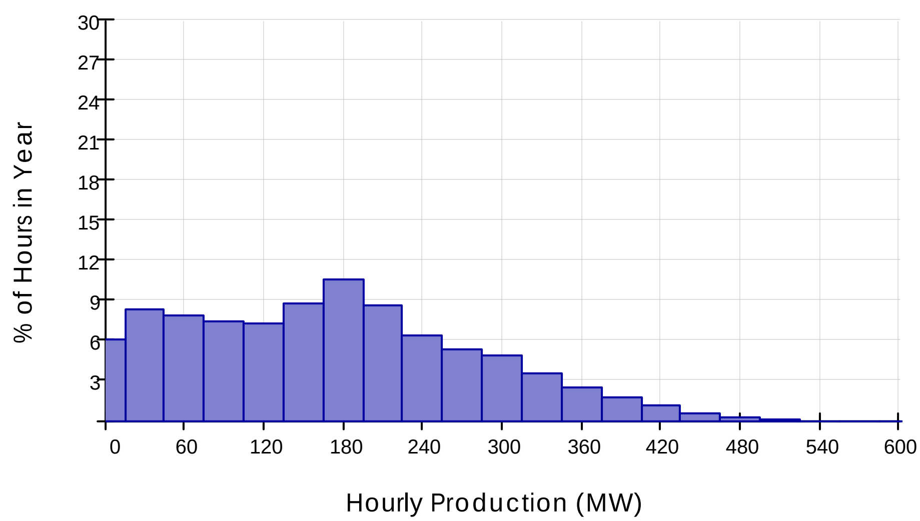

Figure 13: Production distribution for 600 MW scenario.

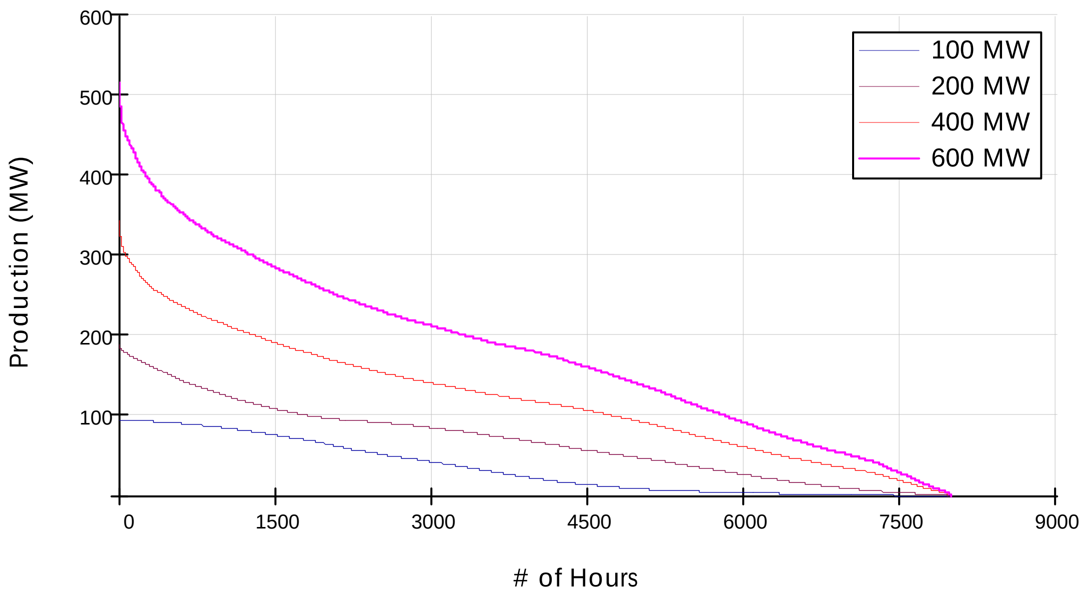

Figure 14: Production duration curves for four wind scenarios.

In Figure 15, the hourly fraction of wind generation relative to load is calculated and sorted to show the number of hours over the year where the wind to load fraction is above the amount on the horizontal axis.

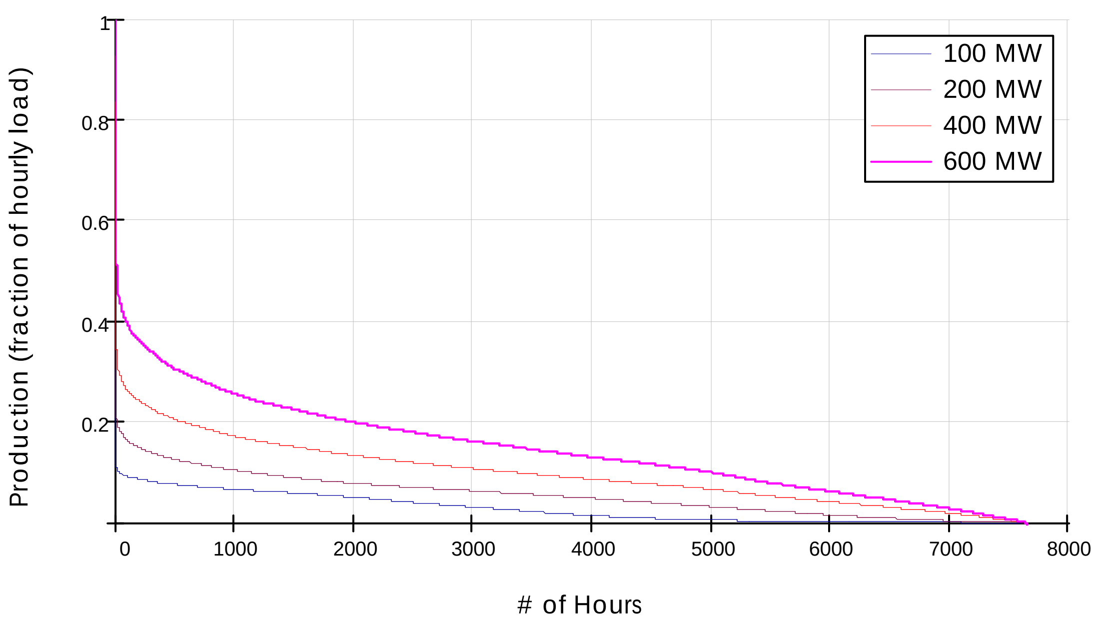

Figure 15: Wind generation "penetration duration" curves for four wind scenarios.

Section 4

OVERVIEW OF AVISTA SYSTEM OPERATION

Avista is a vertically-integrated natural gas and electricity company providing service to 350,000 electricity customers in the states of Idaho and Washington. Avista also provides control area services to a number of smaller external customers, including large industrial facilities and small municipally-owned electric systems.

CONTROL AREA LOAD

In 2006 Avista recorded a control area peak demand of approximately 2,100 MW. The minimum control area demand was approximately 890 MW. Avista is a winter-peaking system, with peak winter loads exceeding peak summer loads by approximately ten to fifteen percent. Table 11 provides 2006 monthly control area peak demand, as well as average and minimum load levels.

Table 11: Avista 2006 Monthly Peak Control Area Demand

Month	Min	Max	Average
1	1109	1820	1477
2	1126	2082	1534
3	1071	1799	1417
4	952	1580	1268
5	963	1761	1277
6	932	1904	1296
7	979	2021	1421
8	975	1850	1356
9	892	1711	1237
10	951	1795	1297
11	978	2110	1455
12	1103	1950	1587

CONTROL AREA RESOURCES

Avista relies on approximately 2,800 megawatts of owned or contracted resources to serve the needs of its control area. In addition to serving control area load, the Company also is obligated to provide approximately 200 megawatts to third-party control areas. The following figure provides a summary of these resources.

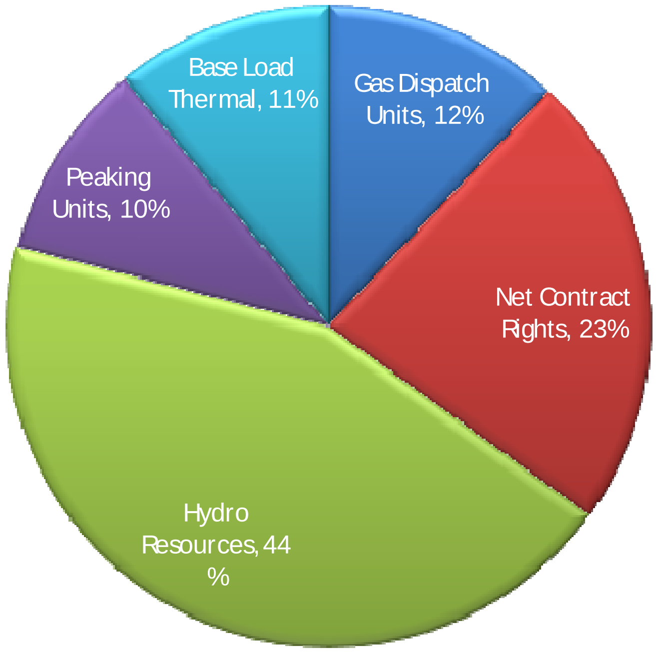

Figure 16: Avista control area resources

Avista uses a variety of resources to meet its overall load obligations; the majority of capacity reserves are met by hydroelectric plants. Hourly schedules “block load” all non-hydro resources in most hours, leaving hydro units with the responsibility to cover intra-hour ramps regulation and load following in most hours. Other system operations are possible; however, the Company has found that firing gas generation, for example, results in higher reserve carrying costs. Integrating wind into Avista’s system does not affect this relationship. The LP Model confirmed the economics of this mode of operation.

The Pacific Northwest Wholesale Marketplace

Utilities in the Northwest benefit from a robust wholesale marketplace, both on the day-ahead pre-schedule timeframe and the next-hour real-time period. Many reserve products are available through short-term bilateral contracts. For many years Avista has operated its resources around the market availability of third-party resources in this marketplace. Where market prices are lower in a given hour than the cost of utility-owned or controlled resources, purchases are made to serve control area obligations. Where resources in excess of control area needs can be operated for a cost less than the wholesale market price, this excess is marketed to the benefit of Avista’s retail customers.

Modeling the wholesale marketplace is essential for studying wind integration in the Northwest. Unlike some large systems in North America, Avista’s costs are not necessarily driven by its system marginal cost. Instead, the wholesale marketplace determines this cost by reflecting the marginal cost of the entire integrated system. With respect to wind, its value in the operations timeframe is equal or nearly equal to the short-term wholesale market price for power.

Overview of Resource Operations Theory

Utilities have a fiduciary responsibility to optimize resource operations in a least-cost and reliable manner. Given a set of generation assets and load obligations, the two should be matched in the most efficient manner. Generation assets enable a utility to create various power products necessary to meet customer requirements. Among these are energy, regulation, spinning and non-spinning reserves. Each resource has a unique mix of abilities to provide these products. For example, a flexible hydroelectric generator on automatic generation control may be able to provide all of these services where a nuclear plant can only provide energy.

In addition to physical limitations a specific generation unit might have, it cannot create power products beyond its capacity rating. A 100 MW plant can create 100 MW of energy or follow 100 MW of increasing load, but not both. Table 12 provides examples of the power products three hypothetical 100 MW generators might generate over an hour in a market where energy, regulation, load following, and non-spinning reserves are demanded. Notice that in each case the non-energy products produced never exceed rated capacity. Capacity in the "down" direction cannot exceed energy generation levels and "up" direction capacity cannot exceed the difference between the nameplate rating of the plant and the energy generation level.

Table 12: Illustration of plant capacity utilization

Product	Direction	Nuclear			Coal			Hydro		
		a	b	c	a	b	c	a	b	c
Energy		100	100	100	100	95	30	100	50	50
Regulation		0	0	0	0	0	0	0	25	20
Load Following	Up	0	0	0	0	5	0	0	25	15
	Down	0	0	0	5	5	0	50	50	15
Forecast Error	Up	0	0	0	0	0	30	0	0	15
	Down	0	0	0	0	0	30	50	0	15

The hypothetical nuclear plant provides 100 MW of energy across the hour in all operating cases. The plant is base loaded and unable to move within the hour. Coal, on the other hand, has some modest intra-hour flexibility. In Case A the plant generates 100 MW of energy and 5 MW of down load following. The coal plant has the ability when generating at capacity to reduce its generation during the 10-minute window by 5 MW; it therefore can provide 5 MW of this service. In Case A both the nuclear plant and the coal plant are obtaining their maximum value in the energy marketplace.

In Case B the coal plant is dispatched to meet both 5 MW of down load following and 5 MW of up load following to cover variability in both directions. In order to provide the capability to follow load in the upward direction, it is necessary to schedule the plant to produce 95 MW of energy.

Finally, Case C illustrates that even where the coal-fired plant is scheduled at the lower level of 30 MW, it still is able to provide only 30 MW each of down and up forecast error. The limitation in this case is not the capacity of the plant, but that it can only move 30 MW in any single direction during an hour (5 MW x 6 10-minute intervals) load. This later case likely would describe a condition whereby the coal plant was being operated at a loss in the energy marketplace and went into the hour running at a low level to minimize this loss while still providing reserve capabilities.

A hydro plant has very low operating costs and can ramp all of its capacity to meet various reserve products when called on. In Case A the plant is run to produce 100 MW of energy. Its ability to follow load down is split evenly between down load following and down forecast error. This scenario likely would occur during peak hours of the day when market prices are at their highest.

In Case B it is necessary to provide both up and down regulation and up and down load following. The hydro plant lowers its energy production so that it can provide these additional services. This operation profile could be a very expensive one from the perspective of energy production. During a high demand hour market prices for energy could be very high, meaning the utility is losing the opportunity to sell 50 MW of energy. Where market prices are low, the hydro plant might be running to make available reserve products and losing a lot of money relative to where it was not required to run at all.

Case C provides a third look at hydro operations, but shows how a plant can be used to serve load regulation and load following, as well as forecast error, simultaneously.

Section 5

MODELING AND ASSUMPTIONS

OVERVIEW OF THE AVISTA SYSTEM INTEGRATION LP MODEL

The Avista LP Model represents a true system dispatch of Avista generation and contract resources against its control area loads. All resources and obligations are modeled hourly in one-month time steps across many months. Hydro project storage is modeled to minimize system costs over time while reflecting operational and environmental obligations. Hourly deficiencies and surpluses are balanced in the wholesale market, limited by transmission availability.

The LP Model was developed in Microsoft Excel. A linear programming add-in to Microsoft Excel, *What's Best!* by Lindo Systems, is used to optimize operations in all cases. Four system optimization modules in the LP Model represent four unique areas. The first two represent two hydroelectric storage projects. Each of these modules optimizes a hydroelectric project to maximize its value given constraints in the remaining modules. The third optimization module represents the pre-schedule timeframe where forecasted resource availability is scheduled on a day-ahead basis against forecasted obligations. The last optimization module is similar to the pre-schedule LP Model, except that it replaces forecasted data with actual data.

Data used by the LP Model are contained in a Microsoft Access database. All results are stored in another Microsoft Access database. A schematic of the pre-schedule module is shown in Figure 17.

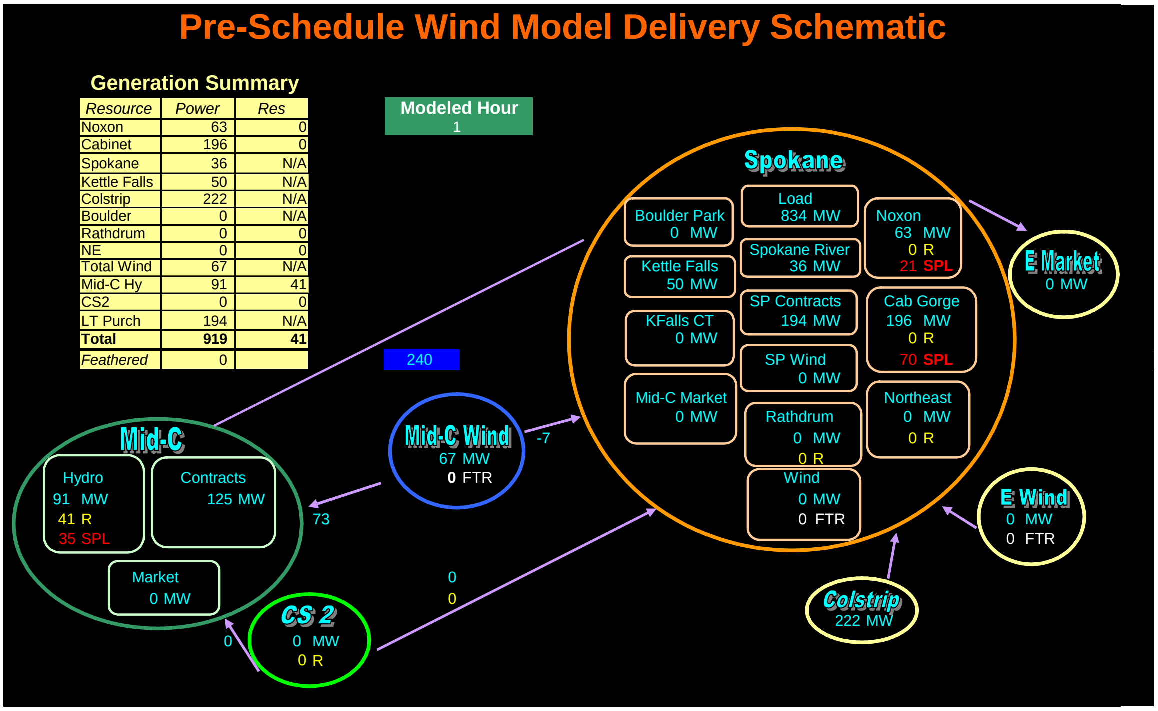

Figure 17: Schematic of Avista LP program – Pre-schedule module

The Controls Module

The Controls module (Figure 18) sets up various modeling runs. A *Start Date* for the run is specified, and must begin on the first day and hour of a month within the study horizon. As explained earlier, the LP Model runs hourly in one-month time steps. The *Months* field can be adjusted to instruct the LP Model on how many contiguous months are to be run. The *Run Description* provides a unique identifier of the run so that it may be found within the output database.

The next three lines allow the user to specify how many megawatts (MW) of nameplate wind capacity will be integrated at three available locations. The three locations can be “mixed and matched” to provide system diversity.

8/1/02 0:00	Start Date
12	Months
600MW_MC_AVG_0.2%FCSTERR	Run Description
0.0	Diversified Wind (MW)
600.0	MC Wind (MW)
0.0	East Wind (MW)
11.0	Incremental Wind Regulation (MW)
20%	Wind Forecast Error
15.0	Forecast Error Credit (MW)
NO	Flat Wind Delivery
AVG	Water Year (LOW, AVG, HIGH)
$0.50	Market Price Differential
$4.00	Spokane Price Differential
$0.10	Clark Fork Spin Penalty
$0.10	Cost of Reserves
$1.00	Henry Hub Basis Differential
(8,801)	What'sBest Result (WBMIN)
(8,823)	Resultant Costs ($millions)
NO	Write Ouput Results to Database
Master_Table_New_LF_2	Input Database Table Name
MCWIND_AVGWTR.mdb	Output Database Name (w/ext.)
$0.00	Spill Penalty ($/MWh)
$65.00	Actual Wind Feather Penalty ($/MWh)
1	Additional Transmission Purchase?
$3.00	Additional Transmission Cost ($/MWh)

Run!

Figure 18: Avista LP Model control interface

Load regulation, load following, and wind forecast error are the three incremental reserve products the LP Model evaluates to determine integration costs. *Incremental Wind Regulation (MW)* provides a placeholder for additional regulation requirements necessary to integrate incremental wind resources. *Wind Forecast Error* is represented as a percentage of installed nameplate wind capacity. It allows the user to vary the perceived accuracy of the hour-ahead wind load forecast and determine the impact. The *Forecast Error Credit* offsets by the specified amount the incremental wind forecast error obligation in each hour. This value reflects the forecast error of the Avista system for both load and generation variability on the hour-ahead timeframe.

The Controls module allows the user to specify whether a wind delivery is "Flat" or not. Today's generally accepted wind integration analyses method is to consider wind on a system, and then in the comparison case deliver a flat (i.e., across all hours of the analysis period) quantity of wind that is equal on an energy basis.

Wind integration costs on a hydroelectric-based system vary depending on how much water is in the system. The Model is capable of running low, average, and high water year scenarios. The *Market Price Differential*, *Spokane Price Differential*, *Clark Fork Spin Penalty*, and *Cost of Reserve* fields generally are not changed by the user. These fields provide incentives for the LP Model to avoid certain behavior. For example, it is not efficient, or realistic, for the LP Model to purchase and sell thousands of megawatts of power in any given hour. Unless there is some price differential, the LP Model will randomly buy and sell too much power. Inserting a modest differential between the market price for sales and purchases solves this logic error without affecting overall results. A similar incentive is used to prevent the LP Model leaning on the Clark Fork hydroelectric facility for spinning reserves, and ensuring the LP Model provides only those reserves necessary in any given hour to meet load and wind obligations.

The LP Model uses Henry Hub for its natural gas price history; the *Henry Hub Basis Differential* was estimated to be $1.00 per decatherm. The next two fields explain the financial results of the optimization routine. The *What'sBest Result (WBMin)* field provides the actual solution of the LP routine. The *Resultant Costs ($millions)* field provides the actual value used in the wind integration calculation. This field ignores artificial adders and penalties used to help the LP Model to emulate certain behaviors (e.g., not to over-provide operating reserves), as described in a previous paragraph.

The next three fields tell the Model to or not to write its results to a database, what the input database name for the run is, and the name of the database where results are to be written to.

The *Wind Feather Penalty* incents the LP Model to not feather, or spilling, generation. Under rare certain circumstances Avista's system cannot integrate all wind generation at high wind penetration levels; wind must be feathered for the LP Model to solve. When wind is feathered, the project owner looses the federal production tax credit. This value is approximately $20 per MWh above the wholesale cost of power. Unlike many of the penalties discussed in this section, the Wind Feather Penalty is carried through to the ultimate solution and adds to integration costs.

The LP Model allows the user to specify if additional firm transmission was purchased or constructed for the project. The *Additional Transmission Purchase?* field ultimately affects how much energy can be sent to or delivered from Avista's system; this affects wind integration costs. For this study firm transmission purchases were assumed for the full nameplate capability of all added wind generation.

Short-term transmission purchases are made where long-term contracts are incapable of meeting model requirements. It is assumed to be purchased from the Bonneville Power Administration at a cost of $3 per MWh, excluding losses. Short-term transmission purchases in any given hour are limited to 300 MW (total of 540 MW including firm transmission rights) in the east-to-west direction and 760 MW (total of 1,000 MW including firm transmission rights) in the west-to-east direction.

The Assumptions Module

The Assumptions module details various operating characteristics and capabilities of Avista's portfolio, including operating reserves and transmission losses. Firm and non-firm transmission availability are also represented. Input for the Assumptions module is shown in Table 13 and Table 14.

Table 13: Avista LP Model Resource Assumptions (two tables)

RESOURCE ASSUMPTIONS	HYDRO RESOURCES				DISPATCHABLE GAS RESOURCES			
	Spokane River	Noxon Rapids	Cabinet Gorge	Mid Columbia	Coyote Springs 2	Boulder Park	Rathdrum 1	Rathdrum 2
Capacity	180	554	236	138.4	280	25	75	75
Heat Rate	0	0	0	0	7,100	9,000	12,000	12,000
Trans Node	SP	SP	SP	MC	SP/MC	SP	SP	SP
Non-Spin Res	2.5%	2.5%	2.5%	2.5%	3.5%	3.5%	3.5%	3.5%
Spinning Res	2.5%	2.5%	2.5%	2.5%	3.5%	3.5%	3.5%	3.5%
Variable O&M	0.00	0.00	0.00	0.00	2.50	5.50	1.25	1.25
Spin Resource	No	Yes	Yes	Yes	No	No	No	No
Minimum Gen	10	0	35	27	180	0	75	75
Storage	0	2,006	0	1,569	0	0	0	0
H/K Factor		3.788	5.933					

RESOURCE ASSUMPTIONS	DISPATCHABLE GAS RESOURCES			FIXED RESOURCES			
	Kettle Falls CT	Northeast A	Northeast B	Colstrip	Kettle Falls	MC Fixed Contracts	SP Fixed Contracts
Capacity	7	30	30	222	50	125	125
Heat Rate	8,750	13,000	13,000	0	0	0	0
Trans Node	SP	SP	SP	SP	SP	0	0
Non-Spin Res	3.5%	3.5%	3.5%	3.5%	3.5%	None	None
Spinning Res	3.5%	3.5%	3.5%	3.5%	3.5%	None	None
Variable O&M	5.00	3.00	3.00	0.00	0.00	0.00	0.00
Spin Resource	No	No	No	No	No	No	No
Minimum Gen	7	30	30	0	0	0	0
Storage	0	0	0	0	0	0	0
H/K Factor							

Table 14: Avista LP Model Transmission Assumptions

TRANSMISSION ASSUMPTIONS	NODES
	Spokane Node
Reserve Requirmt	6.0%
Firm Transmission	240
Trans Losses	1.9%
Max E2W Trans	540
Max W2E Trans	(1,000)

The Clark Fork Logic and Mid-C Logic Modules

The Clark Fork Logic Mid-C Logic modules dispatch Avista's hydroelectric projects that have intra-week energy storage. The modules take daily average inflows into each of the projects and optimize generation and spill levels over time. The results are handed off to the Pre-Schedule and Real-Time modules for within-day optimization. The Mid-C Logic module is illustrated in Figure 19.

	NOXON DAILY GENERATION AND SPILL										C
Run Description	Date	Project Inflow (sfd)	Noxon Inflow (MWh)	Begin Storage (MWh)	PSStorage Max Con	PSStorage Min Con	PSStorage Change	PSStorage Change	RTDaily Gen	RTDaily Spill	RTEnd Storage
600MW_MC_AVG_0.2%FCSTERR	7/1/2003	49,500	13,068	**1,806**	<=	>=	<=	=>=	12,266	1,605	1,003
600MW_MC_AVG_0.2%FCSTERR	7/2/2003	46,400	12,250	1,003	<=	>=	<=	>=	12,416	0	837
600MW_MC_AVG_0.2%FCSTERR	7/3/2003	48,100	12,698	837	<=	>=	<=	>=	12,546	0	989
600MW_MC_AVG_0.2%FCSTERR	7/4/2003	50,800	13,411	989	<=	>=	=<=	>=	12,542	67	1,792
600MW_MC_AVG_0.2%FCSTERR	7/5/2003	47,600	12,566	1,792	=<=	>=	<=	>=	12,352	0	2,006
600MW_MC_AVG_0.2%FCSTERR	7/6/2003	41,700	11,009	2,006	<=	>=	<=	>=	11,178	0	1,837
600MW_MC_AVG_0.2%FCSTERR	7/7/2003	37,700	9,953	1,837	=		<=	>=	9,984	0	1,806
600MW_MC_AVG_0.2%FCSTERR	7/8/2003	35,100	9,266	1,806	<=	>=	<=	>=	9,454	0	1,618
600MW_MC_AVG_0.2%FCSTERR	7/9/2003	34,800	9,187	1,618	=<=	>=	<=	>=	8,799	0	2,006
600MW_MC_AVG_0.2%FCSTERR	7/10/2003	31,900	8,422	2,006	<=	>=	<=	>=	8,762	0	1,666
600MW_MC_AVG_0.2%FCSTERR	7/11/2003	27,500	7,260	1,666	<=	>=	<=	=>=	8,063	0	864
600MW_MC_AVG_0.2%FCSTERR	7/12/2003	33,600	8,870	864	<=	>=	<=	>=	8,339	0	1,395
600MW_MC_AVG_0.2%FCSTERR	7/13/2003	34,100	9,002	1,395	=<=	>=	<=	>=	8,391	0	2,006
600MW_MC_AVG_0.2%FCSTERR	7/14/2003	31,000	8,184	2,006	=		<=	>=	8,385	0	1,806
600MW_MC_AVG_0.2%FCSTERR	7/15/2003	32,400	8,554	1,806	=<=	>=	<=	>=	8,353	0	2,006
600MW_MC_AVG_0.2%FCSTERR	7/16/2003	32,200	8,501	2,006	<=	>=	<=	>=	8,872	0	1,635
600MW_MC_AVG_0.2%FCSTERR	7/17/2003	31,400	8,290	1,635	<=	>=	<=	>=	8,557	0	1,367
600MW_MC_AVG_0.2%FCSTERR	7/18/2003	32,000	8,448	1,367	<=	>=	<=	>=	8,872	0	943
600MW_MC_AVG_0.2%FCSTERR	7/19/2003	33,500	8,844	943	<=	>=	<=	>=	8,192	0	1,595
600MW_MC_AVG_0.2%FCSTERR	7/20/2003	31,400	8,290	1,595	<=	>=	<=	>=	8,721	0	1,163
600MW_MC_AVG_0.2%FCSTERR	7/21/2003	23,300	6,151	1,163	=		<=	>=	5,509	0	1,806
600MW_MC_AVG_0.2%FCSTERR	7/22/2003	24,400	6,442	1,806	<=	>=	<=	>=	7,044	0	1,204
600MW_MC_AVG_0.2%FCSTERR	7/23/2003	24,500	6,468	1,204	=<=	>=	=<=	>=	5,665	0	2,006
600MW_MC_AVG_0.2%FCSTERR	7/24/2003	14,000	3,696	2,006	<=	>=	<=	=>=	4,499	0	1,204
600MW_MC_AVG_0.2%FCSTERR	7/25/2003	15,500	4,092	1,204	<=	>=	<=	=>=	4,895	0	401
600MW_MC_AVG_0.2%FCSTERR	7/26/2003	23,900	6,310	401	<=	>=	<=	>=	6,074	0	637
600MW_MC_AVG_0.2%FCSTERR	7/27/2003	19,500	5,148	637	<=	>=	<=	>=	4,495	0	1,290
600MW_MC_AVG_0.2%FCSTERR	7/28/2003	20,300	5,359	1,290	=		<=	>=	4,843	0	1,806

Figure 19: Mid-C Logic Module

The Pre-Schedule Model and Real-Time Model Modules

The Pre-Schedule and Real-Time modules are too large for a visual representation in this discussion. Both are similar in organization, with the significant difference being that the Pre-Schedule module uses forecasts of load, market prices, and wind generation in its optimization routine. The Real-Time Model uses actual values for these variables. Each module performs an hourly optimization of resources against loads, honoring resource constraints, transmission paths, tracking reserve obligations, and balancing the portfolio using the wholesale marketplaces for natural gas and electricity. Purchases and sales entered into during the pre-schedule timeframe are carried through to the real-time as obligations that must be met in addition to real-time loads and resources.

Scenario Analysis and Objectives

The exact impacts of future wind acquisition are uncertain. It will be many years before we learn how accurate our forecasts of integration costs are. Many studies have provided integration cost estimates based on a set of assumptions. Some scenarios were studied to determine the sensitivity of wind integration costs to various key changes in assumptions. More scenarios are necessary.

Limitations in scenario analysis oftentimes are the result of long solution times necessary to model systems accurately. Wind integration studies require a complex level of analysis beyond traditional engineering-economics studies. Production cost models oftentimes have been used to determine how a larger system changes its dispatch in response to bringing wind online.

This study benefits from a new LP Model developed internally by Avista over the past six years. The LP Model focuses on the re-dispatch of Avista resources balanced by an hourly wholesale electricity marketplace. Instead of modeling all generation resources in the Western Interconnect, hourly market prices represent the world outside of Avista's control area.

Solution times for the Avista System Integration LP Model are short, requiring approximately thirty minutes for a one-year control area dispatch. This efficiency lends itself well to more scenario analysis.

Debates continue in our industry about the level of incremental regulation, load following, and forecast error reserves necessary to integrate wind. This study, while identifying a level of integration cost, focuses on quantifying sensitivities around these levels. Many in the wind industry advocate better forecasting to reduce wind integration costs. Irrespective of the ability of the forecast industry to provide better forecasts, it is difficult to decide whether or not to pursue such avenues absent a means to measure what a better forecast would mean for wind integration costs. By studying varying levels of forecast error, one can determine the value of a better wind forecast and spend resources appropriately.

Scenario analysis for this study falls into five categories. The first explores wind diversity to learn how much costs potentially change where a geographically diversified mix of wind farms is pursued. The second looks at system wind penetration levels to evaluate how integration costs change as wind become a larger share of the utility generation mix. Third, as the Northwest marketplace is driven by hydroelectric demand, the impact of varying water conditions is explored. The fourth scenario reviewed the impacts of market price levels on integration costs. Finally, as forecast error levels were found to represent a significant portion of the total cost of wind integration, and in fact are a large portion of the debate around wind integration today, varying levels of wind forecast error were modeled.

This study considered four mixes of wind generation: a mix of Columbia Basin wind farms, a mix of wind farms in Montana east of the Continental Divide, a combination of Columbia Basin and Montana wind farms and a diversified mix of five wind sites located across the Northwest and into eastern Montana. The impacts of these mixes are driven primarily by their reserve obligations. Montana wind tends to be more volatile, requiring more reserves than Columbia Basin wind. The diversified mix provides the lowest mix of incremental reserve requirements, driving it to have the lowest integration costs. Table 15 details the estimated reserve requirements of these wind resource mixes.

Table 15: Total Operating Reserve Assumptions for Wind Scenarios

Wind Capacity	System Penetration	Wind Location	Regulation (MW)	Load Follow (MW)	Forecast Error (MW)	Total (MW)	% of Nameplate
100 MW	5%	C. Basin	2.1	1.3	0.0	3.3	3.3%
200 MW	10%	50/50 Mix	4.1	5.5	5.0	14.5	7.3%
400 MW	20%	Diversified	7.9	15.8	15.0	38.7	9.7%
600 MW	30%	Diversified	11.0	27.7	30.0	68.7	11.5%

Operation Of A Hydro-Based Control Area

Avista, like the majority of its Northwest peers, operates a control area backed predominately by hydroelectric resources. Hydroelectric generation plants offer tremendous flexibility when compared to other generation technologies. In many cases a turbine can be ramped from zero to full capacity almost instantaneously. This flexibility makes hydroelectric turbines ideal for covering variations in generation and load, including variation due to wind generation. A second characteristic of hydroelectric generators is much like wind generation plants: zero fuel cost.

Hydroelectric generation plants generally are "energy-limited," in that they do not have enough fuel to operate during all hours at maximum capacity; they have vast capacity relative to their energy generating potential. This is in contrast to other traditional resources that have essentially unlimited fuel supplies, but instead are limited by their generating capacity. Hydroelectric facilities tend to be operated over peak and super-peak hours of the day to maximize the value of their limited energy generation potential. Water is stored overnight and, where adequate storage exists behind a dam, on days with lower demand and market prices. This stored energy is then shifted to higher value periods.

Maximizing a hydroelectric facility's value is affected by the level of reserves necessary to balance control area loads and resources. Higher reserve levels generally necessitate hydroelectric generators operating away from their optimal energy generation points.[2] Energy not generated during peak hours must be shifted to less valuable shoulder hours. Figure 20 provides a graphical depiction of this impact.

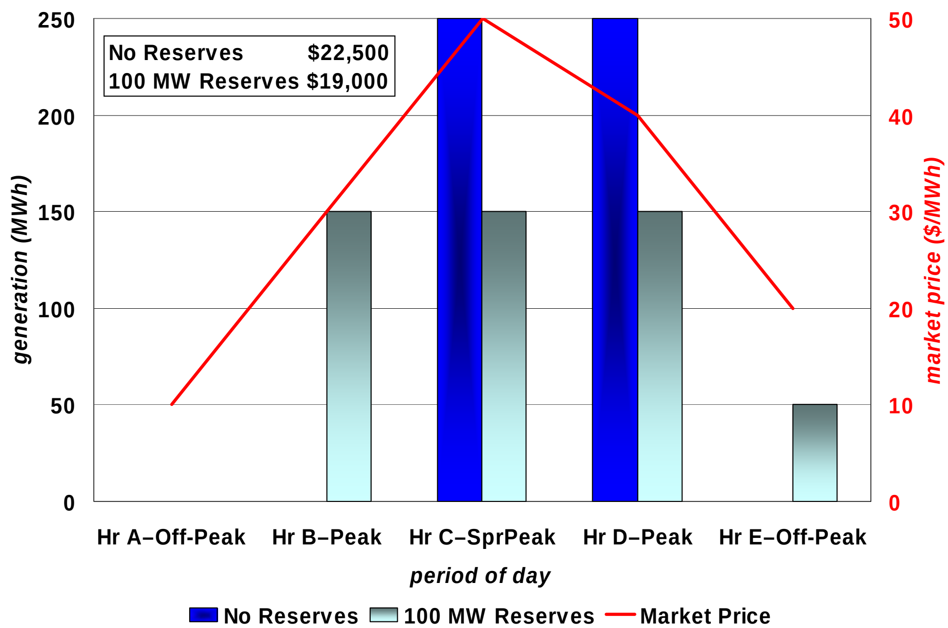

Figure 20: Maximizing Hydro Facility Value

The figure shows how a 250 MW hydroelectric plant would theoretically dispatch against a set of five market prices representing a 5-hour day. Total inflow for the day is 500 MWh. In the No Reserves case, generation is focused on the two highest-value hours, generating 250 MWh in each period for a total value of $22,500. Where 100 MW of reserve are carried in the second case, the maximum generation level in any hour is

[2] In some cases, changes in thermal plant operations can be made at a lower cost; but, generally it is hydroelectric units that provide reserves on Avista's system.

lowered to 150 MW. This forces the hydroelectric plant to maximize its value by generating during four hours for a total value of $19,000. The reserve costs in this example equal $3,500, or $7 per MWh [$3,500 / (100 MW * 5 hours)] of reserves. Economists define this as opportunity cost. Providing reserve capacity de-optimizes generation efficiency on a hydroelectric system. Wind integration magnifies reserve obligations, thereby increasing opportunity costs. This is the key concept underlying this study.

Section 6

IMPACTS OF WIND GENERATION WITHIN THE HOUR

MODELING AND ANALYSIS FOR WIND INTEGRATION ASSESSMENT

The common methodology for assessing the cost of integrating wind energy into a utility control area is based on chronological simulations of scheduling and real-time operations. Production costing and other optimization tools are generally used to conduct these simulations. In most cases, the "time-step" for these simulations is in one-hour increments. Consequently, many details of real-time operation cannot be simulated explicitly. Generation capacity that is used by operators to manage the system in real-time – i.e. the units on AGC utilized by the EMS for both fast response to ACE and that which is frequently economically re-dispatched to follow changes in control area demand – is assigned to one or more reserve categories available in the various programs.

At this level of granularity, the total reserve requirements for the system are a constraint on the optimization and dispatch. Supply resources are designated by their ability to contribute to system requirements in one or more reserve categories. In the course of the optimization or dispatch, the solution algorithm must honor system reserve needs, and therefore is not able to use some capacity to meet load or fulfill transactions.

In this context, there are two primary types of reserves. The first is comprised of the excess capacity that must be carried at all times for reliability. These are generally known as "contingency reserves", and as the name implies, can only be utilized when a contingency actually occurs.

The second category of reserves is used to balance the supply with the control area demand on a continuous basis. This includes minute-by-minute (or faster) adjustments to generation to compensate for load variations and frequency economic dispatch of units with movement capability to follow slower variations in control area demand.

There are periods where demand is higher or lower than the average over an hour. Generation must be adjusted to meet these values within the hour. Figure 21 illustrates this with actual data.

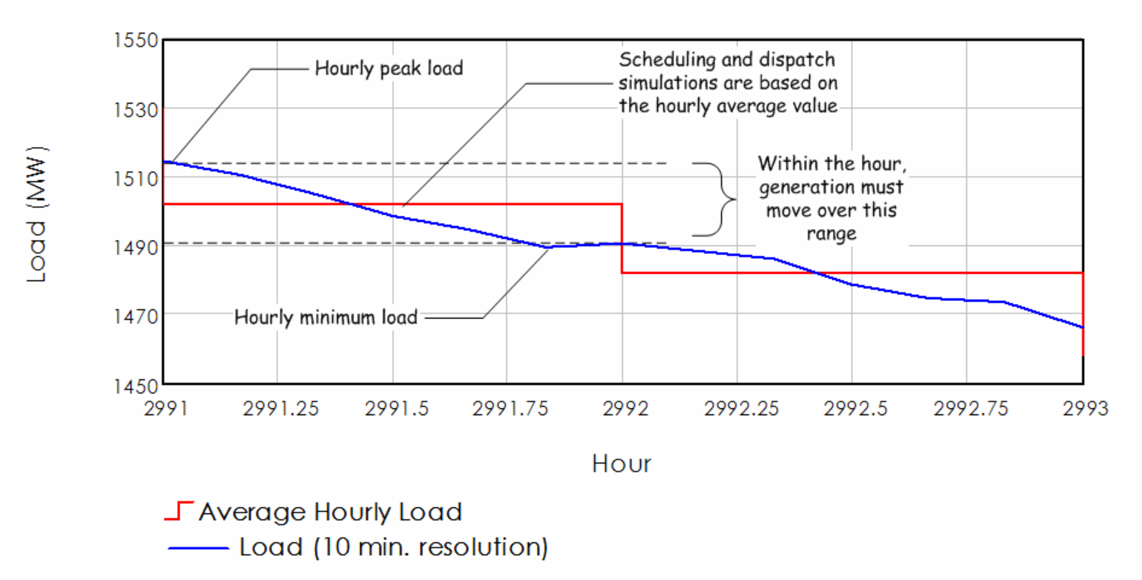

Figure 21: Hourly average and ten-minute load

CALCULATING REQUIREMENTS FOR MANAGING VARIABILITY WITHIN THE HOUR

The purpose of this study is to develop a procedure for estimating the additional flexibility within the hour that would be required to manage a control area with significant wind generation. The analysis and experimentation are based on an annual record of load and wind generation at ten-minute intervals. The goal is to develop a "rule" for the amount of flexibility that would be required using information that would be available in the control room. The extended data records also provide a way to test the proposed rules.

The procedure for determining the required flexibility for load alone is as follows:

1. Using the ten-minute data, compute the hourly average value for load
2. Compute the difference between each ten-minute value of load and the hourly average. The difference is the load following requirement.
3. Because of defined WECC ramp which takes place from 10 minutes before until 10 minutes after the hour, the average load value at the top of each hour is actually the average of the previous and next hour values (Figure 22). This adjustment will reduce the magnitude of the hourly load following "envelope", since the greatest departure of ten-minute values usually occur at the start and end of each hour using this method.
4. Devise an algorithm that could be implemented by operators to project the maneuverability needed to follow the load movements. For load alone, this algorithm is based on the previous hour average value (which is known) and the forecast average value for the next hour (which we will assume can be perfectly forecasted for load alone).
5. The estimated load following capability is then the difference between the next hour forecast average and the previous hour average.

6. The requirements are roughly symmetrical about the average value. In the morning, for example, the load at the beginning of the hour will be less than the hourly average. If the unit base points are moved to the hourly average, there will be a need to back some generation down, and then move it up over the hour as the load increases.
7. This load following rule is tested with the ten-minute data. The number of ten-minute load values outside of the up and down load following bands is computed. For the rule above, the number of "violations" is about 1,800 out of almost 50,000 ten-minute samples. It was also necessary to add in regulation capacity, as the ten-minute values are snapshots, not interval averages.

Figure 22 and Figure 23 show the results of the mathematical procedure described above in points 1 and 2.

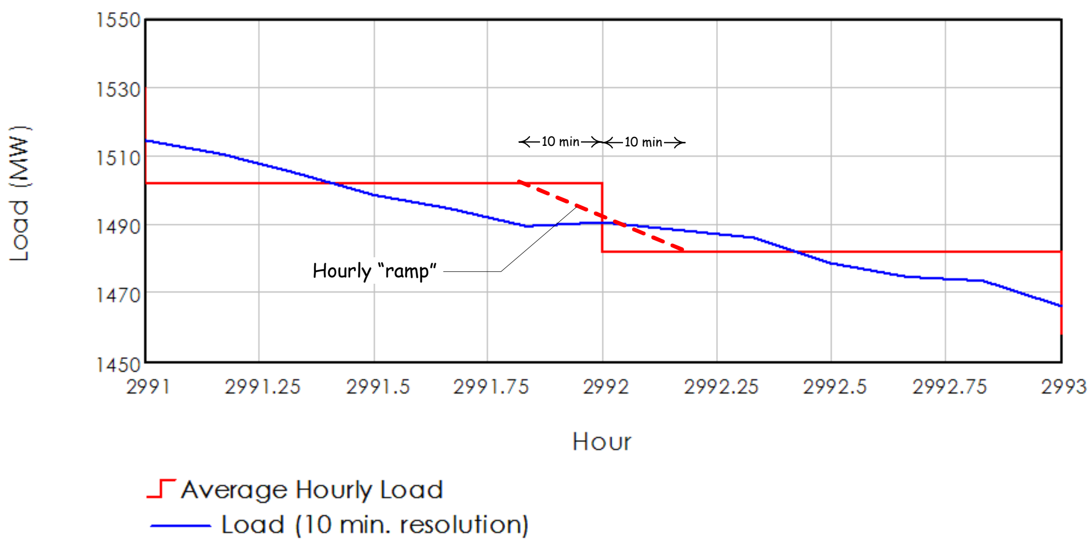

Figure 22: Hourly average and ten minute values, with over-the-hour ramp period

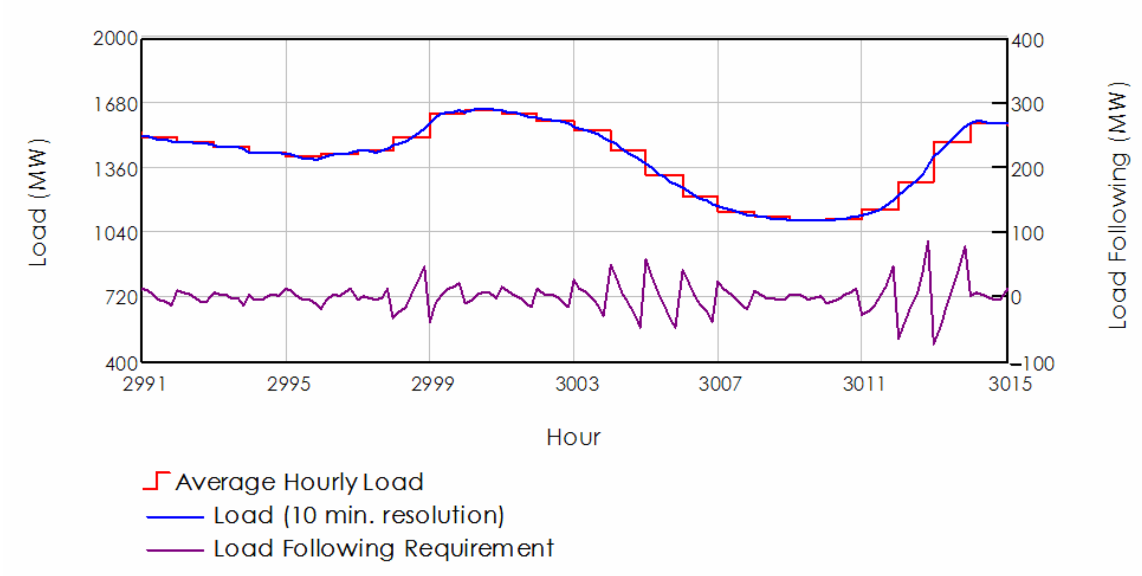

Figure 23: Hourly load, ten-minute load, and load following "requirement".

In this initial analysis of load following requirements, it is assumed that base-point scheduled generation is committed to meet the hourly average load plus hourly transactions. All deviations from the hourly schedule, then, fall into the load following bin.

A point should be made here regarding the combination of regulation and load following functions–as is the practice in the Northwest–and the type of data utilized for the analysis described here. The ten-minute data used in this analysis was calculated from one-minute samples, and is therefore very near the ten-minute average load level. This is important as the ten-minute area control error used for CPS2 compliance is calculated as a ten-minute average. If the data is actually a sample taken every ten minutes, it will be less indicative of the ten-minute ACE that is a primary driver for the EMS.

The algorithm for calculating intra-hour variability is based on information available to operators at the time that they would be making short-term operating plans. In Avista's case, the reserves for a given hour are determined approximately one hour prior to the beginning of the target hour. In the current situation, the operators have established that a 20 MW band of regulation reserves during each hour will provide adequate control capability.

A check of this load following rule against one year of ten-minute load data shows that with a 20 MW load following band in each hour, there are over 7,000 ten-minute intervals where the deviation from the hourly average value is outside this band. It is not necessary to compensate for all deviations, only a number of deviations that bring the system within a defined L_{10} for the control area (per the NERC Control Performance Standards). The L_{10} for the Avista control area is 25 MW. Applying the L10 reduces violations to 1,500, constituting a high level of CPS2 compliance (96.8%). Figure 24 shows how this works for a typical day out of the sample.

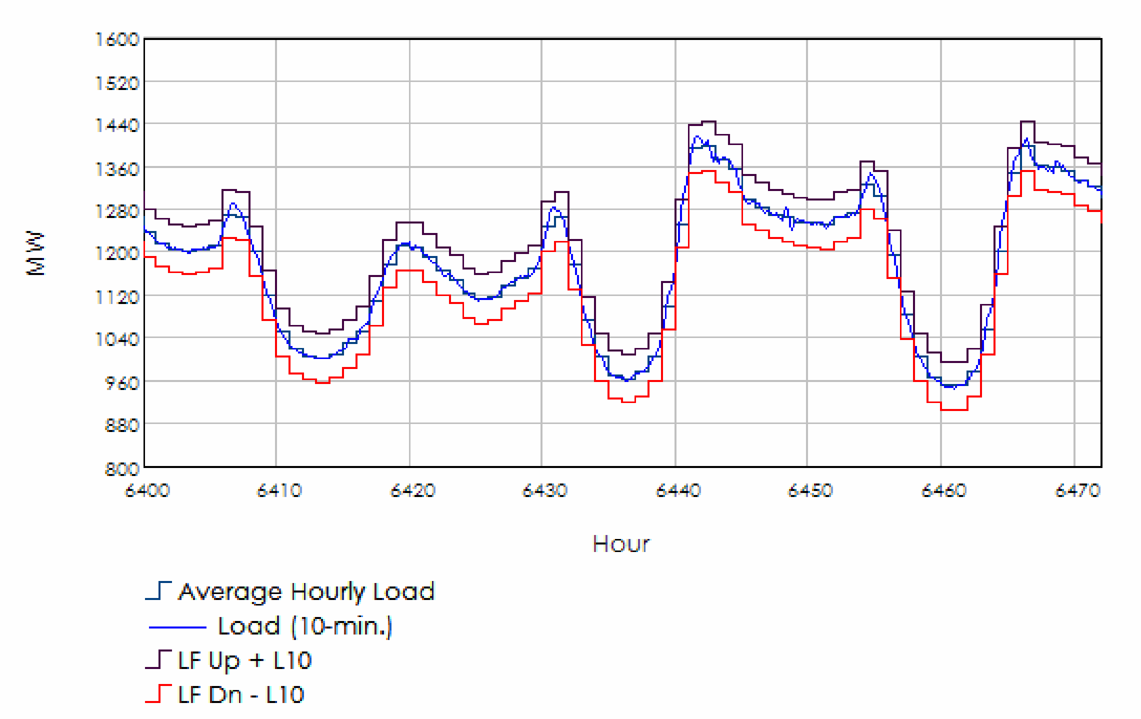

Figure 24: Ten-minute average load shown with up/down intra-hourly load following capability

From this baseline, incremental reserves are added in each wind case to maintain the same level of CPS2 compliance. Both wind generation and load are assumed to be forecast perfectly, so the hourly average value from which the deviations are computed is the net of the hourly average load and the hourly average wind. The amount of wind generation change over an hour is the metric for characterizing wind generation variability. There are other metrics that could be developed, but this study's approach lends itself well to the data.

Using hourly average wind generation data, variability over one hour is computed for ten deciles of production. The results for the Avista Mid-C wind scenarios are shown in Figure 25. The curves show that the maximum variability occurs in the mid-range of aggregate wind capacity.

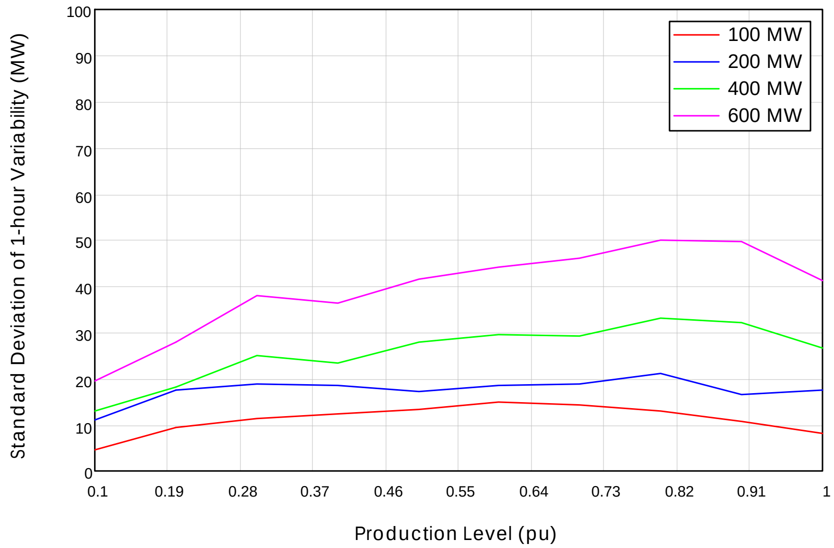

Figure 25: Variability of wind generation over one hour from LP Model data (by scenario)

The empirical results from Figure 25 are approximated as quadratic expressions, with the input to the expression being the current average production. This facilitates a rule that can be applied on an hourly basis. In this first example, reserve planning for the hour is performed just prior to the start of the hour, so that the average production is from hour t-1 and the amount of change predicted for hour t.

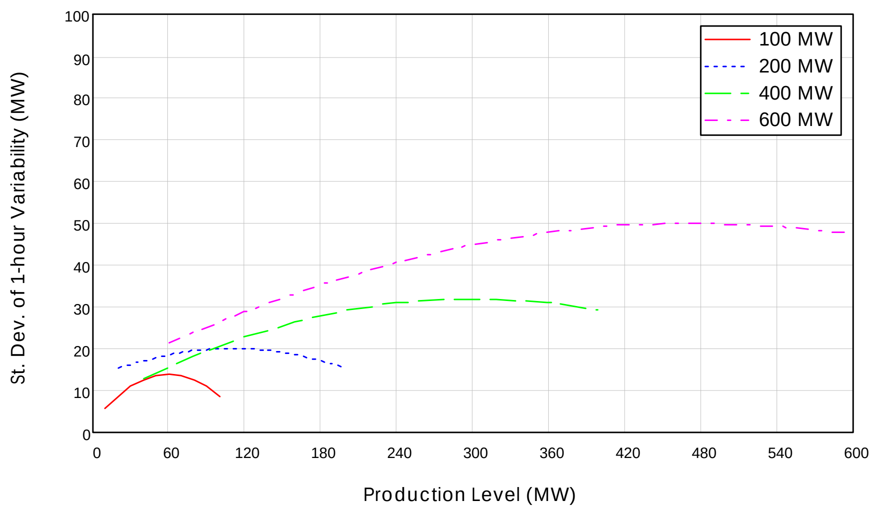

Figure 26: Approximation of empirical wind generation variability with quadratic expressions

The quadratic expressions are:

$$f1(x) := 14 - \frac{(x-60)^2}{300}$$

$$f2(x) := 20 - \frac{(x-110)^2}{1700}$$

$$f4(x) := 32 - \frac{(x-300)^2}{3500}$$

$$f6(x) := 50 - \frac{(x-475)^2}{6000}$$

where f1 through f6 correspond to the 100 MW, 200 MW, 400 MW, and 600 MW scenarios respectively.

The load following rule for each wind scenario is of the form

$$F1_{h1} := F0_{h1} + k1 \cdot \left[15 - \frac{\left(HWind1_{h1-1} - 60\right)^2}{300} \right]$$

where the variable in the expression is the current hour average wind generation (h-1 because we are planning for hour h), the quadratic constants are from the empirical analysis described previously, and F0 is the load following requirement for load alone. The coefficient k1 is adjusted so that the number of CPS2 “violations” is the same as for the case with no wind–about 1,500 with a 20 MW band of regulation capability. Running these experiments for each wind generation scenario, the following coefficients are determined:

k1 = 0.25

k2 = 0.30

k4 = 0.35

k6 = 0.40

The required additional load following capability is much less than one standard deviation of the hourly change for all cases. Also, the coefficients will vary depending on the nature of the wind generation scenario. Concentrated and correlated wind generation facilities would lead to higher coefficients, while well-distributed scenarios would tend to reduce them. The scenarios developed for the Avista study bear this out. Figure 27 depicts the hourly load following bands for the 400 MW Mid-C wind scenario for the same three day period shown in Figure 24.

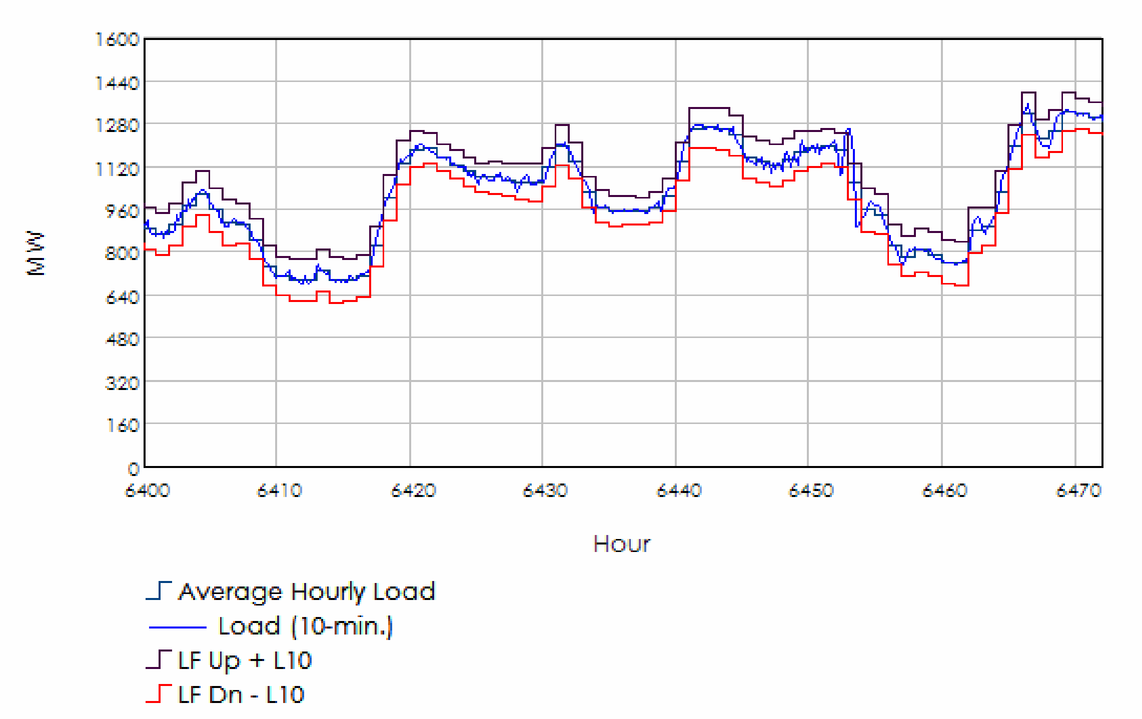

Figure 27: Ten-minute load net wind generation and intra-hourly load following capability

The average load following capabilities over all hours of the sample year for the four wind generation scenarios are shown in Table 16.

Table 16: Average Hourly Flexibility Requirements for Managing Control Area Variability

Case	Average Hourly Flexibility (+/-)
Load only	20 MW
100 MW	22.3 MW
200 MW	26.6 MW
400 MW	34.8 MW
600 MW	44.6 MW

IMPACTS OF SHORT-TERM FORECAST ERROR ON REAL-TIME OPERATIONS

The previous analysis assumes that the reserves for the hour are planned on the basis of perfect knowledge of the next hour average load and wind generation. This is the situation with the minimum uncertainty, and relates mostly to the real-time operation of the system to compensate for inside-the-hour variations from some constant average value. In reality, there are operational decisions made some hours prior to this hour that will affect the generation flexibility that is needed to manage the control area.

If reserves must be allocated an hour or more before the operating hour, the known wind generation at that time may be substantially different than in the hour in question. This could impact the projected variability, as it is a function of the current production level. However, since the variability curves (Figure 25 and Figure 26) do not change dramatically with slight changes in production level, the error here would be slight.

Larger impacts stem from decisions made based on short-term forecast information. If the window for hourly transactions closes one hour prior to the hour, it is necessary to cover deviations (i.e. forecast error) in the average hourly load net wind from the forecast hourly average load net wind (Figure 28). These deviations are covered by internal generation capacity which has been set aside for the hour in question since there is no other alternative. The deviation is constant through the hour in question and is actually an offset in the operating position (Figure 29). To cover the deviation, a resource must be scheduled at an operating point for the hour different than what was planned when setting up the hourly schedules. This action is not really following the load, but rather addressing a energy deficit or surplus from schedule. Generation capacity must be reserved to make this adjustment.

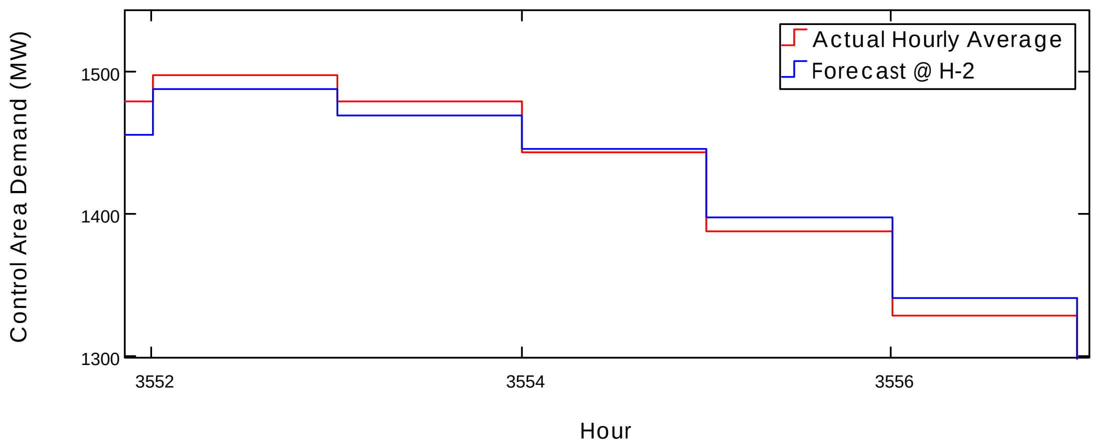

Figure 28: Actual and forecast hourly average values. Short-term forecast is made 1.5 hours prior to the start of the subject hour.

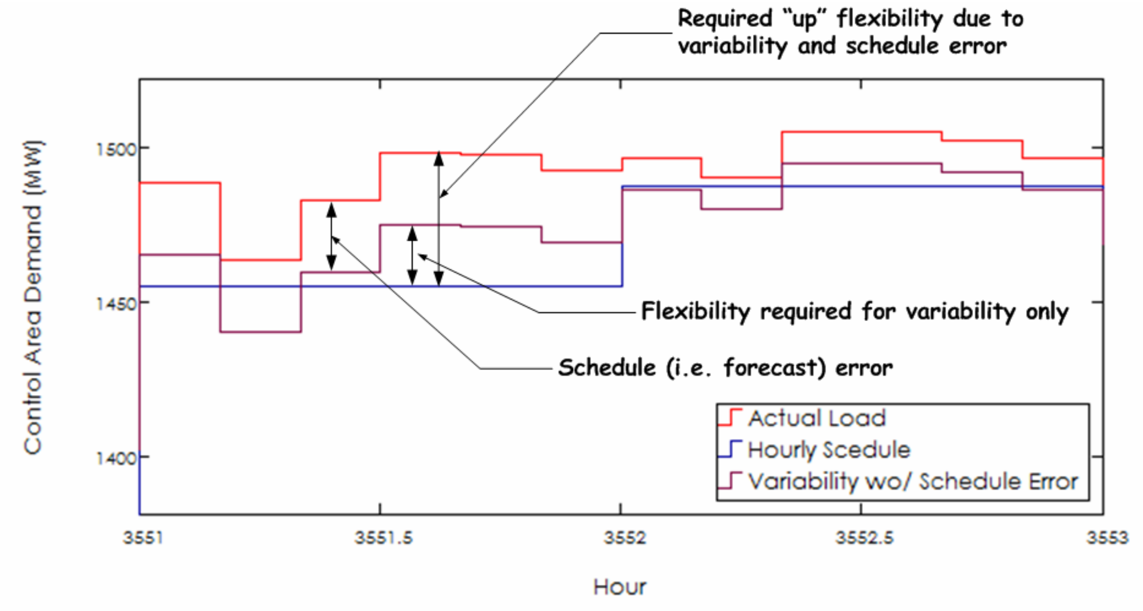

Figure 29: Additional intra-hour flexibility requirements due to schedule error bias.

Schedule deviations are a consequence of short-term load and wind generation forecast errors. Avista currently carries approximately a 15MW band to cover load variation. The schedule deviation will be larger with wind generation. An approach similar to that used to calculate incremental regulation and load following reserves can be employed to determine how much additional capacity must be allocated to cover incremental forecast error. The error in a persistence forecast over a two hour horizon is calculated from the hourly wind generation data and summarized in Figure 30. Note that the standard deviations here are larger than for the 1-hour persistence forecast (which would correspond to Figure 25 and Figure 26), illustrating the relatively rapid degradation of the persistence assumption over longer time frames.

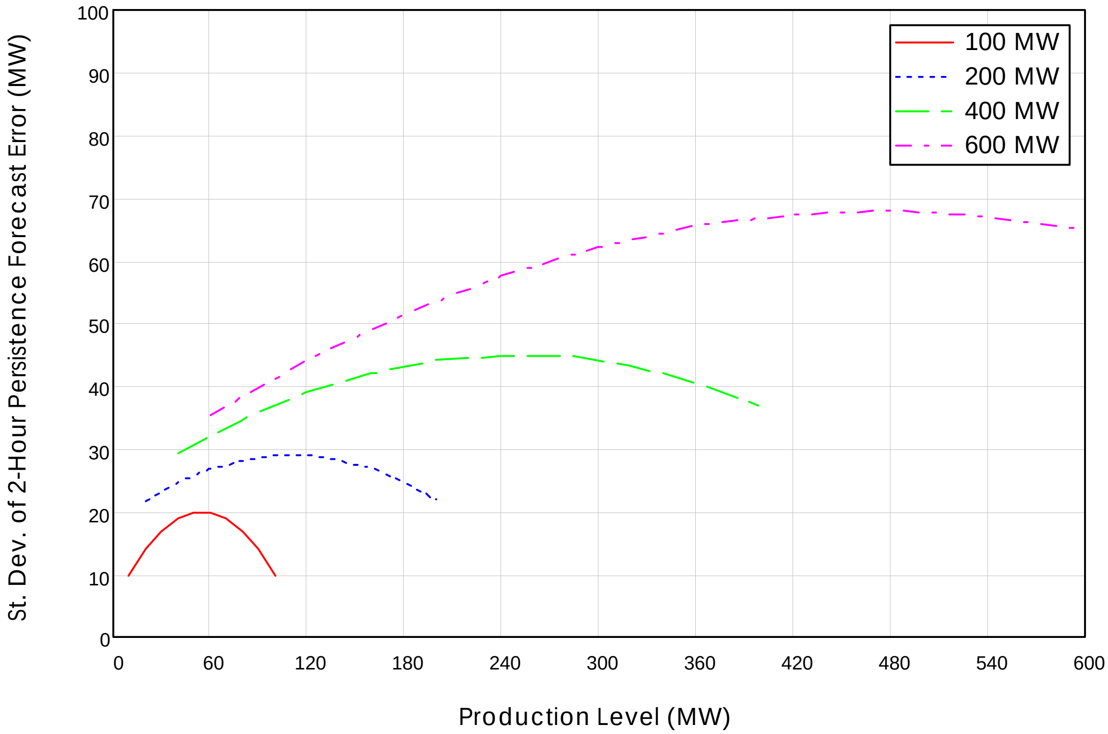

Figure 30: Standard deviation of persistence forecast error over a two hour horizon for the four wind generation scenarios.

Quadratic formulas for the curves of Figure 30 were added to the equations for hourly reserves, and the coefficients adjusted to achieve the same control performance as for load variability alone. Load forecast error was modeled as a normally distributed random variable with a standard deviation of 7.5 MW (one-half of the 15 MW Avista currently carries to account for short-term load forecast error). Table 17 shows the results.

Table 17: Total Reserves for Variability and Schedule Deviations

Case	Average Hourly Flexibility for Variability (+/-)	Average Hourly Flexibility for Variability and Schedule Deviation (+/-)
Load only	20 MW	35.0 MW
100 MW	22.1 MW	38.3 MW
200 MW	24.1 MW	49.5 MW
400 MW	27.9 MW	68.7 MW
600 MW	31.0 MW	103.7 MW

Where both load and wind generation forecast errors are random variables, the schedule deviation error planned in advance of the operating hour would be the root-mean-square value of the respective standard deviations. With 100 MW of wind generation, the component of reserves is increased from 15 MW for load alone to 32.8 MW. This incremental amount is very close to the root-mean-square value of standard deviation of load (7.5 MW) and the two-hour persistence forecast error for 100 MW wind generation scenario (14.6 MW). This relationship holds for the other scenarios, with wind generation forecast error becoming the dominant factor at the higher penetration levels.

Just prior to the operating hour, the direction of the forecast error will be known. Intra-hour variability, as computed earlier in the study, must still be covered and is not affected by the forecast error. So, it seems that the real-time operators would know at the beginning of the operator hour how the scheduling error would impact the reserve requirements. If there is additional energy to be provided to cover the forecast error, the capacity set aside to move up would be used, with no need to retain the downward movement capability. The operating plan for the hour must be sufficient to cover both the up and down side of the forecast error.

Because it is an offset in the flat schedule for the hour, there is minimal intermingling with load following error. While the same resource may in fact be called upon to address both, computation of the individual requirements in developing the plan for the hour is separate.

Section 7

RESULTS

BASE CASE RESULTS

Total integration costs for the four base scenarios are detailed in Table 18. Costs range from $2.75/MWh of wind generation for the 100 MW Columbia Basin scenario to $8.84/MWh for the 600 MW diversified mix, which equates to a 30% capacity penetration level.

Table 18: Integration Costs for Base Scenarios

Wind Location	Wind Capacity	System Penetration	Forecast Error	Cost ($/MWh)	Cost (% Mkt)
Columbia Basin	100 MW	5%	15%	$2.75	5.0%
50/50 Mix of CB & MT	200 MW	10%	10%	$6.99	12.7%
Diversified Mix	400 MW	20%	8%	$6.65	12.1%
Diversified Mix	600 MW	30%	8%	$8.84	16.1%

The incremental reserve requirements are detailed in Table 19. The ratio of the incremental reserve amounts for the larger penetration scenarios is consistent with what has been reported in numerous studies. The costs are also in the range of what has been reported in previous North American wind integration studies.

Table 19: Incremental Reserve Assumptions for Base Scenarios

Wind Capacity	System Penetration	Wind Location	Regulation (MW)	Load Follow (MW)	Forecast Error (MW)	Total (MW)	% of Nameplate
100 MW	5%	C. Basin	2.1	1.3	0.0	3.3	3.3%
200 MW	10%	50/50 Mix	4.1	5.5	5.0	14.5	7.3%
400 MW	20%	Diversified	7.9	15.8	15.0	38.7	9.7%
600 MW	30%	Diversified	11.0	27.7	30.0	68.7	11.5%

By changing certain input assumptions, it was possible to determine the contribution of various factors to integration cost. Table 20 and Table 21 decompose the integration costs calculated for the base cases into four components. The "wind shape" cost is the monetized difference of the market value of the actual wind delivery relative to the proxy resource shape. Regulation and load following are attributable to the opportunity cost of the incremental reserve capacity required to manage the additional variability of the control area demand with wind generation. The Forecast Error component relates to the additional capacity that must be reserved to cover deviations in actual wind energy delivery from the short-term (hour + ahead) forecast.

Table 20: Components of Wind Integration Cost - Dollars

Wind Capacity	System Penetration	Wind Location	Wind Shape ($/MWh)	Reg-ulation ($/MWh)	Load Following ($/MWh)	Forecast Error ($/MWh)	Total Cost ($/MWh)
100 MW	5%	C. Basin	$ 0.30	$ 1.13	$ 1.03	$ 0.30	$ 2.75
200 MW	10%	50/50 Mix	$ 0.44	$ 1.62	$ 3.23	$ 1.70	$ 6.99
400 MW	20%	Diversified	$ 0.50	$ 1.67	$ 1.79	$ 2.69	$ 6.65
600 MW	30%	Diversified	$ 0.52	$ 1.43	$ 3.88	$ 3.00	$ 8.84

Table 21: Components of Integration Cost - Percent

Wind Capacity	System Penetration	Wind Location	Wind Shape ($/MWh)	Reg-ulation ($/MWh)	Load Following ($/MWh)	Forecast Error ($/MWh)
100 MW	5%	C. Basin	10.7%	40.9%	37.6%	10.7%
200 MW	10%	50/50 Mix	6.3%	23.1%	46.2%	24.3%
400 MW	20%	Diversified	7.5%	25.1%	26.9%	40.5%
600 MW	30%	Diversified	5.9%	16.2%	43.9%	33.9%

A significant portion of integration cost stems from changes to hydroelectric operations. These plants operate less efficiently to provide the incremental reserves necessary to integrate wind, as shown in Table 22.

Table 22: Hydroelectric Generation Portion of Integration Costs

Wind Capacity	System Penetration	Wind Location	Spilled Hydro (MWh)	Spilled Hydro (% MWh)	Value Change (% 000s)	% of Integration (percent)
100 MW	5%	C.Basin	3,423	0.1%	312.8	42.8%
200 MW	10%	50/50 Mix	12,818	0.3%	1,421.0	38.3%
400 MW	20%	Diversified	25,952	0.7%	2,630.6	37.2%
600 MW	30%	Diversified	50,919	1.4%	5,369.4	38.2%

Hydro conditions affect integration costs. Lower hydro conditions appear to increase integration costs relative to average and high hydro conditions. Table 23 provides the integration cost estimates associated with low, average, and high water years. This result was a bit surprising and further analysis will be necessary to understand exactly what factors are driving this result. For example, are higher costs driven not by actual water conditions but by the higher market prices witnessed during a low water year?

Table 23: Impact of Hydro Conditions on Integration Cost

Wind Capacity	System Penetration	Wind Location	Average 3 Years	Low Hydro	Average Hydro	High Hydro
100 MW	5%	C.Basin	$ 2.75	$ 2.07	$ 2.72	$ 3.49
200 MW	10%	50/50 Mix	$ 6.99	$ 8.76	$ 6.32	$ 6.02
400 MW	20%	Diversified	$ 6.65	$ 9.85	$ 5.79	$ 4.39
600 MW	30%	Diversified	$ 8.84	$ 12.14	$ 7.80	$ 6.75
Average Market Price			**$ 54.85**	**$62.58**	**$ 56.52**	**$45.45**

Sensitivity Analysis

The efficiency of the Avista LP model allowed the execution of a number of additional cases where input assumptions were modified to assess the impact on integration cost. Six separate areas were investigated:

- Impact of market structure, specifically in the hourly trading that is prevalent in the Pacific Northwest
- Value of limited wind generation curtailment as a system control option
- Value of improved wind generation forecasting
- Impact of market conditions on integration cost
- Integration benefits of geographic distribution of wind generation

Findings from the sensitivity cases for each of these topics are described and discussed in the following sections.

Impact of Market Structure

The Northwest marketplace transacts on various time steps with the shortest being one hour. Other areas of the United States and the world run markets that shorten these time steps to as short as 5 minutes. Shorter-term markets have a number of costs and benefits relative to the current Northwest system. A significant benefit of moving away from an hourly marketplace to one that operates on a 5- or 10-minute basis would be the ability to transact more frequently, thereby reducing reserve obligations substantially. Wind power advocates, as well as some utility operators interested in lowering regulating reserve obligations, have encouraged the Northwest to consider moving to a shorter-term marketplace; however, to date there is a general consensus that the costs of operating a shorter-term marketplace would outweigh the benefits.

Table 13 explains that forecast error and intra-hour load following account for between 45% and 75% of wind integration costs. To quantify the potential value of a shorter-term marketplace, Avista analyzed reserve obligations in a 10-minute marketplace. The 10-minute timeframe was selected because it represented the most granular data available for this study. Using the methodologies previously described in this report it was found that forecast error calculated on an N-2 timeframe could be reduced by approximately one-third, and that load following would fall by two-thirds in a 10-minute marketplace.

With reserve obligations adjusted, Avista re-ran its LP Model under average water conditions for each mix of wind resources identified in the Base Case. A 10-minute market would appear to provide significant savings in the range of between 39% and 62%. Table 24 shows that savings could exceed $6 million per year for Avista at the 600 MW penetration level.

Table 24: Effect on Integration Cost of Short-Term Liquid Markets

Wind Capacity	System Penetration	Wind Location	Base Cost ($/MWh)	10-Min Mkt Savings (percent)	10-Min Mkt Savings ($/MWh)	10-Min Mkt Cost ($/MWh)	Annual Savings ($000/yr)
100 MW	5%	C. Basin	$2.75	61.7%	$1.70	$1.05	$490
200 MW	10%	50/50 Mix	$6.99	60.8%	$4.25	$2.74	$2,456
400 MW	20%	Diversified	$6.65	38.9%	$2.59	$4.06	$2,994
600 MW	30%	Diversified	$8.84	40.6%	$3.59	$5.25	$6,224

Value of Wind Curtailment

Control area operators balance resources and loads in real-time, on a second-by-second basis. Plant forced outages, transmission line outages, environmental obligations (e.g., flows for fisheries, thermal plant emission limits), and other factors can force operators to make changes that they otherwise would not make under perfect conditions. Prior to this study Avista recognized the importance of having some amount of wind generator control to manage short-term emergency operations. It also expected that under certain conditions it would be economically advantageous to displace wind generators for reasons other than pure reliability. All Base Case analyses included the option to feather wind generation so long as the wind resource owner was compensated for both the contract power price and the federal production tax credit.

In contract negotiations Avista has pursued wind plant operational flexibility. Wind developers, especially those offering to sell under traditional power purchase agreements, where payments are made only where energy is delivered, have not historically been excited about bringing their plants down except for reliability. Avista believes that the major barrier to developer acceptance is a compensation mechanism where wind generation is displaced, especially in the case where such displacement is for reasons other than system reliability.

This study evaluated the potential for interrupting deliveries from wind farms, both for system reliability and for system economics. Additional LP Model runs were made where wind feathering only occurred for system reliability purposes; no economic dispatch was allowed. Integration costs did rise, however, even when compared to the base case where developers were compensated both for their lost energy value *and* the value of the lost federal production tax credit in the case of interruption. Table 25 shows that integration costs rise by approximately 20% when the control area operator does not have the ability to interrupt wind generation for economic reasons. It also shows that the amount of wind curtailment to achieve this significant reduction in integration costs is modest, especially at lower penetration levels.

Table 25: Impact of Limited Wind Curtailment on Integration Cost

Wind Capacity	System Penetration	Wind Location	Base Cost ($/MWh)	Wind Curtailment (%)	Cost with no Curtailment	Change (%)
100 MW	5%	C. Basin	$2.75	0.4%	$3.78	37%
200 MW	10%	50/50 Mix	$6.99	0.9%	$8.49	21%
400 MW	20%	Diversified	$6.65	0.9%	$7.98	20%
600 MW	30%	Diversified	$8.84	1.4%	$10.69	21%

Though wind energy is not feathered for system reliability in these cases, it was discovered that feathering for system reliability would be necessary where the company focused all of its development (i.e., above 10% system penetration) in one basin or wind farm due to the increased variability associated with a non-diversified wind portfolio.

The Value of Improved Wind Generation Forecasting

Wind generation forecasting errors, as with load, contribute to a sub-optimal power system operation, creating a need for additional reserve capacity. The influence of both day-ahead and short-term (one to two hours) wind generation forecast errors was assessed through sensitivity cases using the Avista LP Model.

Table 26 shows integration costs where wind generation deliveries are known perfectly for day-ahead system scheduling. In the Base Case scenarios, approximately 35% of the total wind integration cost can be attributed to day-ahead wind generation uncertainty.

Table 26: Integration Costs with Perfect Day-Ahead Forecast (no pre-schedule penalty)

Wind Capacity	System Penetration	Wind Location	Base Cost ($/MWh)	Real-Time Cost ($/MWh)	Portion of Base (percent)	Difference ($000/yr)
100 MW	5%	C. Basin	$ 2.75	$ 1.76	63.9%	$ 264
200 MW	10%	50/50 Mix	$ 6.99	$ 4.60	65.8%	$ 1,268
400 MW	20%	Diversified	$ 6.65	$ 4.27	64.2%	$ 2,532
600 MW	30%	Diversified	$ 8.84	$ 5.79	65.5%	$ 4,849

In the shorter term, wind generation uncertainty requires additional operating reserves. The impact was illustrated in the previous discussion of market structure, as the principal impact of closer-to-real time markets is the attendant reduction in operating reserves required to cover schedule deviations. With perfect day-ahead knowledge of wind generation, and short-term uncertainty covered by real-time markets, the sole contributor to integration cost is the additional variability that must be managed to maintain control performance.

Integration Cost Sensitivity to Market Conditions

For hydro systems, energy markets are a critical factor in system economics. To assess the impact of energy market prices on wind integration cost, two market price sensitivity cases were constructed. In the low market price scenario, wholesale prices were reduced by 50% from the Base Case. In the high market price case, prices were doubled from the Base Case. As expected, integration costs change in accord with the assumed market prices, though not in a perfectly linear fashion.

Table 27: Market Price Impacts on Integration Cost

Market Case	Wind Capacity	System Penetration	Wind Location	Forecast Error	Integration Cost ($000)	Integration Cost ($/MWh)	Base Case Savings (percent)
Low Market Prices	100 MW	5%	C. Basin	15.0%	$ 181.90	$ 1.32	-52%
	200 MW	10%	50/50 Mix	10.0%	$ 589.87	$ 2.67	-62%
	400 MW	20%	Diversified	7.5%	$ 1,872.51	$ 3.88	-42%
	600 MW	30%	Diversified	7.5%	$ 2,404.10	$ 3.98	-55%
High Market Prices	100 MW	5%	C. Basin	15.0%	$ 920.56	$ 2.99	9%
	200 MW	10%	50/50 Mix	10.0%	$ 5,792.80	$ 8.53	22%
	400 MW	20%	Diversified	7.5%	$ 9,489.50	$ 7.54	13%
	600 MW	30%	Diversified	7.5%	$ 20,280.32	$ 10.45	18%

Impact of Reduced Forecast Error

In the previous section on intra-hour impacts and operating reserves, it was shown that expected errors in short-term wind generation forecasts, one to two hours ahead, translate into an additional reserve requirement due to the lead time associated with hourly energy markets in the Pacific Northwest. Forecast error, therefore, is a significant contributor to wind integration cost. It is uncertain at this time what improvement can be expected over persistence from state-of-the-art wind generation forecasting techniques. To illustrate how this component affects integration cost, a series of cases was run with differing assumptions about the expected forecast error over the time frame from hourly trading deadlines to the subject hour. Results of these sensitivity cases for the base scenarios are shown in Figure 31. As the expected error rises beyond a certain level, integration costs increase dramatically for all scenarios. The inflection point for each scenario corresponds to the level where the effects of wind generation uncertainty begin to dominate the overall uncertainty. At low wind penetrations, for example, the uncertainty in MW is lower than the short-term load forecast error, and therefore does not significantly increase the total short-term uncertainty.

As the graphic shows, there is significant benefit from improvements in short-term wind generation forecasting given the current structure of the hourly energy markets in the Pacific Northwest.

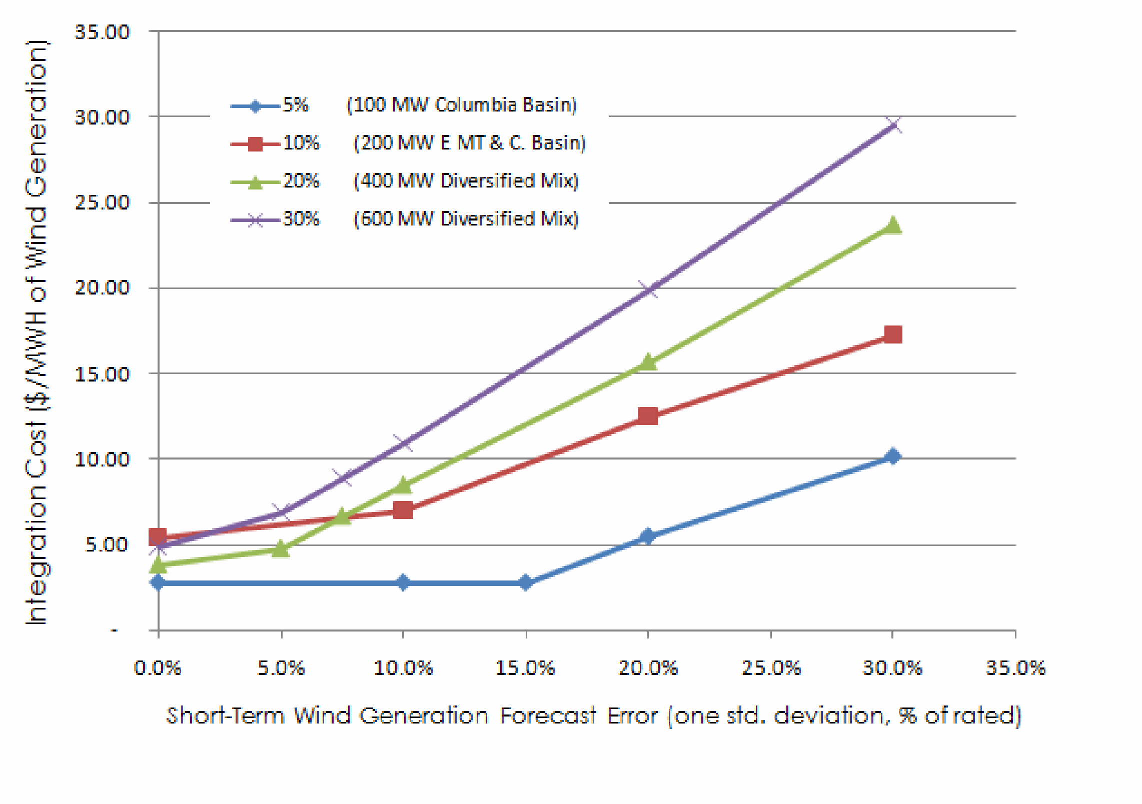

Figure 31: Integration cost as function of short-term wind generation forecast error for base scenarios.

Benefits of Geographical Diversity

This study supports earlier work indicating that geographical diversity is one of the keys to lowering wind integration costs. The Base Case wind integration cost curve does not rise substantially due to the assumption that Avista over time will acquire a geographically-diverse mix of wind resources. One of the interesting results of this study is that wind integration costs actually fall modestly when going from a 10% to a 20% wind penetration level. This is not a data anomaly, but the result of moving from a 2-basin to a 5-basin mix of wind projects.

Wind generation scenarios were originally developed for all penetration levels by site. While this leads to some unrealistic variability at higher penetrations due to limitations of wind speed data, dispatch simulations were run for all of these situations. Figure 32 illustrates how the higher (albeit artificial) correlation and less geographic dispersion of wind generation production effects integration cost.

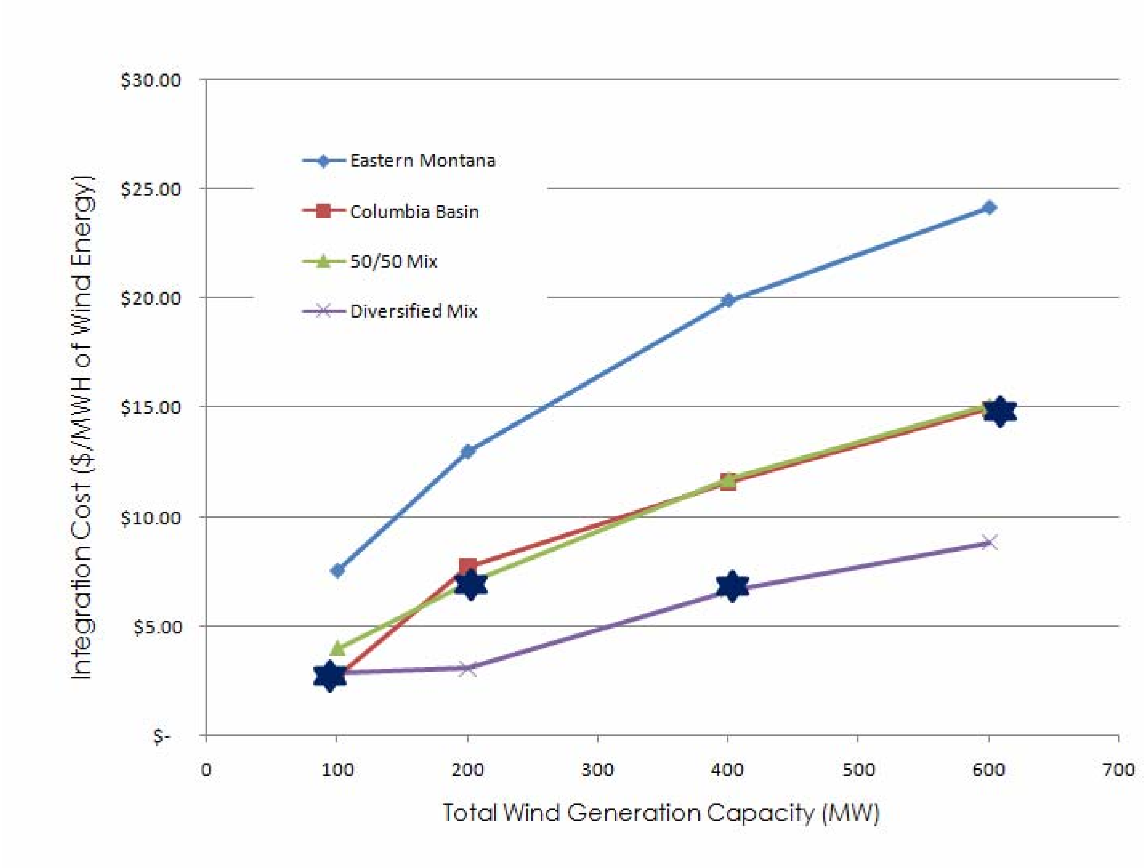

Figure 32: Effects of geographic dispersion of wind generation facilities on integration cost. Base case scenarios are indicated by the star symbols.

Section 8

SUMMARY

The results presented in the previous discussion are the culmination of an exhaustive and iterative process involving several hundred annual simulations of the Avista system. Throughout the investigation all aspects of Avista operations were explored, and the data and assumptions were refined accordingly. Some new understanding of wind integration cost drivers were developed as a result of the study. The influence of wind generation variability and short-term uncertainty was analyzed extensively and incorporated into the analysis. From this, new insights such as the effect of rules for energy transactions on wind generation integration were developed and quantified. In all, the analytical approach built on the latest developments in wind integration analysis and then extended them significantly.

The results show that the **costs for integrating significant amounts of wind generation into the Avista power system are modest**. In addition, there are opportunities for reducing these costs. As wind generation continues to grow in the Pacific Northwest, mechanisms for managing the additional variability and uncertainty will be explored and implemented. As reported here, the integration costs reflect current-day assumptions and rules for Avista system operation.

HIGHER WIND PENETRATION EQUALS HIGHER INTEGRATION COST

The Avista study confirms what other studies before it have theorized or shown through analysis. Higher wind penetration levels, all other things being equal, increase wind integration costs. To provide a full understanding of wind integration costs, this study ran the LP Model through varying levels of wind penetration, from five percent up to approximately thirty percent. This wide range covers where many systems are today, and pushes the envelope well beyond the 20% level mentioned by many as an upper bound for wind penetration.

INTEGRATION COSTS ARE CORRELATED WITH MARKET PRICES

Capacity opportunity costs are a significant component of wind integration. As prices rise, all things equal, one might expect integration costs to rise as well. Wind resource value, therefore, does not rise equally with the market price, as integration costs consume some of the additional value. Avista used the LP Model to look at two price sensitivities − market prices equal to half of forecasted levels, and twice forecasted levels − and found that market prices and wind integration costs are correlated.

SHORTER-TERM MARKETS CAN REDUCE COST OF VARIABILITY

In this study, the increased short-term uncertainty due to wind generation forecast errors increased the amount of reserve capacity required to operate the system. Much of this is driven by rules that govern short-term exchanges of energy in the Pacific

Northwest. Because the “window” for hourly trading closes well in advance of the hour, probable errors in wind generation forecasts become significant.

While improvements in wind generation forecasting can assist, reduction of the lead time for energy transactions would also have an influence. In regions with well-functioning short-term energy markets (some cleared at intervals as short as 5 minutes), variability in demand due to both wind generation and load variability is spread out over a much larger footprint. When the aggregation effects on variability over this larger geographical area are considered, the net effects on system operation can be substantially reduced.

RISING FORECAST ERROR INCREASES INTEGRATION COST

Forecast error affects the overall level of reserve capacity necessary to integrate wind resources. As forecast error rises, so do integration costs. Many participants to the wind integration debate disagree on how accurate wind forecasts, and hence forecast error, are. This study strives to identify an appropriate level of reserves to account for forecast error; the debate will continue. To this end, Avista ran its LP Model under various levels of forecast error, from zero percent, or perfect foresight, to thirty percent.

GEOGRAPHIC DIVERSITY HAS DIRECT INFLUENCE ON INTEGRATION COSTS

Additional generation capacity must be reserved to manage increased control area variability and uncertainty. This capacity is a major component of integration cost. Wind plants concentrated in a small region will exhibit a much higher degree of correlation in their output than plants separated by larger geographic distances.

OPERATIONAL COORDINATION BETWEEN THE CONTROL CENTER AND WIND GENERATORS CAN REDUCE INTEGRATION COSTS

There can be times where the incremental cost for managing wind generation rise dramatically. In these times, the most economic solution may be to “feather” wind energy via production curtailments.

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APPENDIX A
WIND GENERATION
CONTRIBUTION TO PLANNING MARGIN

This section explains how the majority of wind integration costs is created by the consumption of reserve capacity products, namely regulation, load following, and forecast error. Each of these products is met by other resources with "quick-start" capabilities. While wind is unable to self-provide these quick-start reserve capacity products, it does appear capable of meeting another key capacity product—on-peak generation capacity.

BACKGROUND

On-peak generation capacity is the contribution of a given resource to meeting system requirements during the highest load hours of the year. Most traditional resources provide contributions near their nameplate capacities. For example, a coal-fired plant would be expected to generate approximately 90% of its nameplate capacity during on-peak periods. Hydroelectric plants can provide a nearly 100% contribution during peak load times. Wind generators, due to their limited and unpredictable fuel supply, have a much lower on-peak capacity contributions.

Resource planners tabulate the on-peak capacity of their portfolios and compare them to expected peak loads. Peak load is subtracted from the total of on-peak resource capacity to determine a utility's position. On-peak resource capability must equal or exceed expected on-peak load in a reliable system. In fact, given reliability considerations, on-peak resource capability is expected to exceed on-peak load by an additional planning margin. In California, regulated utilities are obligated to a planning margin level of between 15% and 17%. Recent work by the Northwest Power and Conservation Council (NPCC) identifies both winter and summer planning margin targets of 25% and 17%, respectively for the Northwest.

Resource planners account for the impact of wind generation in their respective capacity plans. Various methods exist to estimate resource contributions to system peak periods. Some are more data- and time-intensive than others. Avista for this report chose the Energy Load Carrying Capability (ELCC) method to evaluate wind generation on-peak capacity contribution. The ELCC method is fairly straight-forward. Generation at a given plant is tracked during historical peak hours as a percentage of nameplate capacity. The results of this analysis are then used to estimate the on-peak capacity contribution of the resource.

DATA AND ANALYTICAL METHOD

Avista analyzed wind data from the BPA Long Term Wind Database over a 16-year period ending in 2004. This period of record was selected because Avista has ready access to its area loads on an hourly basis beginning January 1, 1989. Five wind locations across the Northwest were considered both individually and in combination to understand the benefits of geographical dispersion to on-peak capacity contribution.

Hourly wind generation values based on the OSU database at each wind location, and for all of the locations combined, were matched up with historical hourly Avista loads. For each year studied, the top 10 and 100 hours in both the summer (July through September) and winter (November through March) periods were evaluated. Blank data points, where no data existed for the wind location, were ignored.

RESULTS

The results of the top 10 and top 100 load hours had similar results, so the 100-hour data are presented in this report. Additionally, given that some wind data was missing, using only the top 10 load hours in each year resulted in many fewer data points to examine. The ELCC analysis found large differences between wind locations, and also between the winter and summer. For example, Browning Depot, MT, provided an average ELCC contribution in the summertime of approximately 14%; in the summer the value was slightly higher than 41%. Goodnoe Hills, in Klickitat County, WA, had a higher summer ELCC, at 32%, but a lower winter rating of 14%. The following table details average results of the Avista ELCC work.

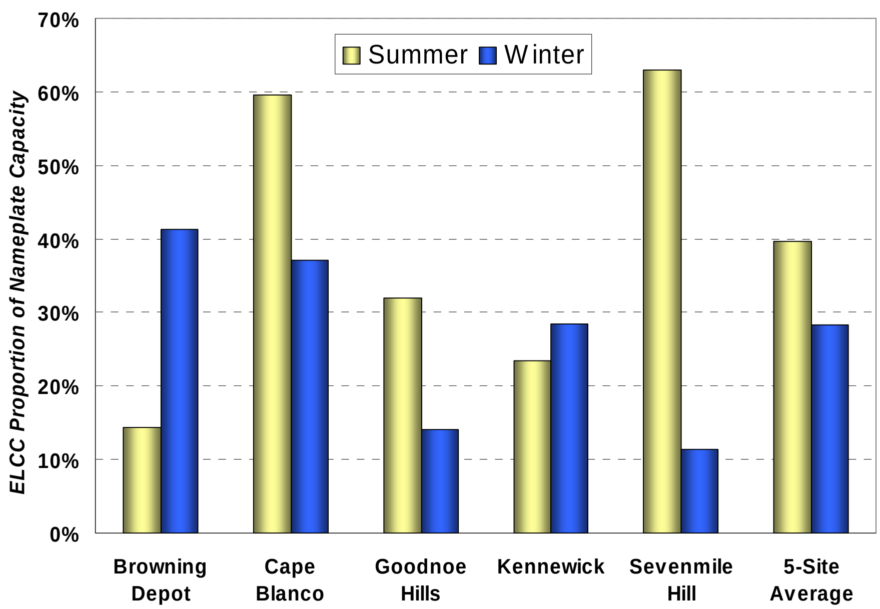

Figure 33: Average Summer and Winter ELCC Contributions

Avista believes that using average ELCC results for capacity planning is inappropriate, for 5 reasons: 1) a relatively small base of wind resources presently located in the Northwest; 2) Northwest generation is not as geographically diverse as shown in the Avista analysis; 3) the lack of Northwest utility operating experience; 4) the low on-peak capacity contribution exhibited by the Northwest wind fleet over the past 2 years; and 5) the reality that Avista's wind fleet will not be diverse for at least a period of 10 years.

Average results from the ELCC prove interesting; however, the variation in results across the 16 evaluated years is significant. Figure 31 details results of the same wind resources, but provides the minimum and maximum annual ELCC values for each during the winter months, the traditional peaking period of both Avista and the Northwest.

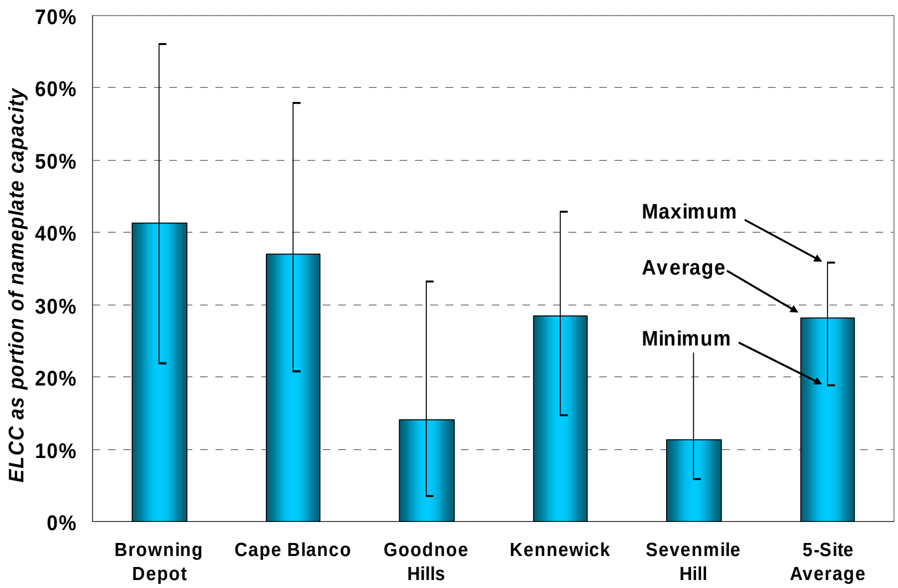

Figure 34: Winter ELCC Contribution Distributions 1989-2004

The 5-site 16-year average of 28% is bounded by a minimum annual value of 19% and a maximum annual value of 36%. Over the period the regional look at wind would explain that the 100-hour average value in the worst year was nearly a third less than the average. Additionally, the ELCC look is a 100-hour average contribution. Individual hourly or even daily contributions will necessarily be less.

APPLICATION TO AVISTA RESOURCE PLANNING

Avista probably will never have the full benefit of the 5-site diversity. It is likely to take Avista many years to procure enough wind generation to make geographic diversity real. Additionally, transmission constraints likely will preclude the utility from acquiring wind sited in high on-peak capacity factor Montana for many years. There also appears to be significant opposition to wind generation located on U.S. coastlines, where the high on-peak capacity factor Cape Blanco resource resides.

It is most likely that Avista will acquire wind in the Columbia Basin, where the majority of Northwest wind presently is being generated and sited. Three of the 5 sites evaluated by Avista are located in the Columbia Basin: Goodnoe Hills, Kennewick, and Sevenmile Hill. The average capacity factor of these resources is 17 percent over 16 years, with the simple average minimum generation level equaling 10%. Individually, the on-peak contribution falls to a low of 3% for Goodnoe Hills. ELCC during 6 of 16 years at Goodnoe Hills is below 10%; 2 years are below 5%. ELCC at Sevenmile Hill is below

10% in 5 of 16 years. Kennewick has larger average and minimum ELCC levels, bringing up the 3-site average.

The variability of ELCC statistics over time and location concerns Avista, especially in light of the fact that it will be a number of years before Avista is taking generation from more than one wind site. On one hand it is unreasonable to ignore the on-peak contribution of wind generation entirely. On the other it is equally unreasonable to rely on a diversified mix of sites averaged over 16 years when defining an on-peak capacity contribution. Avista believes that future resource acquisitions should evaluate wind generation on-peak capacity contribution on a case-by-case basis, using the lowest annual average ELCC value. Resource capacity planning, as stated before, is intended to protect against adverse conditions. Average values are overly optimistic for adverse planning. The average annual ELCC still exposes the utility to some risk of lower-than-planned-for wind contribution, but hedges this risk by picking the low-end range of on-peak capacity contribution. For Integrated Resource Planning, where future wind acquisitions are theoretical and not tied to any specific basin, Avista will assume an on-peak wind capacity value of zero. This decision is based on the large number of low on-peak contributions found in the 3 Columbia Basin locations, as well as recent experience over a few high load conditions where regional wind generation was very low, or non-existent, and Avista's share of The Stateline Wind Generation Facility produced no power.

APPENDIX B
ADDITIONAL CHARTS AND TABLES

Market Prices -- High Price Case

	Average Water			Low Water			High Water		
Month	**Peak**	**Off-Peak**	**Flat**	**Peak**	**Off-Peak**	**Flat**	**Peak**	**Off-Peak**	**Flat**
Jan-07	$ 163.43	$ 128.02	$ 148.26	$ 153.96	$ 135.50	$ 146.05	$ 79.41	$ 84.93	$ 81.78
Feb-07	$ 168.25	$ 143.24	$ 157.53	$ 167.68	$ 140.10	$ 155.86	$ 118.71	$ 108.50	$ 114.33
Mar-07	$ 155.94	$ 149.05	$ 152.99	$ 153.62	$ 142.56	$ 148.88	$ 122.95	$ 106.87	$ 116.06
Apr-07	$ 115.00	$ 89.17	$ 103.93	$ 121.59	$ 92.45	$ 109.10	$ 62.27	$ 37.93	$ 51.84
May-07	$ 131.39	$ 92.20	$ 114.59	$ 110.16	$ 66.81	$ 91.58	$ 9.90	$ 6.21	$ 8.32
Jun-07	$ 47.89	$ 28.60	$ 39.62	$ 77.70	$ 49.86	$ 65.77	$ 6.57	$ 5.55	$ 6.14
Jul-07	$ 30.76	$ 16.60	$ 24.69	$ 95.19	$ 69.94	$ 84.37	$ 75.16	$ 45.21	$ 62.32
Aug-07	$ 123.07	$ 101.01	$ 113.62	$ 135.88	$ 99.87	$ 120.45	$ 128.97	$ 104.39	$ 118.44
Sep-07	$ 155.08	$ 111.00	$ 136.19	$ 139.54	$ 121.11	$ 131.64	$ 136.31	$ 111.60	$ 125.72
Oct-07	$ 114.42	$ 115.06	$ 114.69	$ 136.63	$ 113.21	$ 126.59	$ 127.53	$ 106.11	$ 118.35
Nov-07	$ 131.23	$ 115.17	$ 124.35	$ 151.88	$ 128.85	$ 142.01	$ 152.85	$ 125.72	$ 141.22
Dec-07	$ 135.87	$ 112.68	$ 125.93	$ 185.98	$ 171.19	$ 179.64	$ 149.59	$ 141.96	$ 146.32
Average	**$ 122.69**	**$ 100.15**	**$ 113.03**	**$ 135.82**	**$ 110.96**	**$ 125.16**	**$ 97.52**	**$ 82.08**	**$ 90.90**

Market Prices -- Low Price Case

	Average Water			Low Water			High Water		
Month	**Peak**	**Off-Peak**	**Flat**	**Peak**	**Off-Peak**	**Flat**	**Peak**	**Off-Peak**	**Flat**
Jan-07	$ 40.86	$ 32.01	$ 37.06	$ 38.49	$ 33.87	$ 36.51	$ 19.85	$ 21.23	$ 20.44
Feb-07	$ 42.06	$ 35.81	$ 39.38	$ 41.92	$ 35.03	$ 38.97	$ 29.68	$ 27.13	$ 28.58
Mar-07	$ 38.98	$ 37.26	$ 38.25	$ 38.40	$ 35.64	$ 37.22	$ 30.74	$ 26.72	$ 29.02
Apr-07	$ 28.75	$ 22.29	$ 25.98	$ 30.40	$ 23.11	$ 27.28	$ 15.57	$ 9.48	$ 12.96
May-07	$ 32.85	$ 23.05	$ 28.65	$ 27.54	$ 16.70	$ 22.90	$ 2.48	$ 1.55	$ 2.08
Jun-07	$ 11.97	$ 7.15	$ 9.91	$ 19.42	$ 12.47	$ 16.44	$ 1.64	$ 1.39	$ 1.53
Jul-07	$ 7.69	$ 4.15	$ 6.17	$ 23.80	$ 17.48	$ 21.09	$ 18.79	$ 11.30	$ 15.58
Aug-07	$ 30.77	$ 25.25	$ 28.40	$ 33.97	$ 24.97	$ 30.11	$ 32.24	$ 26.10	$ 29.61
Sep-07	$ 38.77	$ 27.75	$ 34.05	$ 34.89	$ 30.28	$ 32.91	$ 34.08	$ 27.90	$ 31.43
Oct-07	$ 28.60	$ 28.76	$ 28.67	$ 34.16	$ 28.30	$ 31.65	$ 31.88	$ 26.53	$ 29.59
Nov-07	$ 32.81	$ 28.79	$ 31.09	$ 37.97	$ 32.21	$ 35.50	$ 38.21	$ 31.43	$ 35.31
Dec-07	$ 33.97	$ 28.17	$ 31.48	$ 46.49	$ 42.80	$ 44.91	$ 37.40	$ 35.49	$ 36.58
Average	**$ 30.67**	**$ 25.04**	**$ 28.26**	**$ 33.95**	**$ 27.74**	**$ 31.29**	**$ 24.38**	**$ 20.52**	**$ 22.73**

Market Prices -- Low Spread Case

	Average Water			Low Water			High Water		
Month	Peak	Off-Peak	Flat	Peak	Off-Peak	Flat	Peak	Off-Peak	Flat
Jan-07	$ 77.92	$ 69.07	$ 74.13	$ 78.13	$ 66.49	$ 73.02	$ 38.69	$ 44.12	$ 40.89
Feb-07	$ 81.45	$ 75.19	$ 78.77	$ 82.30	$ 71.93	$ 77.93	$ 57.26	$ 57.30	$ 57.17
Mar-07	$ 77.23	$ 75.51	$ 76.49	$ 74.66	$ 74.35	$ 74.44	$ 60.53	$ 54.62	$ 58.03
Apr-07	$ 54.73	$ 48.28	$ 51.97	$ 55.70	$ 54.70	$ 54.55	$ 29.53	$ 20.67	$ 25.92
May-07	$ 61.50	$ 51.70	$ 57.30	$ 50.68	$ 39.09	$ 45.79	$ 4.53	$ 3.68	$ 4.16
Jun-07	$ 21.88	$ 17.05	$ 19.81	$ 37.56	$ 26.24	$ 32.88	$ 3.04	$ 3.22	$ 3.07
Jul-07	$ 13.86	$ 10.32	$ 12.35	$ 43.53	$ 41.59	$ 42.18	$ 35.45	$ 24.93	$ 31.16
Aug-07	$ 59.17	$ 53.66	$ 56.81	$ 65.16	$ 53.29	$ 60.22	$ 60.82	$ 57.57	$ 59.22
Sep-07	$ 72.82	$ 61.80	$ 68.09	$ 67.06	$ 64.39	$ 65.82	$ 66.23	$ 58.23	$ 62.86
Oct-07	$ 57.28	$ 57.44	$ 57.35	$ 65.86	$ 59.87	$ 63.30	$ 61.42	$ 56.19	$ 59.18
Nov-07	$ 63.89	$ 59.88	$ 62.17	$ 73.06	$ 68.40	$ 71.01	$ 73.94	$ 66.07	$ 70.61
Dec-07	$ 65.45	$ 59.65	$ 62.97	$ 91.97	$ 86.91	$ 89.82	$ 73.52	$ 72.73	$ 73.16
Average	**$ 58.93**	**$ 53.30**	**$ 56.52**	**$ 65.47**	**$ 58.94**	**$ 62.58**	**$ 47.08**	**$ 43.28**	**$ 45.45**

Market Prices -- High Spread Case

	Average Water			Low Water			High Water		
Month	Peak	Off-Peak	Flat	Peak	Off-Peak	Flat	Peak	Off-Peak	Flat
Jan-07	$ 86.92	$ 57.62	$ 74.13	$ 79.82	$ 64.11	$ 73.02	$ 42.51	$ 37.69	$ 40.89
Feb-07	$ 85.72	$ 69.73	$ 78.77	$ 88.54	$ 64.03	$ 77.93	$ 61.18	$ 51.85	$ 57.17
Mar-07	$ 85.47	$ 62.19	$ 76.49	$ 89.67	$ 45.15	$ 74.44	$ 67.79	$ 43.81	$ 58.03
Apr-07	$ 64.85	$ 33.75	$ 51.97	$ 70.52	$ 30.50	$ 54.55	$ 36.38	$ 11.93	$ 25.92
May-07	$ 77.04	$ 28.33	$ 57.30	$ 58.75	$ 29.89	$ 45.79	$ 5.71	$ 2.11	$ 4.16
Jun-07	$ 28.67	$ 7.33	$ 19.81	$ 45.49	$ 15.49	$ 32.88	$ 3.66	$ 2.21	$ 3.07
Jul-07	$ 16.56	$ 7.26	$ 12.35	$ 51.48	$ 30.27	$ 42.18	$ 41.85	$ 17.95	$ 31.16
Aug-07	$ 69.03	$ 39.04	$ 56.81	$ 73.22	$ 43.62	$ 60.22	$ 68.13	$ 47.66	$ 59.22
Sep-07	$ 77.36	$ 55.68	$ 68.09	$ 74.79	$ 53.57	$ 65.82	$ 73.16	$ 49.21	$ 62.86
Oct-07	$ 60.21	$ 52.94	$ 57.35	$ 73.51	$ 49.63	$ 63.30	$ 67.91	$ 47.64	$ 59.18
Nov-07	$ 70.42	$ 50.81	$ 62.17	$ 77.61	$ 62.45	$ 71.01	$ 79.03	$ 59.76	$ 70.61
Dec-07	$ 73.29	$ 49.09	$ 62.97	$ 99.30	$ 76.40	$ 89.82	$ 80.66	$ 61.89	$ 73.16
Average	**$ 66.29**	**$ 42.82**	**$ 56.52**	**$ 73.56**	**$ 47.09**	**$ 62.58**	**$ 52.33**	**$ 36.14**	**$ 45.45**

Market Prices by Water Year

Month	Average Water Peak	Average Water Off-Peak	Average Water Flat	Low Water Peak	Low Water Off-Peak	Low Water Flat	High Water Peak	High Water Off-Peak	High Water Flat
Jan-07	$ 81.72	$ 64.01	$ 74.13	$ 76.98	$ 67.75	$ 73.02	$ 39.71	$ 42.47	$ 40.89
Feb-07	$ 84.12	$ 71.62	$ 78.77	$ 83.84	$ 70.05	$ 77.93	$ 59.35	$ 54.25	$ 57.17
Mar-07	$ 77.97	$ 74.53	$ 76.49	$ 76.81	$ 71.28	$ 74.44	$ 61.48	$ 53.44	$ 58.03
Apr-07	$ 57.50	$ 44.59	$ 51.97	$ 60.79	$ 46.22	$ 54.55	$ 31.13	$ 18.97	$ 25.92
May-07	$ 65.70	$ 46.10	$ 57.30	$ 55.08	$ 33.41	$ 45.79	$ 4.95	$ 3.10	$ 4.16
Jun-07	$ 23.95	$ 14.30	$ 19.81	$ 38.85	$ 24.93	$ 32.88	$ 3.29	$ 2.78	$ 3.07
Jul-07	$ 15.38	$ 8.30	$ 12.35	$ 47.60	$ 34.97	$ 42.18	$ 37.58	$ 22.60	$ 31.16
Aug-07	$ 61.54	$ 50.50	$ 56.81	$ 67.94	$ 49.93	$ 60.22	$ 64.48	$ 52.20	$ 59.22
Sep-07	$ 77.54	$ 55.50	$ 68.09	$ 69.77	$ 60.56	$ 65.82	$ 68.16	$ 55.80	$ 62.86
Oct-07	$ 57.21	$ 57.53	$ 57.35	$ 68.31	$ 56.61	$ 63.30	$ 63.77	$ 53.06	$ 59.18
Nov-07	$ 65.62	$ 57.59	$ 62.17	$ 75.94	$ 64.43	$ 71.01	$ 76.42	$ 62.86	$ 70.61
Dec-07	$ 67.94	$ 56.34	$ 62.97	$ 92.99	$ 85.60	$ 89.82	$ 74.80	$ 70.98	$ 73.16
Average	**$ 61.35**	**$ 50.07**	**$ 56.52**	**$ 67.91**	**$ 55.48**	**$ 62.58**	**$ 48.76**	**$ 41.04**	**$ 45.45**

APPENDIX C

NEXT STEPS

In early research performed to prepare for this study, it was not always easy to understand the many differences, strengths and weaknesses of each work. This made comparing the methods and their merits difficult. For the benefit of future studies, Avista highlights below areas of its study that warrant additional consideration in future work. As with any study performed in a fairly new field, it is almost impossible to be certain that an outcome is all-inclusive. This said, Avista is confident that the results presented in this report are substantially correct in the total and cannot at this time be certain that re-visiting these issues in total will lead to either higher or lower integration costs.

This study applies the latest methods of wind integration analysis. In reviewing the final work product, the authors would like to acknowledge that further work should be performed in the following areas:

CALCULATING RESERVES

Wind integration costs stem primarily from incremental system reserves necessary to balance instantaneous output with power schedules. This study identified incremental reserves for regulation, load following, and forecast error. The method for calculating regulation was based on a "5-sigma" approach applied to one-minute data.

Forecast error was calculated for wind by using an average of wind generation from 60 to 120 minutes prior to the delivery hour. This method was applied to reflect the real-time scheduling window. Forecast error was reduced by 25% to reflect actual statistics the Company has witnessed from "state-of-the-are" wind forecasting techniques. Avista does not record its hour-ahead load forecasts so that forecast error of combined wind and load may be calculated. Wind forecast error was reduced by a further 15 MW (1.5% of average hourly load) to reflect an estimated load forecast error level.

Forecast error and load following represent machine flexibility that must be reserved and do not appear correlated. This lack of correlation allows a lower combined level of reserves to be held. Load following in this report was determined as the combined load following and forecast errors less the forecast error calculated above. This method necessarily overstated forecast error and understated load following reserves. However, together the two values represent the appropriate level of total intra-hour reserves.

Load following and forecast error reserves were calculated in a method that represents the best thinking today. For this study the calculations were broken into ten deciles based on the capacity factor of the wind. This approach was found to reduce overall forecast error and load following reserve levels modestly.

Further discussion over the best means to approximate how operators would schedule load following and forecast error reserves is warranted. Given the high degree of correlation between operating reserve levels and integration costs, future studies should look for new ways to reduce the necessity of such reserves.

WIND GENERATION DATASET

Wind generation datasets for the Northwest are very limited. Absent a robust dataset, this study relied on a set of anemometer data collected by the Bonneville Power Administration. Six individual anemometers located across the Northwest were used as the basis for the study's wind data. There appear to be methods to approximate diversification of a wind farm in the regulation timeframe using a single anemometer; however, the "science" of extrapolating a single anemometer to a larger wind farm over an hourly or multi-hour period is less known, especially in cases where large wind quantities were analyzed.

Avista is reasonably confident that its datasets provide a good representation of wind generation in its Base Case scenarios. However, some of the large single-basin penetration levels used in the study likely overstate wind variability due to reliance on a single anemometer to represent the wind regime. Avista looks forward to the wind data expected to become available in 2007 or 2008 in response to an action item in the recent Northwest Wind Integration Action Plan. This data will be used to enhance the Avista work once it becomes available.

THERMAL GENERATION MODELING

The Avista study did not model all of the costs associated with its thermal resources. Starting Coyote Springs 2, a combined-cycle combustion turbine, costs the company on the order of $20,000. This start-up cost will limit the hourly dispatch of the resource and likely will increase wind integration costs. Our other thermal plants also witness similar costs that are not modeled in the current Avista analysis.

Avista owns 15% shares in two coal-fired power plants located in Montana. These resources were not modeled to provide any reserve products given their position in the resource stack and modest reserve capabilities.

These modeling simplifications likely did not impact the results of the Avista study in any significant way. They enabled the Avista LP Model to solve more quickly and thereby enabled significantly more scenarios to be evaluated. Future integration studies based on the LP Model will consider enhancing thermal plant logic to better represent costs.

TRANSMISSION

The LP Model contains detailed transmission logic. All energy (purchases and sales) and reserve (transfers from remote Avista resources to its load center) transfers occurring at or below Avista contract rights do not pay any transmission tariff, as these costs are “sunk.” Only system losses are charged for energy moving across the grid. Any hourly transmission quantities in excess of existing contract rights pay both losses and the hourly cost of firm transmission.

New wind resources are assumed to have come with firm transmission paths to Avista’s system. The assumption lowers wind integration costs stemming from wind variability since no new transmission bottlenecks are created by the inclusion of wind. It might not be appropriate to assume a one-for-one purchase of transmission. This assumption will be re-evaluated in future analyses.