

December 2011

Final Technical  
Report

**IEA Wind Task 24**

Integration of Wind and  
Hydropower Systems

Volume 2: Participant Case Studies



**iea wind**



# **IEA Wind Task 24 Integration of Wind and Hydropower Systems**

## **Volume 2: Participant Case Studies**

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Prepared for the International Energy Agency Implementing Agreement for Co-operation in the Research, Development, and Deployment of Wind Energy Systems

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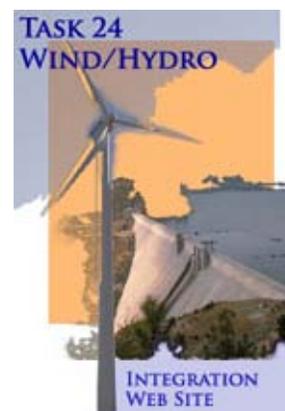
## Preface

In November 2003, the International Energy Agency (IEA) Wind Implementing Agreement (IA) for Cooperation in the Research and Development of Wind Turbine Systems held its Topical Expert Meeting #41 on the Integration of Wind and Hydropower Systems. This meeting convened a group of industry, academic, and government officials with expertise in wind power, hydropower, and utility and transmission system planning and operation.

Their purpose was to discuss the potential for coordinated operation of wind and hydropower in serving load, the benefits and detriments in doing so, and to identify the related opportunities and issues. As a result of this meeting and interactions with the IEA Hydropower IA, a recommendation was made to IEA Wind to establish a formal research task to address the myriad of questions and unresolved issues pertaining to the topic. Subsequent to this meeting, in 2004, IEA Wind established a research and development (R&D) task to investigate the potential for integrating wind and hydropower resources on the electrical grid. The research task, also known as an “Annex,” was the twenty-fourth such task established by IEA Wind, and was entitled, Task 24: Integration of Wind and Hydropower Systems. Seven member countries of IEA Wind joined the task: Australia, Canada, Finland, Norway, Sweden, Switzerland, and the United States. When established, an R&D task is assigned an Operating Agent (i.e., managing director). For Task 24, the National Renewable Energy Laboratory (NREL) in the United States, on behalf of the U.S. Department of Energy, was selected as the Operating Agent.

The primary purposes of Task 24 were to conduct cooperative research concerning the generation, transmission, and economics of integrating wind and hydropower systems, and to provide a forum for information exchange. The former of these two purposes was addressed through case study projects performed at participating institutions within each member country. The latter purpose related to information exchange was accomplished via a series of collaborative R&D meetings, seven of which were held: a kickoff meeting (February 2005 in the United States); one web meeting (June 2006); and five R&D meetings (September 2005 in Switzerland, September 2006 in Australia, May 2007 in Italy, September 2007 in Norway, and June 2008 in Quebec, Canada).

The IEA Wind Task 24 Final Report summarizes and presents the results of the work conducted by the task participants, the important issues and analysis methods identified, and the related conclusions. The report was assembled in two volumes: the first providing objectives, background, summary results, and conclusions; and the second describing the methods of study employed and details about the participant case studies upon which the conclusions of the task were drawn.



## Acknowledgments

There were many organizations and people that contributed to the Task 24 final report via contributions to the various case study projects conducted by the participants, more than can be acknowledged here. Thanks are due to all these people. Special recognition is due to the following contributors for their participation in the task, its meetings, for oversight of their country's contributions to the case studies, and for organizing their contributions to this report:

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## List of Acronyms

AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
BA	Balancing Area
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
ELCC	Effective Load Carrying Capacity
EMPS	Multi-Area Power Market Simulator
FCAS	Frequency Control Ancillary Services
HLH	High Load Hour
HVDC	High-Voltage Direct Current
IA	Implementing Agreement
IEA	International Energy Agency
IEA Wind	The IEA Implementing Agreement for Co-operation in the Research, Development and Deployment of Wind Energy Systems
ISO	Independent System Operator
LOLP	Loss of Load Probability
LLH	Low Load Hour
MM5	Mesoscale Model
NERC	North American Electricity Reliability Corporation
NREL	National Renewable Energy Laboratory, U.S. Department of Energy
NordPool	The Nordic Power Exchange: The Single Power Market for Norway, Denmark, Sweden, and Finland
O&M	Operations and Maintenance
NPC	Non-Power Constraint
PIRP	Participating Intermittent Resources Program
PNCA	Pacific Northwest Coordination Agreement
PUD	Public Utility District
R&D	Research and Development
RMSE	Root Mean Square Error
RNL	Reanalysis
RTO	Regional Transmission Organization
SINTEF	The Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology
SMUD	Sacramento Municipal Utility District
TSO	Transmission System Operator
TWD	Tail Water Depression
U.S.	United States
USACE	U.S. Army Corps of Engineers
VTT	Technical Research Centre of Finland
WAPA	Western Area Power Administration

## Executive Summary

Worldwide, hydropower facilities possess a significant amount of installed electric generating capacity. IEA statistics indicate that at the end of 2001 there was in excess of 450,000 MW of installed capacity within IEA member countries, with about half in Europe and half in North America. In addition to conventional hydropower, there is more than 80,000 MW of installed pumped-hydro capacity in IEA countries. In contrast, utility-scale wind power is relatively new in the electric market, but increasing rapidly. In 2003, when the topic of Task 24 was initially being discussed, there were just over 31,000 MW of wind power installed, an amount that increased to in excess of 140,000 MW by the end of 2009. Due to its competitive costs, coupled with the fact that it is a clean energy resource, wind energy capacity is likely to continue to grow substantially over the next two decades. Because of the potential for synergistic operation of wind and hydropower facilities, many countries are investigating the opportunity to integrate wind and hydropower systems in order to optimize their output through coordinated operation. The hope is to realize such benefits as lowering the cost of ancillary services required by wind energy, taking advantage of the built-in energy storage available at hydro facilities; the opportunity to more effectively utilize existing hydro and transmission facilities; the potential for improving hydrologic operations; and an overall energy supply portfolio that is more diverse, robust, and cleaner. With wind power penetrations increasing worldwide, the topics of Task 24 are more relevant than ever.

For the reasons described above, in 2004, IEA Wind formed R&D Task 24,<sup>1</sup> entitled, “Integration of Wind and Hydropower Systems.” The primary purposes of this task are to conduct cooperative research concerning the generation, transmission, and economics of integrating wind and hydropower systems, and to provide a forum for information exchange. The following are specific goals of Task 24:

- Goal 1) Establish an international forum for exchange of knowledge, ideas, and experiences related to the integration of wind and hydropower technologies within electricity supply systems.
- Goal 2) As it pertains to wind and hydropower integration, share information among participating members concerning grid integration, transmission issues, hydrological and hydropower impacts, markets and economics, and simplified modeling techniques.
- Goal 3) Through information sharing and exchange of ideas, identify technically and economically feasible system configurations for integrating wind and hydropower, including the effects of market structure on wind-hydro system economics with the intention of identifying the most effective market structures.
- Goal 4) Document case studies pertaining to wind and hydropower integration, and create an on-line library of reports.

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<sup>1</sup> It is worth noting here that the topics of the task were discussed and the objectives formed through conversations with the IEA Hydropower IA, and formation of a joint task (i.e., sponsored by both IAs) was seriously considered. Though a joint task did not materialize, the collaboration strengthened the work plan of the task and the robustness of the analysis and conclusions.

Case studies that analyze the feasibility, benefits, detriments, and costs of specific wind-hydro integration projects were the mechanism through which the goals of the task were addressed and the feasibility of wind-hydro integration was investigated. Although specific wind-hydro integration projects may differ substantially, there are many characteristics common to each. Consequently, there was ample opportunity for each participant of the task to leverage one another's case study projects to enhance their own findings, discuss difficulties faced in analysis and interpretation of results, and debate methods and conclusions.

Volume 2 of the Task 24 final report is devoted to the case studies performed by the participants. Chapter 1 presents a uniform framework for describing the methodologies employed in the case studies and from which they will be compared. Furthermore, this chapter presents a few methods for defining wind penetration because it is an important metric when considering wind integration into a power system. Because of the significant differences in constraints, flexibility, and operating environment/market that frequently exist between different hydropower plants and systems, the thought process related to simplified modeling of the potential for wind/hydro integration evolved to characterizing the “flexibility” inherent in a given system; therefore, a portion of Chapter 1 will be dedicated toward the topic of “system flexibility.” After this introductory chapter, there are six chapters devoted to the case studies performed on behalf of the member countries. As described in Volume 1 of the Task 24 final report, the case studies are each intended to address at least one of the following: (1) grid integration impacts; (2) hydropower impacts; and (3) economic impacts. The case studies, which are described below, each fall within one or more of these broad categories (as indicated by the text in brackets and italics at the end of each description below).

Australia:

- *Case Study 1: Large-Scale Wind Integration to the Tasmanian System (hydropower impacts study)*
- *Case Study 2: The Costs of Wind-Firming Service Provided by a Hydro Plant (hydropower impacts study)*
- *Case Study 3: Inertia Support in a Hydro, Wind, and High-Voltage Direct Current (HVDC) Hybrid Power System (grid integration impacts study)*

Canada:

- RETScreen<sup>2</sup> analysis for a case study involving the financial feasibility of wind integration by the Okanogan Public Utility District (PUD) in Washington State, United States (*economics study*)
- Hydro Quebec case study providing a summary of the impacts of a wind- and hydro-dominated power system on the electricity markets and the characteristics of Nordic hydropower (*grid integration impacts and economics study*)

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<sup>2</sup> See [www.retscreen.net/ang/home.php](http://www.retscreen.net/ang/home.php); RETScreen stands for Renewable-energy and Energy efficient Technologies Screening tool, and was developed for Natural Resources Canada.

## Finland:

- A case study focusing on the handling of wind power prediction errors for a single hydrothermal power producer in Finland (*grid integration impacts study*)
- A summary of the impacts of a wind- and hydro-dominated power system on the electricity markets and the characteristics of Nordic hydropower (*grid integration impacts and economics study*)

## Norway:

- The first study looked at wind power in areas with limited power transfer capacity and subject to grid congestion. The question to be addressed here was to see how much wind power could be integrated without deleteriously affecting the hydropower production. (*grid integration impacts study*)
- The second case study considers the impact of wind power on system adequacy. Considering that the region has favorable wind resources, the study was conducted to determine whether or not adding wind power to the hydro-based system will be sufficient or if additional measures must be taken to secure system adequacy (*grid integration impacts study*)

## Sweden:

- Case study for balancing of wind power integrated into the Swedish system using balancing resources located along just one river (*hydropower impacts study*)
- Case study for balancing large amounts of wind power integration by coordinating operation with hydropower in North Sweden (*grid integration impacts study*)

## Unites States:

- Case studies are from three different river systems and electrical balancing areas, as listed below:
  - Missouri River and the Western Area Power Administration (*grid integration impacts study*)
  - Upper American River and the Sacramento PUD (*grid integration impacts study*)
  - Columbia River and the Grant County Public Utility District (*hydropower impacts study*)
- The first and third of these studies focus on statistically estimating the impacts of wind integration on balancing area requirements for regulation (minute-to-minute) and load following. The Grant County study further estimates the impacts on system flow and reliability constraints caused by wind integration. The study performed for Sacramento PUD aimed at simulating the system and arrived at estimates of the wind integration impacts and costs.

The aforementioned case studies are presented in a uniform manner to aid in comparison and in discerning the most relevant characteristics and results of the studies. In this sense, the case study chapters are summaries of more complete and detailed reports (references provided), and focus on highlighting the results that pertain most directly to the objectives of Task 24. For further details about the case studies than are presented here, see the appropriate reference reports.

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# 1 Introduction

Volume 1 of IEA Wind Task 24: Integration of Wind and Hydropower Systems presented foundational information recounting the operational issues electric utilities, or Transmission System Operators (TSOs), face when balancing load with generation, and it described what is meant by “wind and hydropower integration” (Chapter 1). Volume 1 also discussed the characteristics of wind energy (Chapter 2) and hydropower (Chapter 3) relevant to wind and hydropower generation. Volume 1, Chapter 4, addressed the questions posed in the formation of Task 24 regarding wind-hydro integration and referenced Task 24 participant case studies. The purpose of Task 24, Volume 2, is to describe in more detail the case study reports performed by participants.

Each member country of Task 24 agreed to perform and submit at least one case study addressing some or all of the study themes defined in the Task 24 proposal and work plan, which are as follows: grid integration, hydropower impacts, market and economics, and simplified modeling of wind-hydro integration potential. As is the case with many IEA tasks, not every member country was either interested in or able to address all study themes. However, one of the great strengths of the IEA implementing agreements is their ability to bring together the research capabilities and interests of many countries in a collaborative environment, more thoroughly address an important and broad topic, and take advantage of the unique and diverse expertise possessed by the member countries. Table 1 summarizes the Task 24 case study themes that were to be addressed by each member country’s case studies.

**Table 1. Study themes originally identified to be addressed by Task 24 member countries**

Country	Effort (man-months/year)	Grid Integration Case Studies	Hydrologic Case Studies	Economic and Market Case Studies	Simplified Modeling	Comments
Australia	6	x	x	x	x	Three to five studies
Canada	4.5	x	x	x		Two studies plus RETScreen
Finland	4-6	x		x	x	Three studies
Norway	6	x	x	x	x	Two studies
Sweden	2-4	x		x		Four studies
Switzerland	3-4	x		x		Two to four studies
USA	6-12	x	x	x	x	Three or more studies

Early on in the formation of Task 24, the participants recognized that even though the electricity grids operated by the member countries were all tasked with the same objective of balancing load and generation while maintaining system reliability, they differed in many ways—some trivial and some significant. Additionally, the vernacular used to describe electrical system operation and balancing differ in subtle yet important ways, and the *case studies themselves* differ in many important areas, including the base assumptions upon which the studies were built, the types of study tools employed, and the study outcomes desired. Therefore, prior to delving into the case study reports, readers must understand these differences so that the results

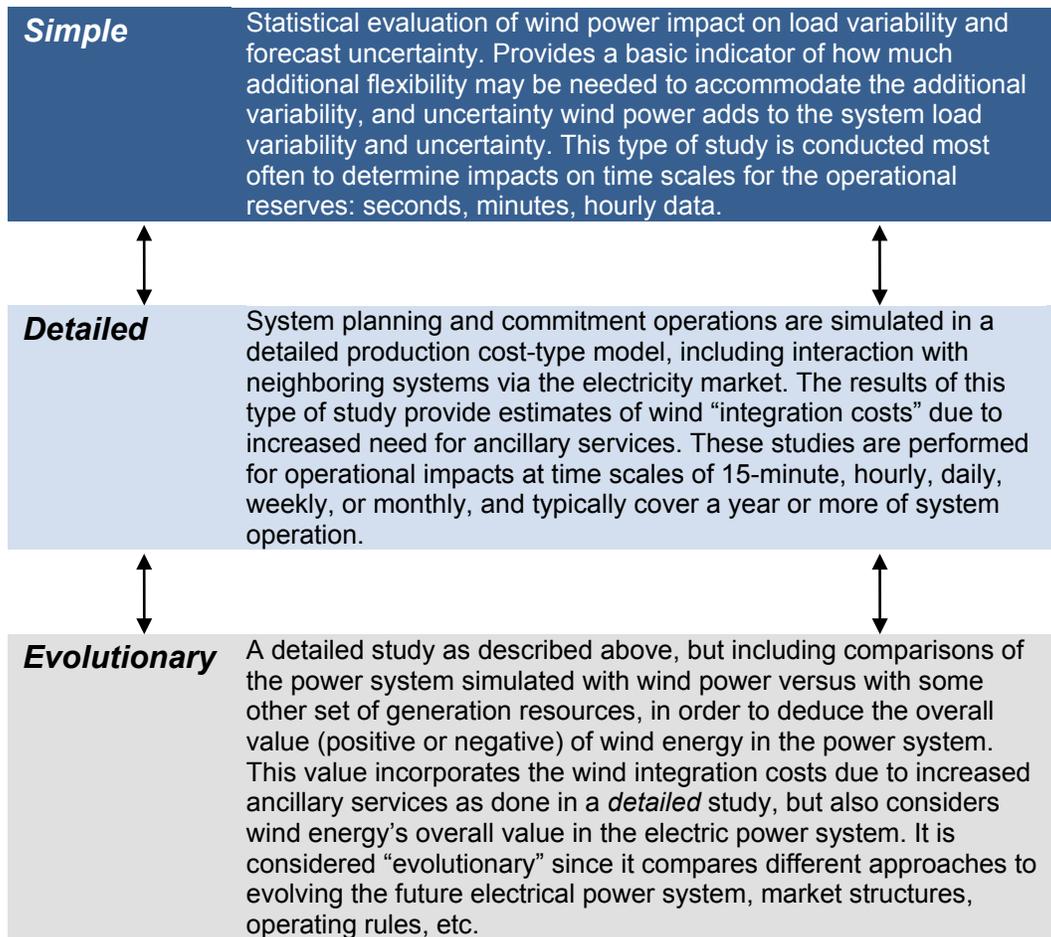
presented in each case study can be understood in the correct context and in comparison to the body of case studies.

The remaining portions of this introductory chapter are devoted to presenting a uniform framework for describing the study methodologies employed in the case studies and from which they will be compared. Furthermore, this chapter presents a few methods for defining wind penetration since it is an important metric when considering wind integration into a power system. As listed in Table 1, four of the member countries originally intended to perform simplified modeling of potential for wind-hydro integration within their given electrical systems—however, as the work of the case studies progressed, it was decided that trying to model the potential for wind-hydro integration of a given system (i.e., predicting how much wind power could be reasonably integrated/balanced using the hydro resources available in a given system) was not necessarily a practical problem to solve. Due to the significant differences among constraints, flexibility, and operating environment/market that may exist between different hydropower plants and hydro systems engaged in different grid systems and electrical markets, it did not appear fruitful to try to construct a general, simplified model. Rather, the thought process related to this question evolved to characterizing the “flexibility” inherent in a given system; therefore, some chapters will be dedicated toward this topic.

## 1.1 Study Methodologies

As mentioned, power system studies considering the impacts from and influences of wind power may differ in many ways, some trivial and some significant, beginning with the complexity and detail of the study method and its assumptions to the questions the study intends to answer. This issue led to much useful discussion and debate among the Task 24 participants concerning how to frame the study objectives, contrast the methodologies employed, and compare the results obtained. The result of these discussions is presented below.

In regard to overall scope, wind integration studies can vary from simple to detailed to evolutionary, as illustrated in Figure 1. A *simple study* typically looks only at the effect of wind power on system net load, and in particular the variability of that net load (net load will be defined shortly). A *detailed study* involves simulation of the system operation in order to deduce the impacts and costs of wind integration. And an *evolutionary study* simulates the system like a detailed study does, but goes further to consider the overall value of the wind energy (i.e., goes beyond addressing the impact of wind energy’s variability and uncertainty), and possibly considers changes in how the system is constituted, constrained, and operated, in search of better ways to incorporate wind into the power system. It is worth noting that studies are also conducted to determine dynamical effects on the electrical grid, for network stability, etc.; these types of studies are not included as part of Task 24 and were addressed in Task 21 (Dynamic Models of Wind Farms for Power System Studies).

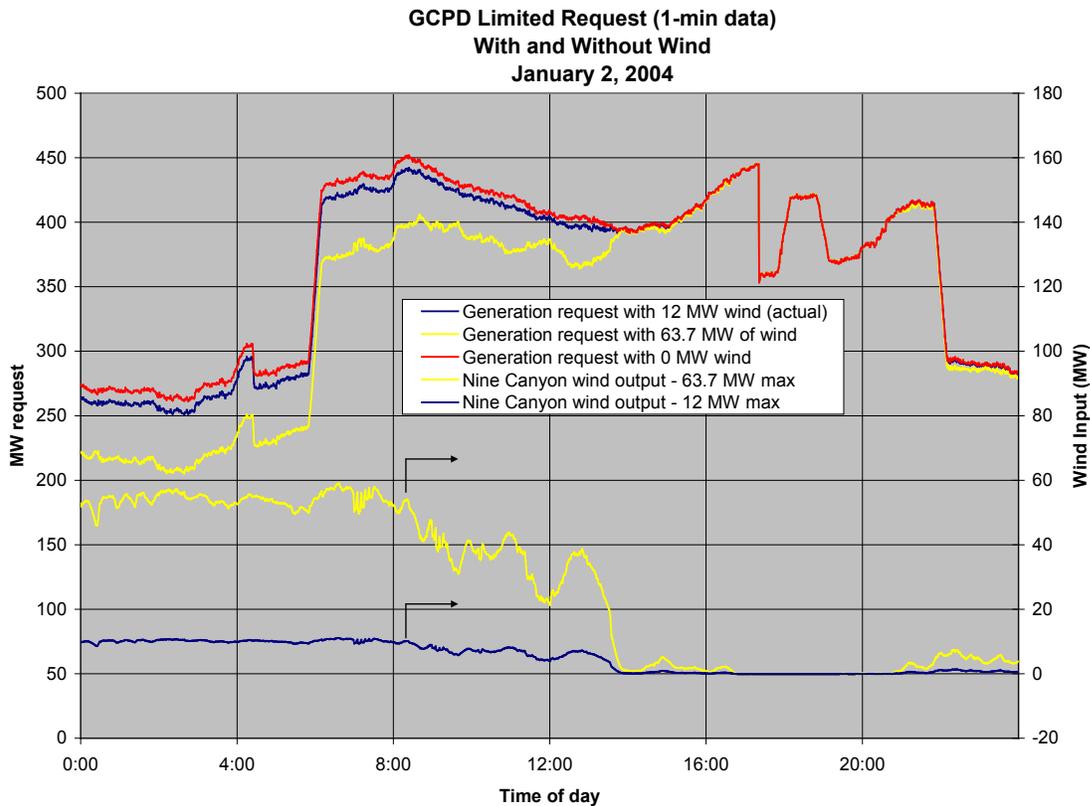


**Figure 1. Illustration of the range of complexity that can be employed in wind integration studies**

Wind power is typically absorbed into the power system when it is generated, just as the load is served at the time it is required; therefore, it is convenient to look at the system’s *load net wind* (i.e., the system load with the wind power subtracted), also referred to as *net load*. The remaining power system must balance load net wind via unit commitment, load following, and regulation. In essence, wind power is treated similar to negative load.

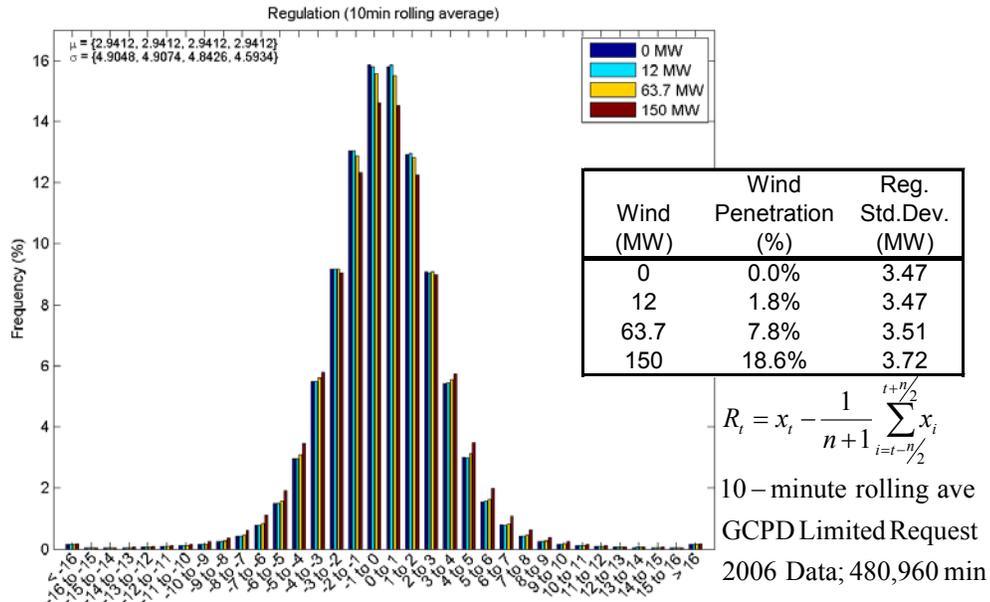
An example of how a load signal may differ from a load net wind signal is shown in Figure 2, which presents the wind power input at a hydropower utility in the United States (the Grant County PUD, No. 2, in Washington State, U.S.) and the generation request for a single day (Acker 2007). The uppermost of the two dark blue lines represents the actual generation requests made on this day (1-minute data), corresponding to 12 MW of wind power absorbed into the balancing area. The lower dark blue line represents the actual wind power input to the system on this day (and refers to the scale on the right-hand side of the plot). If wind power were not coming into the system, then the red line would have represented the generation request by Grant PUD. In this case, the request would have been increased in the morning by the amount of wind power no longer coming into the system, but the evening request would be the same, since there was no wind production during the evening. Furthermore, the minute-to-minute variations do not

differ much between these lines (i.e., the minute-to-minute regulation), nor do the hourly variations. Projecting the impact of wind generation beyond the 12-MW wind input to the system, the uppermost yellow line shows what the generation request would have been if the full 63.7-MW output of the Nine Canyon wind power plant were coming into the balancing area, and the lower yellow line shows the wind input in this scenario. Comparing the generation requests of 0 MW and 63.7 MW of wind input, one can see that on this particular day, the wind input would create a noticeable effect in the minute-to-minute variations and in the hourly variations, but the magnitude of the ramps during the ramping periods is unchanged. Additionally, the peak generation request for the day is essentially unchanged, but the minimum request during the early morning hours is reduced somewhat. During this day, the maximum instantaneous penetration of wind power (= wind power capacity / maximum generation request) is 4.3% when incorporating 12 MW of wind, and 28.3% when incorporating 63.7 MW of wind. An important point to take away from this plot is how the load is influenced by the wind to create the load net wind, and how the load net wind is inherently more variable than the load alone. Furthermore, the load variability by itself is significant and must be considered when analyzing the influence of wind power. One last point of importance related to this figure: the wind power is coming from one plant, and the system load is relatively small; in larger systems with wind power coming from multiple wind power plants, the relative impact of the wind power on the net load is smaller.



**Figure 2. Generation request and wind power input to Grant PUD for January 2, 2004  
(Source: Acker 2007)**

Useful information can be deduced about the general effect of wind power’s variability on the overall variability that a system operator must manage by comparing statistics resulting from the load net wind time series versus the variability of the load time series alone. Such a statistical study that does not include a chronological simulation of the system would be classified as a simple study in Figure 1. Following the example presented in Figure 2, if one tabulates the “regulation” burden for Grant County PUD, computed here as the difference in the actual 1 minute load (or load net wind) data from a suitable rolling average, in this case a 10-minute rolling average, a histogram as shown in Figure 3 results (using 11 months of data from 2006). In Figure 3, the dark blue, light blue, yellow, and red bars correspond to 0, 12, 63.7, and 150 MW of wind power input into the system, respectively. The distribution shape is close to normal and effectively centered around zero, and the effect on regulation of including wind energy at these levels is very small. The standard deviation in 1-minute regulation generation changes ranges from 3.47 MW for 0 MW of wind, to 3.51 MW for 63.7 MW of wind, and up to 3.72 MW for 150 MW of wind. One method to estimate the increase in need for regulation would be to multiply the difference in the standard deviation between these two cases by 5 (see Holttinen et al. 2008). For example, at 63.7 MW of wind, the additional spinning reserve required to compensate for the increased minute-to-minute regulation during every hour of the year would be 0.2 MW (e.g.,  $3.51 - 3.47 = 0.04$  MW;  $0.04 \times 5 = 0.20$  MW). Thus, hydro generation resources at Grant County PUD can likely absorb the minute-to-minute variations introduced in the system by wind power from the Nine Canyon Wind Project. A similar histogram could be constructed for “load following” to demonstrate the changes in load variation within an hour or hour-to-hour due to the load net wind as compared to the load alone. While these calculations do a reasonable job of indicating the increase in regulation or load following needed, and provide a distribution of expected hourly changes, they are completely decoupled from the actual system operation and do not provide insight into any specific problems that may arise.



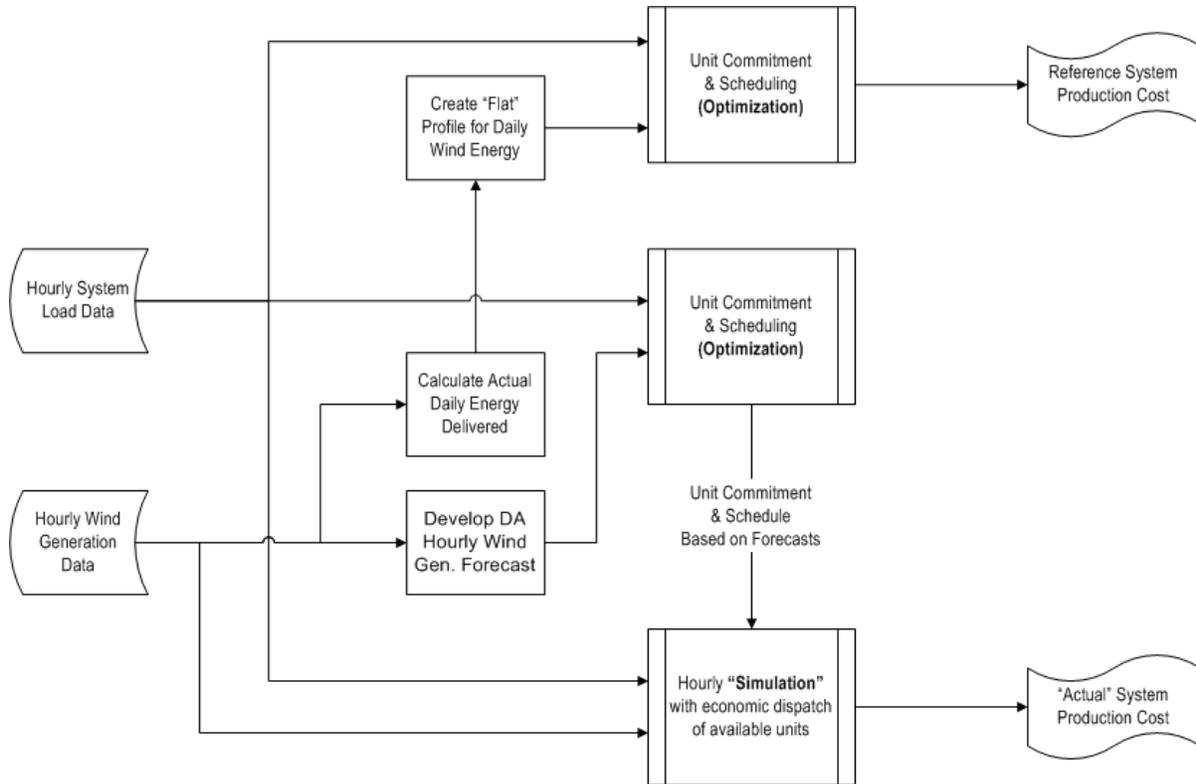
**Figure 3. Tabulation of the 1-minute “regulation” values for the Grant County PUD for various levels of wind penetration (= nameplate wind capacity / peak load) (Source: Northern Arizona University and Grant County PUD)**

In other words, during any given minute or hour of system operation, a large wind ramp-up or cut-out could cause problems in balancing load and generation, if, for example, there were not sufficient flexible generation resources online or rapidly available through the electric market to compensate for an unforeseen change the wind output causes in system net imbalance.

Therefore, although statistical summaries of wind power's influence on the net load are useful and supply valuable insights, they provide only part of the information required to understand wind's impact. Furthermore, a significant fraction of the costs incurred in handling the variability of wind power is due to the *uncertainty* in forecasting the wind, resulting in increased costs due to sub-optimal unit commitment and the need to retain more reserves (Smith et al., 2007). The unit commitment impacts and costs are not captured in the statistics of load net wind.

Typically, to complement and enhance the information provided by a simple study, wind integration studies often employ a chronological simulation of system operation. Many of the recent integration studies, including many of those in the case study chapters to follow, would be classified as detailed studies. In regard to detailed integration study methods, best practice suggests simulating system operation at some fine time resolution (1-hour time steps or less, if possible) using coincident wind and load data (Smith et al. 2007). In such a simulation, system planning and commitment operations are simulated using a production cost model that includes interaction with neighboring systems via the electricity market. The load data in these studies are typically historical, often scaled to some future load level, and the wind power data is typically created using a meso-scale weather model to “backcast” what a hypothetical set of wind power plants would have generated during the same year(s) as the load data. With this method, any innate correlation between the load and the wind is preserved. The data, along with coincident load and wind power forecast data (or simplifying assumptions to approximate them) is then used to drive a deterministic (or a stochastic) production cost simulation of the power system. The simulation proceeds to compute the cost to operate the system over some time frame, most typically 1 year, by mimicking the decision processes made day-ahead and hour-ahead and then deducing the impact of wind integration by comparing some base case scenario to cases that include increased levels of wind energy. In performing the simulation, the modeling platform (e.g., production cost simulation software) is constrained to honor all system reliability requirements and possibly include transmission limitations, while optimizing some performance criteria, such as minimizing the operating costs. A block diagram illustrating a variant of this methodology employed in detailed wind integration studies is shown in Figure 4. The results of this type of study provide, among other things, estimates of wind “integration costs” caused by an increased need for reserves and balancing resources due to the ancillary services of regulation, load following, and unit commitment.

In the methodology used for a detailed study described in Figure 1, the wind integration cost is defined as the difference in cost to operate the system with increased *variability* and *uncertainty* due to wind power versus the cost to operate the system in some fashion without those influences. Often, this deduction of the integration cost is made through a system comparison in which the wind power is replaced by some other generation resource. In some cases, this replaced resource is defined as a benign generation resource possessing none of the variability and uncertainty of wind energy, but available at the same cost as wind energy and in the same quantities. (This is the comparison suggested by the “flat” profile in the block diagram of Figure 4).



**Figure 4. Methodology often employed for conducting detailed wind integration studies**  
 (Source: C. Smith presentation, Task 24/25 Joint R&D Meeting, Milan 2007)

This technique provides useful information about the integration costs due to variability and uncertainty of wind power, and avoids the difficulty of accurately predicting wind power costs/prices and any complex market interactions. However, it is a somewhat limited view of wind's impact in a power system, and an improvement would be to consider wind power's overall influence in the power system, including the value it may bring to the system as a relatively low-cost form of new power generation.

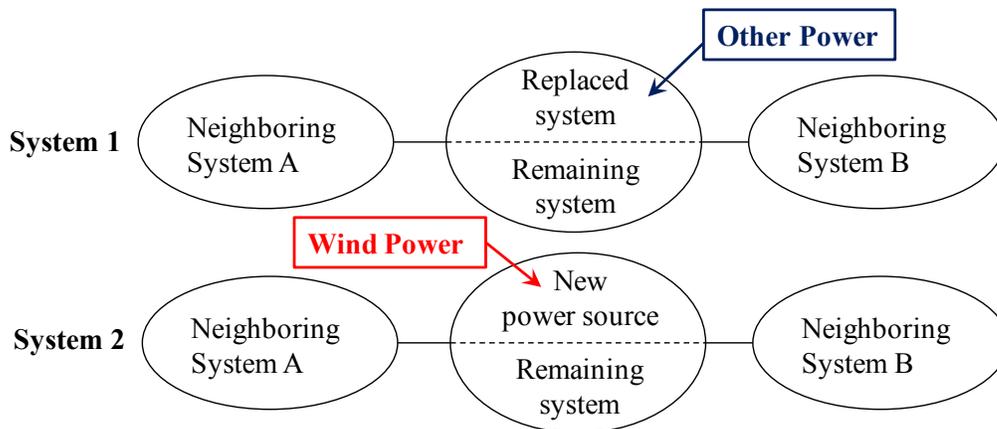
Söder and Holttinen (2008), pursuant to discussions held as part of the Task 24 dialogue, published an article describing different ways of setting up and performing a wind integration study in order to provide a consistent framework to formulate an integration study as well as interpret and compare results from the various studies that have been performed. Adapted from their paper, Figure 5 provides an illustration of two systems (that is, balancing areas) that are otherwise identical except that System 2 possesses some amount of wind power while System 1 includes some set of "other power" generation resources that would be "replaced" by the wind power. The other power sources in the replaced system could be thermal generators, hydro generators, nuclear systems, etc., existing on the system or they could be new, but in either case would be some realistic set of resources that could be employed.

The "remaining system" shown in both Systems 1 and 2 represents the remaining power system and is identical in both systems, as are neighboring systems A and B and the inerties with them. Depending on how the replaced system is defined, and the assumptions employed in modeling both Systems 1 and 2, the study could be classified as either detailed or as evolutionary, as

presented in Figure 1. The essential difference between these classifications, as defined here, is that a detailed study will mimic system operation in a way to deduce the operating cost increment associated with wind energy's variability and uncertainty, whereas an evolutionary study will consider the "integration cost" as the difference in operating costs ( $O$ ) for the two systems, assuming each is run optimally given its technical and economical specifications, including any investments ( $I$ ) that might be made that reduce the overall operating cost. Thus,

$$\text{Integration cost} = (O_{\text{wind}} - O_{\text{replaced}}) - (I_{\text{wind}} - I_{\text{replaced}})$$

***This simple equation applies for any type of integration cost study.*** However, for an evolutionary study, modeling of the system need not be conducted given the existing transmission constraints, market rules, scheduling intervals, etc., of the electrical system as presently configured, but rather can consider changes intended to *evolve* the system to a more efficient, profitable, and/or lower cost realm of operation.



**Figure 5. Deducing integration costs by comparing the costs of operating two variations of the electrical system, one with wind and one with some other set of generation resources (Source: L. Söder presentation, Task 24/25 Joint R&D Meeting, Milan, Italy, May 2007; also Söder and Holttinen (2008)]**

Whether a study is considered detailed, evolutionary, or something in between depends on the specific questions to be answered by the study and the assumptions and methods employed. Furthermore, the composition of the replaced system can have great bearing on the results obtained. As such, Söder and Holttinen go on to present several questions whose answers are significant in determining integration costs; these questions are summarized as follows (with the parenthetical capital letters and their associated category terms later referenced in Table 2 and Table 3):

1. Is the *aim* to study the consequence of a certain amount of wind power and/or to find the limit of what is possible? (A = Aim)
2. What *method* is used for considering wind in the system (i.e., as suggested in the detailed to evolutionary studies already described)? For example, is wind power seen as an extra source that is added to an existing system or is wind power seen as one expansion alternative that is compared with another one? (M = Methods)

3. How is the system *simulated* (e.g., deterministically or with stochastic optimization)? (S = Simulation)
4. What is the *time resolution* of the model (e.g. minute, hour, day)? (R= Time Resolution)
5. Is the integration cost calculated as the “physical cost” (i.e., fuel and investment costs) or is it calculated as the “market cost” (i.e., what different actors can be assumed to get paid)? Is it assumed that the balancing power is traded on the cost level or on the value level? The formal problem is that wind power owners need balancing (i.e., are ready to pay a lot), while sellers of regulating power want to maximize their profit. What is then assumed about the *pricing* of this service? (P = Pricing)
6. When wind power is expanded, is it assumed that the rest of the system, including the grid, is optimized from the economical point of view? Is the system *designed* for optimal operation with wind or other power sources, or does it operate under existing conditions? Is it assumed that the trading rules between neighboring systems are optimal from the total system economic point of view or are existing rules used? (D = Design)
7. How is the *imbalance* in the power system calculated? Are wind speed forecasts included in the studies? Is it assumed that the accuracy of these is on the best available level? Are imbalances in the load and other production units taken into account when determining the reserve requirements? (I = Imbalance)
8. How detailed is the description of the power system especially in its flexibility? For example, what *balancing* resources are considered (B = Balancing), and how are *grid* transmission and interconnection limits handled (G = Grid)?
9. How are *uncertainties* in the system modeled (e.g., uncertainties in hydropower, transmission limits, wind power, load, thermal generation, and forecasting)? (U = Uncertainties)
10. How are the *hydropower plants* modeled (e.g., are head height and coupling of facilities on a river system considered)? (H = Hydropower Plant)
11. In addition to modeling of hydropower plants, does the hydropower provide any type of special *capacity service* for the wind energy (e.g., store excess wind in off-peak times for redelivery during peak hours)? (HC = Hydropower Capacity Service)
12. How are the *thermal power plants* modeled (e.g., are ramp rates and stop/start time considered)? (T = Thermal Power Plant)
13. And finally, how is the *wind power* output modeled? (W = Wind Power Plant)

For the purpose of comparing and contrasting the various wind/hydro integration studies developed by Task 24 participants, as well as other wind integration studies that have been conducted, all of these issues were summarized along with other relevant system information onto a form called the *matrix*. The matrix is split into two parts and displayed in Table 2 and Table 3 because it is too long to fit on a single page. Table 2 shows power system and market characteristics, and parameters describing the system setup and simulation detail. (The capital letters in the left-hand column under *Setup* and *Simulation Detail* in Table 2 and *Uncertainty and Balancing* and *Power System Detail* in Table 3 correspond to the categories defined by these letters in the previous bulleted list.) For each issue listed on the left, the corresponding rows on the right-hand side of the table present options describing the possible approaches or

assumptions that may be employed. More than one of these options, or none of these options, may apply in any given study. For more options descriptions, please see the related paper by Söder and Holttinen (2008).

**Table 2. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for an integration study**

<b>Geographic area of study:</b>						
<b>Power system characteristics:</b>						
<b>Load</b>		<b>Conventional Generation</b>		<b>Interconnection</b>	<b>Wind Power</b>	
<b>Peak (MW)</b>	<b>Min (MW)</b>	<b>TWh/a</b>	<b>Capacity (MW)</b>	<b>Capacity (MW)</b>	<b>MW</b>	<b>TWh/a</b>
<b>Other relevant characteristics of power system:</b>						
<b>Characteristics of system planning:</b>						
<b>Description of market:</b>						
<b>Integration time frames of importance:</b>						
Yes/No	Time Frame					
	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg					
	Regulation, AGC					
	Load following; intrahour ramping; economic dispatch					
	Unit commitment and day-ahead scheduling; economic utilization of resources					
	Resource and capacity planning; reliability					

**Table 3. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in wind integration studies**

<b>Setup</b>		
<b>A</b>	<b>Aim of Study</b>	1 what happens with x GWh wind 2 how much wind is possible
<b>M</b>	<b>Method to Perform Study</b>	1 add wind energy 2 wind also replaces capacity 3 optimal system design
<b>S</b>	<b>Simulation Model of Operation</b>	1 deterministic simulation, one case 2 deterministic simulation several cases 3 Stochastic simulation several cases
<b>Simulation Detail</b>		
<b>R</b>	<b>Resolution of Time</b>	1 day/week 2 hour 3 minute/second
<b>P</b>	<b>Pricing Method</b>	1 costs of fuels, etc. 2 prices for trading with neighbors 3 market actor simulation 4 market dynamics included
<b>D</b>	<b>Design of Remaining System</b>	1 constant remaining system 2 optimized remaining production 3 optimized remaining transmission 4 perfect trading rules

**Uncertainty and Balancing**

<b>I</b>	<b>Imbalance Calculation</b>	1 only wind 2 wind+load 3 wind+load+ production
<b>B</b>	<b>Balancing Location</b>	1 dedicated source 2 from the same region 3 also outside region
<b>U</b>	<b>Uncertainty Treatment</b>	1 transmission margins 2 hydro inflow uncertainty 3 no wind forecasts (assume persistence) 4 best possible wind forecasts 5 load forecasts considered 6 thermal power outages considered
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	1 no limits 2 constant MW limits 3 consider voltage 4 N-1 criteria 5 dynamic simulation
<b>H</b>	<b>Hydropower Modeling</b>	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included 4 hydro optimization considered 5 consider most relevant aspects of affected hydro resources
<b>HC</b>	<b>Hydro Capacity Service</b>	1 interaction with hydro resources not significant 2 real-time integration with impact of wind variability on system managed with hydro 3 capacity service: addition of capacity value through redelivery of wind energy at a later time
<b>T</b>	<b>Thermal Power Modeling</b>	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered 4 heat production considered
<b>W</b>	<b>Wind Power Modeling</b>	1 few wind speed time series 2 many wind power time series 3 time series smoothing considered

This matrix, as presented in Table 2 and Table 3, was used as an organizational tool in describing the case studies performed as part of Task 24 and for aiding in comparing the various studies. It is used prominently in the case study chapters that follow in this volume.

## 1.2 Wind Penetration and System Flexibility

Before proceeding to the case study chapters, it is useful to discuss what is meant by “the penetration level of wind energy.” When wind integration costs or impacts are presented, “wind penetration” is almost universally cited to provide an indication of how much wind power is being assimilated into the balancing area or system for which the integration impacts and costs are incurred. There is usually some implication that systems of a similar wind penetration should experience similar wind integration impacts, but this is not necessarily the case. Perhaps the two most frequently cited definitions of wind penetration are given by the following simple expressions, based upon either capacity and load or energy:

$$\text{Wind Penetration (WP)} = (\text{installed wind power capacity}) / (\text{system peak load})$$

$$\text{Wind penetration (WP)} = (\text{annual wind power production}) / (\text{annual system demand, energy})$$

These expressions correspond to  $WP_C$  and  $WP_A$  shown in Table 4, respectively. The system peak load in the denominator of the former equation can correspond to the peak indigenous load of the system, or the peak of the indigenous load plus synchronous exchanges with neighboring systems (in other words, it includes load obligations exchanged between neighboring systems based upon purchases or sales into or out of the system). For the case in which the calculation is carried out using the peak of the indigenous system load, it is easy to deduce the wind capacity knowing the system peak load, a useful number for wind power political targets. It is generally more useful to the utility system operator and planner when  $WP$  is calculated with the peak of the indigenous load plus synchronous exchanges.

Similarly, the wind penetration calculation represented by  $WP_D$  in Table 4, which uses the system minimum load including synchronous exchanges in the denominator, is also useful for system planners/operators. The reason for this is that these latter two methods of computing the wind penetration hint at the flexibility required to balance the system. It may be more difficult to balance wind power in the system when the load obligation of the system operator is lowest. For example, there are times in Denmark when the wind generation exceeds the load, and the excess is transferred out of the system along synchronous ties (Holttinen 2008a). A chart showing the wind penetration calculated as defined by  $WP_A$ ,  $WP_C$  (without synchronous interconnections), and  $WP_D$  (with synchronous interconnections) in Table 4 for several recent wind integration studies is presented in Figure 6. As the wind penetration based on gross demand increases, the penetration based on peak load generally increases. The wind penetration based on the lowest system load plus interconnection demonstrates system dependency and indicates that even with lower penetration levels some systems will have more challenges in low load times as other systems with better interconnections. In general, impacts of wind power integration increase with the quantity of wind generation in a system. However, it may be more difficult to accommodate the variability and uncertainty of wind power in systems with a higher  $WP_D$  (which results in higher integration costs). That said, although a system may have a large  $WP_D$ , its ability to handle the impacts of wind are directly related to the flexibility of the system generation resources, frequency of scheduling intervals, and setup of the market to trade power.

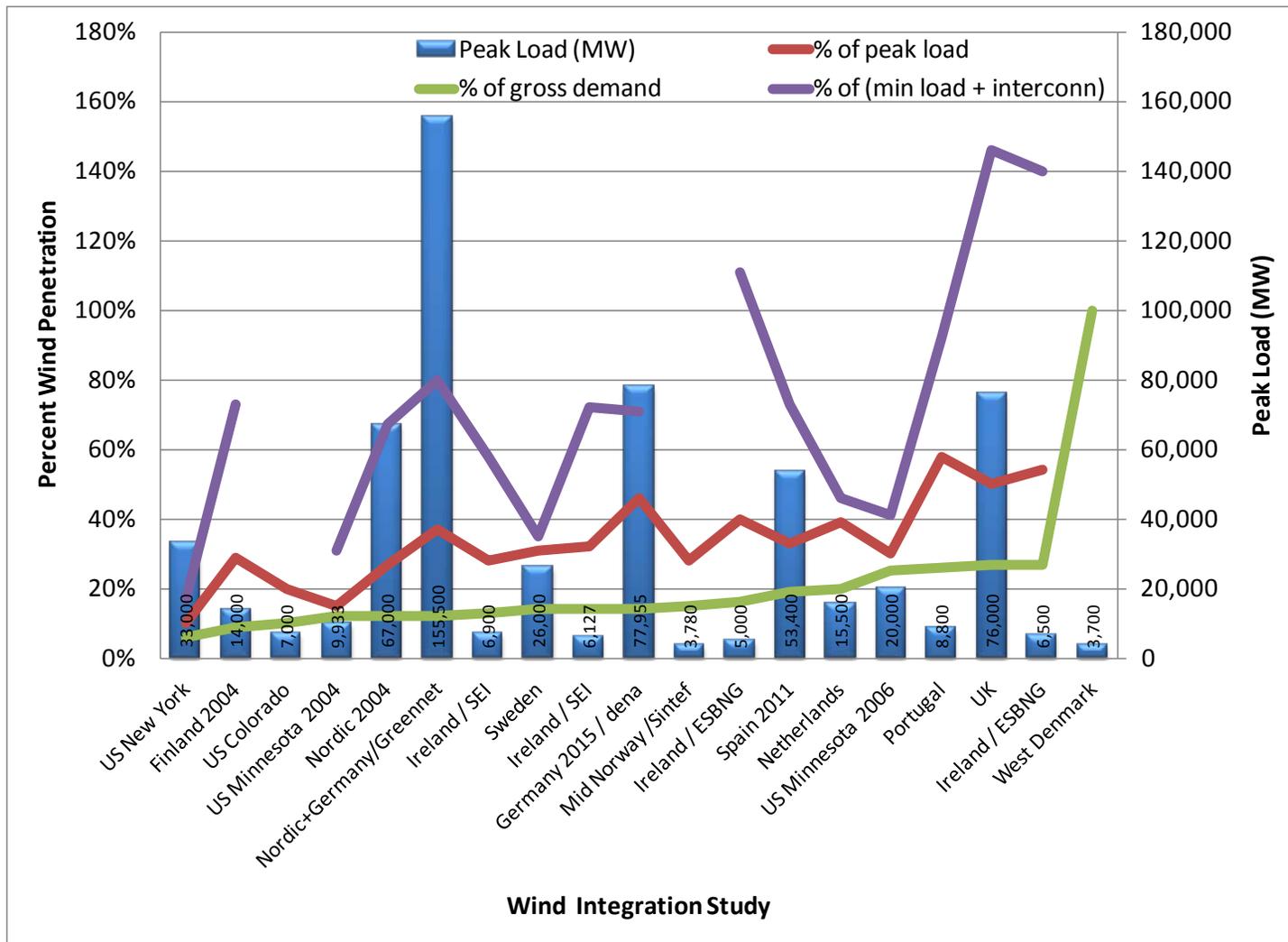
The impacts and costs of wind integration are directly related to the operational flexibility a system possesses to absorb wind power variations and inaccuracies in forecasting, and these costs should be calculated for the different time scales of interest (minute-to-minute regulation, minute-to-hourly load following, hour ahead and day ahead commitment, etc.). For example, in a balancing area possessing ample capacity of simple cycle gas turbines or relatively non-constrained hydropower (e.g., not run-of-the-river hydro), there may be sufficient flexibility in the system to easily absorb the wind power variations. Alternatively, if a system is heavy on base load resources (e.g., nuclear, coal, constrained hydro), it may not have the flexibility to deal with variations introduced by wind in the load net wind signal. In addition to the physical generator capabilities, operational flexibility can be influenced substantially by the flexibility of the institutions that manage the generation resources. This is particularly true with some hydropower resources, where there may be numerous organizations or non-power factors that constrain use of the resource. Hydropower resources such as these may be able to increase their generation flexibility through altering institutional practices.

Utility systems will differ in how much flexibility needs there are (load variability), in how much flexibility exists in their generation and interconnections, and also in how easy it is to increase flexibility with growing needs. Perhaps one useful gauge of existing system flexibility can be inferred from the range of variations currently managed in a given system. One method of gauging the existing flexibility is to consider the overall load variation currently managed, computed as  $(\text{peak load} - \text{minimum load}) / (\text{average system load})$ . The blue, monotonically increasing line in Figure 8 illustrates a plot showing this value for several recent integration studies. Plotted along with this are the peak system load and the wind penetration computed using the minimum load plus interconnections ( $WP_D$ ), demonstrating the variety of characteristics/differences across the many studies.

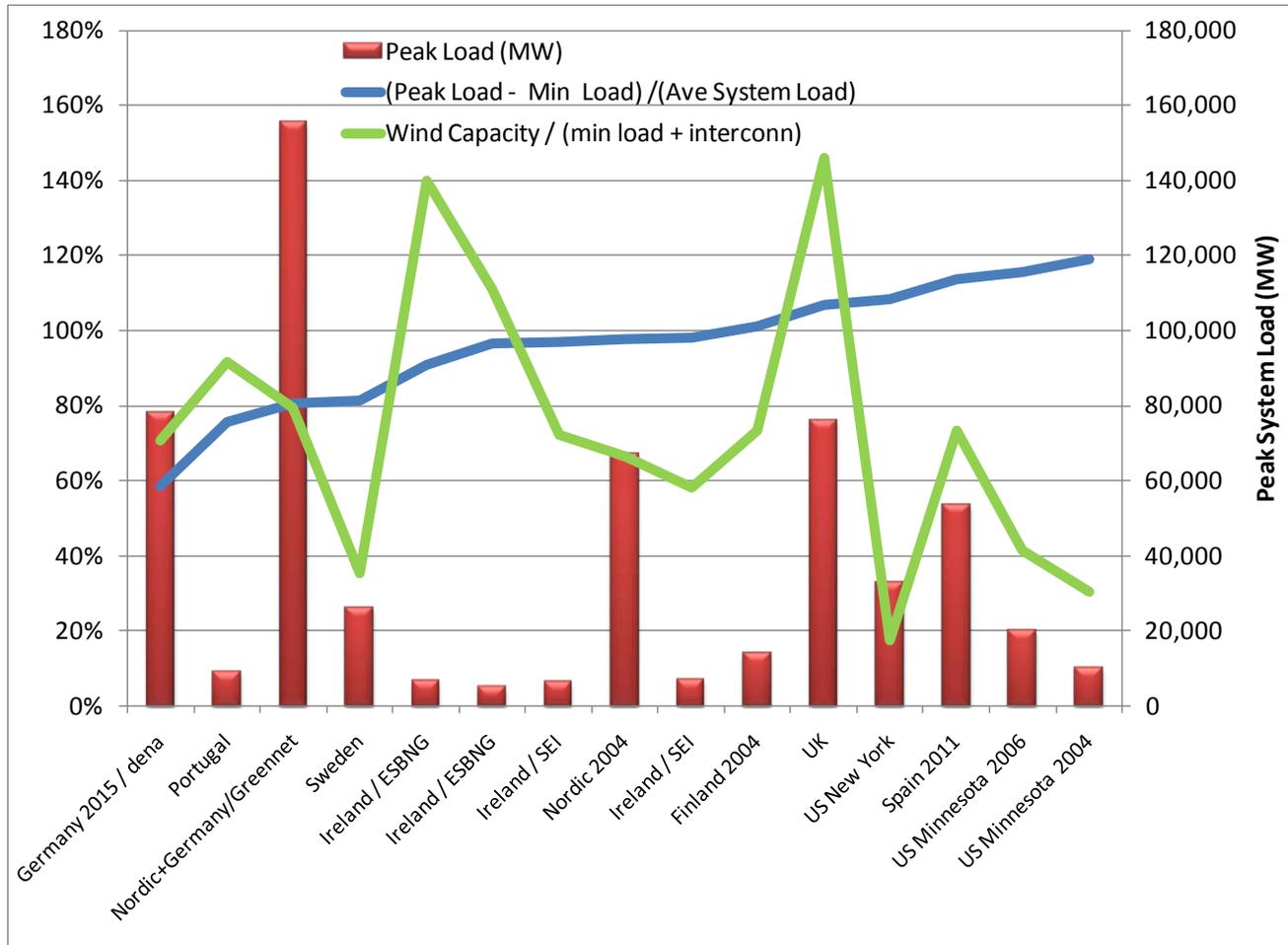
The various definitions of wind penetration and this method of estimating system flexibility provided are straight-forward to compute, and can be used as indirect ways to gauge the relative flexibility of a system and the flexibility required of a system to handle the additional variability and uncertainty of wind energy. Beyond these fairly simple, indirect measures, one would need to drill into the more complex, detailed system data describing the actual generation sources available, the load and wind characteristics, and the interconnections to get a more direct indicator of the potential impact of wind integration and the ease or difficulty of incorporating it. A summary of issues regarding system flexibility, including market aspects, is provided in Table 4. Flexibility that is practicably available during operational situations will depend on the scheduling of the units, as flexibility will result from units that are on-line at a given moment, which can adjust their production level. It is also possible to change operational routines so that some power plants will be operated more flexibly to some extent in future. Wind power can also bring about flexibility if it is used in an “active power regulation” mode restricting the possible generation and using pitch regulation of the rotor blades to provide more or less power when needed. Building new flexible capacity (or storage) is the most expensive measure to increase flexibility.

**Table 4. Relevant methods of defining “wind penetration” (Source: Adapted from A. Robitaille presentation, “Wind Power Integration Into Hydropower System: Discussion,” Task 24 R&D Meeting #5, Quebec City, Canada, June 2008)**

	Wind Penetration Type			
	Gross demand (energy)	In term of installed capacity	Peak Penetration (during peak load)	Maximum penetration (during lowest load)
Calculation	$WP_A = \frac{\text{Annual wind production}}{\text{Annual system demand (energy)}}$	$WP_B = \frac{\text{Wind capacity}}{\text{System generating capacity}}$	$WP_C = \frac{\text{Wind capacity}}{\text{System peak load}}$	$WP_D = \frac{\text{Wind capacity}}{\text{System lowest load}}$
Entity (country, state or company)	Renewable Energy Standard (question of energy independence and ecological target)	Renewable Energy Standard (an easily defined target; relates to peak generation capacity)	Renewable Energy Standard (an easily defined target; relates directly to peak power demand in the system)	Possible to compute, but typically not employed.
Synchronous Network	Renewable Standard Target(a large region within or beyond country borders)	Renewable Energy Standard (a large region within or beyond country borders)	Questions of system stability, regulation (horizon less than a few minutes)	
Balancing Area	Renewable Energy Standard (question of energy independence and ecological target)	System generation capacity (including synchronous import capacities)	Questions of load following reserve, efficiency, unit commitment, system adequacy (cases not taking into account synchronous exchanges to be avoided)	
			In the calculation, use the system <i>most probable peak load</i> (including synchronous exchanges)	In the calculation, use the system <i>most probable lowest load</i> (including synchronous exchanges)



**Figure 6. Values for various measures of the wind penetration and peak load for several recent wind integration studies**  
 (Source: Adapted from A. Robitaille presentation, “Wind Power Integration Into Hydropower System: Discussion,” Task 24 R&D Meeting #5, Quebec City, Canada, June 2008, using data from Table 18 of Holttinen et al., 2008a)



**Figure 7. Comparison of (peak load – minimum load) / (average system load) for several recent wind integration studies against corresponding peak system load and wind penetration computed as a percentage of (minimum load + interconnection capacity) (Source: Adapted from A. Robitaille presentation on “Wind Power Integration Into Hydropower System: Discussion,” Task 24 R&D Meeting #5, Quebec City, Canada, June 2008, using data from Table 18 of Holttinen et al., 2008a)**

**Table 5. Summary of issues surrounding wind integration and system flexibility (Source: A. Robitaille presentation, “Wind Power Integration Into Hydropower System: Discussion,” Task 24 R&D Meeting #5, Quebec City, Canada, June 2008)**

Aspect	Parameters	To Improve the Flexibility
<b>Relative Patterns of Wind Production and Load</b>	Wind influence on net load: <ul style="list-style-type: none"> <li>• Ratio of additional reserve / initial reserve</li> <li>• Ratio of additional operating margin / initial margin</li> </ul> Currently, the ratio <i>Additional reserve / wind capacity</i> is often used.	<ol style="list-style-type: none"> <li>1. Load management</li> <li>2. Wind power plant geographical dispersion strategy</li> <li>3. Wind forecast improvement</li> </ol>
<b>Generation System Capability</b>	Type of generation in the system: <ol style="list-style-type: none"> <li>[1] Base load vs. peaking facility</li> <li>[2] Energy source: hydro or thermal</li> <li>[3] Interconnections</li> </ol> Impacts evaluation: start and stop frequency, inefficiency, etc.	<ul style="list-style-type: none"> <li>• System operation optimization</li> <li>• Plan new flexible installations</li> <li>• Use of existing flexibility</li> </ul>
<b>Market Level Player and Market Flexibility</b>	<ol style="list-style-type: none"> <li>1. Local or national</li> <li>2. Operating reserve cost</li> <li>3. Day ahead market</li> <li>4. Hour ahead market</li> <li>5. Penalties for scheduling errors</li> </ol>	<ul style="list-style-type: none"> <li>• Additional interconnections</li> <li>• Intra-hourly market</li> <li>• Special conditions for renewable energy sources</li> <li>• Increase the size of control area</li> </ul>

### **1.3 Report Organization**

Following this introductory chapter, Volume 2 chapters devoted to the case study or studies contributed by each country, one chapter per country. If a member country submitted more than one case study, then these studies are presented as different sections of the chapter. Each case study report will:

1. describe the study methodology in detail and define the purpose of study, using the matrix described above as a descriptive and unifying template;
2. present defining characteristics of the power system, wind power, hydropower, market characteristics, and study methodology;
3. present the relevant results of study;
4. provide conclusions from the study relevant to the Task 24 objectives and expected results; and
5. provide references to more detailed and lengthy study reports created by the participants for each case study (if applicable).

The case study reports presented here are not full-length project reports typically created by the participants when conducting a study; but rather, they are condensed versions of these reports focused specifically on the information relevant to Task 24.

## 2 Australia

### 2.1 Introduction

Hydro Tasmania is Australia's leading renewable energy business, providing renewable energy to the national grid and trade energy and environmental products in the National Electricity Market. Hydro Tasmania Consulting provides energy and water solutions for hydropower and renewable energy, dams, catchment management, environment and power engineering in the Asia-Pacific region. The studies in this chapter are based on Hydro Tasmania's power system. Because of the potential for significant integration of wind power into the hydro-dominant Tasmanian power system, or provision of ancillary services to the greater Australian system (load net wind), Hydro Tasmania carried-out the studies described below to address various aspects of wind integration.

### 2.2 Hydro Tasmania Case Studies

#### 2.2.1 Introduction to Studies

Hydro Tasmania has carried out three case studies that are reported in Task 24, which are as follows:

*Case Study 1: Large-Scale Wind Integration to the Tasmanian System*

*Case Study 2: The Costs of Wind-Firming Service Provided by a Hydro Plant*

*Case Study 3: Inertia Support in a Hydro, Wind, and high-voltage direct current (HVDC) Hybrid Power System*

All three reported Tasmanian studies are system-based.

Case Study 1 has been updated twice during the period of the task. The most recent (May 2009 update is based on Transend studies). The objective of these studies is to identify limits for the penetration of wind generation in Tasmania based on power system performance. Initial studies focused on the impacts of the addition of the first 300 MW of wind generation; however, the most recent study looks at operation up to full utilization of the interconnector.

Case Study 2 evaluates the impact on the storage system of installed wind generation assuming coordinated operation. Two systems are investigated, including operation of an islanded system and an interconnected system within the Australian mainland. For an isolated system, the wind displaces hydro generation during wet, windy periods, this results in considerable increase in spill. The interconnected system provides much better opportunities for additional wind generation to either be stored or exported to the mainland system.

Case Study 3 focuses on operating issues typical for a small system. The main issue is the effects of large-scale wind generation displacing hydro generators and resulting in very low system inertia and an associated high rate of change of the frequency during system disturbances. The study has identified that the limiting factors in developing wind generation in Tasmania are due to low system inertia and very fast frequency changes affecting the operation of back protection schemes (i.e., under-frequency load shedding). The report also identifies that commitment of additional hydro generators operating in either synchronous condenser mode or tail water depression (TWD) mode can largely improve the integration of the wind generation in Tasmania.

In particular, the use of TWD mode allows fast machine start up from motoring operation and provides three valuable services including voltage/reactive power control, additional inertia, and additional Frequency Control Ancillary Services (FCAS). However, at present, inertia is not a recognized market service and the work on recognition of this service is not accepted as an off-market service, as is the case for reactive power support.

### 2.2.2 Overview of Power System

**Table 6. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the Tasmanian case studies**

<b>Study conducted by:</b> Hydro Tasmania, inertia support in a hydro/wind/HVDC hybrid power system						
<b>Geographic area of study:</b> Tasmania, Australia						
						
<b>Population:</b> 492,700 (March 2007)						
<b>Area:</b> 68,332 square kilometers (26,383 sq mi).						
<b>Power system characteristics:</b>						
Load			Conventional Generation	Interconnection	Wind Power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
1,850	900	11.1	2,810	630/480 export/import via HVDC	140	0.5
<b>Other Relevant Characteristics of the Power System:</b> Conventional generation comprises mostly hydropower generation with a mixture of storage and run-of-the-river schemes (2,267 MW). The installed capacity of thermal generation is 400 MW, and the capacity of wind generation is 140 MW. The HVDC interconnector links the Tasmanian power system to the four-state network on mainland Australia. The Tasmanian power system is small in comparison to its largest generator (210 MW) or load (200 MW), and the frequency standards have been recently tightened for a single contingency to 48.0 to 52.0 Hz.						
<b>Characteristics of System Planning:</b>						
System capacity is managed in the short- and medium-term through the Projected Assessment of System Adequacy. This covers a 2-year window of power generation and consumption.						
Daily dispatch is undertaken as a 24-hour pre-dispatch followed by a 5-minute look-ahead during actual dispatch.						
In terms of generation planning, it is expected that market demand will signal when new generation should enter the market and where that entry could best be made. Annually, the						

market management company publishes a Statement of Opportunities, which details changes to the power system and operational issues that may be relieved through investment in transmission or generation infrastructure.

In terms of renewable energy, the Australian government has a Renewable Energy Target incentive scheme based on Renewable Energy Certificates that requires an additional 9,500 GWh per year of renewable energy by 2010. An expansion in the size of the target to 45,000 GWh per year is being considered by Parliament at present.

**Description of Market:**

The Australian National Electricity Market is a spot market based on 5-minute dispatch intervals (and bids). The market price is set by the marginal generation bid. The market objective is to supply energy at the least cost—practically, this is a constrained least cost due to the limited physical capability of the power system. There is a co-optimization between the spot energy market and the FCAS market. The FCAS market and the mechanism by which constraints apply to the energy market is the focus of this chapter.

<b>Integration time frames of importance:</b>	
Yes/No	Time Frame
Yes	Frequency, system dynamics, grid stability, low-voltage ride through (LVRT), PSS, V-Reg
Yes	Regulation, AGC
Yes	Load following; intra-hour ramping; economic dispatch
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources <sup>3</sup>
Yes	Resource and capacity planning; reliability

**2.2.3 Case Study 1: Large-Scale Wind Integration**

This study addressed coordinated operation of hydro and wind generation. The operation of large-scale wind results in reduced hydro generation production. The HVDC interconnector provides some buffer, with the level of import or export depending on availability of both wind and water in storage. However, hydro plants often need to be scheduled at low output to accommodate wind. This is required not only to accommodate the wind but also to supply ancillary services required to maintain the system frequency. This case study considered the following issues:

- The variable nature of wind generation
- Characteristics of doubly-fed induction generators
  - No contribution to system inertia
  - Limited contribution to fault level
  - Limited voltage control capability
  - Operation of fault ride through devices
- System frequency control
- Quality control impacts

<sup>3</sup> Uses day-ahead scheduling to determine timing of additional inertial support

The original 2004 study was reviewed and updated in 2009 during the task, and results reflect the most recent updates (Future Wind Generation in Tasmania Study, Transend June 2009).

## 2.2.4 Study Methodology

**Table 7. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the first Tasmanian wind integration studies**

Set Up		
<b>A</b>	<b>Aim of Study</b>	2 – Define limits of integration of wind energy in Tasmania
<b>M</b>	<b>Method to Perform Study</b>	1 – add wind energy
<b>S</b>	<b>Simulation model of Operation</b>	2 – deterministic simulation several cases
Simulation Detail		
<b>R</b>	<b>Resolution of Time</b>	3 – minute/second
<b>P</b>	<b>Pricing Method</b>	N/A – it was assumed that wind generation is non-scheduled or self-dispatched (i.e., if available will run)
<b>D</b>	<b>Design of Remaining System</b>	1 – constant remaining system 2 – optimized remaining production
Uncertainty and Balancing		
<b>I</b>	<b>Imbalance Calculation</b>	3 – wind + load + production
<b>B</b>	<b>Balancing Location</b>	2 – from the same region 3 – also outside region <sup>4</sup>
<b>U</b>	<b>Uncertainty Treatment</b>	N/A – simulations based on worst-case approach
Power System Details		
<b>G</b>	<b>Grid Limit on Transmission</b>	2 – constant MW limits 3 – consider voltage 4 – N-1 criteria 5 – dynamic simulation
<b>H</b>	<b>Hydropower Modeling</b>	N/A – historical record of hydro availability was used
<b>HC</b>	<b>Hydro Capacity Service</b>	N/A – individual cases were considered in isolation
<b>T</b>	<b>Thermal Power Modeling</b>	N/A – <i>Note: thermal generation modeled using emergency trigger for Case I</i>
<b>W</b>	<b>Wind Power Modeling</b>	N/A – constant wind power output for duration of dynamic simulation

Issues considered in the study:

1. Generation variability

<sup>4</sup> The study considered the Tasmanian power system as an isolated system as well as linked to the wider Australian power system through Basslink, an HVDC interconnector.

2. Reduced capability to supply frequency control ancillary services
3. Wind farms are usually connected to weak part of the system
4. Power quality
5. Generation scheduling and FCAS (reserves) requirements
6. System inertia
7. Management of HVDC interconnection
8. Wind generator fault ride through
9. System fault level

#### **2.2.4.1 Assumptions**

The assumptions for Case Study 1 are as follows:

1. Tasmania operates as an isolated system
2. Only the main transmission network is represented in the study model; however, the effect of predominant North-South flow constraints is modeled.
3. The system is modeled using hourly production scheduling, historical wind speed data, and hydro inflows; wind generation is scheduled before hydro generation.
4. The following six wind generation scenarios have been studied:
  - Only hydro system with no wind generation scenario
  - Five wind generation development scenarios ranging from 100 MW (350 GWh) to 500 MW (1750 GWh) installed capacity.
5. Energy cost is measured as a change in the energy equivalent of storage volume.

Common assumptions between Case Study 1 and Case Study 2 are as follows:

1. Fixed Annual Base Load (equal to hydro system long term rating), and hourly load profile
2. Change in the Tasmanian load between scenarios is equal to the expected wind generation for that scenario
3. Wind farms are modeled as having an approximate 40% plant capacity factor (based on present experience, this value can be as high as 45%).

#### **2.2.4.2 Limitations**

Limitations affecting Case Study 1 are as follows:

1. Fixed load assumption means that a fixed amount of the load will be met by hydropower generation plus an emergency gas generation, if required. This load is approximately equal to the long-term rating of the hydro system. The approach does not consider that the demand on the hydro system in the future may well be different to this rating.

2. The transmission network is not modeled in any great detail, so local network issues are not considered. However, main power transfer limitations of the network are reflected.
3. The hydro inflows are modeled randomly, based on 1924–2005 inflow sequences. Analysis done now would not consider any inflows prior to 1976 because it is believed that there has been a statistically significant change (less) in hydro inflow since that date.
4. The heuristic operating rules, employed in the modeling, reflect best practice by Hydro Tasmania system operators as of the time of the study. At that time, there was only minor wind integration in the Tasmanian system and, as such, these rules do not properly reflect how the system may be operated with large wind integration.

## **2.2.5 Tasmanian System Characteristics**

### **2.2.5.1 Frequency**

In 2008, the Australian Energy Market Commission changed Tasmanian frequency standards in order to accommodate integration of Combined Cycle Gas Turbine (CCGT) plants, which cannot handle a wide range of frequency variations. In the assessment, the following criteria were applied:

Following a single contingency, Tasmanian frequency must remain within:

Study 1 (2004): 47.5–53Hz

Study 2 (2009): 48–52Hz

Following a multiple contingency, Tasmanian frequency must remain within:

Study 1 (2004): 46–55 Hz

Study 2 (2009): 47–53 Hz

In the Case Study 1, a 0.5-Hz simulation error margin has been used, while Case Study 2 was based on improved dynamic models and no frequency error margin.

### **2.2.5.2 Fault Level**

Displacing synchronous generators with generators connected via power electronics reduces system fault level with consequences of affecting existing designs. To achieve adequate performance of HVDC, a short-circuit ratio can be linked George Town (converter station site), which has to be above minimum acceptable value of 3 (i.e., the fault level must be at least three times larger than the HVDC power transfer required). Additionally, the minimum fault level must be provided to keep the effect of filter switching at an acceptable level. The alternating current filters support reactive demand at the converter station as Basslink power transfer changes. (Tasmania is interconnected to the Australian National Electricity Market via an HVDC monopolar interconnector known as Basslink.) There is a limitation on the maximum number of filter switching operations per hour, which depends on the magnitude of voltage dip and the fault level.

Fault-level limitations also apply to all system locations with installed shunt capacitors. Voltage change on capacitor switching depends on the fault level, and the capacitor sizes have been selected based acceptable quality of power supply. Consequently, any reduction in fault level may impact the quality of power supply. This could be particularly visible in remote locations (i.e., weak systems).

Finally, minimum short circuit level is required to provide satisfactory operation of protective relays.

### **2.2.6 Wind Power Characteristics**

The doubly-fed induction generators were used to represent wind generation. All wind turbines were assumed to be equipped with fault ride-through devices.

### **2.2.7 Wind Generator Dispatching Rules in Australia**

Prior to 2008, all wind generators were classified as non-scheduled, meaning they did not directly participate in the market solution process. Non-scheduled generators:

1. cannot set the energy spot price (they are price takers);
2. are treated as negative loads in the market solution;
3. get priority access to the transmission network over scheduled generators where there are constraints;
4. can cause constraints to be violated even with all scheduled generation constrained off; and
5. are assumed to maintain the same output level across a dispatch interval (persistence forecasting).

With the large increase in wind generation in Australia, dispatching the wind generation as non-scheduled has caused problems with maintaining system security and reliability. As of May 2008, a new classification for intermittent generators was introduced, called *semi-scheduled*. Semi-scheduled generation dispatching became operational at the end of March 2009.

All new wind generation developments with a total installed capacity of greater than 30 MW will now be classified as semi-scheduled. In some cases, developments of less than 30 MW will also be classified as semi-scheduled. Current generators, those under development prior to May 2008 and some future developments of less than 30 MW, are able to remain non-scheduled under the new rules.

The semi-scheduling rules have some similarities with the rules for scheduled generators, but with some freedom to vary output away from the dispatch target. Semi-scheduled generators bid into the market as scheduled generators do, but are not required to maintain output at the dispatch target unless a constraint could be violated. Following the market solution, each semi-scheduled generator will receive a dispatch target and a flag to indicate whether it must maintain output at or below the target. There is therefore no limit on deviating from the target in the lower direction, but there could at times be limits on the deviation in the upper direction.

### **2.2.8 Wind Power Penetration and System Flexibility**

No diversity in wind generation has been assumed. This power system study explored margins of system capability.

Flexibility of hydro system and HVDC allows for accommodating more wind generation. However, the difficulty of operating the Tasmanian system is due to inflexibility of the thermal plant (CCGT), its relatively large output (200 MW), and minimal contribution to FCAS—

particularly during periods of low load when wind generation displaces hydro units, reducing the system inertia and increasing FCAS requirements. Because there is no other plant to supply FCAS, some hydro must be scheduled and typically operates at low output. Low load operation results in increased cavitations, increased maintenance requirements, loss of assets life, and inefficient use of water. Unfortunately, Hydro Tasmania is forced to such operation under low storage conditions when there is a need to minimize water use and consequently maximize HVDC import and contribution of wind energy.

### **2.2.9 Hydro System Characteristics**

Hydro units are not the best providers of fast FCAS. The initial response is slow and usually opening of the guide vanes results in reduction of the pressure and temporary reduction of machine output. This usually takes about 1–2 seconds. Considering that the FCAS contribution is calculated for the 6 seconds after frequency exceeds the 0.15-Hz threshold, there are small time delays in movement of the pilot valve, distributing valve and the main servo. The initial response to opening of guide vanes is a temporary reduction in hydro machine output for typically 1–2 seconds before the output starts ramping out. Consequently, there are only 3–4 seconds within a period covered by R6 definition (6-second reserve) when hydro units ramp its output.

### **2.2.10 Conclusions**

The 2004 report concluded that in order to ensure the security of the power system with minimum system load of about 900 MW together with 300 MW of import to Tasmania through the (then) proposed Basslink HVDC interconnector, wind generation would have the following implications:

- Between 130 MW and 150 MW of wind generation would require very little change in system operation.
- Operation with between 150 MW and 300 MW of wind generation would require increased FCAS (balancing<sup>5</sup>) operation from conventional synchronous plant or advanced wind-plant control systems.

The 2004 report did not attempt to define a maximum limit of wind generation in Tasmania; it merely confirmed that 300 MW could be integrated. Some earlier work has indicated that at least 600 MW could be absorbed, depending on the assumed mode of operation of hydro machines. However, these earlier reports may not have fully considered the implications of the impact on Basslink and thermal generation in Tasmania.

The 2009 paper reviewed the 2004 wind-penetration limits in light of the following issues:

- Two years of operating experience of wind farms in the market environment with the HVDC interconnector
- Significant changes in thermal generation in Tasmania with imminent closure of the Bell Bay plant (April 2009); new, CCGT (200-MW, Babcock and Brown, now AETV); and the expected net export of approximately 60 MW from 122-MW Gunns pulp mill co-generation

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<sup>5</sup> In the Australian National Electricity Market, the balancing function is provided by FCAS products offered into a 5-minute market and co-optimized with energy.

- Improvements in wind forecasting that reduced concern about wind variability and provided a better understanding of the requirements for frequency balancing
- Better modeling of FCAS response of hydro generators, allowing removal of the arbitrary 0.5-Hz safety margin used in 2004

According to the 2004 report, Tasmania has now reached the level of wind generation capacity that can be absorbed with little change to system operation. Due to the new Australian government policy commitments to managing anthropogenic climate change, it is now likely that the pace of development of wind generation in Tasmania will increase in the near future, provided that system integration issues can be dealt with in a commercial manner.

If Tasmania is to carry a reasonable share of the national renewable energy target of 20% by 2020, then the levels assessed in 2004 must be surpassed. This review of the 2004 work was unable to form conclusions on the feasibility of operating with more than 500 MW of wind generation in Tasmania. Consequently, it was considered timely to repeat the modeling process.

A scope of work was developed for further modeling to reflect the current perspective. The new studies should address the following issues:

- Assessment of the impact in the context of both energy and the system security limitations, rather than the single worst-case of 900-MW, minimum-load and medium-import scenario (300 MW)
- Change in assumption of balanced energy flow across the link to predominant import scenario due to a long period of low inflows has resulted in low hydro storage levels with the consequence that currently the duration and magnitude of imports are larger than originally assumed
- Possible changes to allowable Tasmanian extreme frequency and emergency load-tripping response can manage a low-inertia system, which also includes changes to design of under- and over-frequency management schemes
- The impact of the proposed Australia National Electricity Market rule change, bringing wind farms into the dispatch control
- Actual performance of the existing Bluff Point and Studland Bay wind farms in respect to meeting the original assumptions
- Increase in FCAS (balancing) requirements during low loads and high Basslink imports; imports of up to 480 MW (previously 300 MW) and higher Tasmanian demand
- Impact of increasing output of wind generation on generation ramp rates and HVDC power reversal (impact on speed to access the market), which is relevant for both directions of ramp rates
- Clear costing for system services required by wind generation (i.e., impact of multiple asset owners)
- Adequacy of the regulatory framework in relation to scheduling additional inertia or other support from hydro machines

- Management of the shortage of fast frequency lowering response at high exports up to 630 MW (including wind generation participation in the frequency control scheme during export)
- Market impacts of increasing wind penetration in Tasmania

The 2009 Transend Study shows that up to 1,300 MW of wind generation could be incorporated into the Tasmanian system with Basslink in service if mitigation measures identified in the paper are put in place. This figure reduces to approximately 620 MW with Basslink out of service. In both cases, higher wind penetrations would occasionally require wind generation curtailment.

These studies identified several concerns. First, a mechanism needs to be put in place for maintaining system inertia above current minimum levels. Current minimum system inertia is between 3,500 MW and 4,000 MW. Under the new frequency operating standards for Tasmania, system inertia will need to be maintained above the current minimum. Because there are many hydro generators in Tasmania that can operate in synchronous condenser mode, one possible mechanism is to bring generators online in this mode when inertia falls below minimum levels. Synchronous condensers are traditionally used for voltage control support; however, they also provide inertia and fault contribution to the system as added benefits. Where new supplementary voltage control equipment or dynamic reactive power sources are required, synchronous condensers should also be considered in place of power electronic devices (e.g., switched virtual circuit, static synchronous compensators), which do not provide inertia and fault contribution.

In addition, the future supply of local frequency control ancillary services is highly uncertain due to the imminent change in frequency operating standards in Tasmania. In order to maintain system security and to allow Basslink flow direction reversal, wind generators may be required to provide FCAS. When faults occur, wind generators must remain connected and their active power must return quickly following fault clearance.

The study also indicated some issues of less concern. One such concern is that system fault levels will be maintained above minimum acceptable levels as long as system inertia is maintained. Although it is possible to have very low fault levels with high levels of wind generation, fast FCAS requirements become unmanageable before the fault levels drop below current minimum levels. In addition, generation scheduling and regulation reserve requirements should be manageable, even for very high wind penetrations. A modest increase in regulation FCAS requirements is likely to be required. Another concern is that Basslink import constraints will not be adversely affected if system inertia is maintained. Basslink export constraints will not be adversely affected under most circumstances if system inertia is maintained; however, import conditions were concentrated upon in this study and export conditions with very high levels of wind generation require further study. Finally, simulations were performed with system inertia maintained through the use of generators operating in synchronous condenser mode and with wind generators offering FCAS. Maintaining system inertia has the added benefits of improving Basslink import and export constraints and increasing system fault levels, although shortage of FCAS during Basslink flow reversals still remains a problem. To remove problems in achieving Basslink flow reversals, which are an issue even at present, either a significant quantity of inexpensive fast FCAS must become available in Tasmania, or the mechanisms for handling flow reversals must be changed.

### 2.3 Case Study 2: Wind Firming – Case Study of Costs and Effects to the Hydro Tasmania System

The objective of this study was to estimate the cost of supporting various levels of wind generation in Tasmania to the owners of hydro generation. This service is referred to locally as *wind firming*. Two systems were considered: the first covering an isolated operation of a Tasmanian system and the second covering interconnected operation. The study focused on the efficiency of water storage and spill control.

**Table 8. First half of the Task 24 matrix for the second Tasmanian case study that differs from the first Tasmanian case study**

Integration Time Frames of Importance:	
Yes/No	Time Frame
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg
No	Regulation, AGC
Yes	Load following; intra-hour ramping; economic dispatch
No	Unit commitment and day-ahead scheduling; economic utilization of resources
Yes	Resource and capacity planning; reliability

#### 2.3.1 Study Methodology

**Table 9. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the second Tasmanian wind integration studies**

Set Up		
<b>A</b>	<b>Aim of Study</b>	1 – investigate an impact of installed 1,752-GWh wind generation on operation of hydro system <i>Note: the study covers the range of energy increments from 350 GWh to 1,752 GWh</i> 2 – estimate energy cost of providing various level of wind firming
<b>M</b>	<b>Method to Perform Study</b>	1 – add wind energy 2 – wind also replaces capacity
<b>S</b>	<b>Simulation Model of Operation</b>	3 – stochastic simulation several cases
Simulation Detail		
<b>R</b>	<b>Resolution of Time</b>	2 – hour
<b>P</b>	<b>Pricing Method</b>	2 – prices for trading with neighbors 4 – market dynamics included
<b>D</b>	<b>Design of Remaining System</b>	2 – optimized remaining production 4 – perfect trading rules
Uncertainty and Balancing		
<b>I</b>	<b>Imbalance Calculation</b>	3 – wind + load + production
<b>B</b>	<b>Balancing Location</b>	2 – from the same region 3 – also outside region

<b>U</b>	<b>Uncertainty Treatment</b>	1 – transmission margins 2 – hydro inflow uncertainty 3 – no wind forecasts (assume persistence) 4 – best possible wind forecasts 5 – load forecasts considered
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	2 – constant MW limits 5 – dynamic simulation
<b>H</b>	<b>Hydropower Modeling</b>	1 – head height considered 2 – hydrological coupling included (including reservoir capacity) 3 – hydrological restrictions included 4 – hydro optimization considered <i>Note: employed heuristic operation rules</i>
<b>HC</b>	<b>Hydro Capacity Service</b>	2 – real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	<i>Note: thermal generation modeled using emergency trigger for Case I and marginal price in Case II</i>
<b>W</b>	<b>Wind Power Modeling</b>	2 – many wind speed time series

### 2.3.1.1 Assumptions

This case study was carried out excluding the interconnection of Tasmania with mainland Australia. The generation at that time was predominantly hydro with a single gas-fired station providing draught relief. After interconnection, Tasmania has experienced a significant drought period with high interconnector import flow most of the time. Lower yields have encouraged additional wind generation and significant growth in gas generation. The assumptions for Case Study 2 are as follows:

1. Tasmania is interconnected to the Australian National Electricity Market via an HVDC monopolar interconnector known as Basslink.
2. The Tasmanian transmission network is modeled using a simplified current configuration.
3. The system is modeled using an hourly time step, national Victorian generators (interconnect with the national Australian grid in Victoria), and marginal dispatch cost (wind generation is self-dispatched).
4. Historical wind and hydro inflows sequences are randomly selected and used as input to the Monte Carlo simulation model.
5. The same as in the case of isolated operation, five scenarios of wind development have been used including:
  - One case using 100 MW as a base case
  - Four wind generation cases ranging from 200 MW to 500 MW installed capacity
6. Energy shortfall between hourly wind generation and firm capacity is valued at the spot market price. For the purpose of this study, *wind firming* implies the service of supporting wind power production that is assumed to have a firm 40% capacity factor

(40% is a typical, if not low, capacity factor for a Tasmanian wind resource). If the wind production falls short of 40% capacity during any given hour, the energy shortfall between hourly wind generation and firm capacity is valued at the spot market price. Wind energy in excess of the firm capacity is sold into the market. Thus, *wind firming* refers to the service of guaranteeing a firm capacity from the wind power production on a yearly basis, via use of the hydro storage system (either storing water when wind is in excess of its firm capacity or spilling if necessary, and using water for generation when wind production falls short), with energy transactions valued at the spot market price. Two systems were considered: the first covering an isolated operation of a Tasmanian system and the second covering interconnected operation. The study focused on the efficiency of water storage and spill control.

7. Wind energy in excess of the firm capacity is sold into the market. (Effectively, all wind generation is used and hydro spill is marginal comparable to a case with no wind).

Common assumptions between Case Study 1 and Case Study 2 are as follows:

1. Fixed Annual Base Load (equal to hydro system long term rating), and hourly load profile.
2. Change in the Tasmanian load between scenarios is equal to the expected wind generation for that scenario.
3. Wind farms are modeled as having an approximate 40% plant capacity factor (based on present experience, this value can be as high as 45%).

### **2.3.1.2 Limitations**

The limitations for Case Study 2 are as follows:

1. Hydro storage balance issues are not considered.
2. The same inflows (1924–2005) as for Case Study 1 were used.
3. Similar issues relating to simplification of the network as for Case Study 1.
4. Cost of floor contracts was not considered.

### **2.3.2 Impacts of Wind Generation**

Figure 8 illustrates the primary reason why the hydro system is affected by substantial wind generation in a case of isolated operation of a Tasmanian system. Because there is very low load growth, the additional energy generated by wind is scheduled as a priority and, consequently, hydro storage is increasing and reaching spill during substantial portions of a year. During the period of high hydro yields, typically June through October, the average wind speed is also high and the system cannot effectively store the wind generation. In other words, adding wind generation to an already spilling hydro system will result in increasing the duration and frequency of spill events. This is mitigated in the second study case by addition of the interconnector. The statement is a generalization that mainly applies to run-of-the-river and minor storage plants. Low inflow periods from January through April mean that the hydro system has to support a larger proportion of a bigger load when it is least capable of doing so.

### 2.3.3 Hydro System Characteristics

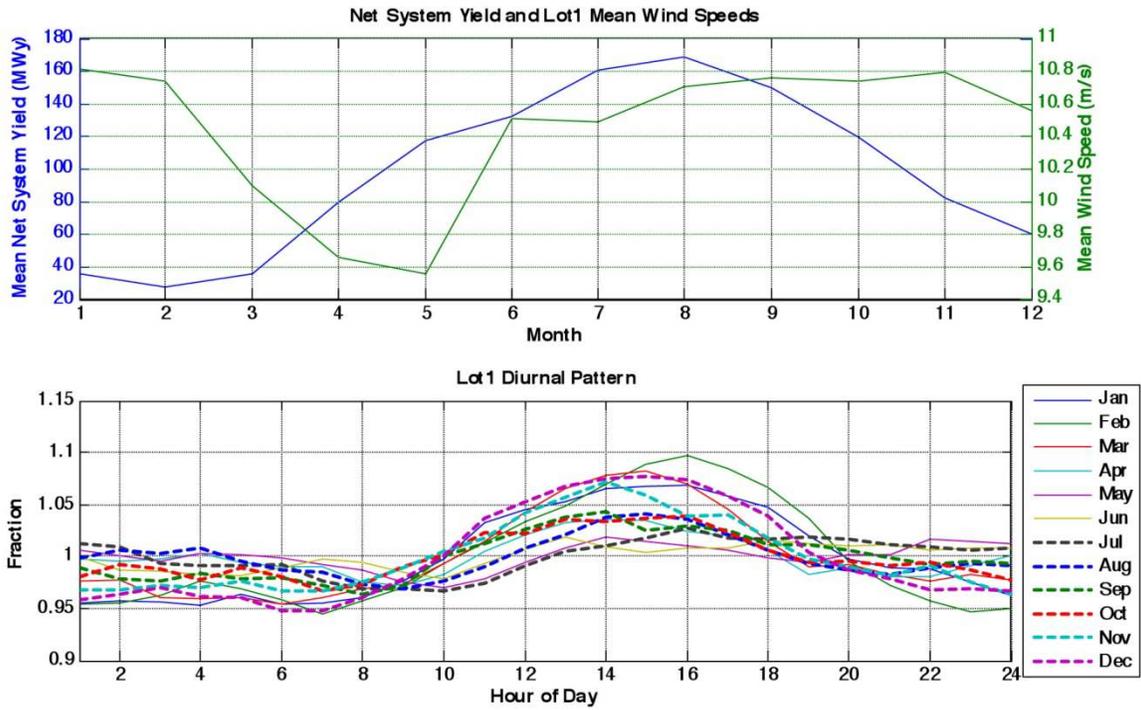


Figure 8. Annual distribution of the net hydro system yield and a mean wind speed; lower figure shows typical daily wind patterns

### 2.3.4 Wind Power Penetration and System Flexibility

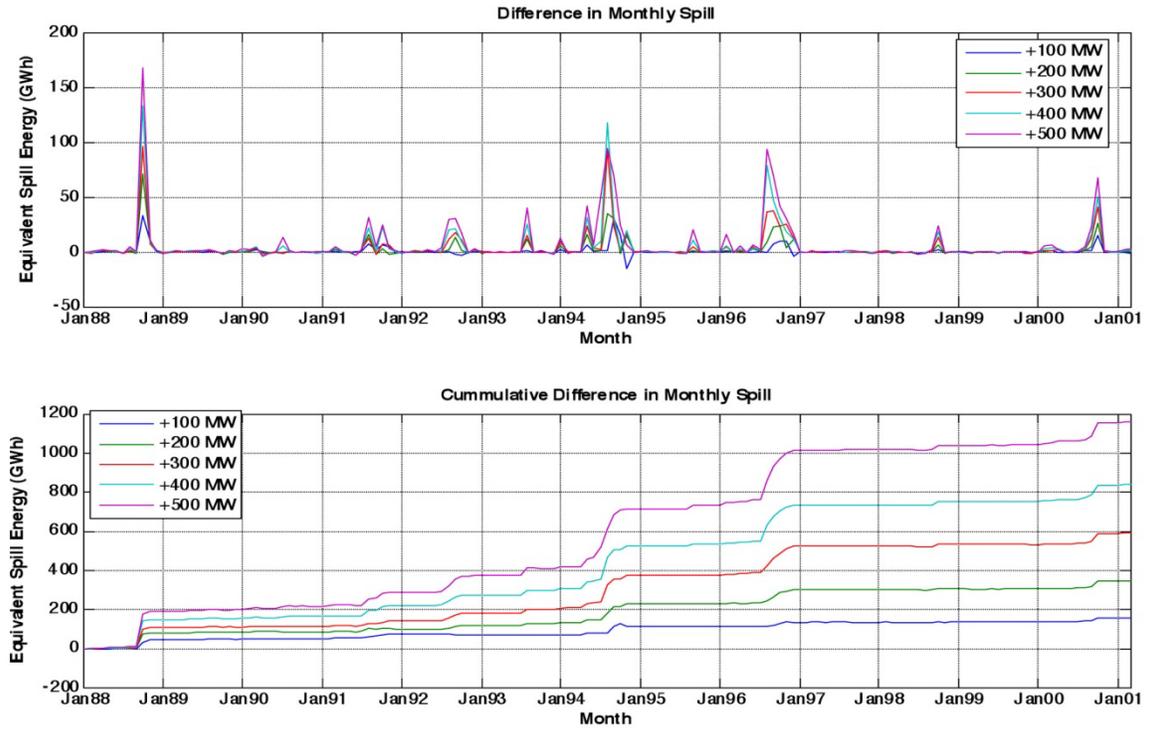


Figure 9. Increase in spill due to installation of wind generation; isolated operation of Tasmanian system

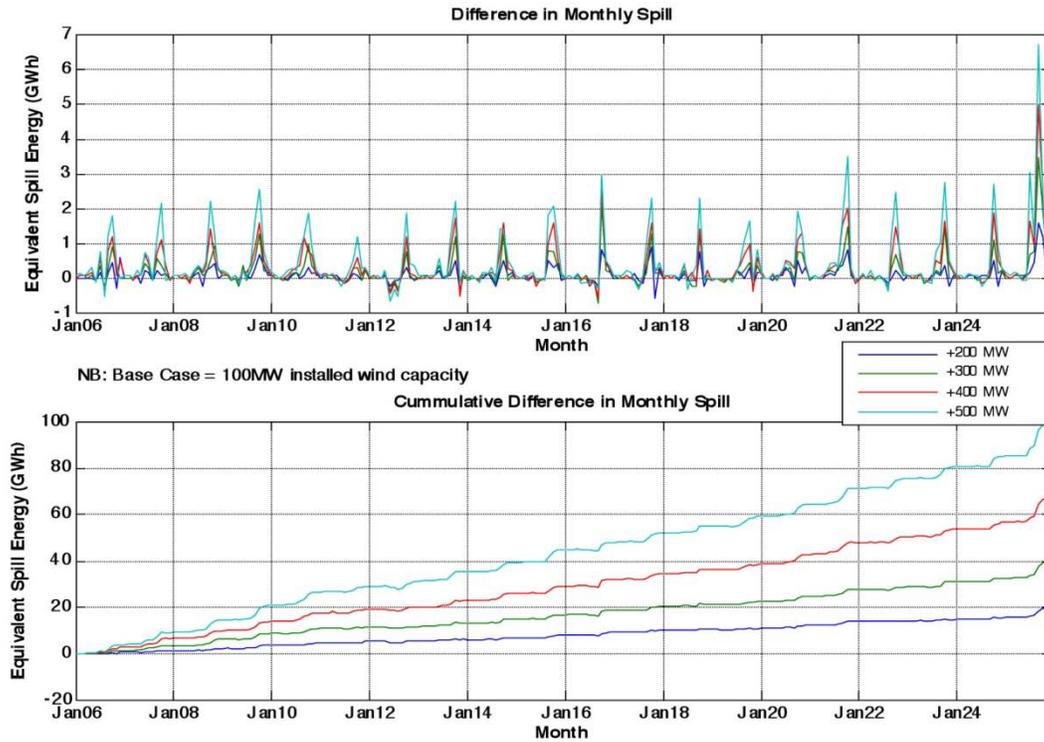
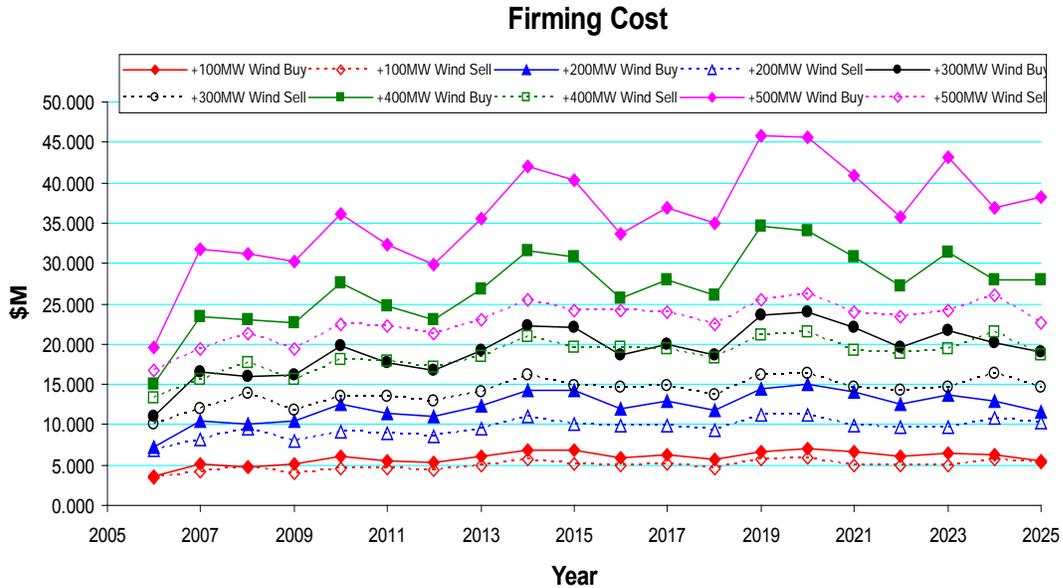


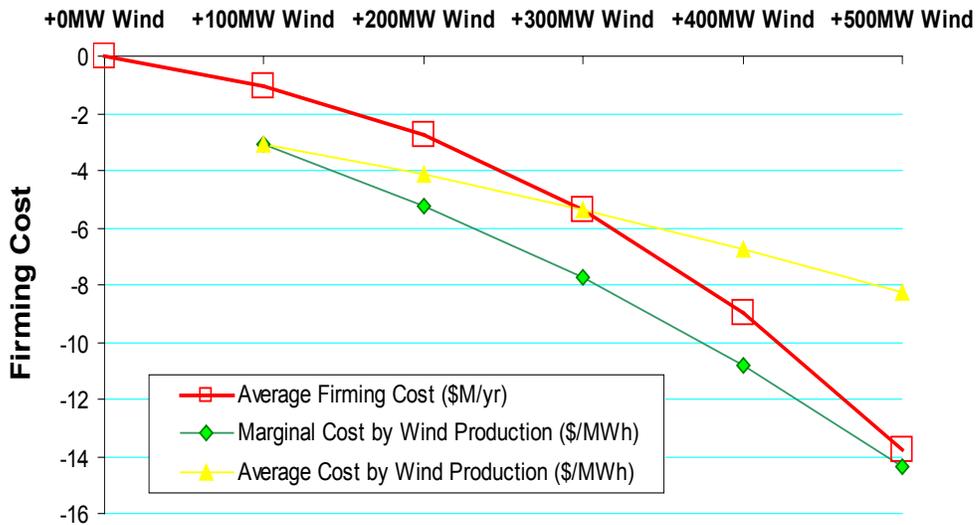
Figure 10. Increase in spill due to installation of wind generation; interconnected operation

Interconnected operation reduces monthly spill of generated energy from 30–50 GWh to less than 2 GWh (see Figure 9 and Figure 10 [top graph]). The annual spill of hydro energy varies between 50 GWh per year to 200 GWh per annum under isolated operation. This amount is reduced to approximately 10 GWh per year with interconnected operation. Even with 500 MW of wind generation, interconnection reduces the spill to about 100 GWh after 10 years. The same spill would have occurred with less than 100 MW of wind generation in a case of isolated Tasmanian system operation.



**Figure 11. Costs (Australian dollars) per megawatt-hour of wind firming service**

Figure 11 shows that the annual costs of firming up wind generation vary from \$5 million AUD to \$45 million AUD. The cost varies with the magnitude of wind generation and with the direction of interconnector flow. For a small installed wind generation capacity (100 MW), the firming price for import is the same as firming up export price. This gap tends to grow with increasing capacity of wind generation. It is noted that the firming price for exporting wind energy is lower than in the case of buying wind energy and using it in Tasmania.



**Figure 12. Average annual cost of firming up wind energy and reduced wind production costs**

Figure 12 summarizes annual average cost of firming up wind energy as varying \$1 million AUD per annum for 100 MW of wind to \$14 million AUD per annum in a case of 500 MW of installed wind capacity. If these costs are added to the cost of a wind project, this effectively results in increasing average production costs by \$3 AUD/MWh in a case of 100-MW wind development to \$8 AUD/MWh in a case of 500-MW wind farm development.

**2.3.5 Conclusions**

**2.3.5.1 Isolated Tasmanian System**

In the case of islanded operation of a Tasmanian power system, the system is unable to effectively absorb all output from large-scale wind generation due to coincident of high winds and high inflows. There is an increasing negative impact on storages as wind generation capacity is increased. The system energy yields (hydro and wind) in the first quarter of the year critically determine how large this effect is. Also, the coincidence of high wind and hydro inflows in the period between September and November led to a small increase in spill. Coincidence of low wind and hydro inflows in the period between February and June resulted in a greater requirement on the hydro system to meet load when storages are low. Under such conditions, there may be minimal reduction of using stored water.

**2.3.5.2 Tasmanian System Interconnected with Mainland**

The addition of the high-capacity interconnection (HVDC, 600-MW export and 480-MW import) with Australian mainland is a major improvement, allowing the ability to significantly increase penetration of wind generation in Tasmania without a negative effect on the energy in storage. A small increase in system spill is noted. The expected marginal cost of firming up wind generation can be as high as \$14 AUD/MWh at 500-MW installed capacity.

## 2.4 Case Study 3: Inertia Support in a Hydro/Wind/HVDC Hybrid Power System

It is well recognized that the regulating capability of hydro-based systems assists with the integration of wind generation. However, these systems are not the best contributor to contingency reserves. The Tasmanian system, with a large proportion of hydro generation, has relatively low inertia (using heavy and low-speed machines) in comparison to thermal units; therefore, frequency disturbances result in a high rate of change of frequency. The initial response of hydro generators to a frequency disturbance is slow. Isolated hydro systems with significant non-synchronous sources (HVDC, wind, and photovoltaic generation) may exhibit a shortage of fast raise<sup>6</sup> FCAS. This section explores linkages between the system inertia and fast FCAS demand, and presents formulas for calculation of additional inertia allowing avoidance of FCAS shortages and consequently allowing integration of greater wind generation to the system. It also addresses strategies for improving frequency control in a Tasmanian system with large-scale wind generation and the large-capacity monopolar HVDC link (energy import results in limiting condition) through dispatching selected hydro generators as synchronous condensers to increase system inertia. Subsequent work recommends gradual conversion of synchronous condenser operation to TWD mode supporting fast start up of units directly from motoring. In this mode, hydro machines contribute both inertia and some fast FCAS raise.

### 2.4.1 Study Methodology

**Table 10. First half of the Task 24 matrix for the second Tasmanian case study that differs from the first Tasmanian case study**

Integration Time Frames of Importance:	
Yes/No	Time Frame
Yes	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg
No	Regulation, AGC
No	Load following; intra-hour ramping; economic dispatch
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources <sup>7</sup>
No	Resource and capacity planning; reliability

**Table 11. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the third Tasmanian wind integration studies**

Set Up		
<b>A</b>	<b>Aim of Study</b>	2 – how much wind is possible
<b>M</b>	<b>Method to Perform Study</b>	2 – wind also replaces capacity
<b>S</b>	<b>Simulation Model of Operation</b>	2 – deterministic simulation several cases 3 – Stochastic simulation several cases
Simulation Detail		

<sup>6</sup> In Australia, the term *fast FCAS* refers to the megawatt reserve available within 6 seconds after the frequency crosses  $\pm 0.15$ -Hz band. The market recognises two services raise (R6) and lower (L6). Other contingency reserves include slow service (R60 and L60) available in 60 seconds and delayed service available in 5 minutes.

<sup>7</sup> Uses day-ahead scheduling to determine timing of additional inertial support

<b>R</b>	<b>Resolution of Time</b>	3 – minute/second
<b>P</b>	<b>Pricing Method</b>	2 – prices for trading with neighbors 4 – market dynamics partially included
<b>D</b>	<b>Design of Remaining System</b>	1 – constant remaining system 2 – optimized remaining production
<b>Uncertainty and Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	3 – wind+load+ production
<b>B</b>	<b>Balancing Location</b>	2 – from the same region 3 – also outside region
<b>U</b>	<b>Uncertainty Treatment</b>	2 – hydro inflow uncertainty 4 – best possible wind forecasts
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	2 – constant MW limits
<b>H</b>	<b>Hydropower Modeling</b>	1 – head height considered 2 – hydrological coupling included (including reservoir capacity) 3 – hydrological restrictions included 4 – hydro optimization considered
<b>HC</b>	<b>Hydro Capacity Service</b>	2 – real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	2 – start/stop costs considered
<b>W</b>	<b>Wind Power Modeling</b>	2 – many wind power time series

### 2.4.2 Modeling Assumptions

Stochastic modeling was performed to select a representative system dispatch. These snapshots were used in a dynamic simulation to determine additional inertia requirements. A further round of stochastic modeling was then undertaken to evaluate the cost of proposed inertial support. Hydro inflows were selected from historical records. High-average and low-inflow years were selected to determine the range of inertia costs. Wind forecasts are based on wind measurements across several years.

It was assumed that an increase of wind generation will not alter the transmission system capacity, the frequency support arrangements, or HVDC inter-connector operation beyond the current operating philosophies.

At the time of the study, the thermal units in Tasmania were operated as drought relief and were therefore only enabled if hydro storages were low. Once thermal unit were committed, a minimum run-time was applied, so start-stop costs were implicitly considered. New thermal generation in Tasmania includes base load combined cycle plants and open cycle gas turbines increasing peaking capability.

The study only considered, in detail, the cost of additional inertia. Dispatch of additional FCAS (balancing reserves) is more compatible with the existing market services and more easily implemented.

### 2.4.3 Wind Power Characteristics

Existing wind turbines for large-scale wind farms are either double-fed induction generators or full-size converters. These types of wind turbines must be equipped with fault ride through devices to avoid tripping during faults. However, if the frequency disturbance is initiated by depressed system voltage (fault), wind farm output is drastically reduced for about 0.5 seconds, increasing the magnitude of the frequency excursion. Studies have shown that the combination of switching power supply action (trip of generators) and fault ride through (FRT) can result in significant frequency swings from over-frequency to under-frequency. It was recommended that wind generation be placed on the switching power supply generator-tripping list with a high priority to improve wind integration.

### 2.4.4 Hydro System Characteristics

The initial response of a hydro generator during a frequency disturbance is to change the position of guide vanes. When low frequency is detected, guide vanes open to increase water flow. However, until the water column is accelerated, machine output is reduced. This takes usually 1–2 seconds, and the time delay significantly reduces the ability to provide fast FCAS raise from the machine. In Australia, fast FCAS raise (R6) service is defined as twice the integral of machine active power response to the disturbance over a period of 6 seconds. The 6-second period starts from the instant when frequency exceeds -0.15 band.

### 2.4.5 Wind Power Penetration and Hydro System Flexibility

Hydro machines provide very good regulation and can easily adjust to particular output requirements. Considering that hydro systems are energy limited, the addition of wind is very beneficial, providing that the hydro stations are supported by large water storage. It is much more difficult to regulate active power output when the storage is small as it is in a case with run-of-the-river stations. Further complications are encountered during periods of high water inflow or specific environmental or irrigation water release requirements.

In practice, there are very few exclusively hydro systems, and characteristics of other generation and interconnections will influence the integration of wind generators.

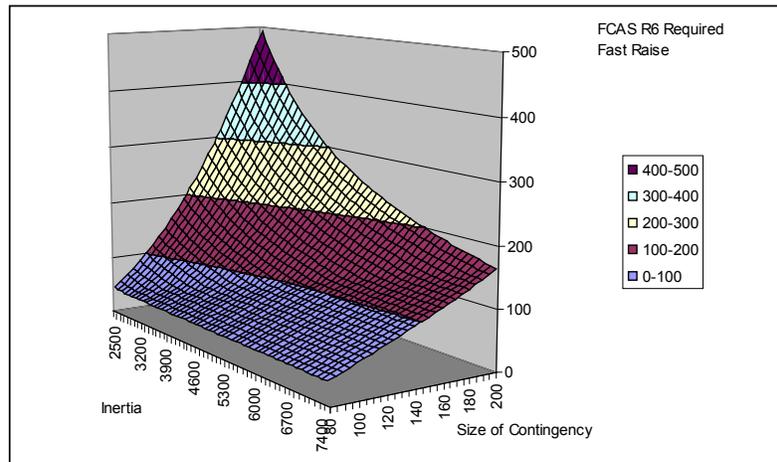
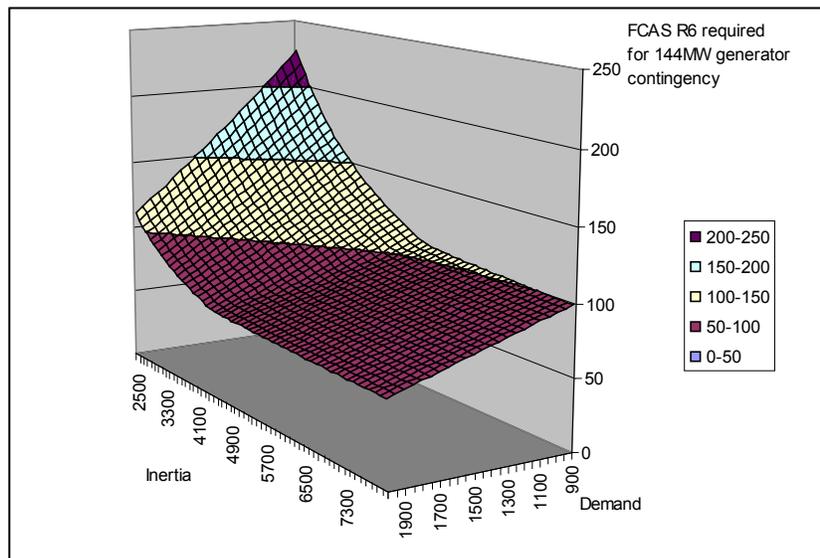


Figure 13. Fast FCAS raise requirements as a function of system stored energy and the size of largest generator contingency (all units in megawatts).

Hydro generator output is not fully flexible, and characteristics depend on the type of turbine. In Tasmanian systems, medium-head Francis turbines are dominant. They exhibit rough running zones, typically in the 20–60% output range, and longer periods of operation in this range are not recommended even with additional injection of air. If the output of Francis units is limited to 50% in a hydro system, then integration of wind generation would be limited. Operation below the rough running zone is not recommended due to loss of efficiency and plant impact.

It is noted that Kaplan turbines have minimum load limitations due to potential turbine uplift. Pelton turbines can operate at low load output because they can have a variable number of nozzles in operation.

The main restriction on integration of wind comes from a significant increase in fast FCAS requirements, both raising and lowering (the frequency). As mentioned, hydro machines provide slow and delayed reserves well, but fast response capability is limited.



**Figure 14. FCAS R6, a function of system-stored rotating energy and system demand (all units in megawatts).**

Figure 14 indicates that for the fixed generator contingency size (144 MW) and with system stored rotating energy above 4,000 MW, the R6 requirements are below 100 MW. Only when the system inertial energy is below 4,000 MW and Tasmanian demand is low can R6 requirements be more than 200 MW. This figure appears to be fairly small; however, it is a difficult target to achieve in a hydro-based system considering the following:

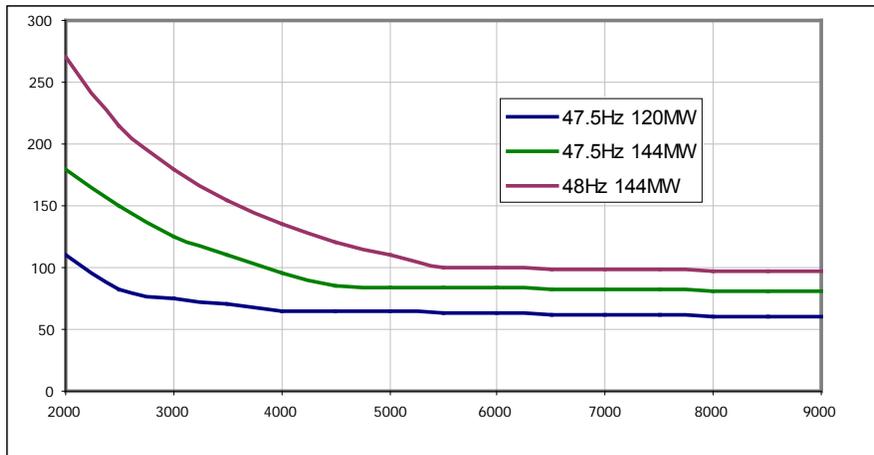
- Overnight Tasmania load is 1,000 MW or less.
- With low-spot market price, Tasmania may import energy from the mainland (e.g., 400 MW).
- The heavy, 1,700-MW CCGT plant is in service operating at half output (100 MW); the inertia of the largest machine is excluded from the calculation of FCAS.

- There is significant wind generation with an output of 200 MW

The above scenario leaves only 200 MW of hydro plant scheduled. Assuming a 50% load factor, 400 MW of hydro capacity is in service contributing to stored inertial energy of about 1,600 MW (average inertia time constant of hydro machines is 4). Securing this dispatch would require more than 200 MW of R6 being scheduled. Under such conditions, available FCAS is typically limited to 30 MW, and HVDC contributes approximately 80 MW. To meet the requirements of constrained dispatch, Hydro Tasmania can either:

- operate hydro generators on low loading with all consequences of such operation considered, which would add both additional FCAS and increase system inertia, or
- add some synchronous condensers to increase system inertia and reduce FCAS requirements.

Adding six large-size hydro generators operating in synchronous condenser mode would increase inertia to above 4,000 MW and reduce R6 required to below 100 MW. It is noted that adding first one or two synchronous condensers drastically reduces FCAS requirements; however, as the flat part of the characteristic is approached, the incremental gains are much smaller (Figure 15).



**Figure 15. Fast FCAS R6 requirements (vertical axis, in megawatts) as a function of system inertial energy (N-1) (horizontal axis, in megawatts).**

Operation of hydro machines in TWD mode (i.e., a mode similar to a synchronous condenser but with the main inlet valve open and governor and hydraulic system active) allows rapid change over to the generation mode with some contribution to FCAS. Tests have shown that not all Francis turbines are equally effective, and units with short water acceleration time and fast guide vanes opening can provide more FCAS. This double contribution of additional inertia and some FCAS (10–15 MW) provides an equivalent support to six synchronous condensers with only two TWD machines.

Unfortunately, there are some institutional constraints imposed by current market rules that are presently being addressed. The Australian electricity market cannot dispatch at present machine in synchronous condenser mode or in TWD mode. This means that it is possible to operate a synchronous condenser, but it will not receive any payment unless it is contracted as network control ancillary service.

TWD mode is used in New Zealand, but it cannot currently be dispatched in Australia. For TWD to be recognized, the provider needs to be registered as a FCAS provider and a switching controller. Assigned frequency triggers activate switching controllers, and the trigger frequency results in slower activation of the controller and lesser FCAS contribution. The rate of change of frequency is not currently recognized as a trigger for switching controllers.

#### **2.4.6 Conclusions**

Large penetration of wind generation in the isolated hydro system would result in commitment of fewer hydro generators under strong wind conditions. Also, generators in service would operate at lower than efficient output. This situation is made more difficult with the HVDC interconnector. Recent experience in Tasmania shows that some generators operate at output as low as 10% to increase system reserves (i.e., FCAS) and to make the system heavier (i.e., add inertia).

The cost of low output operation is high due to low efficiency. Increased cavitation damage and higher maintenance requirements have also been reported. The cost of supplying additional inertia in the hydro-based system with machines capable of operation as synchronous condensers or in tail water depression mode is low in comparison with the potential benefits. The cost of motoring relates to a load of about 2% of machine rating. These benefits include the following:

- Allows maximization of inter-connector flows
- Allows greater fraction of inertia less generation (variable speed doubly-fed induction generators wind generation) in Tasmania
- Improves efficiency of using water comparing to low load operation
- Reduces maintenance requirements on hydro units

Frequency control in the Tasmanian system has become more challenging in recent years due to the following factors:

- An outage of HVDC interconnector (bi-directional flows) has become effectively the largest generator contingency (630 MW) or the largest load (480 MW) contingency. Switching power supply schemes controlling load and generator tripping make the HVDC interconnector outage appear the same as normal load contingencies (200 MW) or generator (144 MW) contingencies.
- Import over the interconnector enables a number of hydro generators to be displaced as well as reduces loading of generators in service. This reduces the inertia of the Tasmanian system and increases FCAS requirements. Some hydro machines are forced into low load operation in order to supply the required FCAS services (with fast FCAS being the limiting constraint). This practice causes deterioration of condition of hydro assets, increased maintenance cost, and loss of machine life. It is noted that HVDC is equipped with a frequency controller that equalizes frequencies in both systems and modulates target HVDC power transfer, also allowing transferring of FCAS.

- Commissioning a large-size CCGT plant has resulted in the following:
  - The inertial contribution of 1,700 MW from these units is much larger than for the largest hydro unit (650 MW), which increases the severity of a single generator contingency and contributes to higher FCAS demand.
  - To accommodate the connection of the CCGT plant, Tasmanian frequency standards have to be tightened with the generator contingency band being reduced by 0.5 Hz from 47.5–48 Hz. This change has increased fast FCAS raise (R6) requirements by at least 30 MW.
  - The increased size of the largest generator contingency to 144 MW (with the remaining 70 MW of CCGT capacity provided by a matching load tripping) increases fast FCAS raise and lower requirements by an additional 30 MW.

Tasmanian wind farm sites located in the “roaring 40s zone” (i.e., the 40th parallel south of the equator, a notoriously windy latitude in the southern oceans) are very attractive to developers because they offer wind utilization of 40–45% (capacity factor). Wind developments tend to displace some hydro generators from the dispatch and further reduce the system inertia.

The work described in this chapter is still in progress. Considering that current wind generation in Tasmania is 140 MW and no significant problems with integration of wind generation are expected until there is more than 300 MW, the issues described are being progressively discussed to improve market rules (i.e., overcome institutional constraints) and allow more renewable energy sources to be integrated. Note the full reports on these projects, from which this case study is condensed, provide formulas allowing calculations for additional inertia required to make FCAS available sufficient to satisfy system security requirements.

## 3 Canada

### 3.1 Introduction

#### **3.1.1 General Description of Study and Goals**

The purpose of this study was to perform a RETScreen<sup>8</sup> analysis for a case study involving a wind power purchase option by the Okanogan PUD in Washington State, U.S.. The RETScreen process is a tool used to evaluate the financial feasibility, energy production estimates, emissions impacts, and general risk assessment for the development of renewable energy projects. The particular focus of this study was assessment of the above objectives regarding plans by the utility to purchase a 25% share of wind power from the Nine Canyon Wind Farm project for integration into its hydro-dominated power structure. Detailed site, system, and wind turbine characteristics were blended with financial information to form a report for use in decision-making. This study differs from most of the other case studies that have been contributed to Task 24; it is an economic evaluation of incorporating wind energy into a system versus other alternatives (an estimate of the value of wind energy), and not a grid integration study that seeks to determine the impacts and costs of wind power's variability and uncertainty.

#### **3.1.2 Organizations Involved and Who Conducted the Study**

The study was conducted by CANMET Energy Technology Center-Varenes, which is part of Natural Resources Canada. Additional information was obtained from Okanogan PUD of Washington State, U.S.

#### **3.1.3 Why the Study was Performed**

The study was performed as a post-project comparison of RETScreen estimations and actual results from an existing purchase agreement. The RETScreen process was used to compile predictions for a 22-year contract period as if the project were still in the planning phase, although the purchase agreement already in effect and 3 years of data were available for validation against RETScreen estimations. The goal was to compare options for continued purchase of supplemental power from the market to options for the acquisition of additional power purchased from wind generation. Okanogan PUD purchases all of its power, approximately 60% of which is supplied by the Bonneville Power Administration (BPA) and 30% by the Wells Hydroelectric Project. The purpose of the study was to determine if the additional energy procured by wind at the proposed rate would be economically favorable to purchasing power from the market when supplementary amounts are needed. Wind resource availability predictions were compared with actual delivered power over the 3-year time period, and correlations between wind output and drought were investigated. Regional market prices tend to be higher during times of drought, when hydro resources are limited. Wind would most likely add to the available power during these times, making costly market purchases less frequent.

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<sup>8</sup> See [www.retscreen.net/ang/home.php](http://www.retscreen.net/ang/home.php); RETScreen stands for Renewable-energy and Energy efficient Technologies Screening tool, and was developed for Natural Resources Canada.

### 3.2 Intended Outcomes

The RETScreen analysis sought to evaluate the economic effects of integrating wind generation into a hydro-dominated utility that was often required to purchase power from the market to supplement the scheduled resources. Particular attention was paid to wind resource availability during times of drought, when hydro resources are strained and market prices tend to be higher.

Grid integration was addressed from the standpoint of system characteristics, as well as a need to procure transmission contracts ensuring power would be delivered to the utility over a distance of 320 km from the wind site.

Detailed economic analysis was performed that included total intended financing, proposed cost per megawatt-hour to power purchasers, avoided cost of energy due to wind, government Renewable Energy Production Incentives, operations and maintenance estimates, and land leasing costs. Net present value calculations were also made, and the cumulative cash flows for the wind project were estimated for the 22-year contract period. Risk analysis was quantified by a set of parameters with outputs shown in Figure 16.

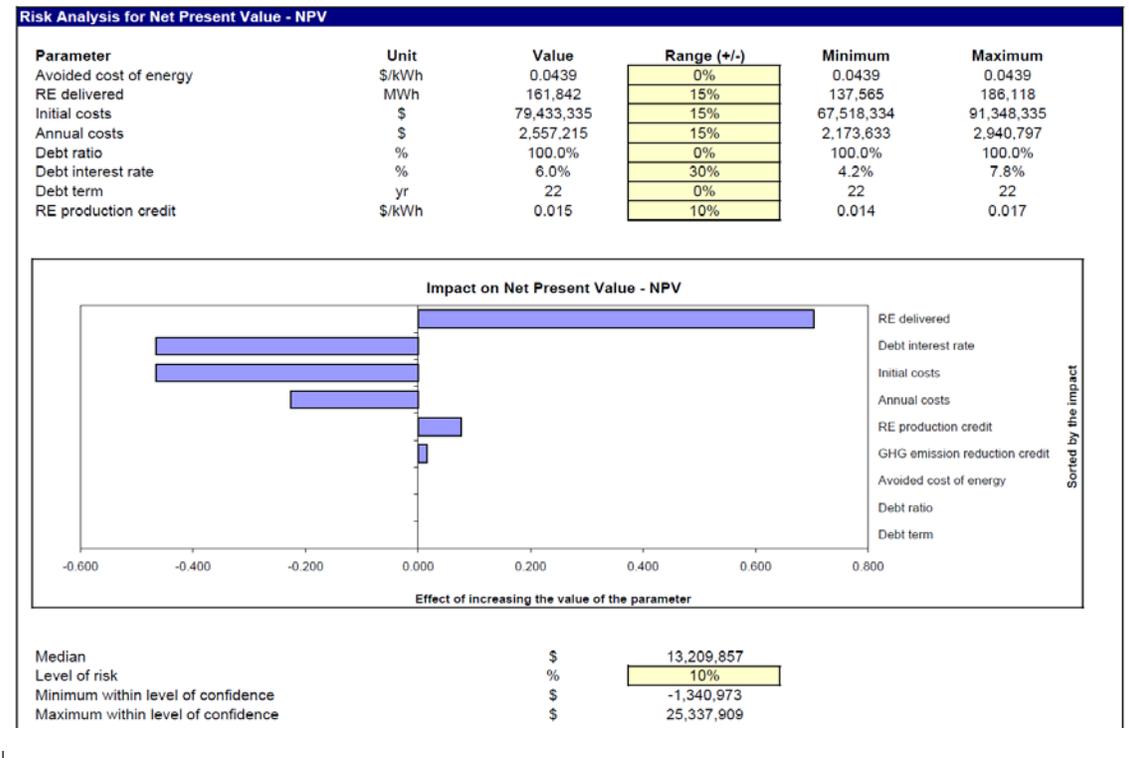


Figure 16. RETScreen outputs for risk analysis and net present value

### 3.3 Overview of Power System

**Table 12. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the NRCCanada case study**

<p><b>Geographic Area of Study:</b> Okanogan County, Washington is the location of the public utility considering the purchase of power from a proposed wind power project. The proposed wind power project is to be located on a high bench overlooking Kennewick, WA, about 340 km east of Portland, Oregon, along the Columbia River Gorge. The bench is roughly perpendicular to the dominant winds, which are channelled through the Columbia River Gorge from the southwest.</p>			 <p>Map source: Wikipedia</p>			
<b>Power System Characteristics:</b>						
Load			Conventional Generation	Interconnection	Wind Power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
145 <sup>9</sup>	40 <sup>10</sup>	0.845	N/A – all power is purchased	75 MW	15.3 MW	0.038 TWh/a
						Estimated CF = 31.4%
<b>Other Relevant Characteristics of Power System:</b>						
<p>The wind power project's underground 34.5-kV power lines and 115-kV substation were constructed by one of the purchasers, Benton County PUD, and interconnects with the BPA 115-kV system. Okanogan PUD's share of the wind project's output is delivered to the network on BPA lines to Douglas PUD's Load Control Area. The Load Control Area operator uses Okanogan's 65-MW part of hydropower capacity at Wells Dam (840 MW) on the Columbia River to smooth wind variability.</p> <p>The system has a dual peak in the winter and summer of approximately 145 MW. Its average load is about 90 MW (based on an assumed 60% system load factor). Its generation resources are almost entirely hydroelectric (86%) with several limiting flow restrictions through dams located on the Mid-Columbia river. (Source: Professional Opinions of Jean-Claude Deslauriers and Jacques Fontaine, energy R&amp;D, and prediction experts)</p> <p>Interconnections to the system are mainly hydro, which is purchased from the BPA sources of which include 30 federal hydro projects, one non-federal nuclear plant, and other non-federal power plants. The Okanogan County PUD receives approximately 60% of its energy supply from BPA.</p> <p>65 MW of hydro is purchased from Wells Hydroelectric Project (840 MW) on the Columbia River operated by Douglas County PUD. Okanogan County PUD receives 30% of its energy from Wells</p>						

<sup>9</sup> Estimate based on non-coincidental maximum demand (160 MW), the sum of power purchases, which is typically 10% higher than the actual peak load (Source: 2005 PUD Annual Report and Professional Opinions of Jean-Claude Deslauriers and Jacques Fontaine, energy R&D, and prediction experts)

<sup>10</sup> Estimate based on assumption of 27% of peak load (Source: Professional Opinions of Jean-Claude Deslauriers and Jacques Fontaine, energy R&D, and prediction experts)

through a long-term power purchasing agreement.	
<u>FUEL breakdown (%) for the year 2005:</u>	
Hydro 86.41%	
Nuclear 6.87%	
Coal 3.56%	
Wind 1.80%	
Other (NG, Biomass, Petroleum) 1.36%	
Total 100.00%	
Wind purchases from Energy Northwest: a membership of 13 public utilities and 3 city municipal utilities, which developed and now own the Nine Canyon Wind Project, a 49-turbines wind farm with a total generating capacity of 63.7 MW. Okanogan PUD has a 24% share of the farm's energy output.	
<b>Characteristics of System Planning:</b>	
Priorities in planning: (1) Fish migration, (2) Flood control (note flood control will take precedence over fish migration when dam structures are threatened), (3) Recreation and lake levels, (4) Navigation, (5) Power production (Source: Grant County PUD case study example as it is also in Washington State and the utility's hydro projects are also on the Columbia river system)	
<b>Description of Market:</b>	
Purchases and sales are made at the Mid-Columbia hub.	
<b>Integration Time Frames of Importance:</b>	
<b>Yes/No</b>	<b>Time Frame</b>
No	Frequency, system dynamics, grid stability, low-voltage ride through, Pumped Storage Station, Voltage Regulation
No	Regulation, Automatic Generation Control
No	Load following; intra-hour ramping; economic dispatch
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources (shorter time frame issues are handled by the Douglas PUD Load Control Area operator)
Yes	Resource and capacity planning; reliability

### 3.3.1 Study Methodology

The study was conducted as a post-project assessment of the RETScreen process. The RETScreen analysis was conducted as if the project was still in development, and results were subsequently compared to the actual performance of the project for the years 2003–2005. Study inputs included wind project site information, applicable system characteristics, wind turbine characteristics, and financing information. Basic parameters of the study analysis are provided in Table 13.

**Table 13. Second half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the NRCanada case study**

<b>Set Up</b>		
<b>A</b>	<b>Aim of Study</b>	<b>1 what happens with x GWh wind</b> 2 how much wind is possible
<b>M</b>	<b>Method to Perform Study</b>	<b>1 add wind energy</b> 2 wind also replaces capacity 3 optimal system design
<b>S</b>	<b>Simulation Model of Operation</b>	<b>1 deterministic simulation, one case</b> 2 deterministic simulation several cases 3 Stochastic simulation several cases
<b>Simulation Detail</b>		
<b>R</b>	<b>Resolution of Time</b>	<b>1 day/week</b> 2 hour 3 minute/second
<b>P</b>	<b>Pricing Method</b>	<b>1 costs of fuels etc</b> 2 prices for trading with neighbours 3 market actor simulation 4 market dynamics included
<b>D</b>	<b>Design of Remaining System</b>	<b>1 constant remaining system</b> 2 optimized remaining production 3 optimized remaining transmission 4 perfect trading rules
<b>Uncertainty and Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	1 only wind 2 wind + load <b>3 wind + load + production</b>
<b>B</b>	<b>Balancing Location</b>	1 dedicated source 2 from the same region <b>3 also outside region – Douglas PUD local control area is a dedicated source. The contract between Okanogan and Douglas likely involves a balancing service.</b>
<b>U</b>	<b>Uncertainty Treatment</b>	1 transmission margins 2 hydro inflow uncertainty 3 no wind forecasts (assume persistence) <b>4 best possible wind forecasts (professional forecast)</b> 5 load forecasts considered 6 thermal power outages considered
<b>Power System Details</b>		
<b>G</b>	<b>Grid limit on Transmission</b>	<b>1 no limits</b> 2 constant MW limits 3 consider voltage 4 N-1 criteria 5 dynamic simulation

<b>H</b>	<b>Hydropower Modeling</b>	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included 4 hydro optimization considered 5 consider most relevant aspects of affected hydro resources <u><b>All of the above – this is done by the Federal Columbia River Power System.</b></u>
<b>HC</b>	<b>Hydro Capacity Service</b>	1 interaction with hydro resources not significant 2 real-time integration with impact of wind variability on system managed with hydro <u><b>3 capacity service: addition of capacity value through redelivery of wind energy at a later time</b></u>
<b>T</b>	<b>Thermal Power Modeling</b>	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered 4 heat production considered <u><b>None of the above – does not apply in this study</b></u>
<b>W</b>	<b>Wind Power Modeling</b>	1 few wind speed time series 2 many wind power time series 3 time series smoothing considered <u><b>None of the above – no time series data was required</b></u>

### 3.3.1.1 Assumptions

The assumptions made for this study were based on information that would have been available to the Okanogan PUD prior to project development. This information included such things as estimated wind energy production, estimated wind power purchase prices including 3% annual increases, estimated market prices, and all project development plus logistical costs.

### 3.3.1.2 Limitations

The comparison aspect of this study was limited by the fact that only 3 years of actual data were available for validation as opposed to the full 22 years projected by the RETScreen analysis. Additional complications were encountered with wind turbine malfunctions that could not be anticipated by the simulation tool.

### 3.3.2 Wind Power Characteristics

The proposal was to purchase a 25% share of power from the 64-MW Nine Canyon Wind Farm located 320 km from the utility. The wind plant is located on an elevated bench along the Columbia River Gorge. The estimated amount of energy that would be delivered by wind was 161,842 MWh/year. Table 14 shows the resource assessment outputs as given by the RETScreen tool.

Table 14. RETScreen outputs for estimated wind power

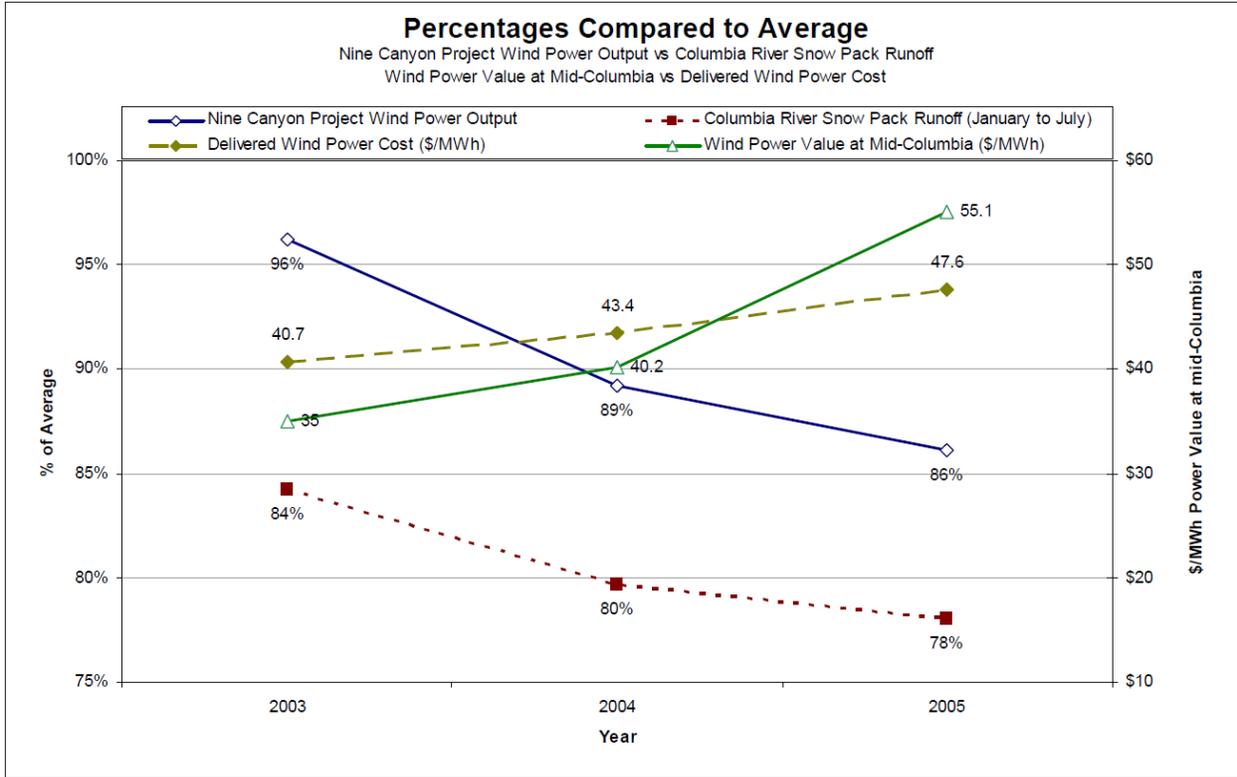
Annual Energy Production		Estimate Per Turbine	Estimate Total	Notes/Range
Wind plant capacity	kW	1,300	63,700	
	MW	1,300	63,700	
Unadjusted energy production	MWh	3,696	181,128	
Pressure adjustment coefficient	-	0.96	0.96	0.59 to 1.02
Temperature adjustment coefficient	-	1.03	1.03	0.98 to 1.15
Gross energy production	MWh	3,655	179,100	
Losses coefficient	-	0.90	0.90	0.75 to 1.00
Specific yield	kWh/m <sup>2</sup>	1,094	1,094	150 to 1,500 kWh/m <sup>2</sup>
Wind plant capacity factor	%	29%	29%	20% to 40%
Renewable energy delivered	MWh	3,303	<b>161,842</b>	
	GJ	11,890	582,630	

[Complete Cost Analysis sheet](#)

### 3.3.3 Hydro System Characteristics

In 2005, 86.4% of the generation mix for the Okanogan County PUD was obtained by hydro purchases from BPA and the Wells Hydroelectric Project on the Columbia River. Hydro planning is prioritized in the order of fish migration, flood control, recreation, navigation, and power production.

Hydro availability is largely contingent on snow pack runoff into the Columbia River from January through July. This study sought to examine the correlation between periods of drought and wind behavior for the region. Positive correlations were found between periods of low snow pack runoff and low wind output for the 3 years of wind data (note a much longer time record would be required to determine if a correlation actually exists between wind production and snow pack runoff), as well as greater wind power cost and higher wind power value as shown by Figure 17.



**Figure 17. Correlation of wind power output and snow pack runoff, along with wind value and cost for the study period of 2003–2005**

**3.3.4 Wind Power Penetration and System Flexibility**

The Okanogan County PUD was interested in acquiring 25% of the power output from the Nine Canyon Wind Farm project. On a capacity basis, this amounts to about 16 MW, or 11.4% of the peak load levels of 140 MW. On an energy basis, this would amount to approximately 7% of the annual energy requirement for the utility, given an estimated capacity factor of 31.4% for the 64 MW project.

Wind variability is smoothed by the Load Control Area operator for Douglas County PUD at the Wells Dam on the Columbia River. This also allows Okanogan PUD’s share of the wind power to be delivered at a later time.

**3.3.5 Wind and Hydro Integration – Benefits and Impacts**

In order to integrate this wind power into the primarily hydro generation mix, the RETScreen report recognized the need for a revised service agreement with the Load Control Area operator for real-time balancing (conducted by Douglas County PUD). Wind energy production variations can be balanced by the flexible ramp characteristics and available storage of the Okanogan PUD’s hydro resources. The study found that the amount of wind being integrated from the Nine Canyon Project would lead to minimal need for additional ancillary services, as fluctuations in wind power production would hardly alter the utility’s existing load swings.

### 3.4 Conclusions

The conclusions of this study offered a comparison of the parameters that were predicted by the RETScreen analysis and those that were encountered in reality. The actual wind power delivered over the 3-year period of 2003–2005 was about 90% of that predicted to be normal by the RETScreen procedure. The net cost of delivered wind energy during this period was \$44.1 CAD/MWh, which exceeded the cost of \$43.9 CAD/MWh that would have been accrued if the energy had been purchased from the market. This negative value was made up for when the utility sold Renewable Energy Credits during 2005 for \$3 CAD/MWh, resulting in a positive net value of \$37,000 CAD for the wind power over the 3-year period. The report also concluded that the wind purchase would not have been economically favorable without the Renewable Energy Production Incentives.

The study highlighted results showing the ease of integrating wind into a hydro-centered Load Control Area, as balancing costs were kept at \$0.9 CAD/MWh instead of the \$4.5 CAD/MWh that would have been required for purchasing balancing services from BPA. It suggested that there would be minimal requirements for additional ancillary services due to wind, as fluctuations were easily smoothed by the Load Control Area operator using hydro flexibility.

During the study years, there was also found to be a positive correlation between periods of drought and low wind for the region. This corresponded to an increase in both the cost and value of available wind power. However, market prices were also found to be higher during these same periods, helping to maintain the economic position of purchasing wind power.

## 4 Finland

### 4.1 Introduction

The IEA Wind Task 24 for Finland includes the following two projects:

1. A case study focusing on the handling of wind power prediction errors for a single hydrothermal power producer in Finland
2. A summary of the impacts of a wind- and hydro-dominated power system on the electricity markets and the characteristics of Nordic hydropower.

In this chapter, several words with specific meanings are used. The word *regulation* is used to mean 10–15-minute balancing. The *balancing market* refers to what is officially called the Regulating Power Market in the Nordic countries. The more neutral word *balancing* is also used.

### 4.2 Case Study for a Single Power Producer

The Technical Research Centre of Finland (VTT) conducted a case study focused on the handling of wind power prediction errors for a single hydrothermal power producer in Finland.

#### 4.2.1 Introduction to Study

The study's description and goals are as follows:

- *Scope of study:* Different options for handling the forecast errors of wind power as well as balancing costs are studied from the producer's point of view.
- *Organizations involved:* VTT conducted the study, with case data from a large hydrothermal producer in Finland.
- *Reason study was performed:* The study was performed to see the possibilities of a hydrothermal power producer with limited regulation possibilities to balance wind power in its portfolio.
- *Published reports applicable to the case study:*
  - Holttinen, H. Koreneff, G. 2007. Imbalance costs of wind power for a hydropower producer in Finland. Proceedings of European Wind Energy Conference EWEC2007. Milan, Italy, 7–10 May, 2007. European Wind Energy Association.
  - Intended outcomes of the report relative to the objectives of Task 24: The study addresses market and economics; it highlights some issues regarding grid integration.

#### 4.2.2 Overview of Power System

This case study is based on one producer using the Nordic electricity market. The producer has 400 MW of run-of-the-river hydropower with very limited storage possibilities. The Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for an integration study is not applicable to this study. Wind power generation is forecast 1 day ahead, and balancing can be left to be done by the system operator at the balancing *market* (which results in paying imbalance prices for forecast errors); or by the *producer* internally by adjusting hydropower production. Part of the forecast errors can be dealt with intra-day trade, which can reduce the imbalance prices paid.

### **4.2.3 Study Methodology**

The case study was based on 1 year of historical data. A simulation model was not used; therefore, a matrix intended to explain simulation assumptions has not been included. A time series of forecast errors for 9 MW of wind in 2004 was up-scaled to 200 MW and 400 MW of wind power (representing 50% and 100% of the producer's installed hydropower capacity, respectively). The first step in the study was pricing imbalances at current Nordic market rules (2004 price data). The second step was using 2004 prices for intra-day market pricing (closing 1 hour before delivery) to calculate how intra-day trading would reduce imbalance costs. The third step was looking at the possibilities of hydropower to handle the imbalances, which was done by looking at the time series of produced hydropower in 2004 and calculating how much of the forecast errors of wind could be corrected by shifting hydropower production some hours. Limits for minimum and maximum hydropower production were kept the same, and the total energy for each day was kept at  $\pm 10\%$  of the original time series.

The study assumed that wind power in Finland (200–400 MW) would not affect the day-ahead, intra-day, and balancing market prices. A limitation of the study is that a simulation was not performed to estimate how much hydropower energy could be shifted from 1 day forward.

### **4.2.4 Wind Power Characteristics**

Data from more than 10 sites along the Finnish west coast were used in the study, at maximum 600 km apart, providing geographical dispersion. A wind forecast time series of 1 day ahead (14–38 hours ahead) was calculated with real wind forecasts for year 2004; errors were calculated based on real, measured wind power production data. An hourly time scale was used, as applied in Nordic electricity markets.

### **4.2.5 Hydro System Characteristics**

The producer studied has a total capacity of 400 MW of run-of-the-river hydropower with limited storage possibilities (used to follow day-night load variations).

### **4.2.6 Wind Power Penetration and System Flexibility**

Wind power penetration in Finland was less than 1% of gross demand (energy) and less than 3% of peak load (capacity). Two wind power scenarios, 200 MW and 400 MW, were studied, which were 50% and 100% of the producer's installed hydropower capacity.

### **4.2.7 Wind and Hydro Integration – Benefits and Impacts**

This section outlines the three steps used for integrating wind power and hydropower.

#### **4.2.7.1 Step One: Balancing Cost from the Day-Ahead Market**

The forecast errors for the 14–38 hours-ahead time series results in a mean absolute error of 8% for the aggregated wind farm data, normalized as a percent of the nominal capacity of wind farms. When calculating energy as a percent of average production, the result is that 31% of the energy generated will result in imbalances for the producer. For the imbalance payments of wind power alone, a fixed volume price is used (€ 0.7/MWh), and regulation price from the market applies for the hours when the net system imbalance has been to the same side as wind power imbalance. For example, if up-regulation has been used from the balancing market and wind power imbalance has been demanding up-regulation, then there is a payment according to the balancing market price. For year 2004 prices, this results in € 0.62/MWh costs for the year's total

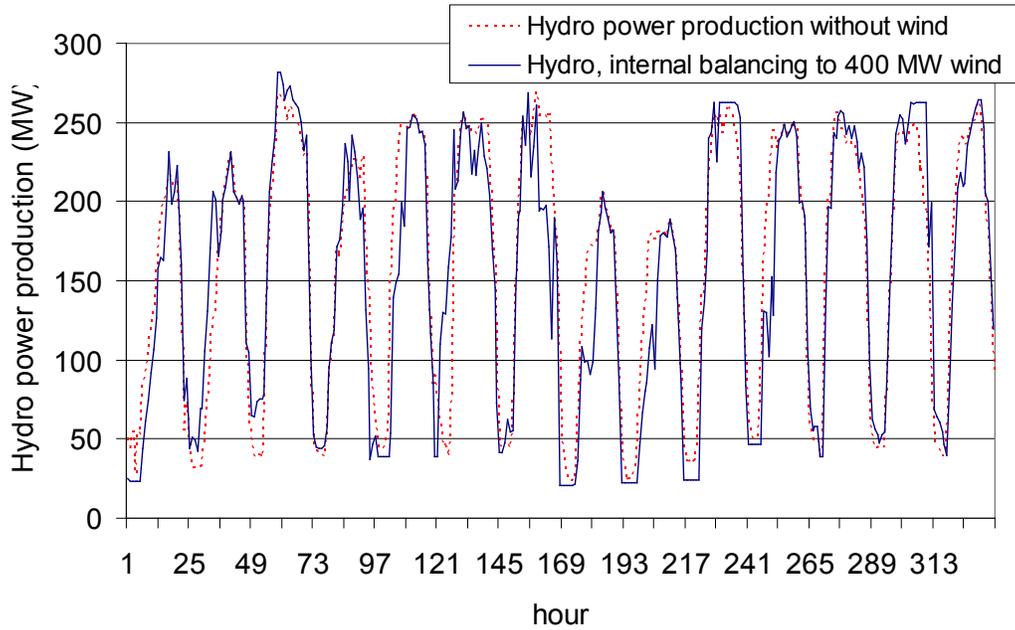
wind power production. The cost of regulation, when there is an extra cost, is on average € 3–4/MWh. However, more than half of the time, the wind power imbalance is opposite to the total system imbalance and only the fixed volume price € 0.7/MWh is paid for the imbalances during those hours.

#### *4.2.7.2 Step Two: Using Intra-Hour Trading (the Elbas Market operating in Nordic countries)*

In this step, a 3-hours-ahead forecast leaves a balancing power requirement of 21% of production, compared to 31% for the 14–38-hour forecast. This results in an imbalance cost reduction of 34%. On the other hand, to manage the balance gap between the spot trades and the 3-hours-ahead forecast requires Elbas market trading, which will bring costs. At the intra-day Elbas market, the trade is continuous, resulting in several prices for each hour. Using average Elbas prices for each hour in 2004 results in overall imbalance cost reductions, but calculating with maximum-minimum prices at Elbas shows that if the Elbas price is significantly deviating from the day-ahead market price, the trading costs can deplete the benefit of reducing balancing costs. This occurs especially at low penetration levels of wind power when at least 50% of the time, wind power will only pay the fixed volume price € 0.7/MWh for the imbalances due to an error being to opposite side than the regulation price.

#### *4.2.7.3 Step Three: Using Internal Balancing by Hydropower*

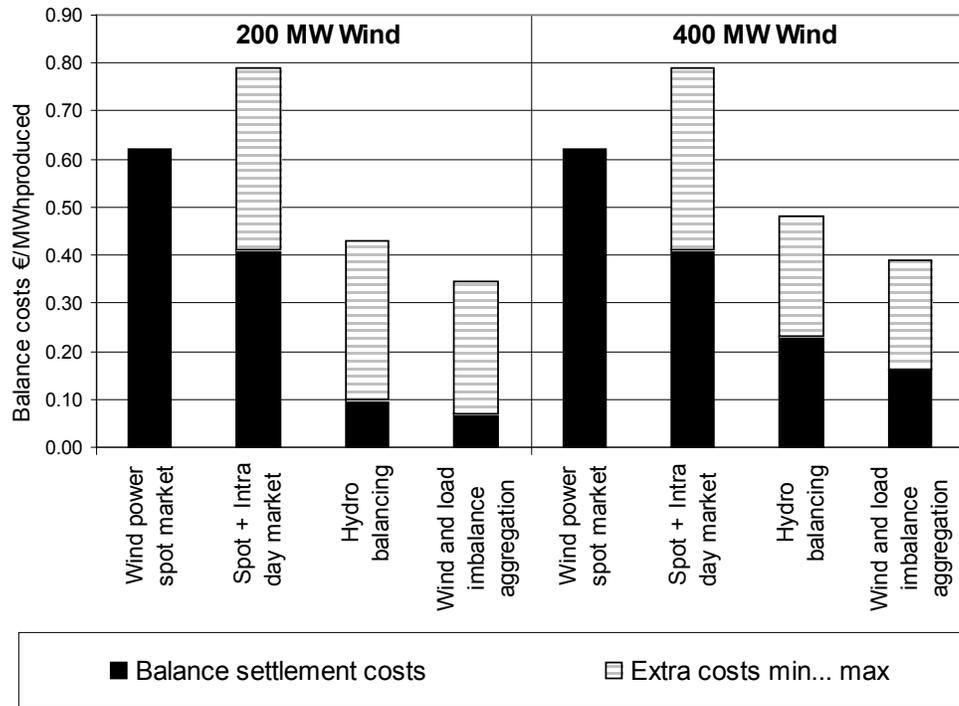
Even if the hydropower is operating with no large reservoirs, it is usually possible to change a part of the production some hours ahead or before the schedule starts. This was analyzed by using an up-scaled time series for wind power (200 MW and 400 MW) together with actual production of hydropower from the year 2004. In the internal balancing model, hourly values of hydropower generation were restricted to operating between the maximum and minimum production that had occurred during the day in question. In addition, the daily production flexibility (daily sum of generation) of hydropower was restricted to  $\pm 10\%$  of original daily energy based on current operational practice. A deviation of 10% from the daily produced energy is assumed to be tolerable and manageable by the hydropower plants (Figure 18). Operating this way, 83% of prediction errors could be corrected by internal balancing for 200 MW of wind power. For 400 MW of wind power, 63% of the imbalances could be balanced internally. The internal balancing of wind production imbalances with hydropower would reduce the balancing costs by 84% for the 200-MW case and 63% for the 400-MW case, assuming the internal balancing were without costs. Depending on the price set for the internal balancing and the wind power capacity, the balancing costs for the wind power producer would be reduced by roughly 20–85%. On the other hand, the same balancing offered to balancing markets would be worth an equivalent of € 1.31–1.32/MWh wind regulation.



**Figure 18. Example of how 400 MW of hydropower production could change when correcting errors on day-ahead forecasts of 400 MW of wind power**

#### 4.2.7.4 Step four: Passive Internal Balancing Aggregating the Imbalances of Wind with other Imbalances of a Large Producer

Aggregating wind power with all other imbalances of a Balance Responsible Player, from consumption and production, would benefit a wind power producer and reduce balancing costs. Even if wind power would get half of the benefit, this would reduce the imbalance costs considerably if there was a possibility to combine the imbalances with load. This is shown as the last option in Figure 19, where the black area shows how much imbalance costs increase as wind imbalances are added up with load imbalances, and the grey area shows how much this would be if wind would get only part of this benefit.



**Figure 19. Costs for balancing day-ahead forecast errors for wind power (cases 200 MW and 400 MW wind power); extra cost range is from using different assumptions for the cost of the balancing option**

#### 4.2.8 Summary of Results

Imbalance costs vary for different cases, as can be seen from Figure 19. The costs for Elbas intra-day market depend on luck at Elbas trade (e.g., average Elbas price, the minimum and maximum Elbas price for each hour). The cost for hydropower options depends on the internal balancing price (€ 0.0–1.3/MWh, internally regulated). The benefit from combining wind and load imbalances depends on how large a share wind gains from the total balancing crossover effect (100–50%).

This study shows that even with limited flexibility of hydropower (run-of-the-river with small reservoirs), a large part of wind power forecast errors can be provided for by shifting hydropower back and forth inside 1 day. This is because the wind power forecast errors are on average 0, so both up- and down-regulation are used and the side of balancing varies from up to down and back frequently.

The study also shows that when correcting the forecast errors of wind power at a large balancing market in which hydropower produces most of the balancing (such as in Nordic countries), there is not a great benefit of combining/integrating wind and hydro at a single producer. It is more cost effective to bid all flexibility of hydro to the balancing market, and use it from there to correct the system imbalances, than to use it for dedicated balancing of wind power.

#### 4.2.9 Conclusions

The imbalance costs from day-ahead forecast errors for aggregated wind power in Finland is roughly € 0.62/MWh, when calculated per megawatt-hour total produced. The cost of regulation, when there is an extra cost, is on average € 3–4/MWh. But, more than half of the time, the wind power imbalance is opposite to the total system imbalance. For those hours, the only cost effect is the fixed volume cost of € 0.7/MWh for the imbalances. These results apply for the Finnish power system in which wind power is not affecting the price level or direction of regulation used in the power system. Also, the balance settlement rules affect the results. Two price models are used in this study, which means that the imbalance pricing is according to regulation market prices when the imbalances are to the same side as regulating market price (e.g. up-regulation price and up-regulation required for wind power) and the spot market price is used for the hours when imbalances are to the opposite side of regulation market price (f.ex. up-regulation price and down-regulation required for wind power). The use of a one-price model where a single price is used for all imbalances, would drop the balancing costs to near 0. This is because wind power gets extra benefit for the imbalances during the hours where it has been opposite the regulating power market (e.g., during an up-regulation hour wind power has required down regulation which means providing up-regulation for the system).

Compared with leaving all day-ahead forecast errors to balance settlement, intra-day trading is only cost effective when trading close to spot price levels. Actively trading to reduce the forecast errors of wind means making trade almost all the time. Leaving the forecast errors to imbalance settlement means that more than half of the time there is no penalty (at low penetration of wind). Approximately 60% of the time, there is only a € 0.7/MWh volume fee for the imbalances so usually the intra-day trade is not cost effective.

Additionally, 400 MW of hydropower could provide internal balancing to correct 83% of prediction errors for 200 MW of wind power. For 400 MW of wind power, 63% of the imbalances could be balanced internally. Using hydropower to balance wind power imbalances is profitable for both parties. Depending on the price set for the internal balancing and the wind power capacity, the balancing costs for the wind power producer would be reduced by roughly 20–85%.

This study shows that even with the limited flexibility of hydropower (run-of-the-river with small reservoirs), a large part of wind power forecast errors can be provided for by shifting hydropower back and forth inside 1 day. This is because the wind power forecast errors average 0, so both up- and down-regulation are used and the side of balancing varies from up to down and back frequently.

This study also shows that when correcting the forecast errors of wind power at a large balancing market in which hydropower produces most of the balancing (like in Nordic countries), there is not a great benefit of combining/integrating wind power and hydropower at a single producer. It is more cost effective to bid all flexibility of hydropower to the balancing market and use it from there to correct the system imbalances than to use it for dedicated balancing of wind power.

### 4.3 Market Impacts for Nordic Countries

This section discusses the impacts of a wind- and hydro-dominated power system on the electricity markets and the characteristics of Nordic hydropower.

#### 4.3.1 Introduction to Study

This study is part of a doctoral thesis that examines different ways to increase power system flexibility to decrease wind integration costs. Reservoir hydropower, where available, is often the cheapest method to increase system flexibility. The study also assesses the flexibility of reservoir hydropower in the Nordic system and tries to increase the accuracy and resolution of the hydropower description in the power system model.

The study was conducted with the WILMAR model, which was created with European Union co-operation from Denmark, Finland, Germany, Norway, and Sweden. Juha Kiviluoma at VTT ran the model and made improvements considering reservoir hydropower. The model runs considered the Nordic power system in the year 2010 with different assumptions about wind power penetration.

This section is based on the following published reports:

- Kiviluoma, Juha and Hannele Holttinen, “Impacts of Wind Power on Energy Balance of a Hydro Dominated Power System,” European Wind Energy Conference, 27th February through 2nd March 2006, Athens, Greece.
- Kiviluoma, Juha; Peter Meibom and Hannele Holttinen, “Modelling of hydro and wind power in the regulation market,” Proceedings of Nordic Wind Power Conference, 22–23 May 2006, Espoo, Finland.

In reference to the intended outcomes of the report relative to the objectives of Task 24, the market model WILMAR was used to model the behavior of the Nordic system with different wind power penetrations. The study analyzed the adequacy of hydropower to smooth the variability of wind power, what happens to spot prices when the system is dominated by hydro and wind power, and the use of transmission lines and conventional power plants due to increased wind power production. This work was part of Task 24 efforts on grid integration as well as markets and economics. The latter part of the research includes a separate river system model, including almost all hydropower plants and reservoirs in the Nordic countries. The most important limitations arising from chains of stations and reservoirs were taken into account. This river system model can be used to check the accuracy of dispatch from a more coarse market model, which has aggregated the hydropower plants into larger groups. The database for the hydropower plants and reservoirs also enabled a more accurate and detailed aggregation of hydropower in the market model. This work belongs to the grid integration part of Task 24 and could be extended to hydrological impacts in the future.

### 4.3.2 Overview of Power System

**Table 15. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for an integration study**

<b>Geographic Area of Study:</b> Nordic countries (Denmark, Finland, Norway, and Sweden)						
<b>Power System Characteristics:</b> The study was made for an estimated system at year 2010 with good interconnections and 47 GW of hydropower; nuclear and CHP production was important.						
Load (2010 estimated)			Conventional Generation	Interconnection	Wind Power (base case)	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
74,000	31,000	420	93,000	2,360	6,600	16
<b>Other Relevant Characteristics of Power System:</b> n/a						
<b>Characteristics of System Planning:</b> n/a						
<b>Description of Market:</b> Day-ahead, intra-day, and regulation markets						
<b>Integration Time Frames of Importance:</b>						
Yes/No	Time Frame					
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg					
Yes	Regulation					
Yes	Load following; economic dispatch					
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources					
Yes	Resource and capacity planning; reliability					

The Nordic system gets 60% of electricity from hydropower, of which most have large reservoirs. The study analyzed wind power penetrations of 10%, 20%, and 30% in terms of annual energy demand. Analysis tried to examine whether or not there is enough load following capability available from the hydropower to deal with wind power variation. Since a significant amount of wind power was added and only little conventional capacity was retired, system resource adequacy was not an issue. Study also examined the effect of a large amount of low marginal price production on market prices. In the second study, participation of hydropower plants in the balancing market was also under assessment.

### 4.3.3 Study Methodology

**Table 16. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in wind integration studies**

Set Up		
<b>A</b>	<b>Aim of Study</b>	1 what happens with x GWh wind
<b>M</b>	<b>Method to Perform Study</b>	1 add wind energy
<b>S</b>	<b>Simulation Model of Operation</b>	3 Stochastic simulation several cases
Simulation Detail		
<b>R</b>	<b>Resolution of Time</b>	2 hour

<b>P</b>	<b>Pricing Method</b>	1 costs of fuels etc
<b>D</b>	<b>Design of Remaining System</b>	2 optimized remaining production 3 optimized remaining transmission 4 perfect trading rules
<b>Uncertainty and Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	Not applicable in this study since forecasts are perfect and only load following capabilities are being investigated.
<b>B</b>	<b>Balancing Location</b>	3 also outside region
<b>U</b>	<b>Uncertainty Treatment</b>	2 hydro inflow uncertainty
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	2 constant MW limits
<b>H</b>	<b>Hydropower Modeling</b>	2 hydrological coupling included (including reservoir capacity) 3 <b>some</b> hydrological restrictions included 5 consider most relevant aspects of affected hydro resources
<b>HC</b>	<b>Hydro Capacity Service</b>	2 real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	2 start/stop costs considered 3 efficiency variation considered <b>partially</b> 4 heat production considered
<b>W</b>	<b>Wind Power Modeling</b>	2 many wind power time series 3 time series smoothing considered

#### 4.3.3.1 Assumptions

The price of fuel and power plant variable costs determine the merit order and scheduling/dispatch. Wind power was perfectly forecasted in these model runs since the purpose was to check the energy balance in the system.

#### 4.3.3.2 Limitations

Hydropower modeling was aggregated in the simulation study because there are more than 2,000 hydropower plants and more than 1,000 reservoirs in the Nordic system.

#### 4.3.4 Wind Power Characteristics

Wind power penetration was set to 10%, 20%, and 30% in terms of annual energy demand in different cases for each country: Finland, Norway, and Sweden. The penetration in Denmark was kept at 4,600 MW. The time series for wind power is based on data from existing wind power plants as well as wind speed measurements, which have been smoothed and up-scaled to represent production from a larger amount of turbines in the future.

#### 4.3.5 Hydro System Characteristics

There are numerous large hydropower reservoirs in the Nordic region, especially in Norway and Sweden. There are some run-of-the-river power and river reservoirs with low time constants, especially in Finland.

### 4.3.6 Wind Power Penetration and System Flexibility

Wind power penetrations were 10%, 20%, and 30% in terms of annual energy demand. Most of the system is very flexible due to large amount of reservoir hydropower. Inflexibilities arise from transmission limits, nuclear units, and those combined heat and power (CHP) units that operate based on the heat load.

### 4.3.7 Wind and Hydro Integration – Benefits and Impacts

In relation to grid integration, reserves were adequate to enable a system with little else than wind power and hydropower. However, old units were not retired when wind power was added. WILMAR makes a reservation for spinning and non-spinning reserves. The latter is influenced by the wind power output. The model does not provide data for actual intra-hour changes, but because the reserves were adequate and hydropower is rather flexible, it is expected that there would be no trouble to meet the additional intra-hour changes due to wind. At all times capacity was adequate, but old units were not retired in the study.

System-level change in the operation of the reservoirs was apparent in the results. Wind power production during the winter helped keep the reservoir levels higher, and a spring-summer-fall with higher than usual rains forced some water spillage. It becomes more difficult to keep water levels at optimum when there is an additional stochastic variation in the form of wind power.

Work was begun to better understand the restrictions arising from river systems, and while the data were improved, further work is still required. The Nordic hydropower plants were aggregated based on the river systems and the restrictions arising from reservoirs being far from the downstream stations. The results, while inconclusive, indicate that the flexibility of most plants is excellent as shown in Table 17.

**Table 17. Top: Yearly mean production (GWh) from hydropower in Norway (NO) and Sweden (SE) divided into three groups that have clearly different operation principles; Bottom: Characteristics of hydropower plants in the third group, which have reservoir capacity upstream**

Group	NO south	NO middle	NO north	SE south	SE middle	SE north
Pure Run-of-River (RoR)	1 130	1 070	501	150	412	70
Base load (>8000 hours)	2 840	464	492	-	2 810	7 780
Fully reservoir and partly RoR	79 800	21 600	9 330	746	13 100	47 600

	NO south	NO middle	NO north	SE south	SE middle	SE north
Power (MW)	19 969	4 790	2 140	183	2 873	11 329
Reservoirs (GWh)	53 000	16 400	7 730	7	3 520	24 200
Yearly mean production (GWh)	79 800	21 600	9 330	746	13 100	47 600
Share of RoR production (%)	10.3%	5.9%	9.1%	0.2%	3.5%	1.0%
Average time from reservoir to station	2.0	0.1	0.0	0.6	4.6	1.8
Average full load hours in full reservoirs	2 600	3 900	3 400	42	1 300	2 300

The most difficult situations for the system took place during the high-wind power production periods because some conventional units were unable to decrease their production further. This resulted in water spillage or wind shedding. This is likely to be a somewhat artificial situation since the flexibility of the CHP plants was neither fully included in the model, nor could the flexibility be increased with electric resistance coils or steam bleed points.

The second study analyzed hydropower in the balancing markets. Hydropower can be very practical in balancing the market because adjustments to the production can be made remotely and at short notice. The cost of balancing service for reservoir hydropower is dependent on the water value of the reservoir. This creates a cost curve for balancing services sourced from hydropower and is dependant on the size and number of different reservoirs and their filling status. It is further affected by the participation of different hydropower plants in the balancing market and the restrictions arising from river systems.

In a system with large hydropower penetration, it becomes difficult to build a significant amount of wind power based solely on market economics. As wind power pushes marginal production out of the system, there will be a larger amount of hours when the marginal price is very low or zero. The formation of water values for reservoir hydropower will be based on more speculation and, as a result, price volatility will increase.

It appears that only a quarter of the Nordic hydropower plants are participating in the balancing market. This could be due to the low prices and would correct itself if a larger share of wind power would raise the balancing prices. However, the reasons for the low participation should be investigated, and this could yield some insight on how to organize the markets more effectively.

#### **4.3.8 Conclusions**

A large penetration of wind power in a hydro-dominated power system will lower the spot price of electricity dramatically, which creates a challenge to get new investments in the system. It is unclear whether this kind of system could arise based on the markets even if it would be the most cost-effective way to serve load from a system perspective. It appears that the load following capability of hydropower in the Nordic countries is large enough to support at least 30% wind energy penetration.

Because the Nordic system has thousands of hydropower plants and more than a thousand reservoirs, they have to be aggregated for a market model in order to keep the model solvable. The study aggregated hydropower based on a database of river systems and on analyses of the restrictions that river systems and reservoir sizes place on the use of hydropower. Results show that a large part of hydropower capacity should be capable of flexible operation.

Relative to these conclusions, the expected results of Wind Task 24 for this study are as follows:

- The study identified a practical system configuration of 60% of electricity from hydropower, most of which being reservoir hydropower, and 30% of electricity from wind power. Because old power plants were not retired, there were no problems with system resource adequacy.
- A large penetration of wind power in a hydro-dominated power system will lower the spot price of electricity dramatically, which creates a challenge to get new investments in the system. It is unclear whether this kind of system could arise based on the markets even if it would be the most cost-effective way to serve load from a system perspective.

#### **4.4 Market Impacts for Nordic Countries**

This section discusses the impacts of a wind- and hydro-dominated power systems on the electricity markets and the characteristics of Nordic hydropower.

#### **4.4.1 Introduction to Study**

This study is part of a doctoral thesis that examines different ways to increase power system flexibility to decrease wind integration costs. Reservoir hydropower, where available, is often the cheapest method to increase system flexibility. The study also assesses the flexibility of reservoir hydropower in the Nordic system and tries to increase the accuracy and resolution of the hydropower description in the power system model.

For this study, the model WILMAR was created with European Union co-operation from Denmark, Finland, Germany, Norway, and Sweden. The model runs and model improvements considering reservoir hydropower were made at VTT by Juha Kiviluoma.

This study was performed because reservoir hydropower is one of the most economic ways to increase system flexibility and is of vital importance in the Nordic system.

This section is based on the following published reports:

- Kiviluoma, Juha; Peter Meibom and Hannele Holttinen, “Modelling of hydro and wind power in the regulation market,” Proceedings of Nordic Wind Power Conference, 22–23 May 2006, Espoo, Finland.
- Kiviluoma, Juha and Hannele Holttinen, “Impacts of Wind Power on Energy Balance of a Hydro Dominated Power System,” European Wind Energy Conference, 27th February through 2nd March 2006, Athens, Greece.

In reference to the intended outcomes of the report relative to the objectives of Task 24, the market model WILMAR was used to model the behaviour of the Nordic system with different wind power penetrations. The study analyzed the adequacy of hydropower to smooth the variability of wind power, the effects of combined very large penetration of wind power and hydropower on spot prices, and the use of transmission lines and conventional power plants due to increased wind power production. This work was part of Task 24 efforts on grid integration as well as markets and economics. Later research includes a separate river system model, including almost all hydropower plants and reservoirs in the Nordic countries. The most important limitations arising from chains of stations and reservoirs were taken into account. This river system model can be used to check the accuracy of dispatch from a more coarse market model, which has aggregated the hydropower plants into larger groups. The database for the hydropower plants and reservoirs also enabled a more accurate and detailed aggregation of hydropower in the market model. This work belongs to the grid integration part of Task 24 and could be extended to hydrological impacts in the future.

#### 4.4.2 Overview of Power System

**Table 18. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the second VTT (Finland) integration study**

<b>Geographic Area of Study:</b> Nordic countries (Denmark, Finland, Norway, and Sweden)						
<b>Power System Characteristics:</b> The study was made for an estimated system at year 2010 with good interconnections and lots of hydropower; nuclear and CHP production was important.						
Load (2010 estimated)			Conventional Generation	Interconnection	Wind Power (base case)	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
74,000		420	93,000	2,360	6,600	16
<b>Other Relevant Characteristics of Power System:</b> n/a						
<b>Characteristics of System Planning:</b> n/a						
<b>Description of Market:</b> Day-ahead, intra-day, and regulation markets						
<b>Integration Time Frames of Importance:</b>						
Yes/No	Time Frame					
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg					
Yes	Regulation, AGC					
Yes	Load following; <del>intra-hour ramping</del> ; economic dispatch					
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources					
Yes	Resource and capacity planning; reliability					

The Nordic system gets 60% of electricity from hydropower, most of which has large reservoirs. The study analyzed wind power energy penetrations of 10%, 20%, and 30% (based upon annual energy required to serve load). Analysts tried to identify whether or not there is enough regulation available from the hydropower to deal with wind power variation and forecast errors. The model had stochastic wind power presentation. Since a significant amount of wind power was added and only little conventional capacity was retired, system resource adequacy was not an issue. Study analysts also examined the effect of a large amount of low marginal price production on market prices. In the second study, participation of hydropower plants in the regulation market was also under assessment.

#### 4.4.3 Study Methodology

**Table 19. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the second VTT (Finland) case study**

Set Up		
<b>A</b>	<b>Aim of Study</b>	1 what happens with a certain number of GWh of wind
<b>M</b>	<b>Method to Perform Study</b>	1 add wind energy
<b>S</b>	<b>Simulation Model of Operation</b>	3 Stochastic simulation several cases
Simulation Detail		
<b>R</b>	<b>Resolution of Time</b>	2 hour

<b>P</b>	<b>Pricing Method</b>	1 costs of fuels etc
<b>D</b>	<b>Design of Remaining System</b>	2 optimized remaining production 3 optimized remaining transmission 4 perfect trading rules
<b>Uncertainty and Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	Not applicable in this study since forecasts are perfect and only load following capabilities are being investigated.
<b>B</b>	<b>Balancing Location</b>	3 also outside region
<b>U</b>	<b>Uncertainty Treatment</b>	2 hydro inflow uncertainty
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	2 constant MW limits
<b>H</b>	<b>Hydropower Modeling</b>	2 hydrological coupling included (including reservoir capacity) 3 <b>some</b> hydrological restrictions included 5 consider most relevant aspects of affected hydro resources
<b>HC</b>	<b>Hydro Capacity Service</b>	2 real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	2 start/stop costs considered 3 efficiency variation considered <b>partially</b> 4 heat production considered
<b>W</b>	<b>Wind Power Modeling</b>	2 many wind power time series 3 time series smoothing considered

#### 4.4.3.1 Assumptions

The price of fuel and power plant variable costs determines the merit order and scheduling/dispatch. Wind power is deterministic in these model runs since the purpose was to check the energy balance in the system.

#### 4.4.3.2 Limitations

Hydropower modeling was aggregated in the simulation study because there are more than 2,000 hydropower plants and more than 1,000 reservoirs in the Nordic system.

#### 4.4.4 Wind Power Characteristics

Wind power energy penetration was set to 10%, 20%, and 30% in different cases for each country: Finland, Norway, and Sweden. The penetration in Denmark was kept at 4,600 MW. The time series for wind power is based on data from existing wind power plants as well as wind speed measurements, which have been smoothed and up-scaled to represent production from a larger amount of turbines in the future.

#### 4.4.5 Hydro System Characteristics

There are numerous large hydropower reservoirs in the Nordic region, especially in Norway and Sweden. There are some run-of-the-river power and river reservoirs with low time constants, especially in Finland.

#### 4.4.6 Wind Power Penetration and System Flexibility

Wind energy penetrations were 10%, 20%, and 30%, based upon annual energy required to serve load. Most of the system is very flexible due to large amount of reservoir hydropower.

Inflexibilities arise from transmission limits, nuclear units, and those CHP units that operate based on the heat load.

#### 4.4.7 Wind and Hydro Integration – Benefits and Impacts

In relation to grid integration, reserves were adequate to enable a system with little else than wind power and hydropower. However, old units were not retired when wind power was added. WILMAR makes a reservation for spinning and non-spinning reserves. The latter is influenced by the wind forecast. The model does not provide data for actual intra-hour changes, but because the reserves were adequate and hydropower is rather flexible, it is expected that there would be no trouble to meet the additional intra-hour changes due to wind. WILMAR schedules day-ahead and then reschedules every 3 hours according to new wind forecasts. At all times capacity was adequate, but old units were not retired in the study.

System-level change in the operation of the reservoirs was apparent in the results. Wind power production during the winter helped keep the reservoir levels higher, and a spring-summer-fall with higher than usual rains forced some water spillage. It becomes more difficult to keep water levels at optimum when there is an additional stochastic variation in the form of wind power.

Work was begun to better understand the restrictions arising from river systems, and while the data were improved, further work is still required. The Nordic hydropower plants were aggregated based on the river systems and the restrictions arising from reservoirs being far from the downstream stations. The results, while inconclusive, indicate that the flexibility of most plants is excellent as shown in Table 20.

**Table 20. Top: Yearly mean production (GWh) from hydropower in Norway (NO) and Sweden (SE) divided into three groups that have clearly different operation principles; Bottom: Characteristics of hydropower plants in the third group, which have reservoir capacity upstream**

Group	NO south	NO middle	NO north	SE south	SE middle	SE north
Pure Run-of-River	1 130	1 070	501	150	412	70
Base load (~>8000 hours)	2 840	464	492	-	2 810	7 780
Fully reservoir and partly RoR	79 800	21 600	9 330	746	13 100	47 600

	NO south	NO middle	NO north	SE south	SE middle	SE north
Power [MW]	19 969	4 790	2 140	183	2 873	11 329
Reservoirs [GWh]	53 000	16 400	7 730	7	3 520	24 200
Yearly mean production [GWh]	79 800	21 600	9 330	746	13 100	47 600
Share of RoR production [%]	10,3 %	5,9 %	9,1 %	0,2 %	3,5 %	1,0 %
Average time from reservoir to station	2,0	0,1	0,0	0,6	4,6	1,8
Average full load hours in full reservoirs	2 600	3 900	3 400	42	1 300	2 300

The most difficult situations for the system happened during the high-wind power production periods because some conventional units were unable to decrease their production further. This resulted in water spillage or wind shedding. This is likely to be a somewhat artificial situation since the flexibility of the CHP plants was neither fully included in the model nor could the flexibility be increased in the future rather cheaply with electric resistance coils or steam bleed points.

Hydropower can be very practical in regulating the market because adjustments to the production can be made remotely and at short notice. The cost of regulating service for reservoir hydropower is dependent on the water value of the reservoir. This creates a cost curve for regulation services sourced from hydropower and is dependent on the size and number of different reservoirs and their filling status. It is further affected by the participation of different hydropower plants in the regulation market and the restrictions arising from river systems.

In a system with large hydropower penetration, it becomes difficult to build a significant amount of wind power based solely on market economics. As wind power pushes marginal production out of the system, there will be a larger amount of hours when the marginal price is very low or zero. The formation of water values for reservoir hydropower will be based on more speculation and, as a result, price volatility will increase.

It appears that only a quarter of the Nordic hydropower plants are participating in the regulation market. This could be due to the low prices and would correct itself if a larger share of wind power would raise the regulation prices. However, the reasons for the low participation should be investigated, and this could yield some insight on how to organize the markets more effectively.

#### **4.4.8 Conclusions**

A large penetration of wind power in a hydro-dominated power system will dramatically lower the spot price of electricity, which creates a challenge to get new investments in the system. It is unclear whether this kind of system could arise based on the markets even if it would be the most cost-effective way to serve load from a system perspective. A price drop caused by increase in wind production in the Nordic countries can be mitigated with new transmission capacity to the continental grid or with additional consumption possibly in the form of heat pumps, electric vehicles or hydrogen production. Also the functioning of the market mechanism can be questioned, when most of the power comes from sources with low marginal costs. It appears that the regulation capacity of hydropower in the Nordic countries is large enough to support at least 30% wind energy penetration.

Because the Nordic system has thousands of hydropower plants and more than a thousand reservoirs, they have to be aggregated for a market model in order to keep the model solvable. The study aggregated hydropower based on a database of river systems and on analyses of the restrictions that river systems and reservoir sizes place on the use of hydropower. Results show that a large part of hydropower capacity should be capable of flexible operation.

Relative to these conclusions, the expected results of Wind Task 24 for this study are as follows:

- The study identified a practical system configuration of 60% of electricity from hydropower, most of which being reservoir hydropower, and 30% of electricity from wind power. Because old power plants were not retired, there were no problems with system adequacy.
- A large penetration of wind power in a hydro-dominated power system will lower the spot price of electricity dramatically, which creates a challenge to get new investments in the system. It is unclear whether this kind of system could arise based on the markets even if it would be the most cost-effective way to serve load from a system perspective.

## 5 Norway

### 5.1 Introduction

Because the wind resource in Norway is well correlated with the load, and due to the large amount of hydropower generation that is present, the Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology (SINTEF) has investigated the ability to integrate wind and hydropower. For the purpose of the Task 24 research, two case studies were contributed:

1. The first study looked at wind power in areas with limited power transfer capacity and subject to grid congestion. The question to be addressed here was to see how much wind power could be integrated without deleteriously affecting the hydropower production.
2. The second case study considers the impact of wind power on system resource adequacy. Considering that the region has favourable wind resources, the study was conducted to determine whether or not adding wind power to the hydro-based system will be sufficient or if additional measures must be taken to secure system adequacy.

Each of these case studies will be described in the sections to follow.

### 5.2 SINTEF 1: Areas with Limited Power Transfer Capacity

#### 5.2.1 Introduction to Study

When planning wind power in areas with limited power transfer capacity, conservative assumptions may lead to unnecessarily strict limitations on the possible wind installation. By introducing Automatic Generation Control (AGC) and coordinated power system operation, a large increase in installed wind power is viable.

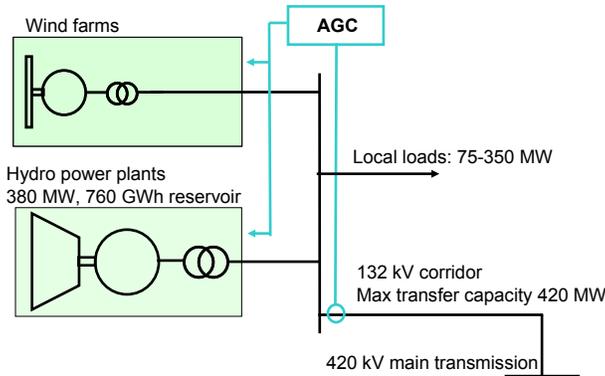
The purpose of this study was to assess grid integration of large wind farms subject to grid congestions. Emphasis was put on how different control strategies for handling congestion situations affect the operation and economics of the studied regional power system. When assessing the impact of wind power on the power system operation, it is necessary to take into account the stochastic and dispersed nature of wind power. This study and previous studies have shown that in the Nordic region, the periods with highest wind generation typically appear in the winter season when the consumption also is high, which has a positive impact on utilization of the existing transmission capacity. Moreover, this study shows that the power smoothing effect of geographically dispersed wind farms gives a significant reduction of discarded wind energy in constrained networks, compared to a single up-scaled wind farm site.

The specific case study presented consists of a regional power system with assumed 420-MW power transfer capacity. With an existing hydropower installation of 380 MW, and 75 MW minimum local, the most conservative approach limits the total wind power installation to 115 MW. By using the developed methodology, the wind power capacity can be increased from 115 MW to at least 600 MW without any noticeable income reduction from energy sales (compared to a case with unlimited grid capacity). The case study was presented at the European Wind Energy Conference 2006 (Korpås et al. 2006).

**5.2.2 Overview of Power System**

**Table 21. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the first SINTEF (Norway) integration study**

<b>Geographic area of study:</b> A generalized regional power system partly based on the characteristics of Northern part of Norway.						
<b>Power system characteristics:</b>						
Load			Conventional Generation	Interconnection	Wind Power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
350	75	1.5	Hydro: 380	420	0–1,000	0–3.5
<b>Other relevant characteristics of power system:</b> 100% hydropower, limited export/import capacity, very good wind conditions, very low population density.						
<b>Characteristics of system planning:</b> Transmission capacity planning is done by transmission system operators in the Nordic power system. Energy companies invest in power plants.						
<b>Description of market:</b> Most of the power in Norway is traded at NordPool. NordPool has a spot market and a financial market. The total production in the Nordic area (Norway, Sweden, Denmark, Finland) was 395 TWh while the volume traded at the Elspot market was 176 TWh in 2005.						
<b>Integration time frames of importance:</b>						
Yes/No	Time Frame					
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg					
Yes (hourly)	Regulation, AGC					
No	Load following; intra-hour ramping; economic dispatch					
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources					
No	Resource and capacity planning; reliability					



**Figure 20. Overview of the case study power system in which AGC is regarded for keeping the power transmission below the maximum export capacity of 420 MW**

The studied system shown in the Figure 20 is a large, 132-kV regional power system connected to the 420-kV main grid by several 132-kV lines with an assumed total export capacity of 420 MW. For simplicity, the grid capacity is represented as a constant value for transmission of active power, although the actual capacity depends on several other factors such as reactive power transfer, voltage stability margins, and steady-state voltage limits. Several hydropower

plants, with a total generation capacity of 380 MW, are connected to the regional grid. The hydropower plants are represented as an aggregated power plant with 760 GWh of reservoir capacity. The water inflow to the hydropower plant is divided into storable (1325 GWh/year) and non-storable inflow (790 GWh/year). The non-storable inflow is used directly for run-of-the-river power generation.

As shown in Figure 20, AGC is regarded for keeping the power transmission below the maximum export capacity of 420 MW. It is assumed that AGC is applied to following two different control strategies:

- Using *control wind*: The power output of the wind farms is constrained, if required. The hydropower plant is operated according to a generation schedule that is unaffected by the wind power output.
- Using *control hydro*: The output of the hydropower plant is decreased as much as possible to prevent overloading of the grid. If this is not sufficient, the wind power output is constrained as for control wind.

The hydropower is increased above the generation schedule at a later stage to keep the annual hydro generation as close to the schedule as possible.

Since part of the hydropower is generated from a non-storable inflow of water, it is seldom possible to reduce the power output to zero.

### **5.2.3 Study Methodology**

A simulation model of the regional power system has been implemented in MATLAB. To run the simulations of the regional power system, a 30-year time series with hourly resolution has been constructed for the following time-varying parameters:

- Normalized wind power output (non-congested) from three wind farms
- Electricity consumption
- Storable inflow
- Non-storable inflow
- Scheduled hydro generation
- Electricity market price

In constructing a wind power time series for each wind farm site, a common 30-year wind speed series with weekly resolution has been combined with the 1-year wind speed series with hourly resolution. The weekly wind speed series is scaled to give a 30-year average of 10.5 m/s. The 1-year time series is normalized and multiplied by the weekly wind speed averages to give an 8760-hour by 30-year matrix of wind speed, which is converted to power by using a typical wind turbine power curve. The total hourly wind generation is simply calculated as the sum of power generation from the three wind farms.

The other time series listed above have been constructed by using the Multi-Area Power Market Simulator (EMPS) model (see [www.sintef.no/Home/SINTEF-Energy-](http://www.sintef.no/Home/SINTEF-Energy-)

Research/Expertise/Hydro-thermal-operation-and-expansion-planning/EMPS/), a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting. This is a complex, stochastic optimization model that simulates the optimal operation of hydropower resources in a region with a stochastic representation of inflow to the hydropower stations and a number of physical constraints taken into account. The electricity consumption has been modeled as temperature-dependent, causing some yearly variations. Long-term increase in consumption has not been considered. An EMPS simulation of the Nordic power system has been run without wind power in the area of interest to provide a basis for the hydropower scheduling as well as the electricity market price.

It is possible to use EMPS to simulate the Nordic power system with geographically dispersed wind power, especially to assess the value of wind power in the electricity market and to determine the effects of large-scale wind power integration on optimum long-term hydro scheduling. In this case, on the other hand, EMPS is less suitable mainly due to the low time resolution of the EMPS model (1 week) and the limited flexibility of defining control strategies for wind-hydro coordination in an area with considerable transmission constraints.

Since the time resolution of the output from EMPS is 1 week, the hour-to-hour variations of consumption, inflow, hydro generation, and price have to be synthetically generated. The hourly values of the consumption and hydro generation have been constructed as products of the weekly average values and typical diurnal variations observed in the Nordic power system. The hourly values of the other parameters (storable inflow, non-storable inflow, and price) are simply constructed by interpolating the weekly values.

**Table 22. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the first SINTEF (Norway) wind integration studies**

Set Up		
<b>A</b>	<b>Aim of Study</b>	<p><i>2 – How much wind is possible to integrate in a power system with limited transfer capacity (also analyzing the benefit of wind-hydro coordination)</i></p> <p>At many locations with excellent wind conditions, grid issues hinder wind farm development. Conservative assumptions are often applied that unnecessarily limit the wind power installation. This work shows that significantly more wind power can be allowed by taking proper account for the wind power characteristics and facilitating coordinated power system operation. The purpose is to assess grid integration of large wind farms subject to grid congestions. Emphasis is put on how different control strategies for handling congestion situations affect the operation and economics of the studied regional power system.</p>
<b>M</b>	<b>Method to Perform Study</b>	<p><i>1 – Add wind energy</i></p> <p>In the case study, two separated simulations are performed. First, the EMPS-model is run for the whole Nordic system to obtain the weekly planned hydropower production and weekly market prices. Then, the regional system is simulated from hour-to-hour with wind power where the hydropower production can be adjusted to take into account wind power variations.</p>

<b>S</b>	<b>Simulation Model of Operation</b>	2 – <i>Deterministic simulation for wind power impact (main simulation)</i> 4 – <i>Stochastic simulation for hydro planning and power market prices (pre-simulation)</i>
<b>Simulation Detail</b>		
<b>R</b>	<b>Resolution of Time</b>	1 week for hydro planning and power market prices (pre-simulation) 2 hours for impact of wind power (main simulation)
<b>P</b>	<b>Pricing Method</b>	3 – <i>Market actor simulation (pre-simulation)</i> Wind power influence on price is not considered
<b>D</b>	<b>Design of Remaining System</b>	1 – <i>Constant remaining system</i>
<b>Uncertainty and Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	No imbalance calculation
<b>B</b>	<b>Balancing Location</b>	No imbalance calculation
<b>U</b>	<b>Uncertainty Treatment</b>	2 – <i>Hydro inflow uncertainty</i> Taken into account in Hydro planning and power market prices (pre-simulation) Wind and load forecasting is not part of the analysis
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	2 – <i>Constant MW limits</i>
<b>H</b>	<b>Hydropower Modeling</b>	Hydro planning and power market prices (pre-simulation): 1 – Head height considered 2 – Hydrological coupling included (including reservoir capacity) 3 – Hydrological restrictions included 4 – Hydro optimization considered 5 – Consider most relevant aspects of affected hydro resources  Impact of wind power (main simulation): 3 – Hydrological restrictions included (reservoir level, stream flows) 5 – Consider most relevant aspects of affected hydro resources
<b>HC</b>	<b>Hydro Capacity Service</b>	2 – Real-time integration with impact of wind variability on system managed with hydro 3 – Capacity service: addition of capacity value through redelivery of wind energy at a later time
<b>T</b>	<b>Thermal Power Modeling</b>	Hydro planning and power market prices (pre-simulation): 4 – Heat production considered (thermal power in the Nordic system)  Impact of wind power (main simulation): Thermal power is not considered, since there are no thermal power plants in the specific region
<b>W</b>	<b>Wind Power Modeling</b>	1 – Few wind speed time series (three different locations) 3 – Time series smoothing considered

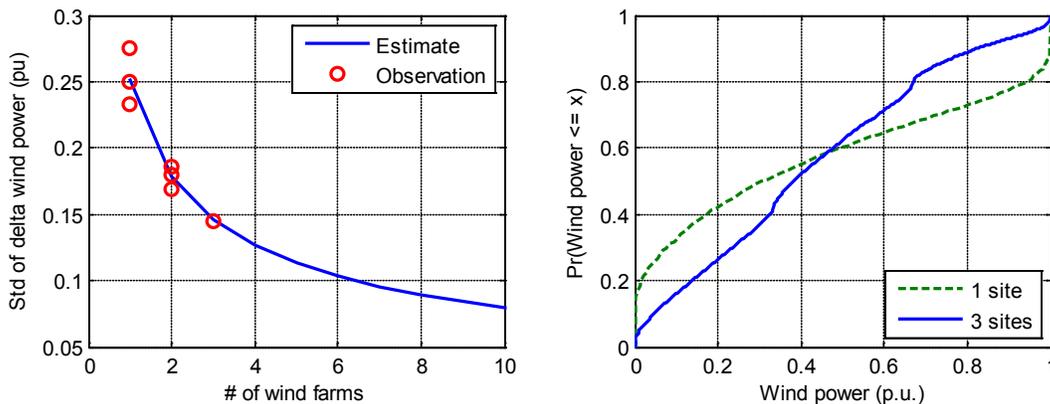
### 5.2.3.1 Assumptions and Limitations

A 30-year time series with hourly resolution has been constructed for wind speed at three locations by combining 1-year time series with a 30-year time series. The smoothed power output is simulated as the sum of the output from the three locations using a typical power curve. The 30-year time series for load, hydro inflow, planned hydro generation, and market price are constructed by using the EMPS model. The influence of wind power on the market price is not considered.

### 5.2.3.2 Wind Power Characteristics

In the case study system, the possible wind farm sites were spread over a large area. Since the instantaneous wind speed varies at different wind farm locations, it is important to consider the smoothing effect this has on the total wind power in-feed to the regional grid. A 1-year time series for wind speed at three different sites was collected to assess the smoothing effect. The time resolution was 1 hour, and the distance between the measurement sites was more than 100 km. The hourly wind farm power output at the three locations was calculated simply assuming a typical wind turbine power curve.

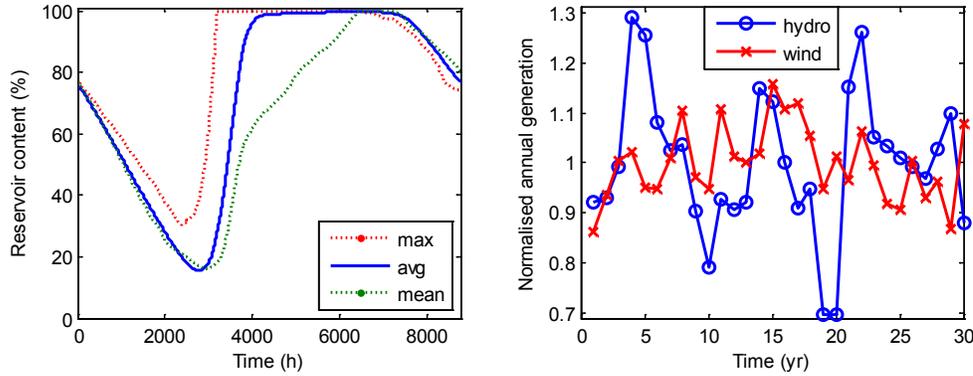
The installed wind power capacity varied from 0 MW to 1,000 MW. With the chosen wind speed time series and power curve, the number of full load hours for wind power generation in the area was 3,500 hours.



**Figure 21. Left Graph: Standard deviation of the hourly wind power variations for individual wind farms and for the sum of generation for one to three wind farms; Right Graph: Cumulative probability distribution of wind power (i.e., the probability that the wind power is less than or equal to a specific value)**

### 5.2.4 Hydro System Characteristics

In the hourly simulations, the hydro system is modeled as an aggregated power plant with 380-MW power capacity and 760-GWh reservoir capacity. The hydropower plant is operated according to the control strategies described in *Section 5.2.2, Overview of Power System*.



**Figure 22. Left graph: Hydro reservoir level for the case with no wind power. Right graph: Annual variations in wind and hydro generation**

### 5.2.5 Wind Power Penetration and System Flexibility

The installed wind power varied from 0 MW to 1,000 MW, which corresponds to 0 TWh to 3.5 TWh of annual generation. With a 350-MW peak load and 1.5-TWh annual load, the wind power penetration and wind energy penetration varies from 0–286% and 0–233%, respectively. In addition to serving the local load, it is possible to export up to 420 MW to the main transmission grid.

### 5.2.6 Wind and Hydro Integration – Benefits and Impacts

The most conservative approach allows for only 115 MW of wind power in the constrained network with 420 MW of capacity, as this will not require any control actions even in the very unlikely case of maximum wind and hydro generation (115 MW + 380 MW) at the same hour as the historically lowest consumption (75 MW).

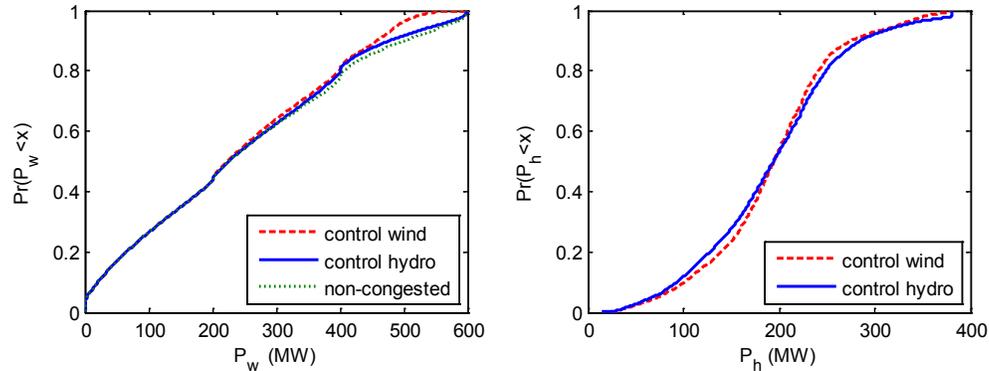
A somewhat less conservative approach is to calculate the hourly power export for the reference case (no wind power) for each hour and use the maximum value to determine the acceptable wind power installation. It is found from the 30-year time series data that the maximum power export without wind power is 237 MW, making it possible to install 183 MW of wind power (420 MW to 237 MW) without affecting the power system operation. However, the viable amount of wind power that can be installed is expected to be much higher, not only because of the smoothing effect of geographically dispersed wind farms, but also because the periods with highest wind generation typically occurs in winter, when the consumption also is at its highest. Since the hydro inflow occurs mostly during summer, this wind characteristic is beneficial for the system operation.

With the chosen input data, it is found that the maximum wind power installation that does not lead to any rescheduling of hydro generation or dissipation of wind energy is 200 MW. This result is valid for three equally sized wind farms (each at 66.67 MW). If the wind power installation exceeds this limit, control actions must be performed to prevent overloading of the 132-kV lines.

The left graph in Figure 23 shows the cumulative distribution function of wind power for the two proposed control strategies (see *Section 5.2.2, Overview of Power System*), in addition to a non-congested case in which the system has been simulated with unlimited transmission capacity. This illustrates that the control wind strategy gives some dissipation of wind energy. Moreover, it

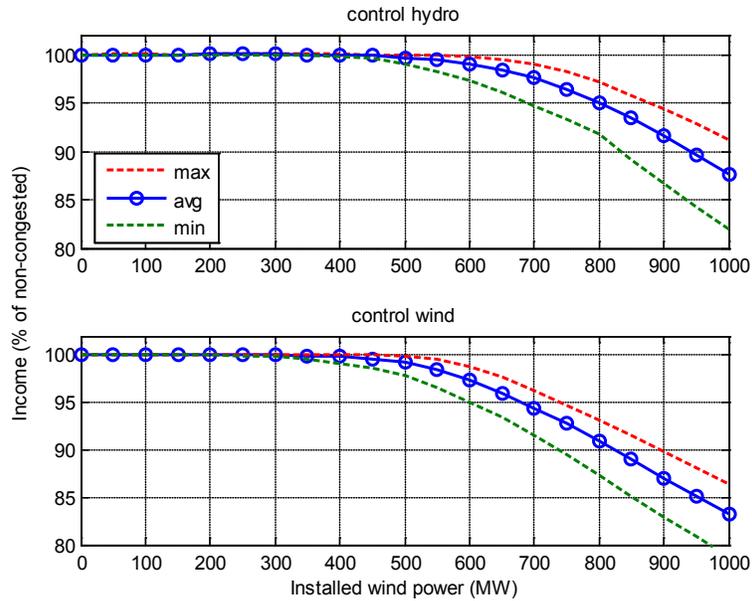
is evident that with the control hydro strategy, it is possible to utilize almost all the available wind energy.

The right graph in Figure 23 shows the cumulative distribution function of hydropower. The curve for control wind represents the scheduled hydro generation, and the graph illustrates that the control hydro strategy causes the power output to fluctuate more, as expected. However, the areas between the curves and the y-axis are almost the same, which means that the annual water spillage is insignificantly increased when coordinated wind/hydro control is introduced.



**Figure 23. Cumulative distribution function of wind power ( $P_w$ ) and hydropower ( $P_h$ ) for three 200-MW wind farms**

The annual income from the electricity market is simply calculated by multiplying the sum of hourly wind + hydro generation with the hourly electricity price (the hourly price is found by interpolation of the weekly values from the EMPS model). Reduction of power output due to the transmission constraint of 420 MW reduces the income compared to the ideal non-congested case. Figure 24 shows the relative reduction in income as the wind power installation is increased for the two control strategies. With control hydro and 600 MW of wind power, the average yearly reduction in income is only 1%, while the control wind strategy gives 3% reduction. It is observed from the upper graph that a wind power installation up to 400 MW gives no income reduction due to transmission constraints if allowance is made for coordinated wind/hydro operation. For 600 MW of wind power, the annual income will be in the range of 97% to 100% and 95% to 99% of the non-congested case for control hydro and control wind, respectively.



**Figure 24. Annual income (wind+hydro) from energy sales to electricity market relative to the non-congested case (*max*, *min*, and *avg* plots refer to the 30-year samples used in this study)**

### 5.2.7 Conclusions

The study shows that for the specific system studied, up to 600 MW of wind power is possible—without noticeable reduction in income from energy sales compared to an ideal non-congested case—by applying coordinated operation of the wind power and hydropower plants. The results emphasize that this is achieved for a hydropower system with a relatively small reservoir and a high share of non-storable water inflow (37% of the total storable plus non-storable inflow). Even if the local hydropower plant follows the generation schedule unaffected by wind power, the reduction in income due to discarded wind energy is as low as 1% to 5%, depending on the annual wind speed and water inflow.

Power system coordination allows for surprisingly large amounts of wind power. It is essential to take account for power system flexibility and the stochastic and dispersed nature of wind power. The presented methodology facilitates this and represents a rational approach for power system integration of wind farms in areas with limited transfer capacity.

## 5.3 SINTEF 2: Regional Hydro-based Power System with Weak Interconnections

### 5.3.1 Introduction to Study

This case study considers the impact of wind power on system resource adequacy. The impact is assessed using data from a real-life, regional, hydro-based power system, although data are simplified and fitted for the purpose of the work. The region has a predicted need for new generation and/or reinforcement of interconnections to meet future demand. Considering that the region has favourable wind resources, the study was conducted to determine whether or not adding wind power to the hydro-based system will be sufficient or if additional measures must be taken to secure system adequacy.

System adequacy relates to the ability of the system to meet the load demand. In this paper, this is addressed considering (1) the system's ability to supply the annual load and (2) the system's ability to meet the peak demand. The system's ability to supply the annual load is assessed using 30 years of recorded data of hydro inflow and wind speed. The system operation is simulated to quantify annual energy balance within the region, including hydro, wind, and import/export through interconnections with neighbouring regions.

The system ability to meet the peak demand is assessed by calculating the loss of load probability (LOLP) for the system. The calculation takes account for the installed generation and transmission capacity, the probability of outages, and the probability of wind power generation at the hour of peak demand. The case study was presented at Nordic Wind Power Conference (NWPC) 2006 as the following: Tande J O, Korpås M, 2006. Impact of large-scale wind power on system adequacy in a regional hydro-based power system with weak interconnections. NWPC, Espoo, Finland, 22–23 May 2006

### 5.3.2 Overview of Power System

**Table 23. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup used in the second SINTEF (Norway) integration study**

<b>Geographic area of study:</b> A generalized regional power system partly based on the characteristics of Mid-Norway. Years: 2006 and future (2010+)						
<b>Power system characteristics:</b>						
Load			Conventional Generation	Inter-Connection	Wind Power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
3,180 (now) 3,780 (future)	750 (now) 900 (future)	18 (now) 21 (future)	Hydro: 2,250 Gas: 375	1,600	62 (now) 1,062 (future)	0.2 (now) 3 (future)
<b>Other relevant characteristics of power system:</b> The load is expected to increase significantly in the future, and new investments in generation and/or transmission are required to meet the load demand. Today, the generation capacity consists almost entirely of hydropower, but there are plans for building new wind power plants and gas power plants.						
<b>Characteristics of system planning:</b> Transmission capacity planning is done by transmission system operators in the Nordic power system. Energy companies invest in power plants.						
<b>Description of market:</b> Most of the power in Norway is traded at NordPool. NordPool has a spot market and a financial market. The total production in the Nordic area (Norway, Sweden, Denmark, Finland) was 395 TWh, while the volume traded at the Elspot market was 176 TWh in 2005.						
<b>Integration time frames of importance:</b>						
Yes/No	Time Frame					
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg					
No	Regulation, AGC					
No	Load following; intra-hour ramping; economic dispatch					
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources					
Yes	Resource and capacity planning; reliability					

This case study uses data from a real-life, regional, hydro-based power system. The system is running on a tight balance, and measures must be taken for meeting a future load increase. This is assessed assuming three alternatives: new wind generation (Case A), new gas generation (Case B), and a combination of the two (Case C).

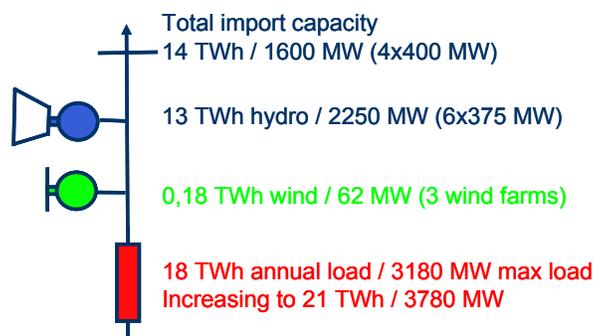


Figure 25. Overview of the case study power system

Table 24. Case study annual load and generation

	Base	A	B	C
Annual load (GWh)	18,024	21,024	21,024	21,024
Hydro (GWh)	12,928	12,928	12,928	12,928
Wind (GWh)	186	3,186	186	3,186
Gas (GWh)	0	0	3,000	3,000
Import (GWh)	4,909	4,909	4,909	1,909
Wind energy penetration (%)	1.0	15.2	0.9	15.2

Table 25. Case study max load and generating capacity

	Base	A	B	C
Max load (MW)	3,180	3,780	3,780	3,780
Hydro (MW)	2,250	2,250	2,250	2,250
Wind (MW)	62	1,062	62	1,062
Gas (MW)	0	0	375	375
Import (MW)	1,600	1,600	1,600	1,600

Table 26. Unit sizes and availability factors

	Wind	Gas	Hydro	Lines
Unit size (MW)	3	375	375	400
Availability (%)	99	99.5	99.5	99.5

### 5.3.3 Study Methodology

#### 5.3.3.1 Energy Balance Calculations

The system's ability to supply the annual load was assessed using results from EMPS simulations. The EMPS-model includes data for the Western European power system divided into 34 interconnected areas. Norway is described in most detail, including about 800 hydro modules grouped into 12 areas, with one of these areas representing the regional power system of this case study. The system operation is simulated for the base case year on a week-by-week basis, and repeated 30 times for considering 30 years of recorded temperature, wind and hydro inflow data (1961–1990). For cases A, B and C, it is assumed (for simplicity) that the hydro generation and prices will remain in the same as the base case, so these cases are assessed without rerunning the EMPS model. The load and wind are simply scaled up based on data already included in the EMPS model, and gas is added by assuming constant generation (8,000 full load hours)

#### 5.3.3.2 Power Balance Calculations

The loss of load probability,  $LOLP = \Pr(P_m < 0)$ , is calculated by using standard statistical methods as briefly described below. The generating capacity margin,  $P_m$ , is the difference between the available conventional capacity,  $P_c$ , and the net load,  $P_n$ .

The generating capacity margin distribution is calculated as the convolution of the available conventional capacity distribution and the net load distribution (i.e., no correlation between the available conventional generating capacity and the net load in the peak hour is assumed). The net load distribution is calculated as the convolution of the wind power distribution and the consumers' load distribution (i.e., no correlation between the wind power variations and the consumers' load within the peak hour is assumed).

The wind power distribution from each group is calculated by a two-step procedure. First, the wind power distribution from one 100% available wind turbine is calculated from a time series of the hour-to-hour wind speed variations and a typical wind turbine power curve. This approach makes it convenient to take into account the smoothing effect of geographically distributed wind power. Next, the wind power distribution from the number of wind turbines is calculated as the convolution of the wind power distribution of the "ideal" wind turbine and the binomial distribution of the available wind turbines.

**Table 27. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the second (Norway) wind integration studies**

<b>Set Up</b>		
<b>A</b>	<b>Aim of Study</b>	1 – <i>What happens with 1,000 MW wind with respect to the system adequacy in a regional power system with limited import capacity</i>
<b>M</b>	<b>Method to Perform Study</b>	<p>1 – Add wind energy 2 – Wind also replaces capacity (or reduces the need for future capacity expansion)</p> <p>The system's ability to supply the annual load is assessed using results from the EMPSmodel with 30 years of recorded data of hydro inflow and wind speed. The system operation is simulated to quantify annual energy balance within the region, including hydro, wind, and import/export through interconnections with neighboring regions.</p> <p>The system's ability to meet the peak demand is assessed by calculating LOLP for the system. The calculation takes account for the installed generation and transmission capacity, the probability of outages, and the probability of wind power generation at the hour of peak demand.</p>
<b>S</b>	<b>Simulation Model of Operation</b>	<p>EMPS simulations: 3 Stochastic simulation several cases</p> <p>Capacity credit calculations: Probability density functions are created for load, wind speed and availability of wind generation, conventional generation, and transmission lines.</p>
<b>Simulation Detail</b>		
<b>R</b>	<b>Resolution of Time</b>	<p>1 week (energy balance) 2 hour (capacity credit)</p>
<b>P</b>	<b>Pricing Method</b>	3 – Perfect market simulation (Base case for energy balance calculations from EMPS simulations)
<b>D</b>	<b>Design of Remaining System</b>	<p>1 – Constant remaining system 2 – Optimized remaining production capacity (avoided new conventional generation) 3 – Optimized remaining transmission (avoided grid reinforcements)</p>
<b>Uncertainty And Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	No imbalance calculation
<b>B</b>	<b>Balancing Location</b>	No imbalance calculation
<b>U</b>	<b>Uncertainty Treatment</b>	<p>Uncertainty treatment in EMPS simulations: 2 – Hydro inflow uncertainty</p> <p>Uncertainty treatment in capacity credit calculations: 6 – Thermal power outages considered: Availability of all generator types are considered Uncertainty of wind power and maximum load are modeled by using probability density functions</p>
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	<p>2 – Constant MW limits 4 N-1 criteria</p>

<b>H</b>	<b>Hydropower Modeling</b>	Hydropower modeling in EMPS model: 1 – Head height considered 2 – Hydrological coupling included (including reservoir capacity) 3 – Hydrological restrictions included (reservoir level, stream flows) 4 – Availability of water, capacity factor, dry/wet year
<b>HC</b>	<b>Hydro Capacity Service</b>	1 – Interaction with hydro resources not significant (Hydro production is not changed due to wind power)
<b>T</b>	<b>Thermal Power Modeling</b>	Thermal power modeling in EMPS model: 4 – Heat production considered
<b>W</b>	<b>Wind Power Modeling</b>	1 – Few wind speed time series (3 different locations) 3 – Time series smoothing considered

### 5.3.3.3 Assumptions and Limitations

#### *Energy balance calculations:*

- A base case is defined from EMPS simulations (30 years with load and hydro inflow).
- Weekly wind (30 years time series) and gas power added to the base case. The gas power plant is assumed to operate at nominal power.

#### *Capacity credit calculations:*

- Use 1-year time series from three locations with hourly resolution. The smoothed power output is simulated as the sum of the output from the three locations using a typical power curve. This time series is used for creating a probability density function for the wind power output in the maximum load hour (assuming that the average wind speed in the maximum load hour is equal to the average wind speed of the whole year)

### 5.3.4 Wind Power Characteristics

The possible wind farm sites are spread over a large area. Since the instantaneous wind speed varies at different wind farm locations, it is important to consider the smoothing effect this has on the total wind power in-feed to the regional grid. One-year time series for wind speed at three different sites was collected to assess the smoothing effect. The time resolution was 1 hour, and the distance between the measurement sites was more than 100 km. The hourly wind farm power output at the three locations was calculated simply assuming a typical wind turbine power curve.

Figure 26 shows the cumulative distribution function of wind power with and without wind power smoothing. It is observed that the probability of zero power output is almost 20% for a single wind farm, while the corresponding value for the sum power output from three wind farms is less than 5%. Therefore, the smoothing effect could have a positive impact on the contribution of wind power to meet the maximum load. The smoothing effect is also evident for the periods with high wind speed; the three wind farms generate at full power at the same time less than 1% of the year, compared to 10% of the year for a single wind farm.

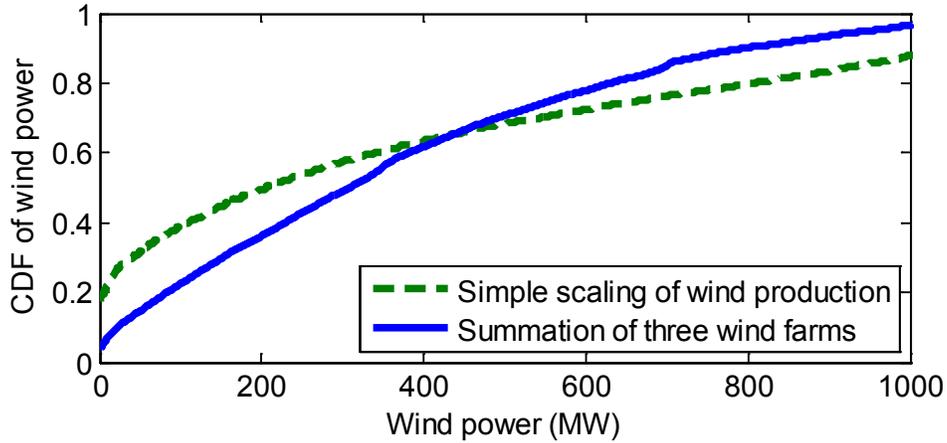


Figure 26. Cumulative distribution function of wind power for Case A

With the chosen wind speed time series and power curve, the number of full load hours for wind power generation in the area is 3,000 hours.

**5.3.5 Hydro System Characteristics**

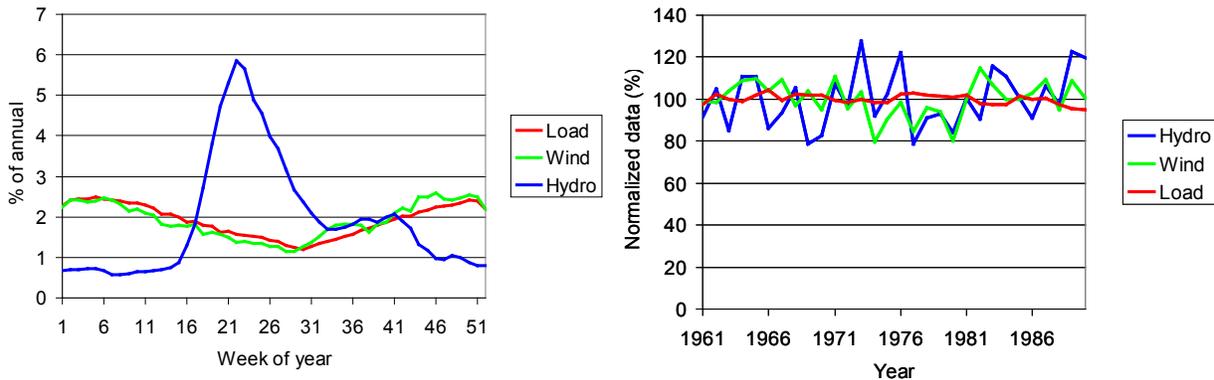
See Section 5.3.3, *Study Methodology*, for a description on how hydropower is modelled for the energy balance calculations. For the power balance calculations, hydropower is modelled as a conventional generator type with 99.5% availability and unit size of 375 MW.

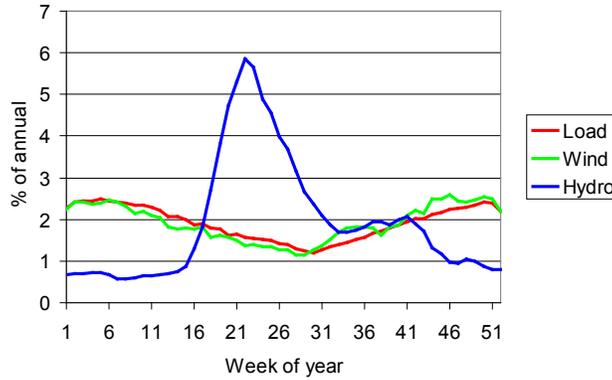
**5.3.6 Wind Power Penetration and System Flexibility**

The installed wind power is 62 MW (Case B) and 1,062 MW (Case A and Case C), which corresponds to 186 GWh and 3,186 GWh of annual generation. With a 3,780-MW peak load, the wind power penetration becomes 1.6% (Case B) and 28.1% (Case A and Case C). The annual load is 21,024 GWh, which gives wind energy penetration levels of 0.9% (Case B) and 15.2% (Case A and Case C).

**5.3.7 Wind and Hydro Integration – Benefits and Impacts**

As illustrated in the left graph in Figure 27, the average week-by-week wind and load follow the same pattern, which is opposite to the hydro inflow. This is beneficial, although variations from year to year may be significant. The year-to-year variations in load, wind, and hydro generation are provided in the right graph in Figure 27.

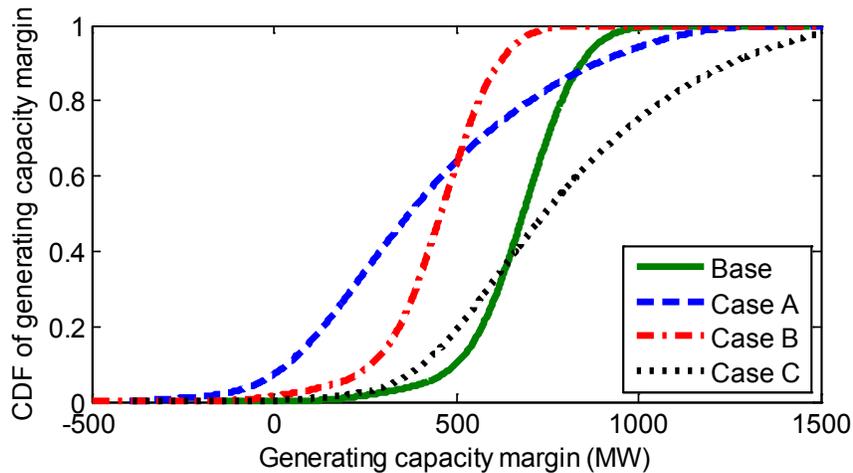




**Figure 27. Left graph: Average seasonal pattern for load, wind, and hydro inflow  
Right graph: Annual variations in load (due to temperature), wind, and hydro generation**

For the power balance calculations within each week modelled by EMPS (which does take into account hydro constraints, availability, inflow, head height, etc.), hydropower is modelled as a conventional generator, and therefore no specific hydro characteristics are taken into account, such as reservoir and inflow. The remainder of this section provides a short summary of how wind power will impact system adequacy in the case study system.

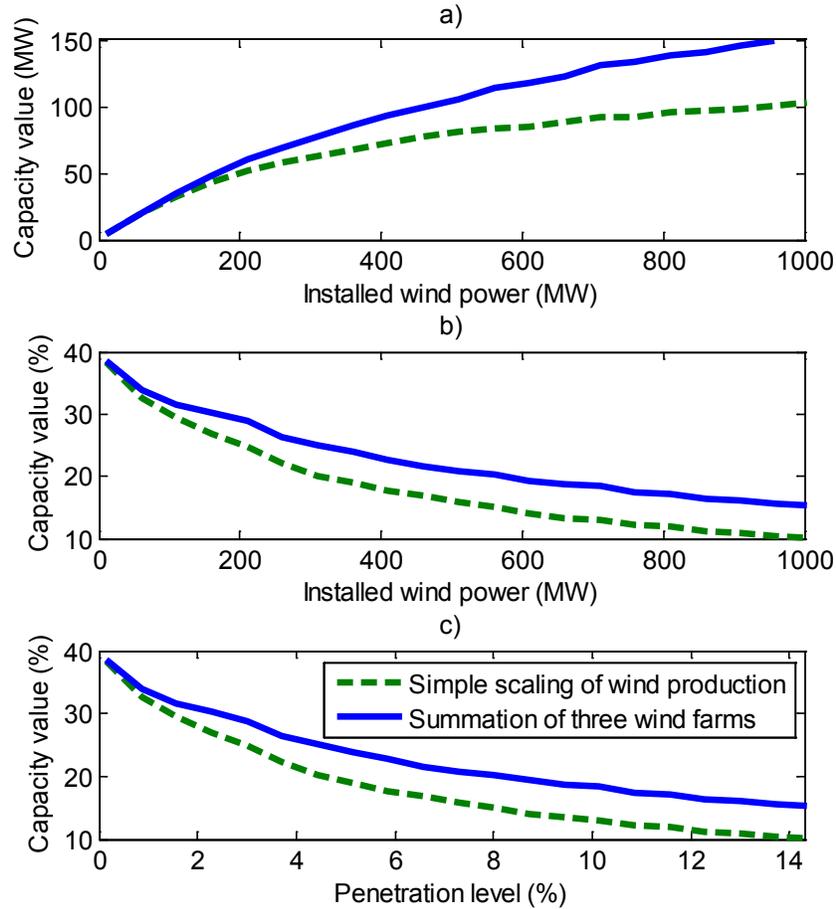
Figure 28 shows the cumulative distribution of the capacity margin for the different cases (see Section 5.3.2, *Overview of Power System*, for an explanation of the cases). Wind power variations result in a higher variability of the capacity margin. By comparing Case B (gas) and Case C (gas plus wind), it is evident that wind power significantly improves the generating capacity margin.



**Figure 28. Cumulative distribution function of the generating capacity margin**

The geographical distribution of wind power in the area was taken into account by adding up the production from three representative wind farms that are geographically separated by up to 100 km. This has a positive effect on the ability of the system to meet the maximum load compared to a case with only one wind farm site and the same installed capacity. These cases are compared in the graphs in Figure 29, which clearly shows that the smoothing effect becomes

more important as wind penetration increases. Capacity value is defined here as the amount of wind power that can be counted upon to meet peak load.



**Figure 29. Capacity value of wind power with and without geographical smoothing effect: (a) Capacity value in megawatts; (b) Capacity value in percentage of installed wind power; (c) Capacity value as a function of wind penetration level**

### 5.3.8 Conclusions

Wind power will have a positive effect on system adequacy in a regional hydro-based power system. Wind power contributes to reducing the LOLP and to improving the energy balance. Adding 3 TWh of wind or 3 TWh of gas generation are found to contribute equally to the energy balance, both on a weekly and annual basis. Both wind and gas improves the power balance. The capacity value of gas is found to be about 95% of rated, and the capacity value of wind about 30% at low-wind energy penetration and about 14% at 15% penetration. The smoothing effect due to geographical distribution of wind power has a significant impact on the wind capacity value at high penetration.

Indeed, similar results have been reported from various national studies. The significance of this study is therefore related to the real-life case studied, being a region rather than a national system, and demonstrating the relevance of applying system adequacy studies for generation expansion and transmission planning of regional systems.

## 6 Sweden

### 6.1 Introduction

In Sweden, there is a large amount of hydropower installed, and there is also an intense discussion concerning large amounts of wind power. This means that there have been some detailed studies concerning the possibilities of balancing wind power in Sweden with the available hydropower resource. The current figures for Sweden (2008) are an installed amount of hydropower of 16,195 MW (47% average, all capacity) with a mean yearly production of 68.4 TWh (47 % of all energy production) and a total storage capacity of 33.8 TWh. In general, the Swedish hydropower comes from comparatively long rivers with many hydropower stations in the same river, which implies that hydrology has to be considered when operation is to be simulated/optimized. In 2008, the installed amount of wind was 1,021 MW (3.0% of all capacity) and the yearly production was 2.0 TWh (1.4 % of all energy production). There are currently discussions in Sweden concerning up to 12,000 MW of wind power corresponding to 30 TWh/year. Sweden has rather strong interconnections to neighboring countries (Norway, Finland, Denmark, Poland, Germany), a total of around 9,000 MW. This is important for handling of dry years (import), wet years (export), and daily trading. Sweden is a part of the Nordpool electricity market, which means a high interaction concerning operation strategies with Denmark, Norway, and Finland—and the Nordpool countries together have 48,776 MW of hydropower; therefore, so in reality a large amount of wind power in Sweden will be balanced in the whole Nordic area.

Below two Swedish studies will be presented. The first one is a detailed study of one river, where the aim is to simulate how this river can balance wind power. The other study is about how the rivers in the North part of Sweden can balance wind power in the same region.

### 6.2 Case Study for Balancing of Wind Power in One River

The following study description was extracted from the following more comprehensive report: Integration study of small amounts of wind power in the power system, by Lennart Söder, March 1994 (in English), 206 pages.

#### 6.2.1 Introduction to Study

- *Study description and goals:* The possibility of balancing wind power with hydropower plants located along one certain river.
- *Organizations involved:* KTH conducted the study, with case data from a large hydrothermal producer in Sweden.
- *Reason study was performed:* The aim of the simulations is to study whether an increased amount of wind power might decrease the efficiency of the hydropower system along an interconnected river system.
- *Published reports applicable to the case study:*
  - Söder L., *Modelling of wind power forecast uncertainty*. Proceedings of 1993 European Community Wind Energy Conference held at Lubeck-Travemunde, Germany, 8-12 March 1993.

- Söder L., *A mixed rule-based – linear programming method applied to daily operation planning of a hydropower system*. Presented at Stockholm Power Tech, 1994.
- Intended outcomes of the report relative to the objectives of Task 24: The study addresses possibilities of wind-hydro coordination.

**6.2.2 Overview of Power System**

The simulation model uses simulated realistic forecasts of the load and total wind power production, and these forecasts are updated each hour. The result from the simulation model includes the efficiency of the hydropower system measured as how many percent of the potential energy in the hydro system that is used for electricity production. The studied system includes seven hydropower stations with an installed capacity of 478 MW and a yearly energy production of 2.2 TWh. In this system 30-90 MW of wind power was installed. A summary of the main system characteristics is presented in Table 28.

**Table 28. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the first Swedish case studies**

<b>Geographic Area of Study:</b> Sweden						
<b>Power System Characteristics:</b> The study was made for an estimated system with wind and hydropower.						
Load			Hydropower Generation	Interconnection	Wind Power (base case)	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	GWh/a
450	100	2,2	478	0	30–90	83
<b>Other Relevant Characteristics of Power System:</b> n/a						
<b>Characteristics of System Planning:</b> planning updated hourly using new forecasts of wind and load						
<b>Description of Market:</b> Day-ahead, intra-day, and regulation markets						
<b>Integration Time Frames of Importance:</b>						
Yes/No	Time Frame					
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg					
Yes	Regulation					
Yes	Load following; economic dispatch					
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources					
Yes	Resource and capacity planning; reliability					

**6.2.3 Study Methodology**

The method used was to (1) plan the hydropower system for a week (deterministic approach), (2) simulate changes in wind power production and load during the coming hour, (3) estimate how the power system was operated since it was not according to plan, (4) replan the rest of the week, and (5) go back to simulating changes in wind power until all hours during the week have been simulated. This means that forecast uncertainties concerning both wind power and load were considered, and the hydropower system operation was optimized and re-optimized when new information was available. But it was assumed that a certain amount of wind power was balanced using hydropower resources in a certain river. A summary of the study methodology in the context of the matrix is provided in Table 29.

**Table 29. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the first Swedish case study**

<b>Set Up</b>		
<b>A</b>	<b>Aim of Study</b>	1 what happens with x GWh wind
<b>M</b>	<b>Method to Perform Study</b>	1 add wind energy
<b>S</b>	<b>Simulation Model of Operation</b>	3 Stochastic simulation several cases
<b>Simulation Detail</b>		
<b>R</b>	<b>Resolution of Time</b>	2 hour
<b>P</b>	<b>Pricing Method</b>	1 costs of fuels
<b>D</b>	<b>Design of Remaining System</b>	2 optimized remaining production 4 perfect trading rules
<b>Uncertainty and Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	2 wind+load
<b>B</b>	<b>Balancing Location</b>	2 from the same region
<b>U</b>	<b>Uncertainty Treatment</b>	2 hydro inflow uncertainty 4 best possible wind forecasts 5 load forecasts considered
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	1 no limits
<b>H</b>	<b>Hydropower Modeling</b>	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 <b>some</b> hydrological restrictions included 4 hydro optimization considered 5 consider most relevant aspects of affected hydro resources
<b>HC</b>	<b>Hydro Capacity Service</b>	2 real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	Not applicable – no thermal power plants considered in this study
<b>W</b>	<b>Wind Power Modeling</b>	2 many wind power time series 3 time series smoothing considered

#### **6.2.4 Wind Power Characteristics**

Wind data from six sites in Skåne in southern part of Sweden are used. Two parallel wind speed series are used, one representative for winter (Jan 1 through March 31 and Oct 1 through Dec 31, 1980) and one for the summer (April 1 through Sept. 30, 1980). In addition to that, the wind speed forecast errors are assumed to be simulated according to estimated forecast errors. The interdependence of forecast errors in different sites with wind power plants are also considered. The wind power is obtained from 10 wind speed series and data from an assumed 2-MW wind power station for each wind speed series: Näsudden II.

### 6.2.5 Hydro System Characteristics

The studied hydropower system consists of seven hydropower stations and has a total capacity of 478 MW. The hydropower stations are modeled with installed capacity, varying efficiency (marginal production equivalents) depending on discharge, reservoir capacity for each station, and delay time between the different hydropower stations. An illustration of the system is provided in Figure 30.

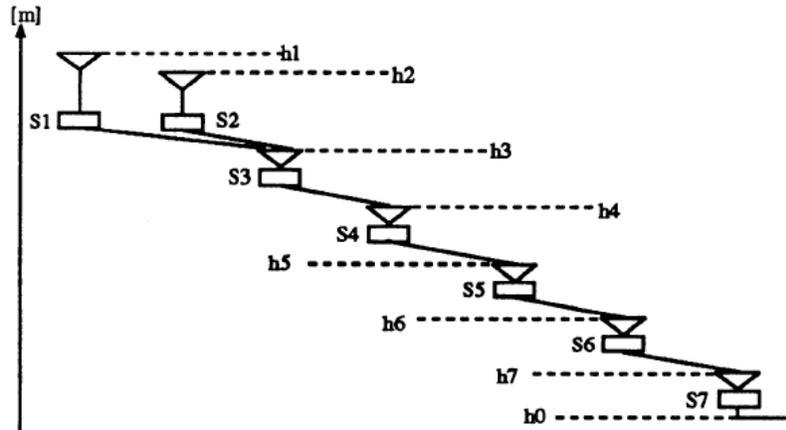


Figure 30. An illustration of the seven hydro stations studied on the Ume River

### 6.2.6 Wind Power Penetration and System Flexibility

Wind power penetration was studied for three different scenarios: 30, 60, and 90 MW. The result was then extrapolated in order to draw conclusions for wind power integration in whole Sweden. The studied amount of wind power in the certain hydropower system corresponds to that the penetration in whole Sweden should be up to 6.5–7.5 TWh/year (i.e., 5 % of total energy production per year). The whole balancing is assumed to be performed in Sweden and in the specific wind turbines.

### 6.2.7 Wind and Hydro Integration – Benefits and Impacts

The whole idea of this project is to simulate the impact of a certain amount of wind power on a certain hydropower system, assuming that only the generation in this hydropower system is used to provide the enhancement in balancing requirements caused by the addition of the wind power. Since there is a detailed model of the hydropower system, including efficiencies depending on discharge level, then it is possible to study whether there is a decreased efficiency depending on wind power integration. With more wind power in the system, the hydropower production will vary more, which may decrease the efficiency in the hydropower system. Table 30 shows simulation results of a the impact on overall hydro generator efficiency due to changes in operation caused by incorporation of 0–90 MW of wind power.

**Table 30. Mean hydropower efficiencies with 0–90 MW of wind power**

Wind MW	Hydro-A		Hydro-B		Hydro-C		Hydro-D		Mean	
	$\eta'_1$	$\eta_2$								
0	87.09	90.89	87.02	90.57	87.81	92.06	87.20	91.10	87.28	91.15
30	87.10	90.89	87.05	90.60	87.74	92.09	87.23	91.27	87.28	91.22
60	87.01	90.90	86.96	90.57	87.74	91.12	87.15	91.29	87.21	91.22
90	86.94	90.87	86.81	90.45	87.68	92.05	87.14	91.32	87.14	91.17

Hydro periods A and B are assumed to be winter periods, while periods C and D are summer periods. The parameter  $\eta'_1$  = hydropower system efficiency with consideration of water flowing in the river. The parameter  $\eta_2$  = hydropower station efficiency in comparison with maximal local efficiency. These two different ways to calculate the hydropower system efficiency have then been used to see how much they change when the amount of wind power is increasing. In general, a lower efficiency means that more water have to be used in order to produce the same amount of hydropower (i.e., a measure of the energy loss).

### 6.2.8 Summary and Conclusions

In the report the results from the study is scaled in order to get an estimation of the impact of small scale wind power on the efficiency in the hydropower system. The result from the simulations in the project is that Swedish wind power installations that generate about 2–2.5 TWh/year do not affect the efficiency of the Swedish hydro system. At wind power levels of about 4–5 TWh/year, the installed amount of wind power has to be increased by about 1% to compensate for the decreased efficiency in the hydro system. At wind power levels of about 6.5–7.5 TWh/year, the needed compensation is probably about 1.2%, but this figure has to be verified with more extended simulations.

The report presented here does not include effects on the losses and limitations in the transmission or distribution system. These effects can increase or decrease the value of wind power in the power system.

## 6.3 Case Study for Balancing of Wind Power in North Sweden

Report: Balancing of wind power and hydropower in Northern Sweden. By Mikael Amelin, Calle Englund and Andreas Fagerberg. Elforsk report 09:88 (in Swedish with an English summary). Available from [www.elforsk.se/rappporter](http://www.elforsk.se/rappporter).

### 6.3.1 Introduction to Study

- *Study description and goals:* The possibility of balancing wind power with the hydropower stations in northern Sweden
- *Organizations involved:* KTH conducted the study, with case data from a large hydrothermal producer in Sweden.
- *Reason study was performed:* The aim of the simulations is to study the possibility of balancing wind power in northern Sweden with hydropower in northern Sweden.
- *Intended outcomes of the report relative to the objectives of Task 24:* The study addresses possibilities of wind-hydro coordination.

**6.3.2 Overview of Power System**

The simulation model uses real hourly data for load, hydro inflow and thermal production. The wind power hourly data are simulated wind power series from 19 sites in northern Sweden. The simulated series have a total installed capacity of 795 MW, and the output has been scaled to 1,000; 4,000; 8,000; and 12,000 MW. The hydropower system consists of 154 hydropower plants with a combined capacity of 13.2 GW, which corresponds to about 80% of the installed capacity of all hydropower in Sweden. This does not include any internal transmission limits within northern Sweden, but the local thermal production, load, and export capabilities from this region are considered with actual values.

**Table 31. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the second Swedish case studies**

<b>Geographic Area of Study:</b> North Sweden						
<b>Power System Characteristics:</b> The study was made for an estimated system with wind and hydropower.						
Load			Hydropower Generation	Interconnection	Wind Power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
4000	3000	30	13200	8500	1000–12000	2,5–30
<b>Other Relevant Characteristics of Power System:</b> There are 633 MW of local thermal production						
<b>Characteristics of System Planning:</b> hourly simulation with assumption of perfect forecasts						
<b>Description of Market:</b> Perfect market, but water movement could not be changed between weeks						
<b>Integration Time Frames of Importance:</b>						
Yes/No	Time Frame					
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg					
No	Regulation					
Yes	Load following; economic dispatch					
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources					
Yes	Resource and capacity planning; reliability					

**6.3.3 Study Methodology**

The method used was, for each week studied (12 different weeks per year were studied), and wind power level, to: (1) set up a certain wind power scenario, (2) define a level for each reservoir level at the end of the studied week including the level of flexibility for this level, (3) perform a deterministic optimization (linear programming approach) for how to use the available water as efficiently as possible (maximize the production) for the studied week considering: wind power production, hydrological constraints including juridical restrictions, export capability, local load, and thermal production.

**6.3.4 Wind Power Characteristics**

The wind power hourly data are simulated wind power series from 19 sites in northern Sweden. Available data are from 1992–2001. The total wind power production is obtained by just summing up the data from the 19 sites since no transmission constraints within the studied are

considered. The simulated series have a total installed capacity of 795 MW and the output has been scaled to 1,000; 4,000; 8,000; and 12,000 MW.

### **6.3.5 Hydro System Characteristics**

All hydropower stations larger than 10 MW in the studied area are considered (i.e., 154 stations). These stations are modeled with a variable efficiency at peak production and at a lower level (piece-wise linear marginal production curve). Reservoir volumes and constraints, juridical restriction concerning things such as minimum flow etc. and delay times between different stations are also considered. Inflows from 2007 (a rather “normal” inflow year) are applied. Twelve different simulations have been performed for different inflows, reservoir start, and end limits.

### **6.3.6 Wind Power Penetration and System Flexibility**

Wind power penetration was studied for four different scenarios: 1,000; 4,000; 8,000; and 12,000 MW. This corresponds to an energy penetration in the whole Sweden of 30 TWh/year (assuming 12,000 MW of wind), or 20 % of total energy production per year. The method used assumed that electric power exported to neighboring countries (Norway and Finland) or southern Sweden can be used in those areas. The study is based on the hydrological constraints and transmission system characteristics at the time the study was conducted (no expansions, etc.), with no balancing in local thermal power and no flexibility in the load.

### **6.3.7 Wind and Hydro Integration – Benefits and Impacts**

The aim of this project was to simulate the impact of a certain amount of wind power on the hydro system in northern Sweden. Since there is a detailed model of the hydropower system, including efficiencies depending on discharge level, minimum discharge level, etc., it is possible to study whether there will be significant spillage depending wind power integration. In a situation with comparatively low load, high inflow and much wind, there may be a problem to export all the power produced. Figure 31 shows the export to Norway and Finland in relation to maximal possible export. The figure shows that there are only a few weeks when the export capacity is totally used. This is primarily because the yearly hydro planning is not assumed to be changed and because there is comparatively more wind power in the winter; therefore, all this wind power has to be exported—and this is a situation in which there is already a lot of hydropower exported from Northern to Southern Sweden.

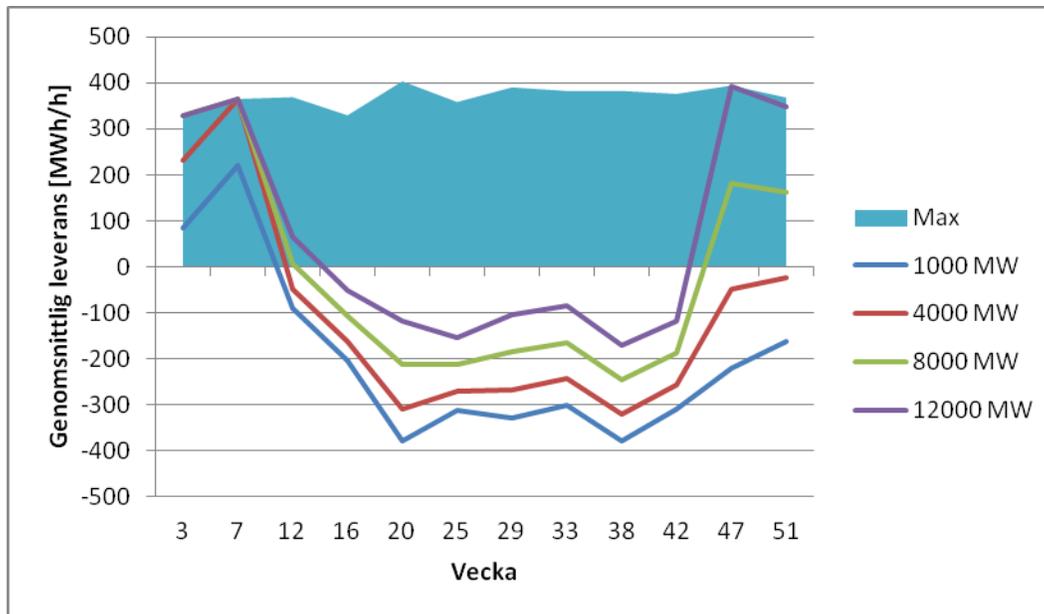


Figure 31. Mean export to Norway and Finland per week in comparison with maximal export capability; Y-axis: “Mean delivery” in megawatt-hours, X-axis: “Week”

### 6.3.8 Summary and Conclusions

The report describes the results from a study of the capability of the hydropower to balance various amounts of wind power in Northern Sweden. To perform such an analysis, a model of the hydropower system north of cut two has been developed. The model includes 154 hydropower plants with a combined capacity of 13.2 GW, which corresponds to about 80% of the installed capacity of all hydropower in Sweden. The model makes it possible to follow the interplay between hydropower, wind power, other power plants, and the load on an hourly basis. The hydropower model has been made as detailed as possible, and considers court decisions, water delay time between power plants, and other physical limitations. However, it has not been possible within this project to develop sufficiently detailed models of season and short-term planning. Also, the modeling of the electricity market is quite simplified. All in all, this results in a model showing what technical possibilities by hydropower can balance wind power variations, but more research is required to study how much of this balancing capability that will be made available to the electricity market under different regulatory frameworks.

The model has been used in a number of case studies to investigate the size of the balancing capability of the hydropower for a wind power expansion of 1,000; 4,000; 8,000; and 12,000 MW, respectively. The spill that can be seen in the case studies is to an overwhelmingly extent a spill that can be avoided by using efficient tools for especially the season planning. Only in a few cases—and then in particular for a wind power expansion of 12,000 MW—will there be a spill that depends on insufficient balancing capability in the hydropower. The conclusion of the study is therefore that the existing hydropower in Northern Sweden has sufficient installed capacity and is fast enough to balance even large amounts of wind power. The challenge for a large-scale expansion of wind power is rather to find an outlet for all electricity generation. Improved planning tools can solve this challenge, but it could also be profitable to make investments in, for example, reinforced export capacity.

## 7 United States

### 7.1 Introduction

Several organizations in the United States originally expressed interest in contributing case studies to the work plan of Task 24. However, due to various circumstances, three case studies emerged with completed, documented studies that could be included as part of the U.S. contribution. The studies are from three different river systems and electrical balancing areas, as listed below:

- Missouri River and the Western Area Power Administration (WAPA)
- Upper American River and the Sacramento PUD
- Columbia River and the Grant County PUD

In these studies, each system differs in its basic characteristics related to wind integration: organizations involved and balancing area set-up and generation resources, hydro system characteristics, purpose of study, and constraining factors. However, each of these studies did seek to determine the basic impacts of wind integration in terms of the ancillary services required to handle the additional variability and uncertainty that wind power introduces into the balancing area net load. The third study also investigated the impact of wind integration on system flow constraints.

### 7.2 Case Study: Western Area Power Administration, Missouri River

#### 7.2.1 Introduction to Study

- *Study description and goals:* The purpose of this study was to determine the amount of wind generation that could be “accommodated” into the Upper Great Plains Region (UGPR) control area of WAPA. The effects of incrementally increasing levels of wind capacity of 80; 100; 250; 500; and 1,000 MW were analyzed. The WAPA power system was kept in its current state with a goal of determining the levels of reserves that would be required with the addition of various wind generation capacities. The incremental regulation requirements for the control area will be computed with the well-accepted statistical methodologies developed by Kirby and Hirst (2000). Implications on load-following reserves will be determined through statistical analysis of the wind generation time series data and WAPA control area load data. Another primary goal of the study was to investigate the existence of any correlation between wind trends in the Dakotas and water runoff (and hence hydro resources) in the Missouri River Valley Basin.
- *Organizations involved:* This study was conducted by EnerNex Corporation and Wind on the Wires for NREL, in cooperation with WAPA and the U.S. Army Corps of Engineers (USACE).
- *Reason study was performed:* The study was conducted to make an assessment regarding the magnitude of impact various levels of wind penetration would have on the system regulation (10-minute variations), load following (hour-to-hour), magnitude of ramping during the morning and evening load ramps, and the effect of wind forecast errors on the aggregate hour-ahead and day-ahead forecast error of load net wind versus load alone. These impacts

were deduced by comparing the relative statistics computed when considering load alone and load net wind.

- *Case study chapter has been condensed from the following project report:* EnerNex Corporation submitted a complete report of the study, titled “WAPA Wind Integration Study,” to U.S. National Renewable Energy Laboratory in August 2006 (available at the Task 24 site at [www.ieawind.org](http://www.ieawind.org)) or from NREL
- *Intended outcomes of the report relative to the objectives of Task 24:* The intended outcomes of the study were to determine the impacts of integrating wind capacity into the given WAPA control area while maintaining the current restrictions and operations of the existing hydro resources. Specifically, an assessment was made of the wind generation impacts on regulation and load following. The long-term correlation between the availability of wind and hydropower was also investigated. Thus, this study falls into the “grid integration” case studies performed for the task.

## 7.2.2 Overview of Power System

**Table 32. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for U.S. WAPA Missouri River integration study**

<b>Geographic area of study:</b> UGPR of WAPA, primarily covering North Dakota, South Dakota, and Montana in the United States: 378,000 square miles						
<b>Power system characteristics:</b>						
Load			Conventional Generation	Interconnection	Wind Power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
2700	1200	~ 12	Hydropower supplemented by Coal	Not relevant in this statistical study	80 100 250 500 1,000	0.30 0.37 0.92 1.80 3.80
<b>Other relevant characteristics of power system:</b>						
<ul style="list-style-type: none"> <li>• UGPR of WAPA includes Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota</li> <li>• 12 billion kWh per year produced in service area</li> <li>• Hydro generation comes from six hydropower plants/dams on the main stem of the Missouri River</li> <li>• Hydropower resources are located in the Missouri River Valley Basin</li> </ul>						
<b>Characteristics of system planning:</b>						
<ul style="list-style-type: none"> <li>• WAPA’s power is planned and dispatched from an operations center in Watertown, South Dakota, to serve the load in its balancing area.</li> <li>• Use of the hydropower adheres to the guidelines (restrictions) defined in USACE’s Master Manual.</li> <li>• WAPA supplements its hydropower with purchases from other generation sources, as required to meet its load.</li> </ul>						

<ul style="list-style-type: none"> <li>For the time frames of interest in this study, WAPA functions with a day-ahead capacity and energy plan for each hour of the day; the plan for any given hour can be updated up to an hour ahead, and within hour adjustments are possible.</li> </ul>												
<p><b>Description of market:</b> Power is delivered to WAPA’s public power customers, many of which contract with WAPA as the balancing area operator. Some of these customers do not actively participate in a market and have their load served entirely by WAPA. Other customers do engage in bi-lateral transactions with other power generators or utilities, and function as a vertically integrated utility. Other customers may participate in a market, such as that operated by the Midwest Independent System Operator. However, for the purpose of this study, the market impacts and costs are not considered. The purpose is simply to understand the impacts of wind within the WAPA control area on its indigenous ancillary services requirements (requirement to regulation and load following). The analysis is statistical in nature, and is meant to assess the increase in variability experienced by WAPA in its balancing area, due to wind generation used to serve a portion of its load.</p>												
<p><b>Integration time frames of importance:</b></p> <table border="1"> <thead> <tr> <th>Yes/No</th> <th>Time Frame</th> </tr> </thead> <tbody> <tr> <td>No</td> <td>Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg</td> </tr> <tr> <td>Yes</td> <td>Regulation, AGC</td> </tr> <tr> <td>Yes</td> <td>Load following, intra-hour ramping, economic dispatch</td> </tr> <tr> <td>No</td> <td>Unit commitment and day-ahead scheduling, economic utilization of resources</td> </tr> <tr> <td>No</td> <td>Resource and capacity planning, reliability</td> </tr> </tbody> </table>	Yes/No	Time Frame	No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg	Yes	Regulation, AGC	Yes	Load following, intra-hour ramping, economic dispatch	No	Unit commitment and day-ahead scheduling, economic utilization of resources	No	Resource and capacity planning, reliability
Yes/No	Time Frame											
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg											
Yes	Regulation, AGC											
Yes	Load following, intra-hour ramping, economic dispatch											
No	Unit commitment and day-ahead scheduling, economic utilization of resources											
No	Resource and capacity planning, reliability											

### 7.2.3 Study Methodology

The objective of this case study was to perform a statistical study of the impact of wind variability on load variability in the WAPA balancing area. Table 33 provides an overall summary of the study technique and assumptions that were employed. A list of key assumptions and limitations follow the table.

**Table 33. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the U.S. WAPA Missouri River wind integration study**

Set Up		
<b>A</b>	<b>Aim of Study</b>	1 what happens with a certain number of GWh of wind 2 how much wind is possible
<b>M</b>	<b>Method to Perform Study</b>	1 add wind energy
<b>S</b>	<b>Simulation Model of Operation</b>	2 deterministic simulation several cases (note: the power system was not simulated in this study; rather, a statistical study was conducted using time-synchronized wind and load data)
Simulation Detail		
<b>R</b>	<b>Resolution of Time</b>	3 minute/second
<b>P</b>	<b>Pricing Method</b>	Not applicable to this study
<b>D</b>	<b>Design of Remaining System</b>	1 constant remaining system
Uncertainty and Balancing		

<b>I</b>	<b>Imbalance Calculation</b>	2 wind + load
<b>B</b>	<b>Balancing Location</b>	2 from the same region
<b>U</b>	<b>Uncertainty Treatment</b>	2 hydro inflow uncertainty 4 best possible wind forecasts 5 load forecasts considered
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	Not applicable to this study
<b>H</b>	<b>Hydropower Modeling</b>	Not applicable to this study
<b>HC</b>	<b>Hydro Capacity Service</b>	2 real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	Not applicable to this study
<b>W</b>	<b>Wind Power Modeling</b>	3 time series smoothing considered (wind power time series was created using the MM5 mesoscale modeling computer program, with the output wind speed time series transformed into a power production time series)

### 7.2.3.1 Assumptions

- This was a statistical study of the influence of wind power on the WAPA control area load to deduce the approximate impact on regulation and load following.
- Interconnection considerations were neglected for this study (because this is a statistical study of the impact of wind variability when combined with load variability, interconnections do not come into play).
- All theoretical wind turbines were either General Electric (GE) 1.5S or 1.5SL, 1500-kW models. Wind power time series were generated at a 10-minute time resolution for the model year using wind speed data generated by a mesoscale model (MM5).
- Load and simulated wind power data were used from the year 2003.
- Wind power forecasting errors were considered alongside load forecast errors to assess the aggregate error in the load plus wind.

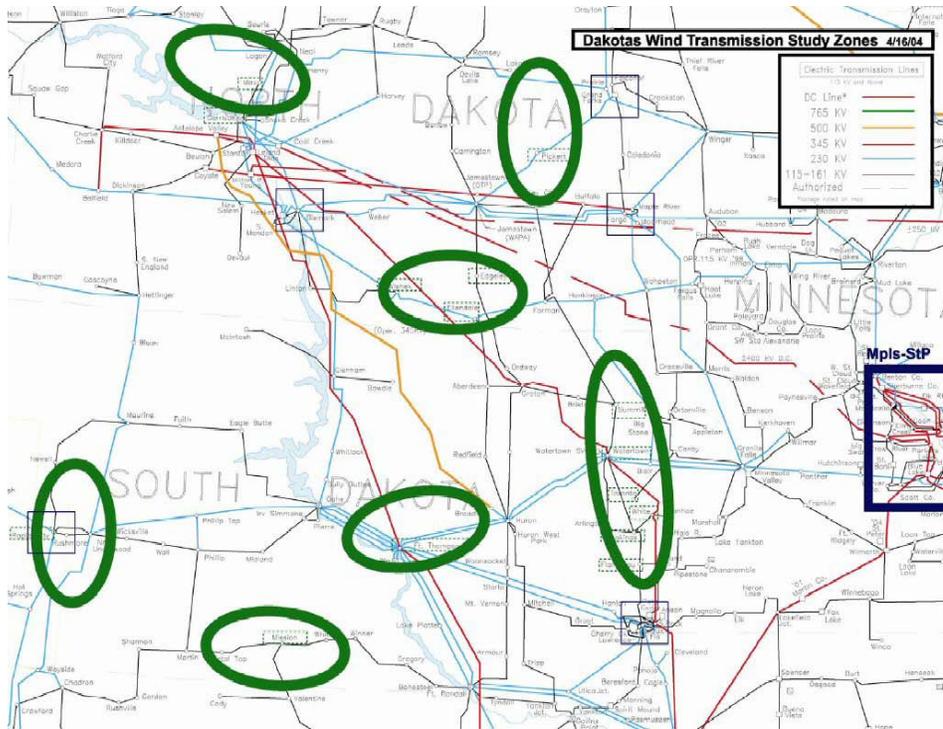
### 7.2.3.2 Limitations

- Ten-minute load and wind data were used for most of the analyses. This causes an underestimate of the minute-to-minute “regulation” variations experience by the load and the load net wind. This data captures the broader within-hour and hour-to-hour variability well, but the “regulation” value reported underestimates that actual amount since the fast 1-minute changes in load and wind are not taken into account.
- All hours of statistical simulations are treated the same, which may create problems when wind production exceeds 30% of the system load. That is, the statistical study shows there are a limited number of instances when wind power causes large swings on the system; however, when these swings occur during low load hours, the consequences on system operation can be significant and should be investigated in detail. No detailed investigation was part of this study.

- The data and analyses in this report do not address how the control area demand with significant wind generation would affect WAPA control area operations or how specific generating resources would be impacted.
- The statistical analysis of the long-term meteorological dataset located in the centroid of the proposed wind farm sites of the Dakotas, with runoff into a watershed that extends hundreds of miles, as far as western Montana, is problematic. There are inherent problems such as precipitation runoff lag for snowmelt in the Rocky Mountains. Other considerations include, for example, a particular meteorological pattern might favor greater-than-normal precipitation over the southern and central Dakotas but could also support drier-than-normal conditions over the westernmost part of the watershed.
- Long-term runoff data was available only as bulk for the entire section upstream of Sioux City, Iowa, but not from individual tributaries or points.

#### **7.2.4 Wind Power Characteristics**

The study included five potential wind plant locations spread throughout North and South Dakota, which provided substantial geographic diversity. A total of 50 points simulating proxy meteorological towers at 80-meters hub height were dispersed within these five regions. Wind speed and power data were simulated at 10-minute intervals for the year 2003. A nested grid was employed within the MM5 of 1–4 km resolution and used over North and South Dakota for power simulations, with a larger resolution meteorological model covering the central United States and parts of Canada. Wind speed data were used to generate power production at an 80-m hub height for GE 1.5S and 1.5SI, 1,500-kW turbines. Figures illustrating the locations of the wind power plants within North Dakota and South Dakota are provided below. Figure 32 shows the general location of the wind power resources relative to the high-voltage transmission system, and Figure 33 shows the MM5 1-km grid covering the region, along with the proxy towers. The black dots of the proxy towers are located in five general areas, and these areas correspond to the five wind power plant sites considered in the statistical determination of the wind impacts on regulation and load following.



**Figure 32. The general location of regions and sites for the MM5 meteorological simulation**

**Figure 33. The inner grid layout deployed for the MM5 meteorological simulation (Numbered black dots correspond to the “proxy” meteorological towers, and the large, magenta dot labeled “RNL PT” indicates the location where long-term climatological data was extracted for comparison of wind and hydropower resources)**

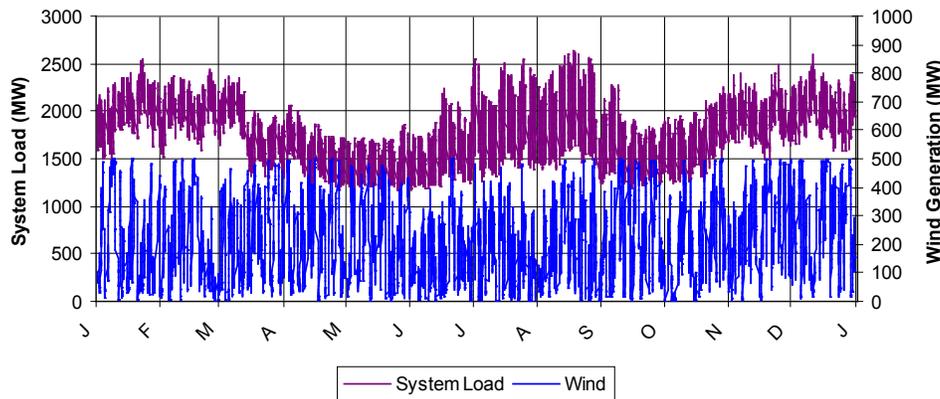
Hub-height data was stored at 10-minute intervals for the entire year at each proxy tower. From this chronological data, a number of wind resource characterizations were generated. These 10-minute wind speed time series were then transformed into wind power time series by

processing them through a GE 1.5-MW power curve. The power time series were then used in a long-term, climatological comparison of wind speed and water runoff, and in assessing wind integration impacts on the WAPA balancing area load. Hypothetical wind power plants proposed at five sites for the different wind scenarios are summarized in Table 34.

**Table 34. The study cases and wind-generation scenarios**

Wind Capacity	Approximate Wind Penetration (wind/peak load)	Mission	Ft. Thompson	Buffalo Ridge	Edgeley	Max
80 MW	3.0%		40 MW		40 MW	
100 MW	3.7%	20 MW	20 MW	20 MW	20 MW	20 MW
250 MW	9.3%	50 MW	50 MW	50 MW	50 MW	50 MW
500 MW	18.5%	100 MW	100 MW	100 MW	100 MW	100 MW
1000 MW	37.0%	200 MW	200 MW	200 MW	200 MW	200 MW

Sample output of the wind power time series are shown in Figure 34. The WAPA balancing area system load is plotted together with the wind power time series (each time series corresponds to a different scale) for the 2003 model year.



**Figure 34. The 2003 WAPA system load plotted with the output from a 500-MW wind power plant**

Annual capacity factors for the five cases ranged from 42–44%. By season, the capacity factors were lowest in the summer months and greatest in the spring and fall. The average daily profiles were generally flat with a decline late in the day, as can be seen in Figure 35.

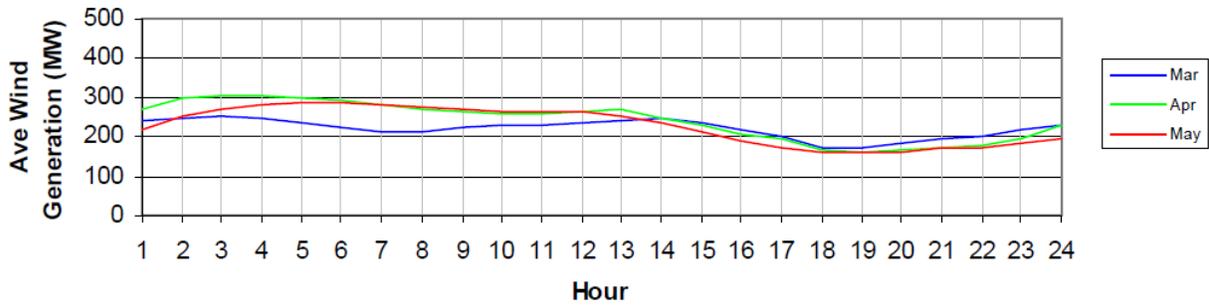


Figure 35. The average daily profile for summer months for the 500-MW scenario

### 7.2.5 Hydro System Characteristics

The six hydropower facilities being considered in this study are located at the dams within WAPA's UGPR are run by USACE, managed within its North-Western Division, and based on written guidelines in the Missouri River Master Manual ([www.nwd-mr.usace.army.mil/mmanual/mast-man.htm](http://www.nwd-mr.usace.army.mil/mmanual/mast-man.htm)). USACE updates this manual each year; provides guidance to the operators at each dam concerning water releases; and incorporates recent and projected hydrological conditions, environmental requirements (e.g., accounting for bird and fish survival), desired lake levels, etc. The dams are all located on the main stem of the Missouri River in the Northern-Midwest United States, as shown in Figure 36; they collect all of the runoff in the Missouri River drainage basin and feed into the Mississippi River at the most Eastern extent of the basin.



Figure 36. The Missouri River drainage basin and the six dams and hydropower facilities operated by USACE (highlighted in red)

The names of the six dams are highlighted in Figure 36—they can store a combined 75 million acre-feet of water (about three times average annual runoff) and have hydropower facilities totaling a combined peak capacity of approximately 2,400 MW (Fort Peck: 185 MW; Garrison:

517 MW; Oahe: 714 MW; Big Bend: 494 MW; Fort Randall: 320 MW; Gavins Point: 132 MW; based on data from the U.S. Department of Energy, Energy Information Administration, 2002). WAPA schedules and markets power generated by these facilities and delivers it to public power customers throughout the Midwest.

The hydro resources available to this control area are in the Missouri River Valley Basin. The dams are situated on the main stem of the Missouri River and therefore all downstream dams are dependent on the water releases from the upstream facilities. However, since the combined water storage capacity in these reservoirs is three times the annual runoff, there is some flexibility in timing of water releases. As with any federally funded hydropower facility in the United States, there are multiple uses for these facilities, and power generation is typically the lowest priority. These dams were created with flood control as their primary purpose, and they are also used for navigation, recreation, irrigation, and power generation. Furthermore, there are numerous environmental regulations regarding water releases from the dams pertaining to bird and fish survival. Combined, these priorities and constraints restrict the use of the indigenous flexibility available in the hydro generators. Therefore, capacity and energy schedules are set subservient to the other priority uses and environmental constraints.

Overlaid on the physical capabilities and constraints of the hydropower facilities are numerous organizations and stakeholders. USACE operates the dams; WAPA markets the power; and there are numerous public power and water customers. Taken together, the collective stakeholders and institutions create a formidable bureaucracy to negotiate. At present, the only practical method of wind integration is for customers of the Federal hydropower (e.g., the customers in WAPA's balancing area) to integrate wind in with their load obligation and utilize the Federal hydropower within its current set of constraints, regulations, and laws. Because of the organizational and legal complexities involved, it was decided to focus this effort on determining the statistical impacts in the regulation and load-following time frames, considering only the balancing area load and proposed wind power generation.

### **7.2.6 Wind Power Penetration and System Flexibility**

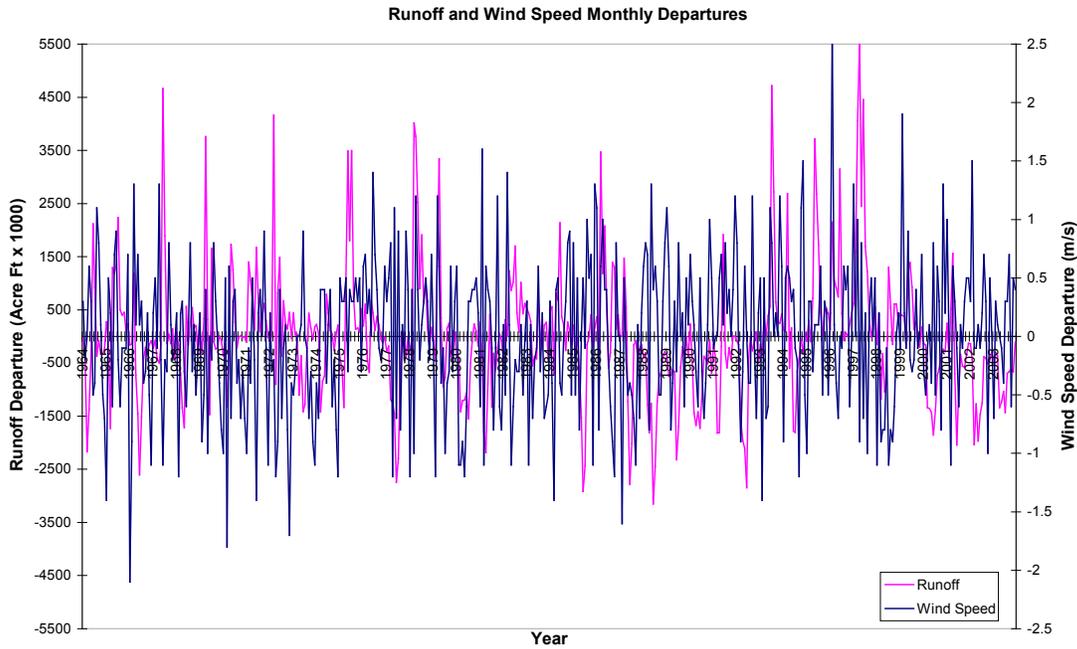
The study includes hypothetical installed wind capacities of 80; 100; 250; 500; and 1,000 MW. Peak load and the penetration rates that these capacities would correspond to are not mentioned explicitly in the project report. However, the peak system load during the period reported (2003) was approximately 2,700 MW. Therefore, the wind penetration computed as a percentage of peak system load, for each wind capacity scenario, is 3.0%; 3.7%; 9.3%; 18.5%; and 37.0%, respectively. Since this study only considers a statistical analysis of wind power variability on system load (i.e., the flexibility of the generators to meet the load is not considered), reporting the wind penetration as a percentage of peak load is appropriate.

### **7.2.7 Wind and Hydro Integration – Benefits and Impacts**

Because this study focused on determining the impact of wind variability and uncertainty on the load following and regulation statistics, the benefits to or impacts on the hydropower system was not assessed. However, an investigation was made pertaining to the question of whether or not the timing of the wind power and hydropower resources was complementary, coincident, or uncorrelated.

In addressing this question, the long-term climatological relationship between the wind speed and water runoff (which is related to the hydropower) was conducted in the region of interest. To understand the statistical relationship between the Missouri River Valley Basin and the Dakotas wind, 40 years of overlapping data from 1964–2003 were selected for analyses. Data on the long-term wind climatology for the Dakotas was obtained from the National Centers for Environmental Prediction / National Centers for Atmospheric Research Global Reanalysis (RNL) dataset (Kalnay, et al. 1996; Kistler, et al. 2001). A representative RNL grid point was selected to represent the wind characteristics of the Dakotas. As shown in Figure 33 displaying the MM5 grid, this RNL grid point is located close to the approximate centroid of wind power generation for the ensemble of proxy wind farm locations. By extracting the approximate hub-height level wind data from the RNL dataset, monthly time series data for the 40-year examination period were produced for the representative grid point. USACE provided long-term runoff data for the Missouri River, above Sioux City, Iowa, in monthly increments for the period of 1964–2003. USACE normalized the runoff data to the 1949 level of development.

Data for runoff and wind speed departures are plotted in Figure 37. The blue line shows the monthly runoff departures for this period (the *departure* is defined as the difference between the monthly average and the long-term, 40-year average), and the magenta line represents the monthly wind speed departures. However, this graph shows no obvious correlation between the data. Numerous statistical tests were conducted to determine if a correlation exists between the data sets, considering the monthly data, yearly averaged data, and rolling averages of the data. Time shifts of the data sets were also considered in order to uncover any time shifting of the data (i.e., one data set leading or lagging the other). Of the many statistical tests conducted, most did not yield any correlation between the data sets. The only trials that yielded small-to-modest inverse correlations were those for the 2- and 3-year running averages ( $R = -0.25$  and  $-0.26$ , respectively) and a trial that involved leading (lagging) the wind speed departure series (runoff departure series) by 1 year ( $R = -0.4$ ). In the latter case, the time series analysis indicated that 67% of the comparison points for the wind speed and runoff departures were of opposite sign. In summary, the most coherent statistical signal resulted from the experiment in which wind speed departure was allowed to lead the runoff departure by 1 year. In physical terms, this would indicate at least some tendency for good wind years to lead (by just 1 year) poor runoff years.



**Figure 37. Time series of monthly runoff and wind speed departures, 1964–2003**

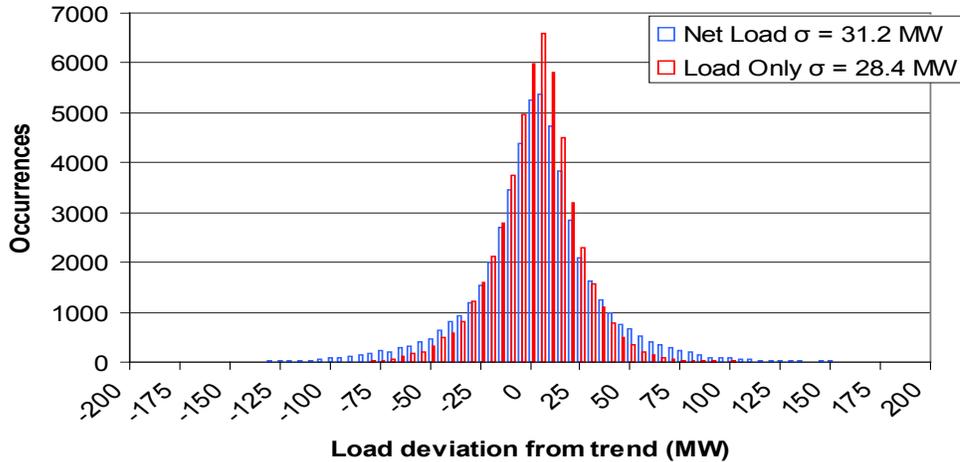
### 7.2.7.1 Regulation and Load Following Statistics

The relative impacts of wind generation on real-time control area operations and day-ahead planning can be estimated by examining various aspects of load and wind generation time series data. In general, the effects are assessed by comparing various attributes of the load alone to the load net of wind generation. For evaluating real-time operating impacts, the variability of the control area demand is the major issue. Generating resources must be deployed and controlled to match demand continuously. This overall objective can be further broken down by time frames over which the adjustments to generation take place. A typical breakdown would include:

- Regulation: tens of seconds to minutes
- Load following: tens of minutes to an hour
- Ramping: one to several hours

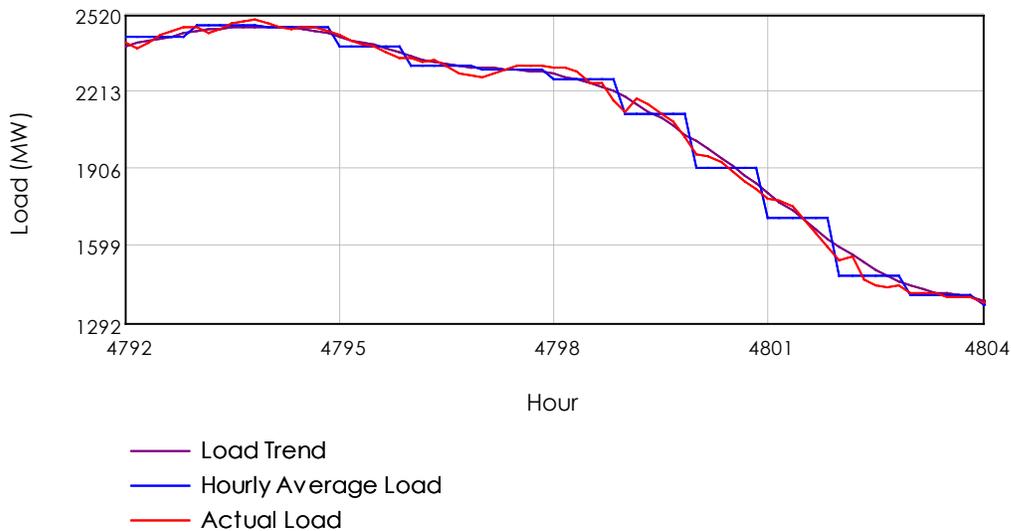
While these terms can take on somewhat different definitions in various control areas, and the division between them may be hard to quantify, in general, they cover the range of generation control that takes place over the course of a day. The effect of wind generation on the behavior of the WAPA control area demand in these operational time frames was investigated in this study, the results of which are described below.

An initial measure of the wind generation impact on the control area demand variability is created by calculating the value of the control area demand changes from one 10-minute interval to the next. Figure 38 shows the statistical distributions of these variations for the existing load alone and the load net 500-MW wind generation. Using the standard deviation of the distribution as the metric, wind generation impacts begin to become significant at the 500-MW level. This measure, however, is relatively coarse and does not account for the faster 1-minute fluctuations experienced by the system.



**Figure 38. Statistical distribution of 10-minute regulation for the 500-MW scenario**

Another method for processing wind and load data is illustrated in Figure 39. A trend characteristic (based on a 2-hour running average) and an hourly average value have been created from the 10-minute resolution load data. Variations of the control area demand were then computed as the differences between the actual load and the trend or the actual load and the average value for the hour.



**Figure 39. A sample of the actual WAPA load, load trend, and average hourly load**

The amount of “10-minute regulation” capacity that would be required to compensate for the additional fluctuations wind adds to the system due to variations of the 10-minute load data about the 2-hour trend are summarized in Table 35. Since the distribution of variations is essentially normal (Gaussian), 99.7% of all variations are accounted for by multiplying the standard deviation by 3 ( $3\sigma$ ) and 99.9999% by computing  $5\sigma$ . The “incremental regulation” is then computed by computing the difference in these measures between the load only and the load net wind. The value of the incremental regulation that the system operator would be required to provide for the system is expected to be in the range of three times the change in the standard deviation (load and load net wind),  $3\Delta\sigma$ , to  $5\Delta\sigma$ .

**Table 35. Incremental 10-minute regulation requirements for wind generation**

Scenario	Incremental Regulation (3 x $\Delta\sigma$ )	Incremental Regulation (5 x $\Delta\sigma$ )
100-MW Wind Generation	0.6 MW	1.0 MW
250-MW Wind Generation	1.2 MW	2.0 MW
500-MW Wind Generation	3.9 MW	6.5 MW
1,000-MW Wind Generation	12.9 MW	21.5 MW

A second component of the variation consists of the difference between the trend (i.e., the 2-hour rolling average) and the average hourly value, which would impact generation that is being adjusted to track slower changes in control area demand. The statistics of these variations are summarized in Table 36. The right-most column in the table shows a value of 2 multiplied by the change in standard deviation between the existing load and the load net wind in each scenario. Two times  $\Delta\sigma$  would account for 95.4% of the additional variations in the longer-term (load following type) trend brought about by the wind in each scenario. The actual increment in this trend can be computed by multiplying the change in standard deviation by between 2 and 4, dependent on the preferences of the system operators and planners. However, the load following trend is typically multiplied by a smaller factor than the regulation characteristic, simply because the system operator typically has time to deal with the changes in trend through economic dispatch of units or via the market, whereas the regulation characteristic must be dealt with in real time with resources available on the system.

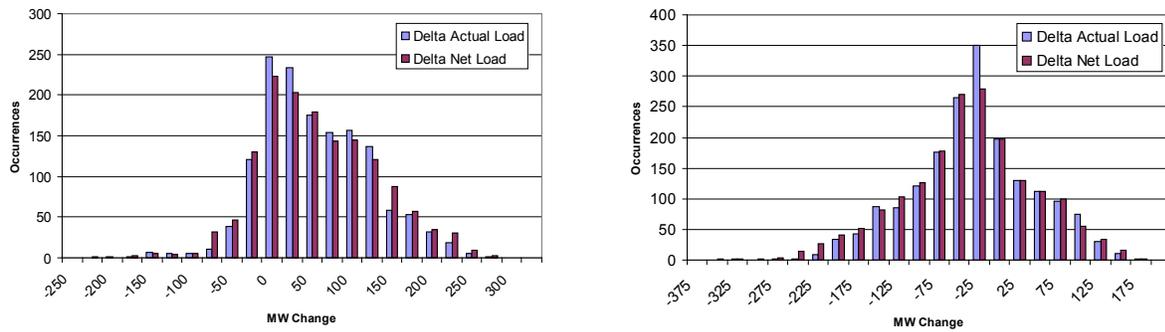
**Table 36. Summary of statistics: variation of 2-hour rolling average from average hourly value**

Scenario	$\sigma$ – Deviations from Hourly Average	2 x $\sigma$	2 x $\Delta\sigma$
Existing Load	31.3 MW	62.6 MW	--
100-MW Wind Generation	31.7 MW	63.4 MW	0.8 MW
250-MW Wind Generation	32.5 MW	65.0 MW	2.4 MW
500-MW Wind Generation	34.3 MW	68.6 MW	6.0 MW

#### 7.2.7.2 Morning and Evening Ramping

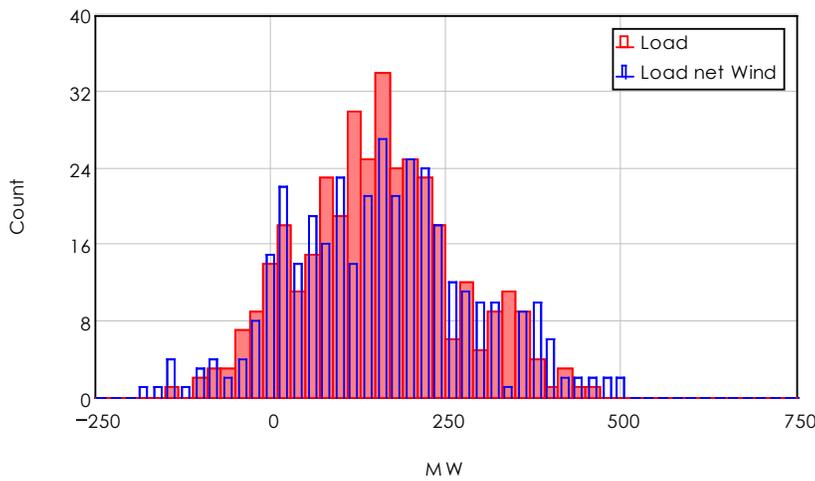
As shown previously, spatial and geographic dispersion of large numbers of individual wind turbines have a significant beneficial effect on short-term variability of wind energy production,

since short-term changes between wind power plants are essentially uncorrelated. Over longer time periods, however, correlation in behavior between even well-separated wind plants will increase. In real-time operations, multi-hour periods when the load is changing substantially can be challenging for operators. With significant wind generation in the control area, there exists a possibility that these ramping periods can be made even more challenging if wind production moves in a direction opposite to that of the load. Therefore, peak ramping load hours in the morning and evening, which are of special interest to operators, were analyzed in greater detail. The effect of wind generation on changes during these important operational periods can be illustrated from the annual record of wind and load data for the study year. The two graphs in Figure 40 show the hourly load changes during the morning and evening ramping periods for load and the various wind scenarios. Perhaps what is most striking about these distributions is how little wind generation effects the hourly changes, even at 500 MW.



**Figure 40. Hourly load changes during ramp periods for 500-MW wind scenario, morning (left) and evening (right)**

The impact of changes/ramps in wind energy on the morning and evening ramps become more pronounced if one considers a 4-hour period of time in the morning or evening. Figure 41 illustrates the net control area demand change over a multi-hour period in the morning (from 6 a.m. to 10 a.m.) for the 500-MW scenario. Here, the effect of wind generation shows up more clearly. At 500 MW, there are 4 days with morning ramps higher than what was seen in 2003 with load alone, and a substantially higher number of very high ramps.

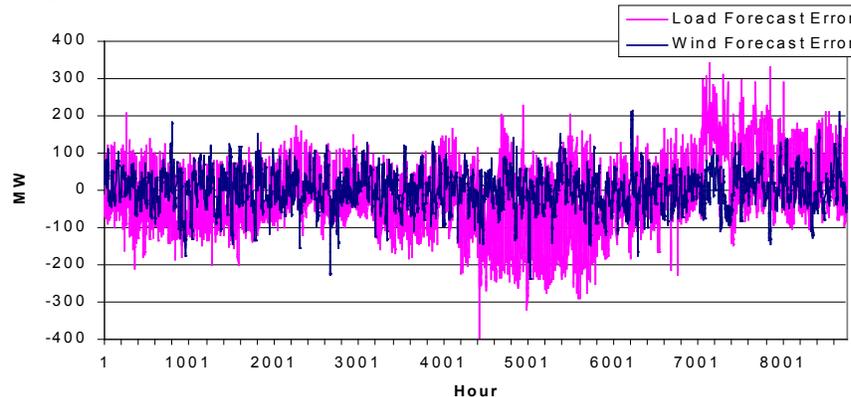


**Figure 41. Distribution of morning ramps for load and load net 500-MW wind generation**

### 7.2.7.3 Wind Generation Forecast Error

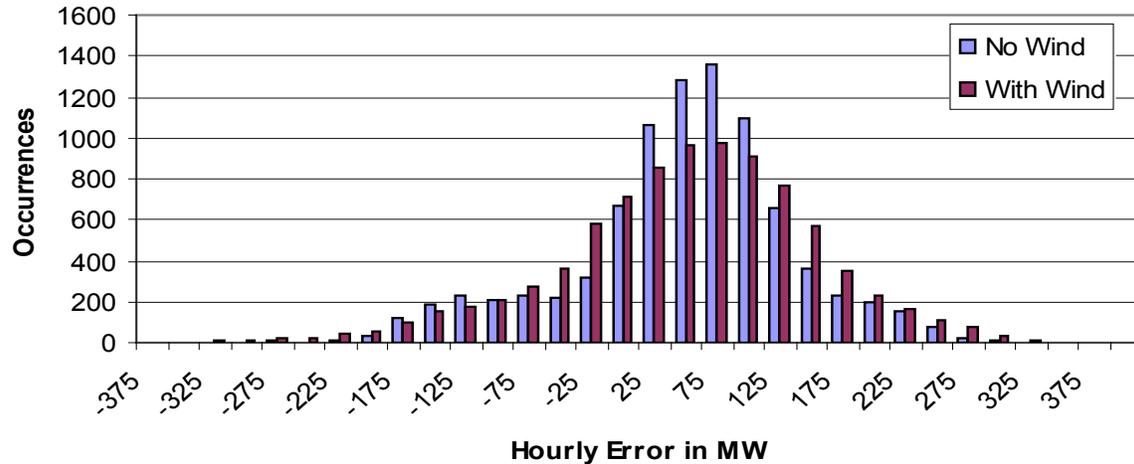
Wind generation forecasting is a relatively new science. At present, day-ahead forecast accuracy of 15–25% mean absolute error of the plant rating over 1 year has been achieved. Even with this level of effectiveness, there will still be hours and days in which the wind generation forecast error can be very high. Mis-timing of frontal passages, for example, can lead to very large hourly errors, even if the overall pattern and daily energy are reasonably close to actual. Day-ahead forecasts of energy delivery can be more accurate since they are not as dependent on the exact timing of meteorological systems. Accuracies of 15–20% of actual energy delivered are possible. For this study, a forecast time series for the 2003 wind scenarios was created, based on a forecast study conducted for Xcel Energy.

The overall impact of day-ahead wind generation forecast errors depends on the accuracy of day-ahead load forecasts. If load forecasting was perfect, then any costs due to sub-optimal plans or day-ahead transaction decisions could be attributed to wind generation. Since load forecasting is not perfect, the effect of wind forecast errors can be muted somewhat, given that there are days or hours in which the sign of the individual errors is opposite. Of course, there will also be times where the errors add mathematically. If the individual error series are uncorrelated, however, the combined error over time would be significantly less than the arithmetic sum. Figure 42 contains a time series plot of the individual day-ahead forecast errors for wind generation and load for the hourly data for the year 2003.



**Figure 42. Time series plot of the load forecast error and the wind forecast error for the 500-MW scenario**

Combining these forecast errors shown in these time series, Figure 43 provides a distribution of the errors for the load forecast and the forecast for load net wind for the 500-MW scenario. Due to the existing load forecast errors in the WAPA system, there is little noticeable impact of wind generation on the day-ahead, hour-by-hour forecast until the penetration reaches 500 MW (as shown).



**Figure 43. Distribution of load and load net wind day-ahead forecast errors for the 500-MW scenario**

In conclusion, the statistical study presented has indicated that in the WAPA system, significant operational impacts from wind energy—those that must be dealt with in planning and operation—will likely arise when the wind penetration approaches 500 MW (about 18% of the peak system load). Below 10% wind penetration, the impacts on 10-minute regulation—load following, morning and evening ramping, and the load net wind forecast error—are somewhat modest.

### 7.2.8 Conclusions

This study considered integrating five levels of wind power (80 MW, 100 MW, 250 MW, 500 MW, and 1,000 MW) into the WAPA control area with its peak load of 2,700 MW. Thus the wind penetration levels (defined by wind power capacity divided by peak load) for these cases were 3%, 3.7%, 9.3%, 18.6%, and 37%, respectively. A statistical study was performed to determine the impacts of the wind integration on the system regulation (minute-to-minute variations), load following (hour-to-hour), magnitude of ramping during the morning and evening load ramps, and the effect of wind forecast errors on the aggregate hour-ahead and day-ahead forecast error of load net wind versus load alone. The following conclusions were drawn:

- The amount of “10-minute regulation” capacity that would be required to compensate for the additional fluctuations wind adds to the system due to variations of the 10-minute load data about the 2-hour trend was found to be minimal for wind penetration levels up to 250 MW, noticeable at 500 MW, and significant at 1,000 MW of wind power.
- The load following trend, computed via changes in hourly load and compared to changes in hourly load net wind, showed a similar result to the regulation in that the influence of the wind power did not become significant until 500 MW of wind was absorbed into the system.
- Of importance in any electrical system is the ability of the system operator to use available generation resources to effectively and economically meet the morning and evening ramping requirements. The statistical study demonstrated that the load changes during the morning and evening ramping periods were very similar for the load alone and the load net wind even

up to 500 MW of wind power (18.6% penetration). After this level, the wind does impact the ramping requirements, increasing the number of larger ramps that occur and increasing the maximum level of ramping needed during the year.

- In investigating the effect of wind forecast errors, the error in the wind forecast was combined with load forecast errors and then compared to the load forecast errors alone. Due to the existing load forecast errors in the WAPA system, there is little noticeable impact of wind generation on the day-ahead, hour-by-hour forecast until the penetration reaches 500 MW.

In conclusion, the statistical study presented has indicated that in the WAPA system, significant operational impacts from wind energy—those that must be dealt with in planning and operation—will likely arise when the wind penetration approaches 500 MW (about 18% of the peak system load). Below 10% wind penetration, the impacts on 10-minute regulation—load following, morning and evening ramping, and the load net wind forecast error—are somewhat modest.

### **7.3 Case Study: Sacramento PUD, Upper American River**

#### **7.3.1 Introduction to Study**

- *Study description and goals:* The study focused on the impacts to the Sacramento Municipal Utility District (SMUD) that four proposed penetration levels of wind generation would have on regulation requirements, equivalent capacity values, and integration costs. The goals of the study are grouped into seven defined tasks. These tasks include such components as creating models of the SMUD system operations by including wind, estimating the capacity value of wind in the system, and determining the reserve requirements and unit commitment practices required for incremental penetration levels. Additionally, educational resources for system operators are considered, as well as interconnection issues with the existing grid system.
- *Organizations involved:* EnerNex Corporation conducted the study for the Public Interest Energy Research Program of the California Energy Commission in collaboration with Sacramento PUD. WindLogics was also involved to assist with the development of the wind generation models.
- *Reason study was performed:* The study was conducted to analyze the impacts that increased intermittent generation will have on system operations, reliability, reserve requirements, and overall integration costs.
- *Case study chapter has been condensed from the following project report:* Zavadil, Robert. 2008. *Wind Integration Study for the Sacramento Municipal Utility District*. California Energy Commission, Public Interest Energy Research Renewable Energy Technologies Program. CEC-500-00-034.
- *Intended outcomes of the report relative to the objectives of Task 24:* This study fits into the grid integration case study category of Task 24. The primary objective was to assess the stochastic nature of the power produced from additional wind energy plants and the impacts they cause on the need for additional fast-ramping regulation and load following reserves in

the SMUD balancing area. Also investigated was the ability to provide “regulation” from the hypothetical Iowa Hill pumped storage facility.

**7.3.2 Overview of Power System**

**Table 37. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for U.S. SMUD wind integration study**

<b>Study conducted by:</b> EnerNex Corporation for Public Interest Energy Research Program of California Energy Commission (WindLogics subcontracted for wind generation modeling)						
<b>Geographic area of study:</b>						
<ul style="list-style-type: none"> <li>- County of Sacramento</li> <li>- 900 mi<sup>2</sup> (source: SMUD website)</li> <li>- Population of area served: 1.4 million (source: SMUD website)</li> <li>- Five wind plants located outside of the SMUD balancing area</li> <li>- Hydropower on the Upper American River</li> </ul>						
Power System Characteristics:						
Load			Conventional Generation	Interconnection	Wind Power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
3,721 (2011)	924 (2011)	13.65 (2011)	972 thermal (including 500 Combined Cycle Gas Turbine) 230 additional contract thermal 688 hydro 10 MW PV	2000 MW (currently and 2011)	Case 1: 102 (current) Case 2: 252 Case 3: 453 Case 4: 855	Case 1: 102 MW = 0.292 Case 2: 252 MW = 0.703 Case 3: 453 MW = 1.291 Case 4: 855 MW = 2.400
<b>Other relevant characteristics of power system:</b>						
<ul style="list-style-type: none"> <li>• SMUD peak load exceeds generating capacity, and excess generation is scheduled through the California Independent System Operator (CAISO) in the form of short-, medium-, and long-term contracts.</li> <li>• Iowa Hill is a proposed 400-MW pumped storage hydro facility</li> </ul>						
<b>Characteristics of system planning:</b>						
<ul style="list-style-type: none"> <li>• Day-ahead scheduling: Schedule 6 a.m. day-ahead for unit commitment</li> <li>• Regulation: Includes minute-to-minute up to a couple of hours</li> <li>• Real-time desk conducts hour-ahead adjustments when needed</li> <li>• Hydro is run on ACG for fast regulation, but is used sparingly to conserve for summer</li> </ul>						
<b>Description of market:</b>						
<ul style="list-style-type: none"> <li>• SMUD is vertically integrated, and tied to CAISO with many long- and medium-term, bilateral contracts.</li> <li>• The integration study relied on the upcoming CAISO Hourly Ahead Scheduling Process market for sales of excess wind. SMUD is unable to purchase energy in the Hourly Ahead</li> </ul>						

Scheduling Process market.	
<b>Integration time frames of importance:</b>	
Yes/No	Time Frame
Yes	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg
Yes	Regulation, AGC
Yes	Load following; intra-hour ramping; economic dispatch
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources
Yes	Resource and capacity planning; reliability

**7.3.3 Study Methodology**

The study was broken into seven separate tasks (of which six were completed) to assess the impacts of integrating wind into the SMUD system. Additionally, a series of four cases were run with different wind penetration levels, and each of these were assessed with and without consideration of the Participating Intermittent Resources Program (PIRP), as well as with and without the proposed Iowa Hill pumped storage facility. The first two cases involve smaller penetration levels, which are also less geographically diversified. The second two cases involve higher and more geographically diversified penetrations. The simulations were conducted by using load data from 2003–2004 as well as physics-based Numerical Weather Prediction wind models using meteorological data from 2003–2004.

Underlying assumptions and the modeling approach are summarized in Table 38.

**Table 38. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the U.S. SMUD wind integration study**

Set Up		
<b>A</b>	<b>Aim of Study</b>	1 – what happens with a certain number of GWh of wind – analyze impacts of various levels of wind generation on: ancillary service amounts and costs, performance and reliability, reserve requirements
<b>M</b>	<b>Method to Perform Study</b>	1 – add wind energy to SMUD (also consider scheduling new wind through ISO)
<b>S</b>	<b>Simulation Model of Operation</b>	2 – deterministic simulation several cases (various levels of wind integrated)
Simulation Detail		
<b>R</b>	<b>Resolution of Time</b>	2 – hour scale for analysis of load following generation and needed reserves; 3 – sub-minute scale for analysis of fast regulation analysis and necessary reserves
<b>P</b>	<b>Pricing Method</b>	1 – costs of fuels 2 – prices for trading with neighbors 4 – market dynamics included
<b>D</b>	<b>Design of Remaining System</b>	1 – constant remaining system 2 – optimized remaining production
Uncertainty and Balancing		
<b>I</b>	<b>Imbalance Calculation</b>	2 – wind+load

<b>B</b>	<b>Balancing Location</b>	2 – from the same region 3 – also outside region
<b>U</b>	<b>Uncertainty Treatment</b>	3 – no wind forecasts (persistence for < 2 hours ahead, rough error patterns and mean absolute error used otherwise) 5 – load forecasts considered 6 – thermal power outages considered
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	2 – constant MW limits – 2000-MW import limit 3 – consider voltage
<b>H</b>	<b>Hydropower Modeling</b>	5 – consider most relevant aspects of affected hydro resources
<b>HC</b>	<b>Hydro Capacity Service</b>	2 – real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	1 – ramp rates considered 2 – start/stop costs considered 3 – efficiency variation considered 4 – heat production considered
<b>W</b>	<b>Wind Power Modeling</b>	3 – time series smoothing considered

### 7.3.3.1 Assumptions

- For the purpose of the study, the short-, medium-, and long-term power contracts that SMUD schedules through CAISO were treated as if they were tangible power produced by conventional sources. Appropriate loss of load and forced outage rates were incorporated.
- The wind and hydro projects involved are out of the SMUD control area, but all are hard-wired to the control area.
- Wind power production values were formulated using Vestas V82 1.65-MW turbines. The peak power rating was scaled to 3 MW for the purpose of achieving 12 MW of generating capacity at each proxy tower site.
- All generating units can exist only at full capacity (up) or zero capacity (down) states, and forced outage, failure, and repair rates are subsequently determined.
- Fuel costs were assumed fixed throughout the year.
- The reference case treats wind as a perfectly predictable source, therefore requiring no change in reserve requirements. The actual or additional cases require additional reserves. Penetration levels and geographic dispersion of the seven cases are shown in Table 5 of the report.

### 7.3.3.2 Limitations

- Meteorological weather simulations were used to determine wind availability at some of the key sites due to a lack of historical weather data.
- There are some inconsistencies between the simulated cases, mostly in the form of different reserve amounts for the cases that included Iowa Hill. These discrepancies were not discovered until later in the study, and there was not sufficient time to re-run all cases to be consistent.

### 7.3.3.3 *More Details About the Simulation*

Many wind integration studies to date have employed an analytical methodology based on chronological simulation of power system operation at the hourly level. This hourly granularity is very common in conventional production costing analysis, and allows for long-term (i.e., annual or longer) simulation of the power system. Because this study applied a novel technique to determine the fast regulation requirements (minute-to-minute), it bears further explanation.

Due to temporal resolution, the real-time control of generation for support of system frequency and balancing of the control area cannot be represented explicitly in an hourly simulation. Instead, the amount of capacity type required to perform this function is deployed indirectly to meet various reserve constraints that are placed on the unit commitment optimization and economic dispatch of units in the simulation. While this has worked quite well for conventional production costing studies, there is some concern that it may be inadequate in some instances for wind generation studies. This is primarily due to the fact that increased reserve requirements and cost is of primary interest in wind integration, whereas the reserve questions are generally much less important for other studies based on production costing simulations. Therefore, one objective of this wind integration study was to employ detailed, high-resolution simulations of the SMUD control area to ascertain the impacts of wind generation on real-time operation of SMUD resources. The platform used for these simulations is the e-terra-simulator from Areva Transmission & Distribution. The simulator is a component of Areva's Energy Management System product line for utility control centers. Its primary purpose is to provide a realistic environment for training of system operators, which is why the product has also been known as the Dispatcher Training Simulator. The Dispatcher Training Simulator uses all the core algorithms and processes used to manage a control area, but operates on a simulation model rather than from Supervisory Control and Data Acquisition signals as inputs and generation control pulses as outputs. Areva's Dispatcher Training Simulator has been modified to allow wind generation to be represented as a point-by-point generation value, so that the type of wind data generated for this study can be used directly to define wind generation.

### 7.3.3.4 *Hourly Simulation*

The hourly cases were completed for at least 1 full year of data for four wind generation penetration levels. Wind generation data for the all cases was synthesized from the WindLogics MM5 meteorological simulation data for the historical year 2003. Integration cost in this study is defined as the difference between the actual production cost incurred to serve the net of actual load and actual wind generation and the production cost from the reference case, where wind is perfectly known and adds no variability to the control area, and where next-day load is the only uncertainty.

The method for determining the costs at the hourly level proceeds as follows:

1. Run the unit commitment program (Areva e-terra Commit) in Unit Commitment mode to develop a plan for serving the forecast load. Wind generation for the day is known perfectly, and is delivered in equal amounts each hour through the day. The results are saved as basis for the next step.
2. Run a second unit commitment simulating a morning-of re-commit with the day-ahead transactions fixed from Step 1, and allow the thermal units to recommit if necessary. This

run uses fixed-block wind energy and assumes perfect load knowledge. The results are saved as a basis for the next step.

3. If Iowa Hill is included in the case, a third unit commitment run is made to simulate hour-ahead commitment decisions on its operation. This run assumes perfect knowledge of load. The day-ahead transactions and unit commitment schedule from Step 2 are fixed, but dispatch is allowed to vary based on the commitment.
4. Using the unit commitment from Steps 2 or 3 above, re-run the day with forecast load replaced by actual load. The program runs an economic dispatch based on the commitments and allows re-dispatched, available units to meet the actual load. Generation is manually committed to meet load that cannot be served from the early same-day commitment. From these results, total production cost for the period is calculated and defined it as the “reference production cost.”
5. Repeat Step 1 with the load forecast and the day-ahead wind energy forecast calculated from the actual wind pattern. Again, the results are saved with the day-ahead energy transactions.
6. Run a second unit commitment simulating a morning-of re-commit with the day-ahead transactions fixed from Step 5, and allow the thermal units to re-commit if necessary. This run assumes perfect load knowledge. Wind forecast uses the same error pattern as Step 5 but reduces the mean absolute error of the forecast to 10%, which is consistent with typical 2–10-hour-out forecasts. The results are saved as a basis for the next step.
7. If Iowa Hill is included in the case, a third unit commitment run is made to simulate hour-ahead commitment decisions on its operation. This run assumes perfect knowledge of load and uses a two-hour persistence forecast for wind. The day-ahead transactions and unit commitment schedule from Step 6 are fixed but dispatch is allowed to vary based on the commitment.
8. Finally, using the unit commitment from Steps 6 or 7 above, re-run the day with forecast load replaced by actual load. The program runs an economic dispatch based on the commitments and allows re-dispatch available units to meet the actual load. Any unserved load left at the end of the dispatch is met using a generic thermal resource at 10.45 heat rate and the prevailing gas cost. From these results, total production cost for the period is calculated and defined it as the “actual production cost.”
9. Integration cost is then calculated as the difference between the “actual production cost” and “reference production cost” normalized to the total annual wind energy for the case and is expressed in \$ USD/MWh of wind energy.

Certain aspects of the methodology enumerated above merit additional emphasis:

- Load megawatt-hours and wind megawatt-hours in “reference” and “actual” cases is identical. If wind generation is assumed to be a “must take” resource, the payment from SMUD to the wind generators is identical in both the “reference” and “actual” cases. Therefore, the cost per megawatt-hour of wind energy is not relevant to the analysis (i.e., it “subtracts out”).

- Reference cases are run with base reserve requirements not modified by the wind. Actual cases are run with reserve requirement that are modified by the wind values, as documented elsewhere in this report. The exception to this rule is the PIRP case in which the base reserve requirements are used also for the “actual” cases. This in effect says that in PIRP cases, SMUD bears no burden for extra reserve requirements due to the wind.
- Consumes combined-cycle plant was set as must-run in all cases. Without this condition, there were a large number of overnight hours that did not meet energy and reserve requirements since no units under AGC were committed based on economics.

Finally, there is the issue of the wind generation attributes defined for the “reference” case. In this method, wind energy delivery is allowed to vary day-by-day, but the delivery within in a day is assumed to have the characteristics of a baseload resource. The argument for such treatment is that baseload resources impose no incremental burden on daily operations (except for decisions to de-commit large baseload resources). They neither assist with nor detract from the ramping or regulation requirements imposed by the load. In some respects, they are nearly invisible to the system operators.

The reference resource for wind assumed here is equivalent to an “as-available” energy contract with a third-party, where the terms of the contract allow the constant delivery to be scheduled a day in advance.

In some circumstances, defining the reference resource to be some type of conventional unit may be appropriate. Care must be taken, however, to operate this unit per the terms of the contract and within the capabilities of the actual proxy unit. As an example, if the reference resource were defined to be a simple cycle-gas turbine, it would not be appropriate to allow that unit to be dispatched to provide load following or other ancillary services unless the terms of the power purchase agreement were to explicitly include consideration of and compensation for this capability.

#### **7.3.4 Wind Power Characteristics**

The study analyzed the impacts of SMUD’s existing 102-MW Solano wind plant and a subsequent expansion to 250 MW. Additionally, the study looked at a third case with 453 MW and a fourth case of 855 MW, using wind at geographically dispersed sites ranging from northern California to southern Oregon. Wind power simulations were divided into seven cases to incorporate the various penetration levels, geographic diversity, and scenarios, including Iowa Hill pumped storage. Each of these included a PIRP and non-PIRP run to assess the impacts of variability. The four most relevant cases are shown in Table 39. Wind and load data from 2003–2004 were used in the simulations. Numerical Weather Prediction simulations MM5 were conducted with a resolution of 20–40 km for entire area, with nested grids of a few kilometers used for wind sites of major interest.

**Table 39. Wind turbine population and capacity by case**

Site	Solano	Abert Rim	Stinkingwater Mountains	Shasta County	Fredonyer Peak
<b>Case 1</b>					
MW	102				
Turbines	34				
Towers	9				
<b>Case 2</b>					
MW	250				
Turbines	84				
Towers	21				
<b>Case 3</b>					
MW	250	200			
Turbines	84	67			
Towers	21	17			
<b>Case 4</b>					
MW	250	200	200	50	150
Turbines	84	67	67	17	50
Towers	21	17	17	5	13

### 7.3.5 Hydro System Characteristics

The hydro component of SMUD comes from both the Upper American River Project and WAPA. All existing hydro resources are outside of the SMUD balancing area. The hydro capacity of 688 MW is generated from 11 units, and the study incorporates forced outage, failure, and repair rates for each of these. The average monthly load served by each of these entities was used to produce the power profiles for hydro component of the system. The study also includes a proposed 400-MW pumped storage hydro facility called Iowa Hill.

### 7.3.6 Wind Power Penetration and System Flexibility

The cases with higher penetration levels correspond to greater geographic diversity of the wind resources. Flexibility is calculated using 10-minute wind and load data. In the full report for the project, a step-by-step procedure is outlined to determine the required flexible generation that will be needed each hour to account for differences between the scheduled resources and the real-time load.

PIRP is a state initiative to assist in the integration of variable renewable resources. The PIRP and non-PIRP cases address levels of variability that will be absorbed by CAISO or left to SMUD alone. CAISO will pick up the deviation from forecast on an hourly basis. There is an associated \$0.10 USD/MWh forecasting fee to join this program and pay for the AWS Truewind forecast, with the balance paid for the cumulative net error at the end of the month.

### 7.3.7 Wind and Hydro Integration – Benefits and Impacts

There were several outcomes of the project related to the impacts of wind integration and the benefits of hydropower in addressing these impacts. To compensate for almost all of the load fluctuations, fast responding regulation capacity equal to some multiple of the standard deviations would be necessary. Integration studies with other control areas have found this factor to range up to 5 (i.e.,  $5\sigma$ ). The average of 5 times the standard deviation ( $5\sigma$ ) of the SMUD load

regulation characteristic for the 14 days analyzed is approximately 18 MW. The average as a percentage of peak load is 1.15%. Therefore, the conclusion of this analysis is that the minimum up-regulation and down-regulation capacity for the SMUD control area is up to 18 MW. Up-regulation in the morning will be higher to account for two-thirds of the expected load pick up over the hour, with down-regulation set to 18 MW. In the evening as the load ramps down, down-regulation will again be two-thirds of the expected hourly decrease, with up-regulation at 18 MW.

Applying the findings from the NREL measurement program and subsequent analysis, the standard deviation of the regulation characteristic for each of the scenarios would be 1 MW, 1.6 MW, 2.12 MW, and 2.91 MW for the four cases, respectively. If the regulation characteristics of the individual subsets are truly uncorrelated, the regulation characteristic of the combination can be calculated from the statistics of the individual characteristics. Using this method, the effect on the system fast requirement can be determined for each of the four cases. The results, shown in Table 40, show that the fast regulation requirement increases to as much as 5.1 MW with 850 MW of wind generation. Additional requirements for hourly variability and schedule deviation can raise the operating reserve requirements as high as 200 MW for 850 MW of wind, as shown in Table 41.

**Table 40. Wind generation increase figures**

Wind Generation	System Fast Regulation Requirement	Increase due to Wind Generation
0 MW (Load Only)	18.0 MW	-
100 MW	18.7 MW	0.7 MW
250 MW	19.7 MW	1.7 MW
450 MW	20.9 MW	2.9 MW
850 MW	23.1 MW	5.1 MW

**Table 41. Operating reserve requirement hourly variability**

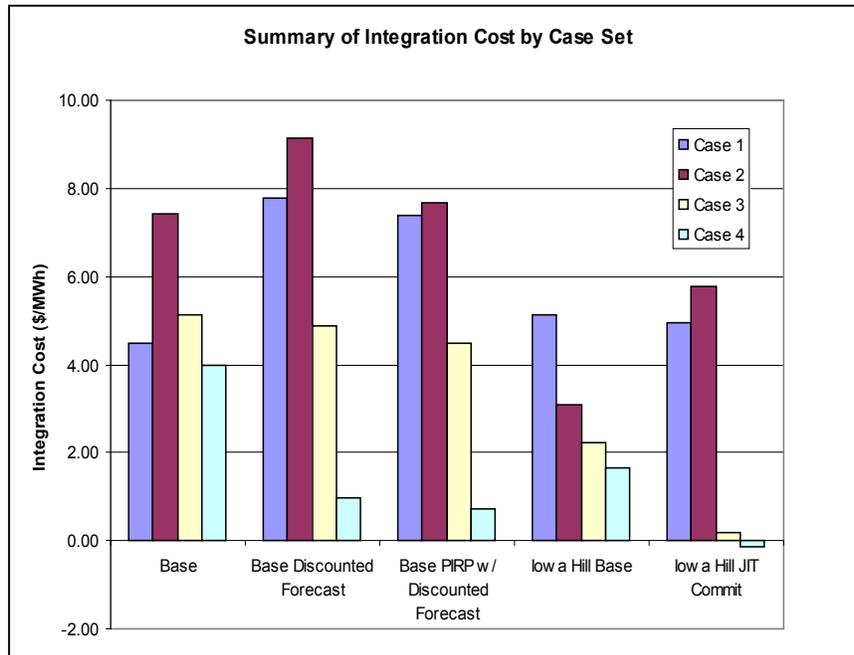
Case	Average Hourly Flexibility for Variability (+/-)	Average Hourly Flexibility for Variability and Schedule Deviation (+/-)
0 MW (Load only)	14.6 MW	26.6 MW
100 MW	18.4 MW	47.8 MW
250 MW	26.4 MW	112.9 MW
450 MW	39.8 MW	146.2 MW
850 MW	46.0 MW	201.1 MW

The study also estimated the integration costs for the different cases under several scenarios. The results show that all case sets except the Iowa Hill base show a peak in integration costs (in \$ USD/MWh) at Case 2, which is 250 MW, all at Solano. This case represents the least diverse scenario of the four cases, which partially accounts for its higher costs. The results for each of the cases are shown in Table 42. They are also shown in Figure 44 and Figure 45, which provide useful ways to visualize the results for comparison.

**Table 42. Integration costs (\$ USD/MWh) for the four cases**

Case Set	Case 1	Case 2	Case 3	Case 4
Base	4.48	7.41	5.12	3.96
Base Discounted Forecast	7.80	9.16	4.87	0.97
Base PIRP w/ Discounted Forecast	7.38	7.67	4.49	0.71
Iowa Hill Base	5.12	3.08	2.22	1.67
Iowa Hill JIT Commit	4.94	5.77	0.20	-0.12

The results show a very substantial reduction in operating cost and integration costs with Iowa Hill operating. The results also show that integration costs decrease with increasing diversity of wind generation assets.



**Figure 44. Integration cost summary by case set**

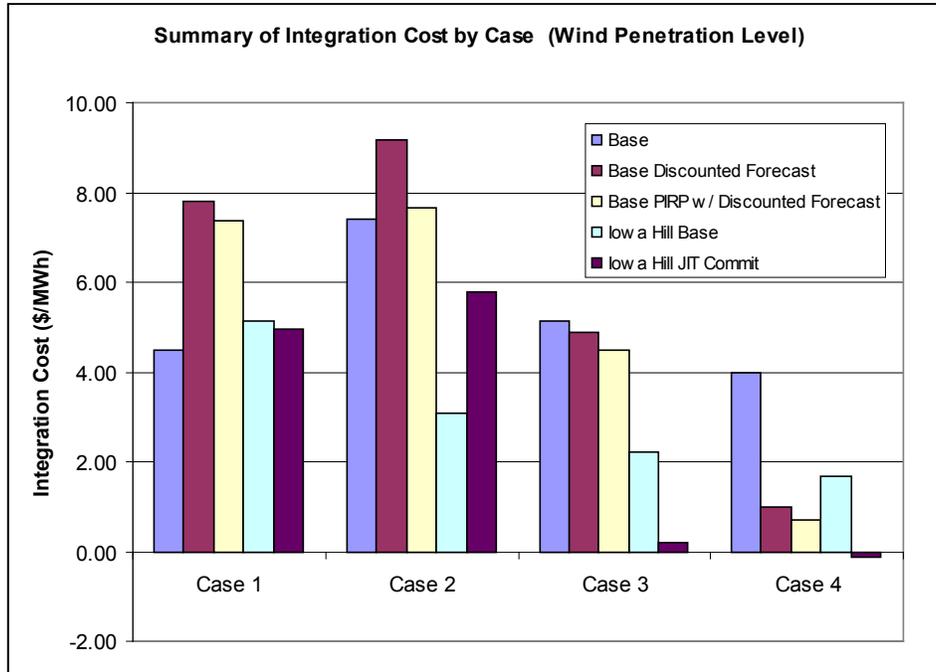


Figure 45. Integration cost summary by case (wind penetration level)

### 7.3.8 Conclusions

The study investigated the affect on SMUD’s control area of four levels of wind generation: 102 MW, 250 MW, 450 MW, and 850 MW. Specifically, the project sought to investigate the effect on the fast regulation requirement and integration costs of wind energy for the different cases. The study found lower penetrations of wind generation have only a small impact on fast regulation requirements, but begin to dominate as the penetration increases. The results show a very substantial reduction in operating cost and integration costs with Iowa Hill operating (as much as \$5 USD/MWh). Furthermore, the results also show that integration costs decrease with increasing diversity of wind generation assets.

The authors determined that the integration cost drops significantly with the wind penetration level. At first, this seems counterintuitive since it would seem likely that more wind would require less efficient commitment to handle the uncertainty and variability in the wind energy delivery. One aspect of lowering the effect of higher wind penetrations is increased geographic diversity. Cases 1 and 2 are concentrated scenarios with all of the turbines in a relatively small area, and are affected by essentially the same meteorology at the same time. In Cases 3 and 4, the wind plants are scattered over a much greater geographic area. This tends to smooth the wind because while one site may have low wind another may have high wind.

The modeling conducted showed that unit commitment and dispatch become difficult at penetration levels of 850 MW without the Hour Ahead Scheduling Process, yet work very well at the 450-MW level. Although the cases that include involvement in the PIRP will require fewer reserves to be provided by SMUD, there are only very small decreases in the integration costs that result from these cases. Changes in the Hourly Ahead Scheduling Process market structure could significantly affect integration costs. A more detailed treatment of error analysis will yield

more accurate results. Wind forecasting error, load forecasting error, and any relation between the two should be studied.

## 7.4 Case Study: Grant County PUD, Columbia River

### 7.4.1 Introduction to Study

- Study description and goals:* The Grant County PUD No. 2 (Grant PUD) was interested in studying ways to expand its wind energy generation through effective integration with its hydropower operations. Grant PUD owns and operates the two-dam Priest Rapids Project on the Columbia River in central Washington, one of the largest hydropower developments in the United States. Grant PUD also purchases a share the 63.7-MW Nine Canyon Wind Project. The two primary goals of the study were: (1) to understand the impacts of Grant PUD's current efforts at integrating wind and hydropower, and (2) to study the potential for future expansion of wind integration. In addressing these goals, the Grant PUD sought to understand the impacts of wind integration on its hydro operations, including effects on spill; approximate an economic value for the wind energy; and, most importantly, identify the frequency and magnitude of surpassing generation limitation or dropping below minimum flow requirement (for fish survival).
- Study results focus:* The study focused on three primary interest areas: (1) wind power effects in the regulation and load following time frames; (2) impacts associated with system planning in the unit commitment time frame, including the influence of wind energy forecasts, and impacts on the hydrological operations; and (3) application of study results to actually extending the district's wind integration, and mitigating any undesirable effects of a non-negligible penetration level over current management requirements. The objectives inherent of this three-part process include determining current operating behavior and requirements (regulation and load following), developing metrics with which to objectively compare operation variations, selecting a finite number of key scenarios to examine, and assessing the impact on flow constraints and generation limits. Statistical summaries of the magnitude and frequency of the metrics' variations could then be used to evaluate impacts of an actual penetration expansion and propose a few leading scenarios.
- Organizations involved:* Three main organizational entities were involved. Northern Arizona University completed original analyses and generated summaries for Grant PUD and NREL. Grant PUD provided operations and management reference and expertise, and guided efforts to ensure Northern Arizona University's modeled actual operation. Detailed wind forecast histories for the Nine Canyon Wind Project were provided by 3TIER.
- Reason study was performed:* The study was conducted to analyze the impacts that increased intermittent generation will have on system operations, reliability, reserve requirements, and overall integration costs. The study was conducted to analyze the impact that increased intermittent generation will have on the existing operating structure of Grant PUD, including the impacts on reliability and reserve requirements.

- *Case study chapter has been condensed from the following reports:*
  - Acker, T.L., Buechler, J., Knitter, K., and Conway, K. (2007). “Impacts of Integrating Wind Power into the Grant County PUD Balancing Area,” proceedings of the 2007 AWEA Windpower Conference, Los Angeles, CA.
  - Acker, T. L., Knitter, K., Conway, K., and Buechler J. (2006). *Wind and Hydropower Integration in the Grant County Public Utility District, Washington*, Proceedings of the 2006 Hydrovision Conference, Portland, Oregon, U.S. Acker, T. L. and Buechler, J., *Final Report: Grant County Public Utility District*
  - *Wind Integration Study*, project report submitted to the U.S. National Renewable Energy Laboratory, 2008.
- *Intended outcomes of the report relative to the objectives of Task 24:* Goals of the study were to determine the impacts of wind integration on the system regulation and load following, and to determine if how wind integration within this predominantly hydro utility effect compliance with generation and flow constraints.

**7.4.2 Overview of Power System**

**Table 43. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the U.S. Grant PUD wind integration study**

<b>Study conducted by:</b> Grant County Public Utility District No. 2, of Grant County, Washington, U.S., the National Renewable Energy Laboratory, and Northern Arizona University, Flagstaff, AZ						
<b>Geographic area of study:</b> Grant County, Washington, USA						
						
Area: 7,229 km <sup>2</sup> (2,791 mi <sup>2</sup> ) (source: Wikipedia)						
Population: 75,000						
Relatively small control/balancing area						
<b>Power system characteristics:</b>						
Load			Conventional generation	Interconnection	Wind power	
Peak (MW)	Min (MW)	TWh/a	Capacity (MW)	Capacity (MW)	MW	TWh/a
610 load (809 including purch & sales)	89 load (9 including purch & sales)	4.4	879 MW hydro 17 MW diesel	n/a in this study	12, 63, 150	0.15, 0.80, 1.90
<b>Other relevant characteristics of power system:</b> dual peak (winter and summer); average load about 250 MW; generation resources almost entirely hydroelectric; several limiting flow						

restrictions through dams located on Mid-Columbia River. Interconnected with Bonneville Power Administration balancing area.

**Characteristics of system planning:**

Three basic time frames: Term (1-2 years down to 1 week), Preschedule (1 week to 1 day), Real time (during operators shift). Utility is vertically integrated (responsible for generation, transmission and distribution). Several dams are on the Columbia River upstream of Grant PUD, and their operation affects Grant PUD's two dam Priest Rapids project. Thus the mid-Columbia dams cooperate in optimizing the hydro system through the Mid-Columbia Coordination Agreement. Electrical dispatch is done via this agreement.

In terms of Grant PUD's load and resource planning and operation, allocating excess or securing additional generation resources in the monthly to annual time frame is characterized as a "term" transaction. These term transactions ensure a balanced load and resource portfolio under changing river conditions and needs, and are typically bi-lateral transactions negotiated between trading partners, and not secured through an open market transaction. In the day-ahead to week-ahead time frame, the load and resource planning transactions are scheduled during the "pre-schedule" period, and transactions occurring during the day of operation occur in "real time." The marketer's make decisions related to pre-schedule and term transactions, whereas the system operator is responsible for the real time transactions. The primary considerations that govern planning in the pre-schedule time frame are the Pacific Northwest Coordination Agreement (PNCA) elevation targets defined for Grand Coulee, the NPCs, the actual hydrology and weather, the anticipated system load, how Grand Coulee is dispatched, the flow estimates provided by USACE, the market conditions for electricity, and the sales and purchase obligations made prior to the preschedule (i.e., term transactions). As with the term transactions, most of the pre-schedule and real-time transactions are bilateral between Grant PUD and a willing partner.

**Description of market:** Purchases and sales made at the Mid-Columbia hub; market is not very liquid and cannot always be depended upon. Preference of utility is therefore to only rely on their hydro resources to account for effects of wind variability.

**Integration time frames of importance:**

Yes/No	Time Frame
No	Frequency, system dynamics, grid stability, LVRT, PSS, V-Reg
Yes	Regulation, AGC
Yes	Load following; intra-hour ramping; economic dispatch
Yes	Unit commitment and day-ahead scheduling; economic utilization of resources
No	Resource and capacity planning; reliability

### 7.4.3 Study Methodology

The objective of this case study was to perform a statistical study of system regulation, load following, and ramping characteristics, and to also perform a simple hourly simulation to determine the impact of wind forecast error on system generation limits and minimum flow constraints. Table 44 provides an overall summary of the study technique and assumptions that were employed. A list of key assumptions and limitations follow the table. All data used for the study were from actual operation during the year 2006.

**Table 44. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the U.S. Grant PUD wind integration study**

<b>Set Up</b>		
<b>A</b>	<b>Aim of Study</b>	1 – what happens with a certain number of GWh of wind (primary objective of study) 2 – how much wind is possible (secondary objective of study)
<b>M</b>	<b>Method to Perform Study</b>	1 – add wind energy
<b>S</b>	<b>Simulation Model of Operation</b>	2 – deterministic simulation several cases
<b>Simulation Detail</b>		
<b>R</b>	<b>Resolution of Time</b>	3 – minute/second
<b>P</b>	<b>Pricing Method</b>	1 – costs of fuels etc (1 <sup>st</sup> attempt) 2 – prices for trading with neighbors (2 <sup>nd</sup> attempt)
<b>D</b>	<b>Design of Remaining System</b>	1 – constant remaining system
<b>Uncertainty and Balancing</b>		
<b>I</b>	<b>Imbalance Calculation</b>	3 – wind+load+ production
<b>B</b>	<b>Balancing Location</b>	1 – dedicated source (Grant PUD's hydro facilities)
<b>U</b>	<b>Uncertainty Treatment</b>	2 – hydro inflow uncertainty 3 – no wind forecasts (assume persistence) 4 – best possible wind forecasts
<b>Power System Details</b>		
<b>G</b>	<b>Grid Limit on Transmission</b>	1 – no limits
<b>H</b>	<b>Hydropower Modeling</b>	1 – head height considered 2 – hydrological coupling included (including reservoir capacity) 3 – hydrological restrictions included 5 – consider most relevant aspects of affected hydro resources
<b>HC</b>	<b>Hydro Capacity Service</b>	2 – real-time integration with impact of wind variability on system managed with hydro
<b>T</b>	<b>Thermal Power Modeling</b>	No significant thermal facilities in Grant's balancing area.
<b>W</b>	<b>Wind Power Modeling</b>	3 – time series smoothing considered - Wind speed measurements from anemometers in county - Actual wind output from nearby wind plant

#### 7.4.3.1 Assumptions

- Hydro, wind, and load data all time synchronized, and 1-minute data from the actual hydro and wind power production and load were employed for the study year. Short periods of missing data could be linearly interpolated at the discretion of researchers.
- The following wind capacity values were used: 0 MW, 12 MW, 63.7 MW, and 150 MW, and the actual wind production data used are from the Nine Canyon Wind Farm in south-central Washington State.

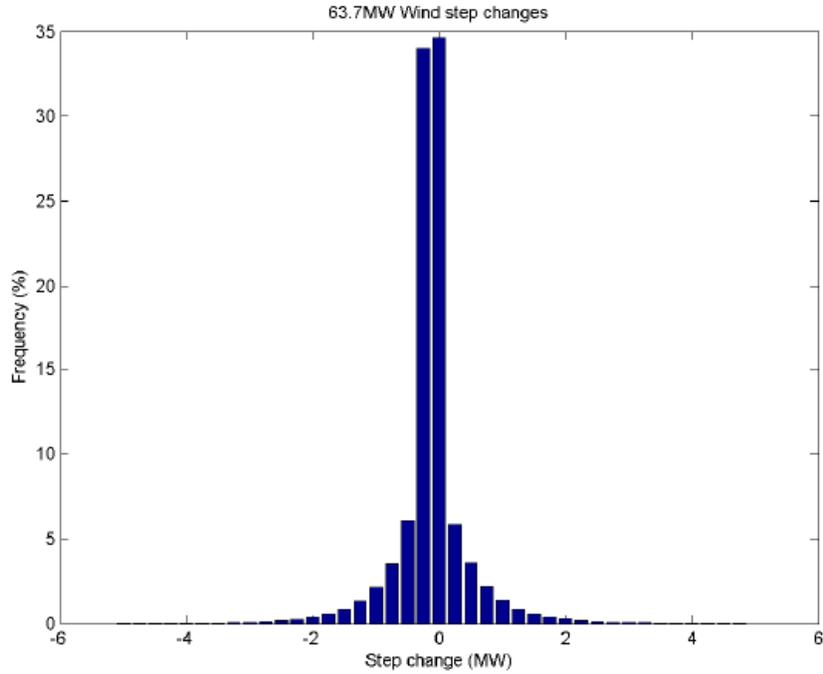
- Wind forecast data being used was the actual professional forecasts available for wind project during study year. Load, generation, and forecast data are exactly what Grant PUD had to work with at the time the data was first available.
- Market prices being used were the actual recorded hourly market prices at Mid-Columbia hub. Transactions made at this price were assumed not to affect the market (the megawatt-hour size of the transactions were all quite small compared to the volume traded daily).
- Forecasted wind data was available each hour of the study year for the following 140 hours.
- Load and generation data were available by minute, while forecast data was only available by-hour.
- System flow and generation constraints were available on an hourly basis for the study year.
- Grant PUD's generation requests cannot exceed 95% of its generating capacity. The remaining 5% of capacity is set aside for "contingency reserves."

#### **7.4.3.2 Limitations**

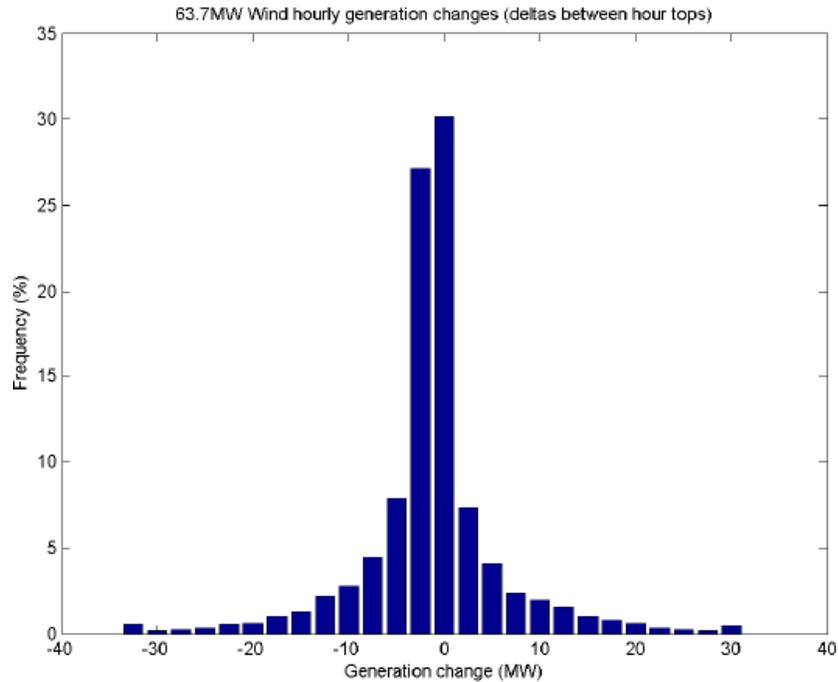
- Forecasts only considered when planning day-ahead.
- No intra-day adjustments were made to the schedule once it was set in the day-ahead planning. The purpose was to see how frequently problems arise when using considering wind and planning for it day-ahead. The goal in doing this was to identify the magnitude and frequency of constraint exceedences would occur and need to be dealt with hour ahead or in real time.
- All pre-schedule planning was conducted the day before operation. In reality, there is some 2-day-ahead planning conducted on weekends, holidays, etc.
- There is only about 1.5 months during the year when no fish flow restriction are in place affecting generation.

#### **7.4.3.3 Wind Power Characteristics**

Wind power generation levels of 0 MW (for comparison purposes), 12 MW (actual), 63.7 MW (full output from Nine Canyon Wind Power Plant), and 150 MW (scaled from 63.7 with no smoothing) were considered. Because Grant PUD was interested in how the wind power impacted its minute-to-minute regulation and hour-to-hour load following, it was of interest to tabulate the variation of the wind power plant on these time scales. Figure 46 shows the 1-minute changes in output out of the 63.7-MW Nine Canyon wind power plant for the 2006 data being considered. As can be seen, about 95% of the 1-minute changes are 1 MW or less (below 1% of capacity). The hourly changes in generation, tabulated as the change between the wind power generation at the beginning of each hour, are shown in Figure 47. The preponderance of generation changes were less than 10% of plant output, and all hourly changes were less than about +/- 50% of the total wind power capacity. Note that the variations shown here become small as a percent of capacity if multiple, geographically diverse wind plants are employed.



**Figure 46. Frequency of 1-minute wind power generation changes for data year 2006, as computed by finding the difference between the actual generation and a 10-minute rolling average**



**Figure 47. Frequency of hourly generation changes found by comparing the wind generation at the top of each hour for data year 2006**

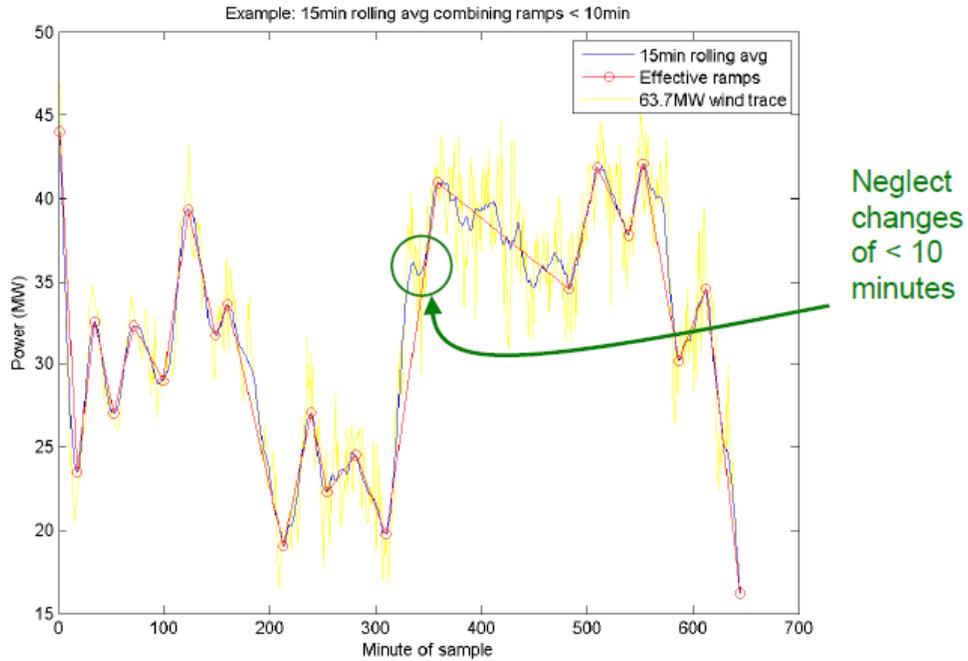


Figure 48. Illustration of the method to identify the magnitude and duration of wind power ramps

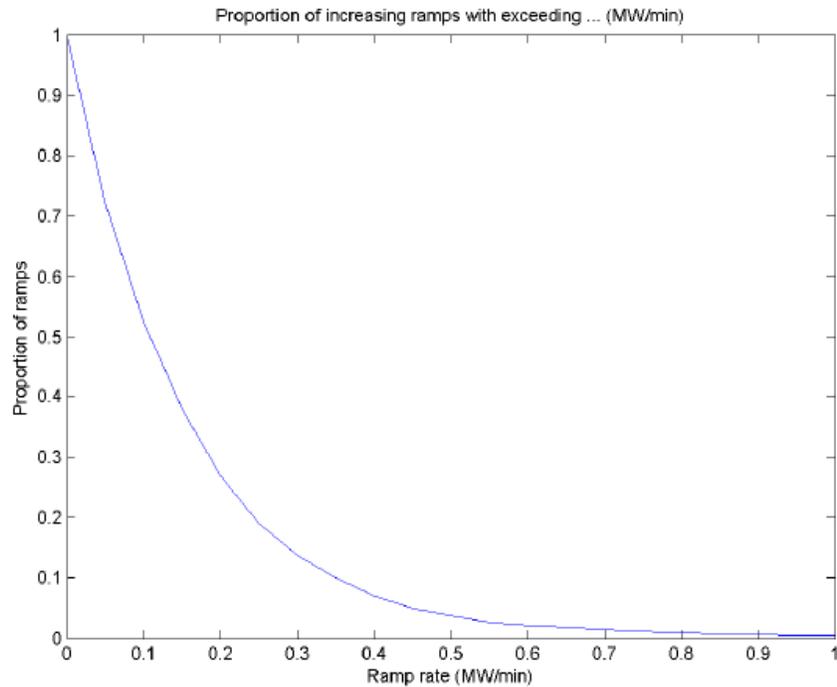


Figure 49. Cumulative exceedence curve showing the proportion of wind power ramps that surpass a given ramp rate

#### 7.4.4 Hydro System Characteristics

Grant PUD’s Priest Rapids Project (including both Wanapum and Priest Rapids dams) is located in central Washington in what is called the mid-Columbia portion of the Columbia River (see

Figure 50). The two dams have a nameplate capacity of just under 2,000 MW, of which nearly 880 MW are devoted to Grant PUDs load and balancing area. With many hydroelectric facilities located along the river, hydro operators realized early on that there were important benefits to coordinating their operation. In 1964, this cooperation was formalized in the form of the PNCA. A main goal of this agreement was to try to optimize benefits of the hydro facilities all along the river by emulating the coordinated operation that could be achieved if operated by a single owner. Priorities of this agreement include producing firm energy based on very low historical stream flows, refilling reservoirs, and producing surplus energy with higher stream flows. Energy production, however, is subsidiary to meeting NPCs. This agreement sets flow requirements from the Priest Rapids dam needed for the spawning of Columbia Fall Chinook salmon. General priorities in planning due to NPCs and power generation (order of priority changes based upon time of year, system operational characteristics, etc.):

1. Fish migration
2. Flood control (note flood control will take precedence over fish migration when dam structures are threatened)
3. Recreation and lake levels
4. Navigation
5. Power production

Priest Rapids Dam is subject to significant NPCs. The area of the Columbia River below the dam is referred to as the Hanford Reach, which extends 82 km downstream of the dam to Richland, Washington. The Hanford Reach supports the larger of two remaining healthy naturally spawning fall chinook salmon populations in the Columbia River System, and is an important component of the Pacific Salmon Treaty between the United States and Canada. River flows for this section of the Columbia River are controlled by discharge from Priest Rapids Dam, which can fluctuate due to changes in hydroelectric power output, or for reasons related to irrigation, water storage, and flood control. These fluctuations have impacted the spawning, incubation, rearing and transportation of fall Chinook salmon in the Hanford Reach. In order to minimize this impact and to encourage a healthy salmon population, Priest Rapids must conform to NPCs that substantially affect energy production and operational flexibility. These NPCs effect the operation and energy production of the projects, and most are reflected in the capacity and energy numbers computed in the PNCA



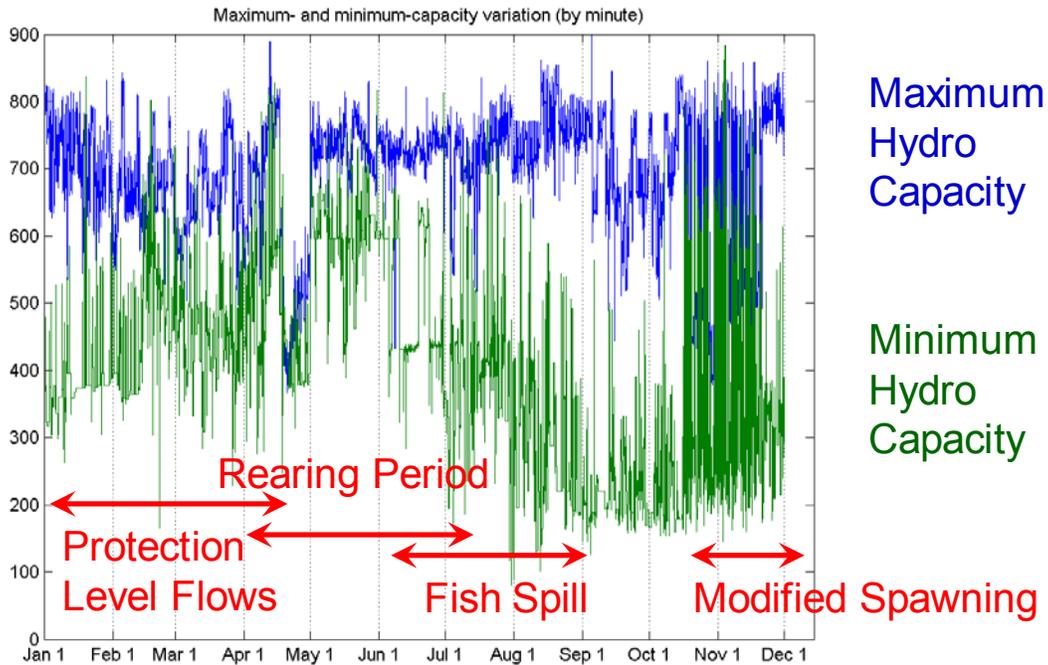
**Figure 50. Map of dams in the Columbia River Basin**

(Source: USACE, [www.nwd.usace.army.mil/ps/home.asp](http://www.nwd.usace.army.mil/ps/home.asp))

process. Some of these NPCs also affect Wanapum due to its close proximity to Priest Rapids. The main NPCs due to fish protection are summarized below:

- *Modified Spawning Operations:* Beginning in mid-October and continuing for about 5 weeks, the daytime capacity at Priest Rapids is severely restricted, and Priest Rapids is forced to generate at high levels during the nighttime hours. In prior years, this mode of operation was opposite to what is generally desired and was, therefore, called Reverse Load Factoring. However, in 2006 this practice was modified such that flows were generally higher at night, pulsed to full capacity discharge for a short (~ 1 hour) duration towards the beginning and end of the high load hours. In order to maximize the survivability of Fall Chinook redds in the Hanford Reach, which are believed that Fall Chinook salmon to primarily spawn during the daylight hours, these measures are taken to encourage salmon to spawn at lower elevations in order to maximize the probability of having enough flow during the incubation period to protect the redds.
- *Protection Level Flows:* Following the Reverse Load Factoring Operation, Priest Rapids has high minimum flows during the incubation period, which generally lasts until mid-April.
- *Rearing Period Operations:* Once the salmon hatch on the Hanford Reach, Priest Rapids conducts rearing period operations from mid-March until June. During the rearing period, the discharge flow band from Priest Rapids is substantially limited in order to prevent temporary pools of water from forming along the banks of the river, which cause small salmon to be stranded and possibly die from lack of oxygen.
- *Fish Spill:* From April 16 to August 31, both Wanapum and Priest Rapids spill substantial amounts of water past the turbines, varying for the purpose of fish passage. This spill has recently varied from 39% to 61% of the total discharge.

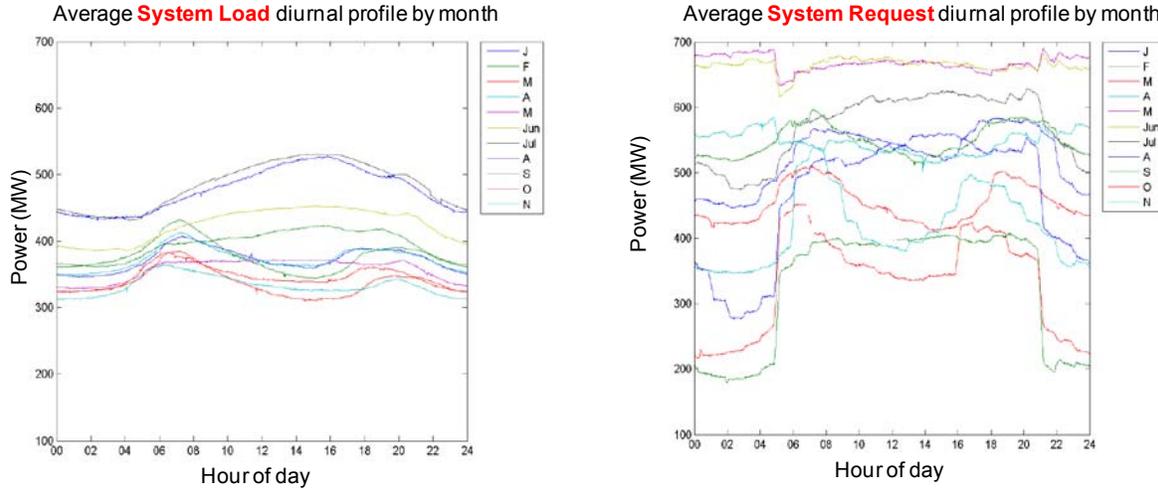
These flow constraints exert a governing influence on the generation capacity available at the Priest Rapids Project, along with the PNCA plan. The upper and lower limits on capacity vary seasonally, daily, and even change within the day (e.g., during the modified spawning operations). A plot depicting the variation of the maximum and minimum capacity in megawatts is available to Grant PUD at the Priest Rapids and Wanapum dams is shown in Figure 51. This plot was made using 1-minute data, and reflects all constraints on generation. From the plot, one can see the tight band on generation (high minimum capacity) during the rearing period fish operations, and the unusual looking mix of minimum/maximum capacities during the modified spawning operation. There is only about 1.5 months during the year when no fish flow restriction is in place that affects generation.



**Figure 51. Variation of the maximum and minimum capacity (MW) available to Grant PUD at the Priest Rapids and Wanapum dams**

#### **7.4.5 Wind Power Penetration and System Flexibility**

The penetration of wind power penetration considered in the project is 12 MW (1.8%), 63.7 MW (7.8%), and 150 MW (18.6%), computed as a percentage of peak load (including sales of energy). The hydropower generators themselves are quite flexible, primarily being 100-MW units. Use of the hydro is constrained by its limited hydro impoundment (on the order of 1–2 days of river flow); the fact that it is at the end of an interconnected system of seven dams (see Figure 50, with Grand Coulee dam standing at the head of the mid-Columbia and essentially dictating flow that will come to Grant PUD facilities); and the significant fish flow constraints. Even with these fairly onerous constraints, there is still substantial flexibility in use of the hydro resource as demonstrated by the graphs shown in Figure 52. On the left of this figure is the monthly averaged diurnal profile of the system load, and on the right side is a plot showing the average diurnal profile of the generation request to cover the system load plus purchases and sales. As can be seen, Grant PUD uses the flexibility available to maximize energy sales during the high load hours of the day.



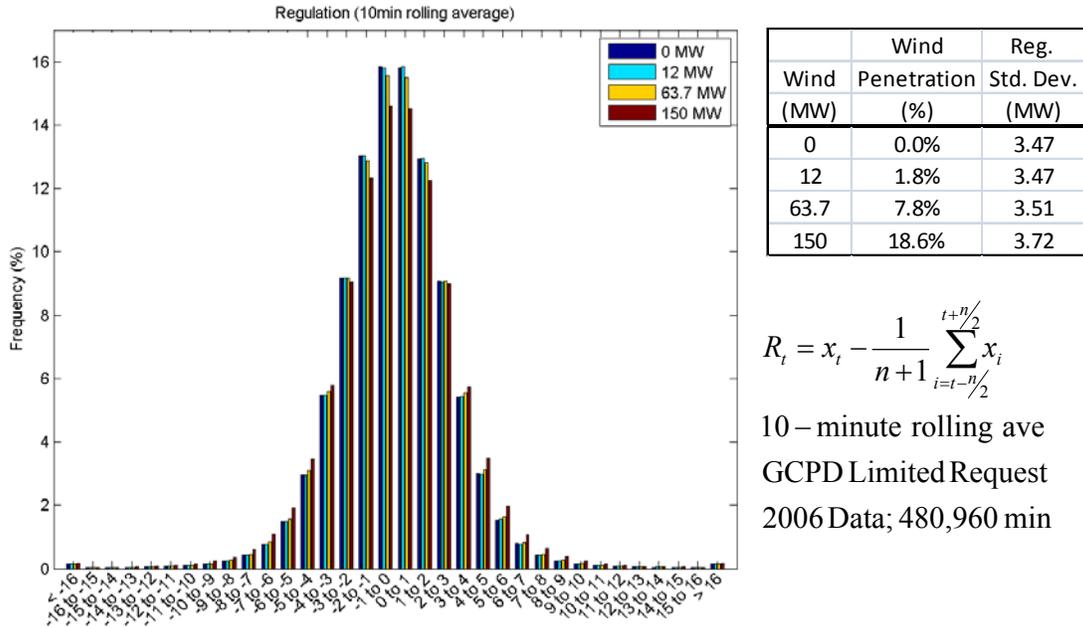
**Figure 52. Average diurnal profile of Grant PUD system load (left) and generation request (right), for the study year 2006**

**7.4.6 Wind and Hydro Integration – Benefits and Impacts**

This wind integration impact described in this section will focus on the impacts of integrating wind power into the Grant PUD balancing area. Specifically, the changes in regulation requirement, load following (in this case, hourly changes in generation), and impact on complying to generation limits and flow constraints (collectively referred to as “exceedances” here). The specific details of the calculations required to demonstrate these impacts is left to the reference documents listed at the beginning of this case study section.

The changes in 1-minute regulation values of the system net load (load minus wind generation) due to the various levels of wind power being considered is shown in Figure 53. Note that the histogram (i.e., bar chart) looks very similar regardless of the wind penetration level, and that the standard deviation of one-minute deviations from the 10-minute rolling average does not change much. This result that wind power does not substantially affect the regulation is consistent with other studies.

Moving to the hourly time frame, Figure 54 shows a bar chart demonstrating the 1-hour changes in generation request (load net wind + purchases – sales) for the wind penetration rates being considered. The general shape of the distribution is normal, centered about a mean near 0. The light blue bars correspond to the hourly changes in the actual generation requests, including 12 MW of wind (1.8% penetration). The standard deviation was 43.8 MW, essentially identical to the case where no wind energy is included in the system. The yellow bars shown in the figure represent the hourly variability if the full 63.7 MW of Nine Canyon wind were incorporated into the generation request (7.8% penetration). This produces a noticeable effect in the distribution, causing a significant dip in the distribution near 0 and increased incidence of higher hourly changes. The standard deviation in hourly changes is 44.6 MW. The difference in the standard deviation between including 0 and 63.7 MW of wind is 0.8 MW. If one were to simply scale up the output from Nine Canyon to 150 MW (which will over predict its variability),



$$R_t = x_t - \frac{1}{n+1} \sum_{i=t-n/2}^{t+n/2} x_i$$

10 – minute rolling ave  
 GCPD Limited Request  
 2006 Data; 480,960 min

Figure 53. Bar chart showing frequency of one-minute “regulation” values (MW) for the Grant PUD net load (load + purchases – sales – wind power)

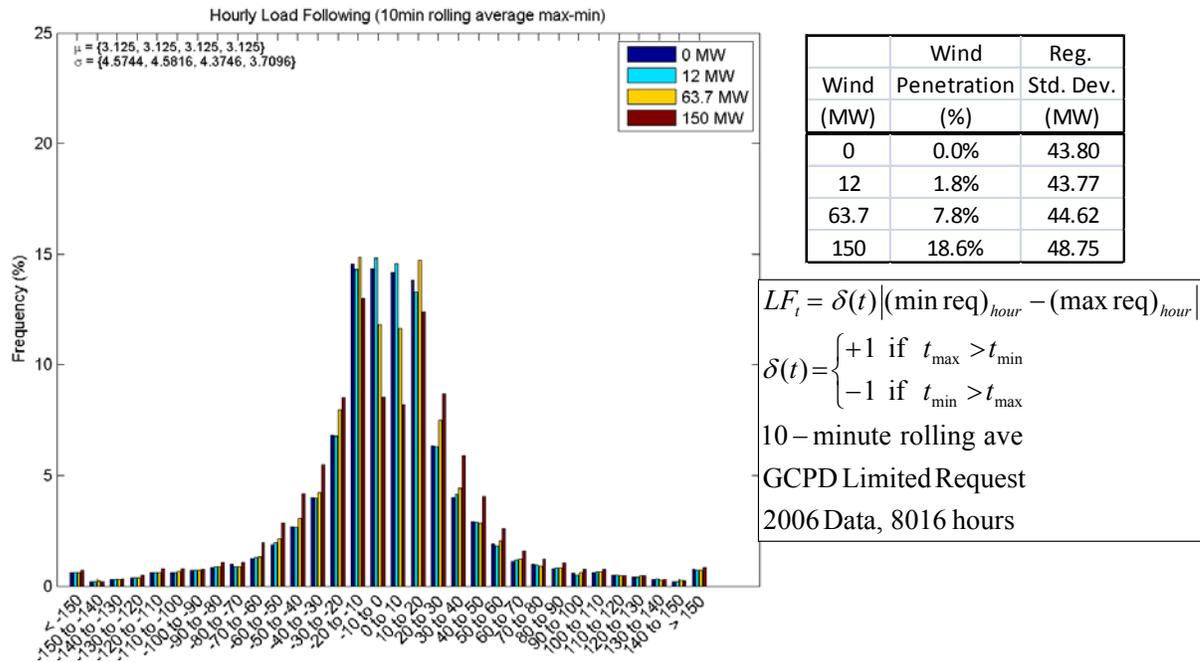


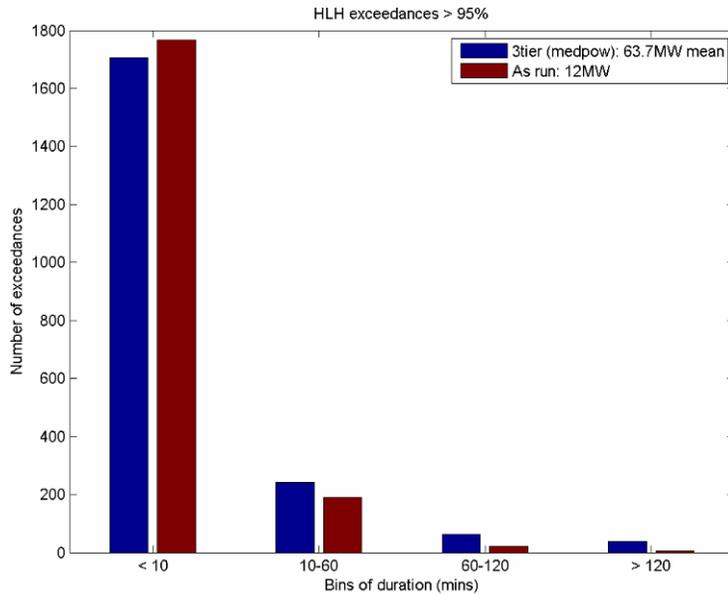
Figure 54. Bar chart showing frequency of hourly load following values (MW) for the Grant PUD net load (load + purchases – sales – wind power)

as shown by the red bars, the standard deviation increases only modestly to 48.8 MW. The more significant impact from the increased wind penetration, both at 63.7 MW and 150 MW, however,

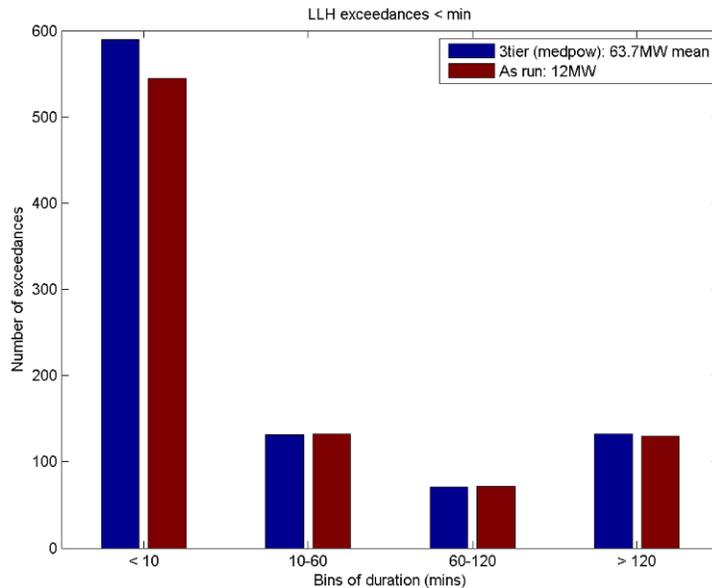
is the altered shape of the histogram. The number of incidences of 0–10 MW hourly generation changes (either positive or negative) is decreased, with a consequential increase of hourly generation changes primarily in the 10–40 MW range. Because Grant PUD’s system operator frequently runs the system within a couple percent of its maximum permissible generation (allowing for reserves), an unexpected (i.e., unplanned or not forecasted) change in generation could incur high costs to manage, cause violation of North American Electricity Reliability Corporation (NERC) reliability requirements, and/or violate a non-power flow constraint (i.e., fish flow requirement). Thus, two important conclusions from the load following results are that the system already deals with a significant amount of variability, and that the ability to handle the increase in overall variability must be dealt with in the day-ahead and hour-ahead planning operations to avoid exceeding generation limits.

In order to determine the effect of wind on exceeding the limiting capacity values, it was first necessary to devise an algorithm for planning wind in the pre-schedule. The method chosen here was to use the actual wind forecasts for the Nine Canyon project to estimate the amount of high load hour (HLH) and low load hour (LLH) wind energy would arrive during the day of operation. The amount of energy expected is then sold day-ahead as a flat block of HLH or LHL energy and represents additional capacity in Grant PUD’s system. This transaction is carried out with two simplifying assumptions: (1) the flat block is sold in the amount estimated and not as a 25-MW block (which is done for a typical transaction); and (2) only consider pre-schedule planning 1-day ahead (i.e., the weekend days are planned 1-day ahead similar to the weekdays). The actual system request that occurred during each day of the year is then modified by adding the flat block capacity to the actual system request during either the HLH and LLH hours, as appropriate. Then, during the day of operation, the wind energy comes into the system with its actual profile (different than the flat block), and is used to meet the increased system request. If the wind were to happen to come into the system as a flat block, then it would decrease the system request and return it to the profile that actually occurred. However, since this never occurs in practice, the system request will be higher during some minutes and lower during others compared to what actually occurred. The modified request is then compared to the minimum and maximum capacities and the exceedences are tabulated. In performing this calculation, the maximum available capacity of the system is reduced because the overall load serving obligation of Grant PUD has increased, and it is now responsible for setting aside 5% of the increased obligation as a contingency reserve. For example, if the maximum capacity during a given HLH happened to be 800 MW, and 40 MW of wind power was sold in the pre-schedule (day ahead) as a flat block for this HLH period, then the maximum available capacity is reduced by 5% of 40 MW, or 2 MW. Thus, the new maximum capacity during the HLH is 798 MW, and this value is used in computing the percent of maximum capacity consumed by the modified system request. Implementing this algorithm yields the results indicated by the blue bars in Figure 55 and Figure 56, which plot on a bar chart the number of exceedences during the year versus duration. As shown in Figure 55, some of the shorter duration HLH exceedences of the 95% capacity threshold are shifted to longer durations, and there is an overall increase, though modest, in the total number of exceedences. Figure 56 shows the effect of day-ahead wind sales on the LLH minimum capacity exceedences (dropping below the minimum capacity, and therefore dipping below the minimum flow permitted from Priest Rapids Dam). With respect to this limit, the effect is not as pronounced, with an increase only in the short-duration violations. Note that no attempt has been made in this analysis to see if the increased violations could be averted by real-time or hour-ahead transactions. Rather, the intent was to assess the impact on

the number of exceedences under a reasonable planning algorithm. These results do show that an increased number of exceedences do occur, but that the increase is only modest. It is also possible that many of these exceedences could be handled during the day of operation, and at some cost. Addressing this latter point would be the next logical step for Grant PUD in continuing this analysis.



**Figure 55. Number of exceedences of the 95% available capacity limit during the 2006 model year for the system as run and with 63.7 MW of wind planned into the system in the pre-schedule**



**Figure 56. Number of exceedences (dropping below) the minimum allowable capacity due to a flow constraint for the system as run and with 63.7 MW of wind planned into the system in the preschedule**

#### **7.4.7 Conclusions**

The goals of this project were to understand the impacts of Grant PUD's current efforts at integrating wind and hydropower into their electrical system operation, and in particular to understand the impacts on exceeding system constraints. These constraints are the minimum and maximum capacity constraints for the Priest Rapids Project, due to reliability and NPCs (fish flows). Study results for the 2006 data year suggest that the overall impact on system statistics for regulation and load following is quite modest, even at a wind energy penetration of 150 MW (~19% wind penetration by capacity). This small statistical impact suggests that, absent other constraints, the physical generation resources are sufficient to handle wind variability at this level. However, due to changes in the distribution of load following hourly changes, there are some potentially significant operational challenges in scheduling the resources without infringing upon system constraints. To assess the impact on system constraints, a pre-schedule planning simulation was devised and conducted. Results of this simulation indicate that when using a professional quality forecast, that an increased incidence of constraint exceedences can occur, though at a modest level. The new instances of exceedences would need to be handled in the hour-ahead and real-time operations, which appears may be a reasonable approach. Assessing the significance of these constraint exceedences and testing other pre-schedule planning algorithms would be an appropriate next step in furthering this analysis.

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## Appendix A: Hydro Quebec Case Study

The information in this document is being provided as a supplement to the Task 24 report entitled:

### Final Technical Report: Results of IEA Wind Task 24 on the Integration of Wind and Hydropower Systems Volume 2: Participant Case Studies

*Hydro-Québec was an active participant in Task 24, but was not able to contribute this report to the final report mentioned above until the related work was approved by Hydro-Québec management for public dissemination. It was known during the task that this date of release was after the date of publication of the final report, so this document is being provided as a supplement to Volume 2. Since Volume 2 finished with Chapter 7, this supplement is included as Appendix A.*

#### Canada – Hydro-Québec – Preliminary Impacts

##### Introduction

By developing Québec's hydropower potential, Hydro-Québec has already demonstrated its commitment to sustainability with a green and renewable energy and now is turning increasingly to wind power as a complementary source of renewable energy. Starting in 1999, with a few wind projects reaching 500 MW, the Québec government has decided by order that its electricity portfolio must contain an additional 3500 MW of wind power by year 2015. The total wind power will be around 5% of its annual energy supply or 10% of its installed capacity. That is the only scenario to be studied until now.

Except for a bloc of 500 MW reserved for small wind projects developed by communities and First Nations, for which the call for tenders selection process will terminate at the end of 2010, the wind project locations are already known. Characteristics and power time series are well defined for around 3500 MW. This report gives the results of wind power integration impacts that the Hydro-Québec will have to manage. For the purpose of the Task 24 research, three studies were contributed:

1. The first study defines the impacts of wind power on operational reserves, specifically on AGC and load following reserve.
2. The second study analyses the impacts on the balancing reserve in order to mitigate the consequences of inherent prediction errors over the time horizon of 1–48 hours. The methodology requires as input the statistical characteristics of load and wind generation forecast errors and of generation outages.
3. Finally, the last study considers the impacts on the system capacity adequacy taking into account the Nordic weather conditions on the wind turbines availability (stopping when the temperature is lower than -30°).

Before presenting these studies, Section 2 describes the characteristics of the Hydro-Québec power system.

### Overview of the Power System

**Table 45. First half of the Task 24 matrix that defines important power system characteristics and some basic parameters of the setup for the Hydro-Québec case studies**

Geographic area of study: Province of Québec, Canada						
Area: 1 542 000 km <sup>2</sup> Around 2 000 km from south to north and 1 500 km from east to west Population: 7,6 millions Very large control / balancing area, load concentrated in the South of the province and power generation in the North.						
<b>Power system characteristics:</b> <ul style="list-style-type: none"> <li>• Synchronous network covers the Province of Québec and Labrador (Newfoundland)</li> <li>• Québec Government defines the wind energy policy with a target of 4000 MW for 2015 and maintains 10% of peak penetration the following years</li> </ul>						
Load			Conventional Generation	Interconnection	Wind power	
Peak (MW)	Min (MW)	TWh/an	Capacity (MW)	Capacity (MW)	MW	TWh/an
37 000	14 000	195	32300 Hydro 5400 other hydro (Labrador long term agreement) 1600 Thermal 700 Nuclear	7,100 import 9,575 export	642 MW in 2010 4000 MW in 2015	~10 in 2015
<b>Other relevant characteristics of the power system:</b> <ul style="list-style-type: none"> <li>• Most interconnections are AC-DC-AC, others are radial and so all asynchronous. These interconnections allow Hydro-Québec to import as much as 8350 MW of electric power or export as much as 10 800 MW to neighboring regions.</li> <li>• Large scale hydro plants equipped with large storage capability (175 TWh)</li> <li>• Most power plants are far from the load and also far from the first wind plants</li> <li>• AGC on most of hydro plants. High level of operational efficiency.</li> <li>• Min / max load ≈ 40% (average out-of-peak and peak daily load)</li> <li>• Load factor = 55% at peak load</li> </ul>						

<p><b>Characteristics of system planning:</b> Utilization of in-house optimization and simulation models for different horizons: planning (1–2 years), scheduling (1–10 days) and real time.</p>
<p><b>Description of energy market:</b> Hydro-Québec generates (Hydro-Québec Production), transmits (Hydro-Québec TransÉnergie) and distributes (Hydro-Québec Distribution) almost all the electricity in Québec. Distribution and Transmission activities are regulated. Internal opened market not established. Hydro-Québec Production exports/imports to/from the United States and the neighboring Canadian provinces under open market rules, mostly on hourly and day-ahead markets.</p> <p>Most of the wind power is procured through long-term (~20 years) power purchase agreements between Hydro-Québec Distribution and private producers through a request for proposal process. Some are directly acquired by Hydro-Québec Production. There is a wind balancing service agreement between Hydro-Québec Distribution and Hydro-Québec Production (covering a first bloc of 1000 MW of wind power under contract with Hydro-Québec Distribution), which involve constant deliveries equal to the average yearly wind power load factor (35%) including a capacity guaranty. The agreement should be updated in 2011 and will integrate all of wind power projects under contract with Hydro-Québec Distribution.</p> <p>Wind forecasting is centralized and processed by Hydro-Québec Distribution.</p>

Basic parameters of the study analysis are provided in Table 46.

**Table 46. Second half of the Task 24 matrix that lists variations of underlying assumptions and modeling approaches used in the first Hydro-Quebec (Canada) wind integration studies**

Set Up		
<b>A</b>	<b>Aim of Study</b>	Evaluation of additional balancing and planning reserves required by the integration of 3000-MW wind power, while maintaining the same system reliability.
<b>M</b>	<b>Method to Perform Study</b>	Simulate the uncertainties resulting from the addition of 3000 MW of wind power to existing uncertainties, use these to estimate additional risk and balancing reserve requirements
<b>S</b>	<b>Simulation Model of Operation</b>	Probabilistic approach and grid simulation model
Simulation Detail		
<b>R</b>	<b>Resolution of Time</b>	Minutes for frequency regulation reserve 10 minutes for load following reserve Hourly for balancing reserve with horizon of 1–48 hours Hourly data for evaluation of planning reserve requirements for capacity adequacy
<b>P</b>	<b>Pricing Method</b>	No price estimation
<b>D</b>	<b>Design of Remaining System</b>	Remaining system unchanged

Uncertainty and Balancing		
<b>I</b>	<b>Imbalance Calculation</b>	For regulation and load following reserve: wind + load For balancing reserve: Wind + load + unavailability due to outages
<b>B</b>	<b>Balancing Location</b>	Only Hydro-Québec area
<b>U</b>	<b>Uncertainty Treatment</b>	For regulation and load following reserve: load forecast and assuming persistence for wind forecast For balancing reserve: load and wind forecast
Power System Details		
<b>G</b>	<b>Grid Limit on Transmission</b>	Use dynamic simulation only for regulation and load following reserve
<b>H</b>	<b>Hydropower Modeling</b>	Use dynamic simulation only for regulation and load following reserve; consider only operational reserve and efficiency losses without adjustment on hydro conditions
<b>HC</b>	<b>Hydro Capacity Service</b>	Complete integration of hydro resources with wind resources
<b>T</b>	<b>Thermal Power Modeling</b>	NA
<b>W</b>	<b>Wind Power Modeling</b>	For regulation and load following reserve: reconstituted hourly wind power data and interpolation for 1-minute data For balancing reserve: wind forecast experience on 1 year For capacity value: 36 years of hourly time series (reconstituted)

## Case Study 1: Frequency Regulation Reserves for Integrating 3,000 MW of Wind Generation at Hydro-Quebec

*I. Kamwa, A. Heniche, R. Mailhot, A. Robitaille*

### Introduction

This study analyses the impacts of 3000 MW of wind power on operational reserves, specifically on AGC and load following reserve in a context of a predominant hydro generation system and with asynchronous interconnections.

Giving the nature of its power grid which consists of a large domestic load (37,230 MW in January 16, 2009) linked asynchronously to the rest of the NPCC through HVDC lines (with 7,600 MW and 5,100 MW of export and import capabilities), Hydro-Quebec TransÉnergie (the regional Independent System Operator [ISO]) has some very specific reserves requirements which fall broadly in the following categories:

1. *Stability (spinning) reserve*: At typically 1,000 MW, it represents about 60% of biggest single lost of generation. At any time, spinning reserve must not fall below 250 MW.
2. *10-minute operations reserve*: At 1000MW, it consists of non-firm sales, interruptible load and a large portion of stability reserve. The ISO has 90 minutes to offset any violation.
3. *30-minute operations reserve*: About 500 MW, this represents 50% of the second-most severe single loss of generation. The ISO has 4 hours to offset any violation.

4. *Frequency regulation reserves*: AGC with 500-MW (minimum) modulation range are used.
5. *Load following*: No strictly defined standard exists because the large hydro-generation base (43,000 MW in 2009) allows for a load following without any practical constraint. However, the largest observed load-following requirement is about 3,000 MW during the winter mornings.

To prepare large-scale wind integration into its system operations processes, TransEnergy undertook a preliminary analysis of the impact of wind variability and uncertainty on operational time frame reserves requirements, essentially within the 1-hour horizon. It was rapidly clear that the first three reserves categories are not sensitive to wind energy integration essentially because wind plants are limited in size (less than 200 MW) and geographically spread over relatively large areas (1,000-km stretch). In this context, the most relevant quantities requiring further investigation were the AGC and load following reserve capacities. Both are required to ensure the reliability of the grid at a level specified by NERC standards CPS1 and CPS2 (BPA 2008, Kamwa et al. 2009) in face of short-term demand and wind generation uncertainties.

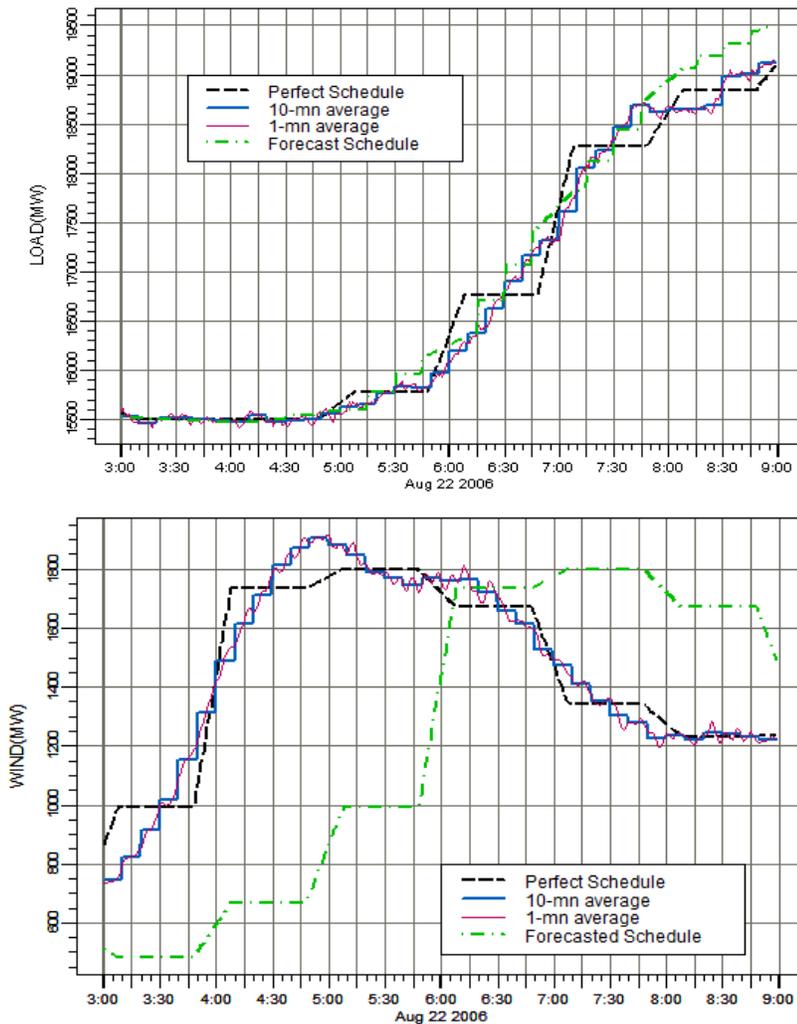


Figure 57. Load and wind scheduling during a summer morning with high wind generation

For the purpose of this study, the regulation and load following definitions follow Kirby's principle of temporal decoupling (Hirst and Kirby 1999), while assuming that the moving-average window for separating the load following and the regulation is set at 10 minutes since the NERC (CPS2) performance index is evaluated every 10 minutes in AGC systems. Figure 57 summarizes our conventions using a 6-hour observation window at the morning peak on August 22, 2006. For extra realism, the load data (and corresponding forecasts) are actual historical data pertaining to Québec requirements that were provided by the Energy Management System. On the other hand, the wind generation data is minute/minute data simulated using the procedure described in Kamwa et al. 2009. Regulation (AGC) is simply the difference between the purple and blue curves while the intra-hourly imbalance is equal to the difference between the green and black curves.

### **Long-Term Variability of Wind Generation**

The demand data (BRD) is based on forecasts of the regular requirements of the load serving entity for the 2016 horizon, based on the April 2009 revision of the load forecast. Meanwhile, the hourly wind generation data comes from historical reconstitutions of the 3,000-MW hourly generation in the first two tenders submitted by Hélimax<sup>11</sup>. The minute-by-minute data demand, wind generation, and forecasts were derived according to Kamwa et al. 2009. Table 47 summarizes some of the typical features of the minute/minute data of the long-term demand and wind generation time series. Generally speaking, wind generation has more variability but less real-time predictability than the load. Following BPA and CAISO studies, real-time wind forecasts are based on a simple 2-hour persistence model.

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<sup>11</sup> Hélimax has published two reports, one on the contracts totalling 990 MW related to the first call for tenders (December 2008, 61 pages), the second on the 15 contracts totalling 2,000 MW, signed at the time of the second call for tenders (June 2009, 74 pages).

**Table 47. Summary statistics of minute/minute data from:  
November 1, 1995 through October 31, 2006**

	Demand (MW)	In % with respect to the mean BRD
Standard deviation of variability 1 minute	38.5	0.2%
Standard deviation of variability 1 hour	83.7	4%
Average real-time forecasting error	522	2,5%
Standard deviation of real-time forecasting errors	686	3,2%

	Wind generation (MW)	In % with respect to mean wind generation
Standard deviation of variability 1 minute	7.5	0.7%
Standard deviation of variability 1 hour	171	15.6%
Average real-time forecasting error	202	18.4%
Standard deviation of real-time forecasting errors	227	21%

Wind: (Average=1 099, Max= 2 801) MW; BRD: (Average=21 204, Max.= 41 774) MW

An illustration of the data set is provided in Figure 58 where the daily maximum and minimum values of the hourly penetration rates are shown on the top curve (i.e., 365 values per year for each curves). The bottom curve presents the daily maximum and minimum hourly ramping of the wind generation.

### Wind Generation Impacts on AGC and Imbalance

The calculation algorithm was first applied to all 11 years without differentiating between the seasons. Thus, for each variable, we had 5,785,920 points per minute (i.e., 241,080 points for each hour of the daily cycle). Sample results, positive (increase) are presented in Figure 59. Each value is normalized with respect to the installed wind capacity (2,995 MW). The Hydro-Québec results are compared with those shown in the BPA report according to (BPA 2009), for a wind capacity of 3,155 MW.

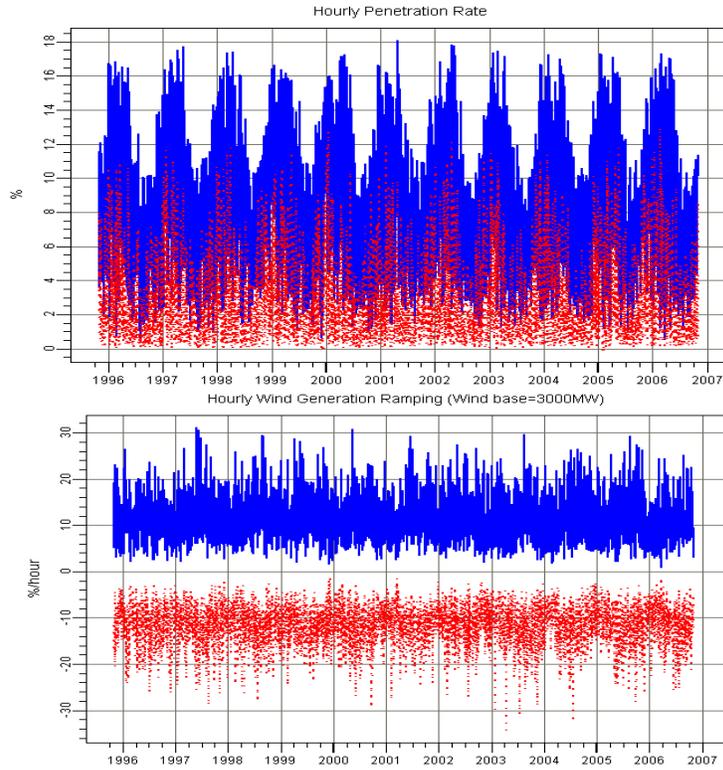
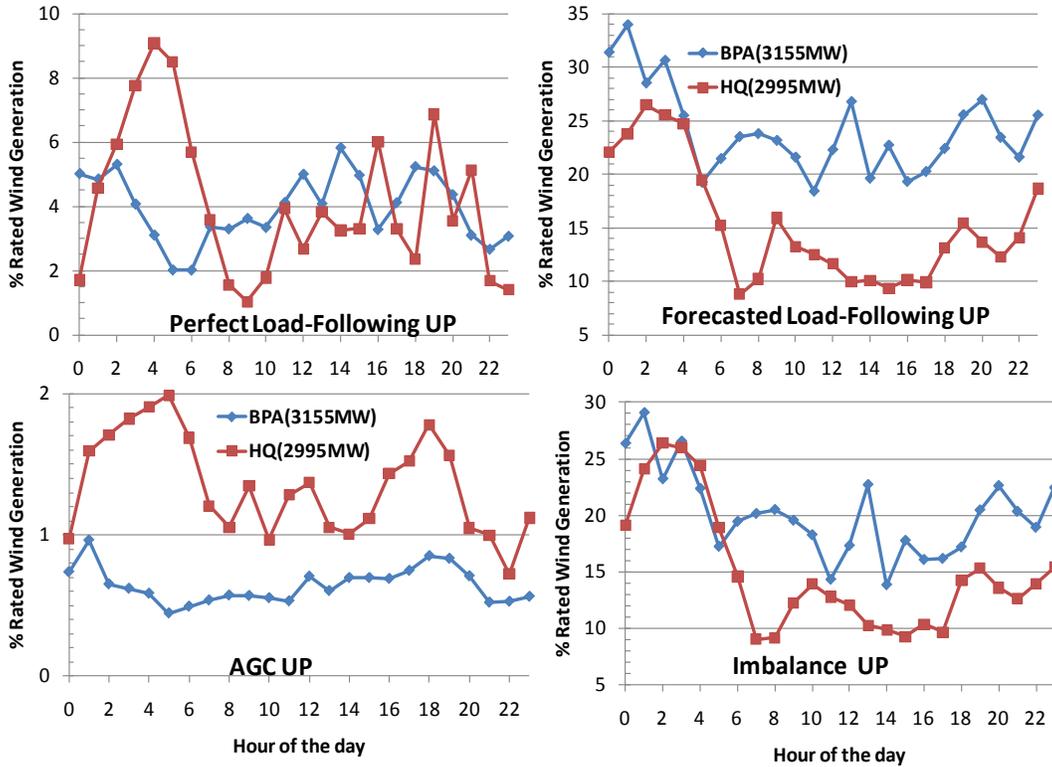


Figure 58. Daily maximum and minimum of hourly penetration and ramping rates



**Figure 59. Comparison of Hydro-Quebec and BPA supplemental reserves at 3,000-MW wind generation (up-regulation)**

In a second step, we analyzed the same load and wind generation data per year, considering the different seasons of the year separately. The yearly values are obtained by applying the algorithm to the entire year (525,000 points for non-leap years) while the seasonal values are based on data for the months of the season. In each case, we first obtain the 24 values related with the daily cycle of the load, the wind, and the net demand. These values are then reduced to a single optimum value for the year, the winter, the summer, and the out-of-season periods using the weighting formulas for the maximum requirements of the net demand. The sample results in Figure 60 show inter-annual variations of the reserves requirements at 3,000-MW penetration.

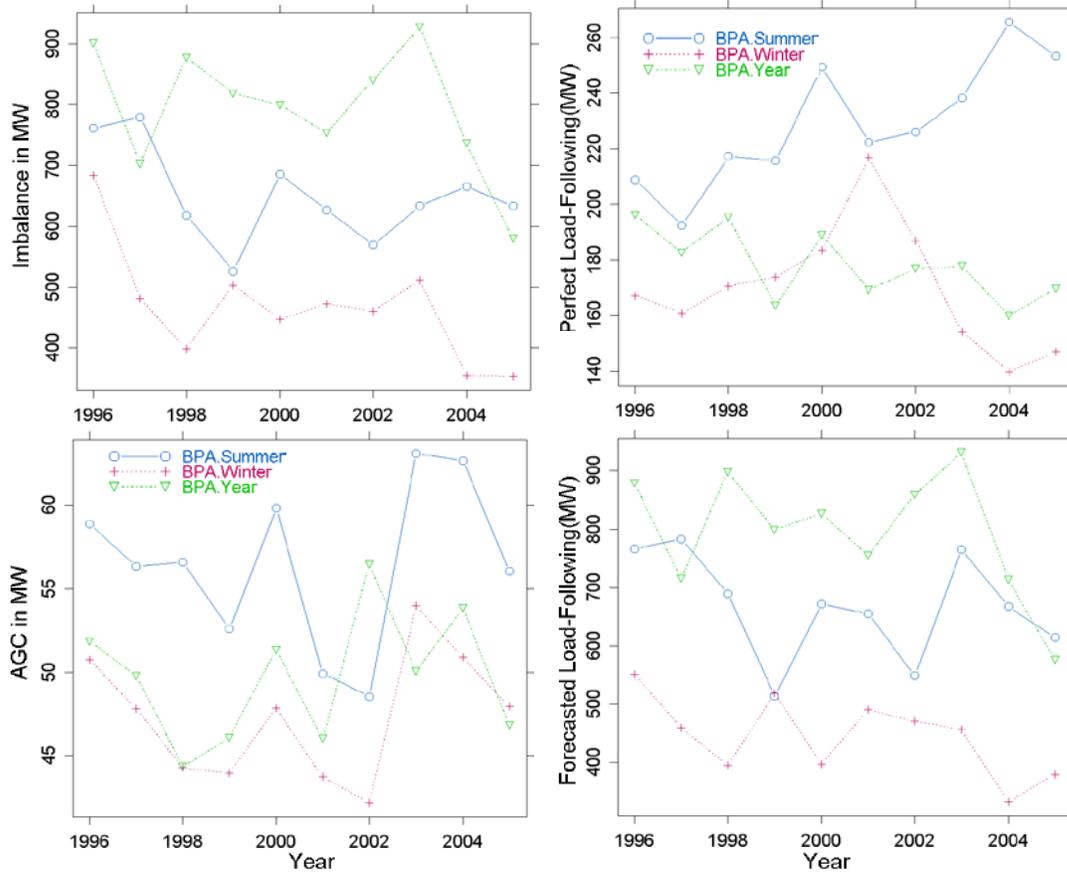
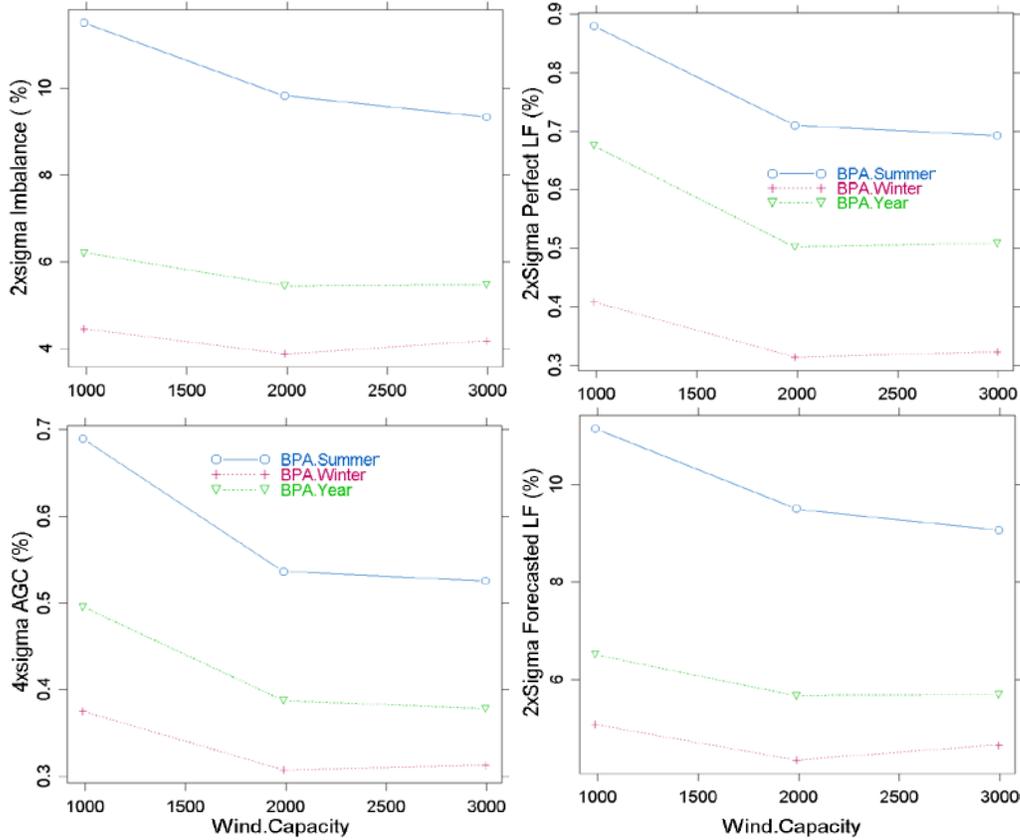


Figure 60. Annual values of supplemental AGC and imbalance based on the BPA approach



**Figure 61. Seasonal assessment of the n-sigma increase of frequency regulation reserves in percent of rated installed wind generation**

For comparisons purposes, Figure 61 presents the results obtained by applying the n-sigma method of reserve assessment to the same data, with n=4 for AGC and n=2 for load following. Although very different from the BPA covariance allocation-based method, these results are broadly in line with recent publications. To simplify decision making, the expected value was estimated by averaging for the BPA and n-sigma approaches, the 10 annual values (see Figure 59) and tabulated them in Table 48. The column “Mean” simply designates the average of the three values, “winter,” “summer,” and “out-of-season,” which themselves are the averages of the 10 annual values.

**Table 48. Frequency regulation reserves requirements for 3,000-MW wind generation integration in the Quebec interconnection****(a) BPA weighted maximum allocation method (BPA 2008)**

MW (Max Up or Down )	Mean	Winter	Summer	Out of Season
AGC	54	49	65	48
Load Following				
• Perfect schedule	191	170	229	174
• Forecasted schedule	663	513	890	768
% of wind capacity (Max Up or Down )	Mean	Winter	Summer	Out of Season
AGC	1.8	1.6	2.2	1.6
Load Following				
• Perfect schedule	6.4	5.7	7.6	5.8
• Forecast schedule	22.1	17.1	29.7	25.6

**(b) ONRL-Holttinen n-sigma allocation method [4]**

MW (Max Up or Down )	Mean	Winter	Summer	Out of Season
AGC	13	10	17	11
Load Following				
• Perfect schedule	17	11	23	15
• Forecasted schedule	203	153	285	170
% of wind capacity (max up or down )	Mean	Winter	Summer	Out of Season
AGC	0.4	0.3	0.6	0.4
Load Following				
• Perfect schedule	0.6	0.4	0.8	0.5
• Forecasted schedule	6.8	5.1	9.5	5.7

## Conclusions

According to the BPA method, the supplementary AGC and load following reserves to accommodate 3,000 MW of installed wind capacity will amount to 1.8–22.1%, respectively, on a yearly average basis. However, there is a considerable disparity between the winter months and the other months of the year: thus, the additional load following requirements increase from 17% of the installed wind capacity in winter to 29.7% during the summer. These numbers can be compared favorably with the results obtained by BPA (28%) BPA 2008) and Manitoba Hydro (26%) (Molinski 2008), which are essentially hydroelectric utilities operating huge dams and having electricity import-export strategies that are not too different from our own. On the other hand, the n-sigma criterion resulted in much lower incremental reserves requirements with only 0.4% and 6.8% increase of the AGC (n=4) and load following (n=2), respectively.

It is generally accepted that such impact evaluation based on a statistical approach is not as accurate as a method based on simulation, which is founded upon far more realistic system operation assumptions. l'Institut de recherche d'Hydro-Québec has been working on such a simulator since 2006, but the initial results on the 3,000-MW-integration will be published separately (de Montigny et al. 2010). The simulator is the proper tool for refining these paper's estimations and, in particular, relating them to the terms of the agreement currently covering the frequency regulation service in Quebec interconnection.

## Calculation of Balancing Reserves Incorporating Wind Power into the Hydro-Québec System over the Time Horizon of 1–48 Hours

*Nickie Menemenlis, Maurice Hunault, Jacques Bourret, and Andre Robitaille*

### Introduction

Balancing reserves ensure the short-term reliability of a power system over a time horizon of 1 hour to 2–3 days ahead. They consist of available generating capacity that could be deployed when needed to offset discrepancies in supply caused by errors on current forecasts.

Traditionally, these reserves have covered uncertainties on load forecasts and forced outages. More recently, several studies in the literature have proposed increasing these reserve levels to counter the presence of uncertainties contributed by wind generation.

### Methodology

One methodology to compute balancing reserves, integrating several sources of uncertainties, is power system reliability theory. It defines the LOLP as the probability that the available generation, including reserves, will not completely meet the demand. It is obtained from capacity outage probability tables considering the possible spread on the variables, including wind generation, through a set of discrete probable states. A specific LOLP target, or what we will call here a risk, is associated with reserves that are implicitly included in these tables.

The methodology adopted here borrows from reliability theory but has some novel features specific to the problem at hand. In its final formulation, the balancing reserve requirement is a function of the statistical characteristics of the forecast errors rather than the forecasts themselves. Hence, we developed distributions of forecast errors on all variables displaying uncertainties over the lead times from 1 to 48 hours. This was done by comparing past forecasts to the corresponding measurements.

Replacing discrete states in the reliability computation by these distributions, more powerful probabilistic tools could be applied to the analysis. This facilitated both the aggregation of the *individual* forecast errors into a *net* forecast error and the graphical representation of results. The distribution of the net forecast error represents the reliability (i.e., the probability of satisfying the entire load). The anticipated risk, given as 1 minus the reliability, was then computed at each forecast lead time. It is the value of a function of the net forecast error distribution corresponding to a predetermined level of balancing reserves. Alternatively, given a target level of risk, the associated balancing reserve requirements can be quantified. Repeating this computation for each lead time over a given time horizon, it reveals the temporal evolution of risk or of balancing reserve requirements.

This methodology was used to evaluate additional balancing reserves required to integrate 3,000 MW of wind power capacity into the Hydro-Québec system, corresponding to a penetration level of wind power of approximately 10%. This was done by comparing the balancing reserves required to maintain the same level of risk before and after the integration of wind generation over numerous system conditions. Several results from this study are illustrated in the following figures and tables.

**Results**

Figure 62 illustrates typical load, wind, and generation unavailability error distributions and the resulting net error distribution at a given instant. The curve  $F_{d+u}$  represents the distribution of the aggregation of conventional forecast errors, shown individually with dotted curves, while the curve  $F_{d+u-w}$  represents the distribution of the net forecast error including wind generation. Values on the curves represent reliability. Including wind generation, without any balancing reserve ( $BR = 0 \text{ MW}$  on the x-axis), reliability is quite low ( $\approx 0.37$ ). By adding balancing reserves, for example,  $BR = 500 \text{ MW}$ , the reliability increases significantly ( $\approx 0.75$ ), indicating that a risk of 25% still persists. Balancing reserves of 1,250 MW result in very high reliability ( $\approx 0.98$ ), and greater balancing reserves contribute little additional reliability.

The risk in Figure 63 is obtained from the relation  $Risk = 1 - Reliability$ .

It illustrates the risk,  $R_0$ , corresponding to some nominal level of balancing reserves,  $BR_{nom}$ , the additional risk incurred,  $\Delta R$ , and the additional reserves  $\Delta BRs$  required following the integration of two different wind generation capacities, with wind forecast error uncertainties modeled as zero-mean low and large variance Gaussian processes. With the given nominal balancing reserves of  $BR_{nom} = 500 \text{ MW}$ , the risk,  $R_0$ , without wind generation is 17% (obtained by reading on curve,  $R_{d+u}$ ). Adding a certain amount of wind generation into the system, and keeping the same amount of balancing reserves, increases the system risk by an amount of  $\Delta R$ . The full and dotted curves,  $R_{d+u-w}$  and  $R_{d+u-w}$ , corresponding to small and large wind generation respectively. In order to maintain the same risk before and after the additions of wind generation, it is necessary to provide the system with additional balancing reserves of the amount of  $\Delta BRs$ . For the case examined, the additional reserves are 50 MW and 140 MW respectively.

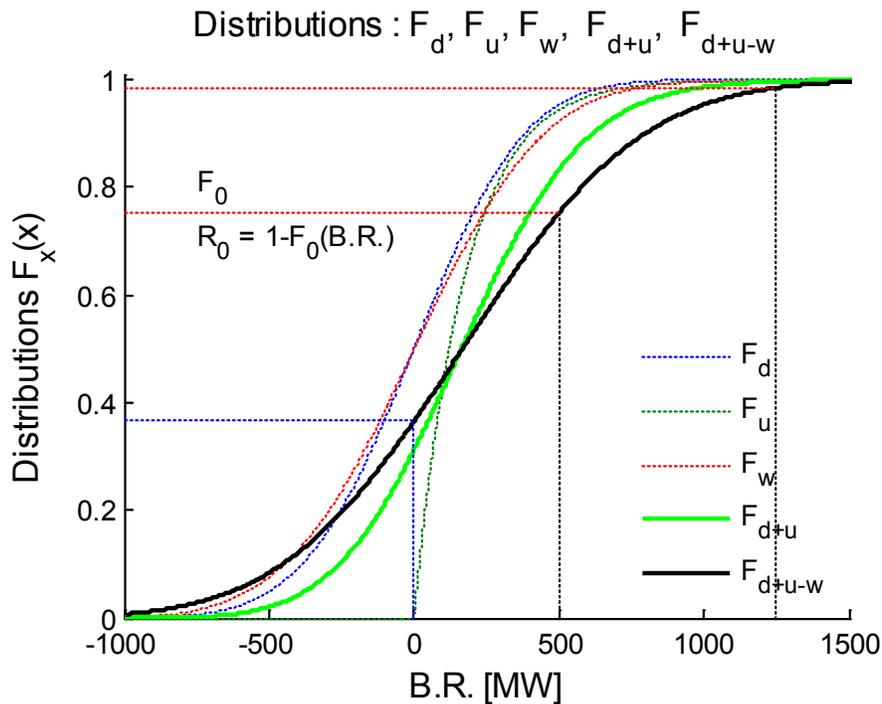
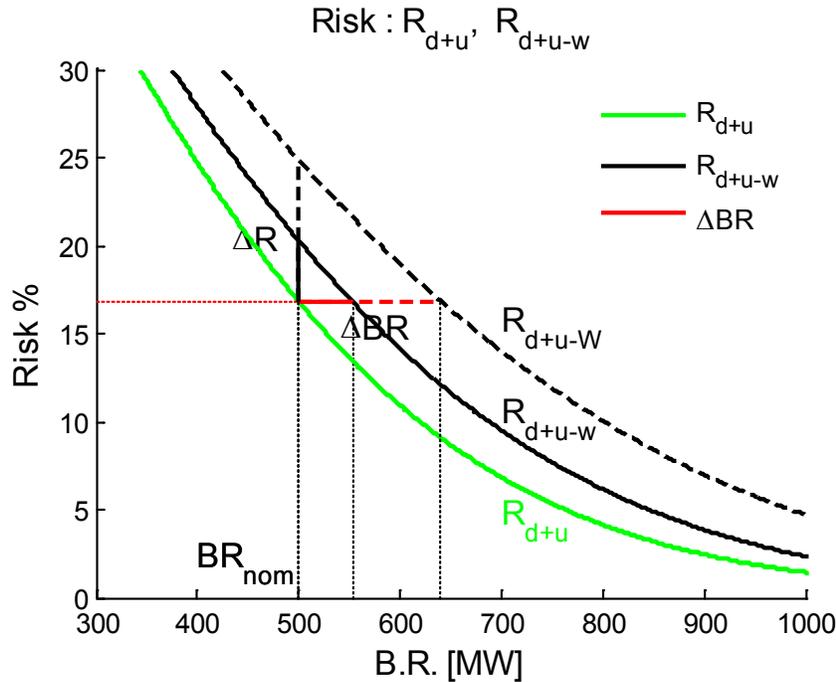


Figure 62. Qualitative illustration of the various components used in the risk calculation



**Figure 63. Qualitative illustration of the risk and additional balancing reserves for two different wind generation penetration levels**

We note that at each instant the original risk without wind generation,  $R_0$ , presented to the system depends on:

- the statistical characteristics of the uncertainties on the load forecast and the forecast of unavailable power, and
- the nominal balancing reserves level,  $BR_{nom}$

In addition, looking at the time evolution of the variables, since the forecast uncertainties may vary over time, the hour during the day and the season, the following is true:

- The risk  $R_0$  incurred with the nominal balancing reserves also varies over time. This is illustrated in Figure 63 over a horizon covering the next day using typical winter data from the Hydro-Québec system. The two curves in each pair represent risk with and without wind generation. The bump in the curves around 16:00 hours reflects the particular signature of load forecast errors.
- The balancing reserves  $BRs$  required to maintain a given risk level also varies over time. This is illustrated in Figure 60.
- The additional risk,  $\Delta R$ , sustained by the system when integrating wind generation, and therefore the additional balancing reserves,  $\Delta BRs$ , depend on the original risk,  $R_0$ ,

corresponding to the given level of reserves,  $BR_{nom}$ , and on the statistical characteristics of the added *wind generation* forecast error. The two quantities  $\Delta R$  and  $\Delta BRs$  also vary over time. Figure 65 shows the risk encountered with and without wind generation, and the required  $\Delta BRs$  beyond the predetermined balancing reserves to maintain risk over a horizon covering the next day.

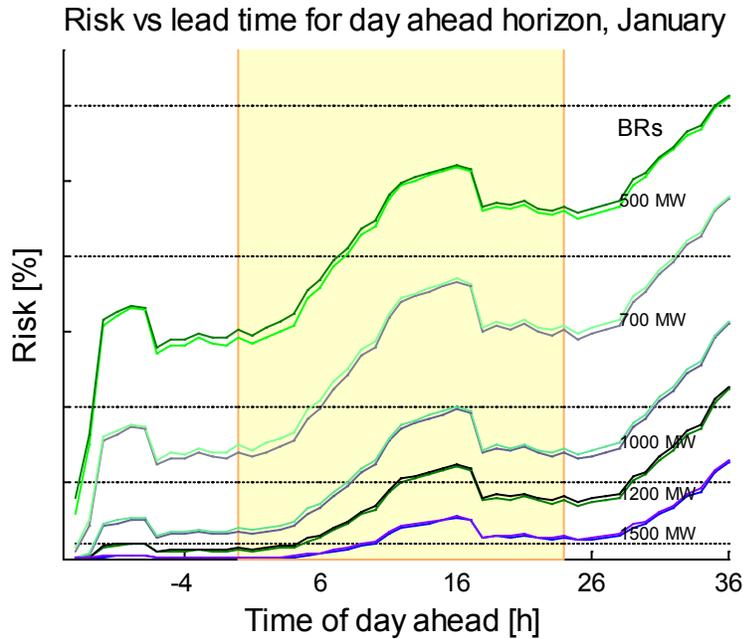


Figure 64. Risk encountered as a function of lead time for various levels of balancing reserves

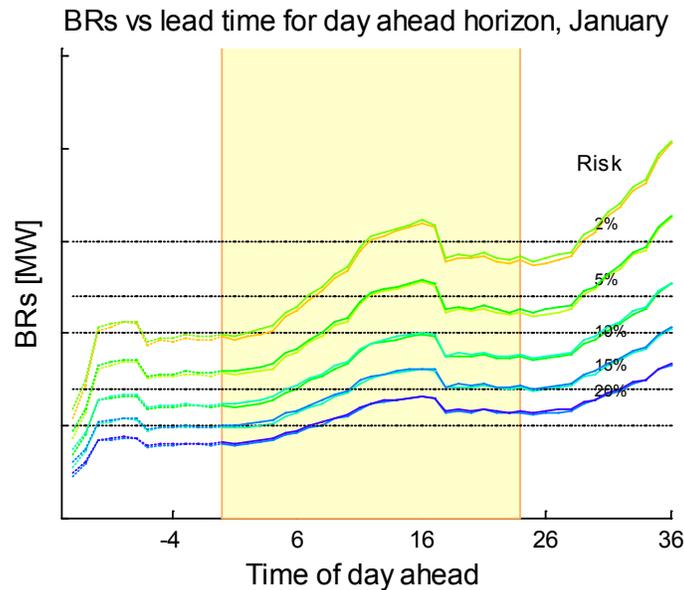
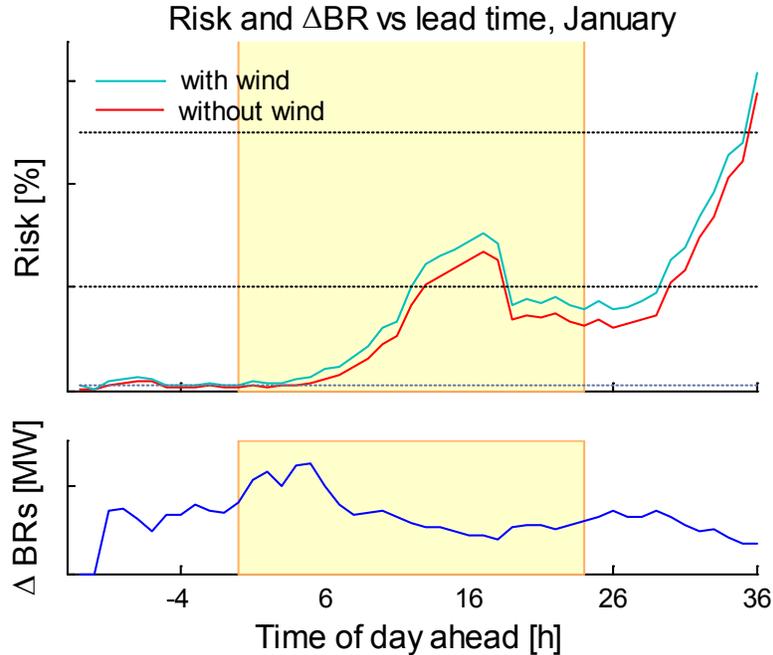


Figure 65. Balancing reserves required as a function of lead time for various levels of risk



**Figure 66. Risk with and without wind generation, and added balancing reserves to maintain the same risk**

Using Hydro-Québec data, risk levels encountered in balancing reserves reach up to 5% more than the day-ahead horizon. This may seem unusually high, but contrary to the regulating reserves, acting in the intra-hour time horizon, utilities have the leisure to accept larger risk levels here because looking forward, they can still call on uncommitted yet available resources to remedy undesirable occurrences. Since the remedies are implemented at extra cost, the choice of risk level is essentially an economic consideration associated with the deployment of resources committed at the last minute.

We have used this measure of risk as a tool to evaluate the risk associated with the use of the present nominal balancing reserves and to compute the extra requirements in balancing reserves brought on by the presence of wind generation while maintaining the present risk.

Looking over the span of 1 year, maximum values over the day-ahead horizon were compiled for risk with and without wind generation, as well as additional risk encountered and additional balancing reserves required with the addition of 3,000 MW of wind capacity. These are summarized in Table 49.

**Table 49. Results for every month over the day-ahead horizon**

Maximum risk w/wo wind, $\Delta R$ and $\Delta BR$ s at maximum risk Day ahead horizon - 3000 MW of wind generating capacity												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Rmax wo/w [%]	4,0	3,7	3,7	1,7	1,6	1,4	1,6	1,6	1,1	<b>3,0</b>	2,2	<b>5,0</b>
Rmax w/w [%]	4,5	4,1	4,1	2,0	1,8	2,0	1,9	2,1	1,4	3,8	2,7	5,5
$\Delta R(R_{max})$ [%]	0,4	0,4	0,4	0,3	0,3	0,6	0,4	0,5	0,3	0,7	0,4	0,5
$\Delta BR(R_{max})$ [MW]	38	40	41	49	47	82	61	67	68	<b>57</b>	52	<b>34</b>

Rmax wo/w: Maximum risk encountered over day-ahead horizon without wind

Rmax w/w: Maximum risk encountered over day-ahead horizon with wind

$\Delta R(R_{max})$ : Variation of risk occurring at maximum risk due to addition of wind power

$\Delta BR(R_{sémx})$ :  $\Delta PAs$  required at maximum risk due to addition of wind power

The last column of the table shows that the maximum risk in winter, when nominal balancing reserves are set to 1,500 MW, is 5% in December. If balancing reserves are not adjusted, this risk climbs to 5.5%. However, the increase in balancing reserves required to maintain a risk of 5% is only 34 MW. In summer, the nominal balancing reserves are set to 1,200 MW, and the system load and its associated uncertainties are lower. The contribution of the wind power uncertainties to the total distribution is therefore augmented. In October, the maximum risk encountered on the day-ahead horizon is 3% without wind power and 3.8% with wind power. The increase in balancing reserves required to maintain a risk of 3% is only 57 MW. We note also that in other months, to maintain much lower levels of risk, higher DBRs are required. However, if the December risk level of 5% is deemed acceptable all year long, then the balancing reserves levels need not be increased beyond the 34 MW required in December.

## Conclusions

In summary with this study, we quantified balancing reserve requirements, with and without wind generation, based on a risk criterion. With the same procedure we have also determined the added reserve requirements to maintain a specified level of risk before and after the integration of 3,000 MW of wind power capacity.

The conclusion to be drawn is that with current Hydro-Québec balancing reserves being relatively high and risk levels relatively low, little additional balancing reserves are required to integrate 3,000 MW of wind power capacity. The 5% maximum risk level revealed in our simulations was not predetermined, but rather was revealed by the present study. It seems to be acceptable, since current practice in operations planning seems satisfactory.

## Wind Power Capacity Credit in Quebec

*L. Bernier and A. Forcione*

### Introduction

#### Climate and load

As is the case for a few northern countries and Canadian provinces, the Quebec annual peak electricity demand occurs during the winter, and is well correlated to actual air temperature and wind at major load centers. The peak usually happens during cold spells where minimum temperature reaches around  $-30^{\circ}\text{C}$  or less during two or more days in a row.

#### Climate and Wind Generation

The winter season is also generally favorable to a good wind power production, on average. However, in order to protect the turbines against structural damage, the wind production is halted when actual temperatures at the turbine site reach a limit set by design. The limit is chosen by manufacturers mainly by comparing the value of expected lost energy over the life of the turbine with the cost of lowering this limit. Based on the climates in which wind capacity is actually deployed, today's turbines are usually available either with a standard operational limit of  $-20^{\circ}\text{C}$ , or with a "cold package" limit of  $-30^{\circ}\text{C}$ . With the Quebec climate, turbines in the control zone are of the latter type, but might still face periods of low temperature induced forced stoppages. However, due to the geographic dispersion of wind power plants and their varying distances from load centers, these stoppages are not necessarily or systematically coincident with system peak load events.

#### Scenario

In such a context, an appropriate evaluation of capacity contribution is crucial to ensure system security and reliability at minimum capacity supply cost. Accordingly, the capacity contribution of wind power in the Quebec control zone has been studied in detail for a "3000MW in 2016" wind scenario<sup>12</sup>. A few articles give in depth description of the study for which a brief summary is provided here.

#### Methodology

A custom-made Monte-Carlo simulation model was used. The model relied on wind and load data series that were matched on an hourly time-step, over a 36 years period using real weather data combined with seven different weekday patterns. The model takes into account forecasting errors and conventional generation outages through Monte-Carlo simulator.

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<sup>12</sup> At the time of the study, the "3000MW in 2016" scenario corresponded to the Hydro-Quebec Distribution firm engagements, with known wind plants locations and some available wind data.

## Results

The capacity contribution results from the comparison of two simulations leading to the same reliability target with the loss of load expectation (expectation of not having enough resources to meet the demand) equaling to one day per ten years:

- A first simulation includes the 3000 MW wind power scenario
- In the second simulation, the wind power is replaced by conventional generation resources having a 0% outage rate.

The amount of conventional generation added in the second scenario is then use as a benchmark for the capacity contribution of wind power.

Obviously, such simulations rely on availability and realism of data over the full 36 years period. Accordingly, hourly load data was provided by highly reliable demand models and based on historical hourly weather time series. However, in absence of real historical wind generation and with the complex spatial and temporal correlations between weather, wind generation and load plus meteorologically triggered stoppages, care had to be given to the evaluation of the underlying long term wind power time series. These were obtained using historical meteorological data available from weather stations that were extrapolated at the power plants sites using a physics based diagnostic model.

Thus, additional evaluations were performed in order to evaluate the sensitivity of wind power capacity contribution estimations to wind power data. Such evaluations indicated that the results were sensitive to wind power hourly data during a limited number of very cold events occurring along the 36 years period. That was not surprising, due to the correlation between extreme cold events and high risk periods of not having enough resources to meet the demand.

Following the results of sensitivity analysis, the time series were then supplemented by in depth analysis of fourteen critical extreme cold weather events, using high resolution numeric weather “hindcasting” models and weather reanalysis data.

After the inclusion of this new dataset, the capacity contribution of 3000 MW of wind power was found to be equivalent to 900 MW of conventional generation.

### *Limitations*

Results were found to be very sensitive to wind data during a limited number of extreme cold events over the 36 years period. That finding also suggests that such evaluations are improved by long time series and by better on site weather data covering critical historical events.

### **Conclusions**

The capacity credit was established at 30% of total wind nameplate capacity, which amounts, for the studied 3000 MW scenario, to an equivalent of about 900 MW of firm conventional generation capacity.