

Review of the WECC EDT Phase 2 EIM Benefits Analysis and Results Report

Decision and Information Sciences Division

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Review of the WECC EDT Phase 2 EIM Benefits Analysis and Results Report

by

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Decision and Information Sciences Division, Argonne National Laboratory

April 2012

FOREWORD

A region-wide Energy Imbalance Market (EIM) was recently proposed by the Western Electricity Coordinating Council (WECC). In order for the Western Area Power Administration (Western) to make more informed decisions regarding its potential involvement in the proposed market, Western asked Argonne National Laboratory (Argonne) to review the analysis performed by Energy and Environmental Economics, Inc. (E3) in estimating the societal benefits of implementing an EIM (the October 2011 revision). Key components of the E3 analysis made use of results from a study conducted by the National Renewable Energy Laboratory (NREL); therefore, we also reviewed the NREL work. This report examines E3 and NREL methods, models, and model applications.

This review was carried out based on limited information available from presentations, reports, and communication with modelers and analysts involved in the EIM benefits study. Therefore, some aspects of this review may need to be refined and/or corrected. Although it is complimentary of several components of the E3 study, it is critical of some aspects of the methodology and interpretation of model results. The intent of this report is to identify areas of potential improvements for the benefit of future analyses. It also recommends studying alternative market structures or cooperative frameworks that may be more cost effective and have fewer economic and financial risks than those associated with the EIM. The Argonne staff has opened a dialogue with WECC, E3, NREL, and other interested parties to find solutions that best meet the needs of utilities in the Western Interconnection and power consumers. We hope to continue the dialogue to advance modeling of complex structures like the EIM.

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TABLE OF CONTENTS

FOREWORD	ii
ACKNOWLEDGMENTS	iii
ACRONYMS AND ABBREVIATIONS	ix
ABSTRACT	1
EXECUTIVE SUMMARY	5
ES.1 Purpose and Intent of the Report	5
ES.2 E3 Findings	6
ES.3 Methods and Assumptions for Estimating the Cost of Market Barriers	7
ES.4 Methods and Assumptions in Developing Flexibility Reserve Requirements	9
ES.5 Modeling Hydropower Plant Operations	12
ES.6 Dispatch Model Granularity	13
ES.7 Electricity Market Participation and Structure	14
ES.8 Market Costs and Net Societal Benefits	15
ES.9 Conclusions and Recommendations	16
1 INTRODUCTION	19
2 BENEFITS FROM REMOVING MARKET IMPEDIMENTS	21
2.1 Dispatch and Modeling Assumptions	22
2.2 Review of Hurdle Rate Methodology	24
3 BENEFITS FROM LOWER FLEXIBILITY RESERVE REQUIREMENTS	29
3.1 Flex Reserve Requirements	32
3.2 Flexibility Spin Reserves Requirements	33
3.3 Flexibility Supplemental Reserves Requirements	34
3.4 Representation of Flexibility and Conventional Reserves in GridView.....	34
3.5 Case Study 1 – Analysis of Flexibility Reserve Requirements for WACM.....	35
3.6 Case Study 2 – WALC PV Patterns	41
3.7 Alternative Representation of Flexibility Regulation and Reserves.....	45
3.8 Grid Transmission Considerations.....	48
3.9 Supplemental Flexibility Reserves and Ramping Events	52
4 MODELING HYDROPOWER	55
4.1 Colorado River Storage Project	55
4.2 Loveland Area Project	56
4.3 Sierra Nevada Region	58

TABLE OF CONTENTS (Cont.)

4.4	Bonneville Power Administration.....	60
4.5	Hydropower Variability.....	62
5	GRIDVIEW MODEL TIME STEP.....	65
5.1	Granularity of the Dispatch Interval in the GridView Model.....	65
5.2	Case Study – Comparing Results of a Simple Dispatch Model with 5-Minute and 1-Hour Dispatch Intervals.....	65
6	MODELING THE ELECTRICITY MARKET.....	71
6.1	Balancing Authority Participation in the Market.....	71
6.2	Behavior of Market Participants.....	73
6.3	Importance of Explicitly Specifying Market Rules.....	76
6.4	Risks to Those Not Participating in a Market.....	76
7	NET SOCIETAL BENEFITS.....	79
8	ALTERNATIVES TO AN EIM.....	81
8.1	Dynamic Scheduling System.....	81
8.2	Area Control Error Diversity Interchange.....	81
8.3	Intra-Hour Transmission Scheduling.....	81
8.4	Intra-Hour Transaction Accelerator Program.....	82
8.5	ISO/RTO Market Structure.....	82
9	CONCLUSIONS AND RECOMMENDATIONS.....	83
10	REFERENCES.....	85
	APPENDIX A: MODELING ASPECTS THAT MAY CONTRIBUTE TO ZONAL FLOW DIFFERENCES BETWEEN EIM MODELED AND ACTUAL 2006 ZONAL FLOWS.....	91
	APPENDIX B: COMPARISON OF 2006 MONTHLY THERMAL POWER PLANT GENERATION AND GRIDVIEW MODELED RESULTS.....	99
	APPENDIX C: BENCHMARK CASE MONTHLY ELECTRICITY PRICES.....	113

LIST OF FIGURES

Figure 3.1 E3 Projections of Wind Production for WACM BAA from March 14 to March 20, 2020	29
Figure 3.2 E3 Projections of Loads and Net Loads for WACM BAA from March 14 to March 20, 2020	30
Figure 3.3 Standard Deviation of the WACM BAA Hourly Forecast Error Distribution as a Function of Wind Production	36
Figure 3.4 Forecast Error Distribution Statistics and Trend Lines	37
Figure 3.5 Skewness for the WACM BAA Hourly Forecast Error Distribution as a Function of Wind Production	37
Figure 3.6 Forecast Error Distribution for the 20-MW to 40-MW Wind Production Class.....	38
Figure 3.7 Forecast Error Distribution for the 1,000-MW to 1,020-MW Wind Production Class	39
Figure 3.8 Forecast Error Distribution for the 540-MW to 560-MW Wind Production Class.....	40
Figure 3.9 Kurtosis for the WACM BAA Hourly Forecast Error Distribution as a Function of Wind Production	40
Figure 3.10 E3 Projections of PV Production for WALC BAA from March 14 to March 20, 2020.....	42
Figure 3.11 Projections of Loads and Net Loads for WALC BAA from March 14 to March 20, 2020.....	42
Figure 3.12 E3 Projections of PV Production for WALC BAA from June 20 to June 26, 2020.....	43
Figure 3.13 E3 Projections of Loads and Net Loads for WALC BAA from June 20 to June 26, 2020.....	43
Figure 3.14 Monthly PV Solar Production in the WALC BAA in 2020.....	44
Figure 3.15 Monthly Variable Resource Production and Load in the Entire EIM Footprint in 2020.....	45
Figure 3.16 Alternative Representation of Flexibility Regulation and Reserves	46
Figure 3.17 Ramping Event Exceedance Curve for Variable Resources (All Wind) in the WACM BAA.....	53
Figure 3.18 Ramping Event Exceedance Curve for Variable Resources (All PV) in the WALC BAA.....	54
Figure 4.1 Comparison of Modeled and Actual Plant Generation at Yellowtail in July 2006.....	56
Figure 4.2 Comparison of Modeled and Actual Plant Generation at Seminole in July 2006.....	57
Figure 4.3 Comparison of Modeled and Actual Plant Generation at Seminole in December 2006	57
Figure 4.4 Comparison of Modeled and Actual Plant Generation at J.F. Carr in September 2006.....	58
Figure 4.5 Comparison of Modeled and Actual Plant Generation at Shasta in December 2006.....	59
Figure 4.6 Comparison of Modeled and Actual Plant Generation at Whiterock in April 2006.....	60

LIST OF FIGURES (Cont.)

Figure 4.7 Comparison of Total BPA Hydroelectric Generation under Benchmark and EIM Cases in April 2020	61
Figure 4.8 Comparison of Total BPA Hydroelectric Generation under Benchmark and EIM Cases in October 2020	61
Figure 4.9 Hydropower’s Supply Contribution in WI.....	62
Figure 5.1 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Decreasing Load and No Wind Generation.....	66
Figure 5.2 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Decreasing Load and 600 MW of Forecasted (but Variable) Wind.....	67
Figure 5.3 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Increasing Load and No Wind Generation	68
Figure 5.4 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Increasing Load and 600 MW of Forecasted (but Variable) Wind	68
Figure 6.1 Example of a Hockey-Stick Bid Profile Submitted to PJM for a Unit in July 2010.....	74
Figure 6.2 Example of an Economic Withholding Strategy Bid Submitted to PJM for a Unit in July 2010.....	75
Figure 6.3 Example of Offers with Large Daily Bid Price Fluctuations Submitted to PJM in July 2010.....	75
Figure 6.4 Maximum and Minimum Market Prices at the Palo Verde Hub from 1996 to 2005.....	77

LIST OF TABLES

Table 2.1 Generation Breakdown in 2006 for Portion of WI Located in the United States.....	23
Table 3.1 Reserve Requirement (MW) Computed by NREL.....	51
Table 6.1 SNR Purchases Made in the CAISO As Compared to Total Power Purchases, Including Bilateral Contracts.....	71
Table 6.2 Comparison of Bilateral Contract Costs versus Spot Market Costs Incurred by SNR	72

ACRONYMS AND ABBREVIATIONS

The following is a list of the acronyms and abbreviations (including units of measure) used in this document.

ACE	area control error
ADI	Area Control Error Diversity Interchange
AESO	Alberta Electric System Operator
AGC	automatic generation control
Argonne	Argonne National Laboratory
BA	balancing authority
BAA	Balancing Authority Area
BAU	business-as-usual
BOR	Bureau of Reclamation
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CPS	control performance standard
CRSP	Colorado River Storage Project
CSP	concentrated solar power
CVP	Central Valley Project
DSS	Dynamic Scheduling System
E3	Energy and Environmental Economics, Inc.
ECC	Enhanced Curtailment Calculator
EDT	Efficient Dispatch Toolkit
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIS	Energy Imbalance Service
EMS	energy management system
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data Set
HTC	hydrothermal coordination
ISO	independent system operator
I-TAP	Intra-Hour Transaction Accelerator Program
I-TS	Intra-Hour Transmission Scheduling
JIP	Joint Initiative Program
LAP	Loveland Area Project
LP	linear programming

ACRONYMS AND ABBREVIATIONS (Cont.)

LMP	locational marginal price
MAF	million-acre-feet
MW	megawatt (one million watts)
NERC	North American Electric Reliability Corporation
NPV	net present value
NREL	National Renewable Energy Laboratory
OASIS	Open Access Same-time Information System
PV	photovoltaic
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
SCED	security-constrained economic dispatch
SNR	Sierra-Nevada Region
SPP	Southwest Power Pool
SRP	Salt River Project
SWPA	Southwestern Power Administration
TEPPC	Transmission Expansion Planning Policy Committee
Western	Western Area Power Administration
WACM	Western Area Power Administration – Colorado-Missouri
WALC	Western Area Power Administration – Lower Colorado
WECC	Western Electricity Coordinating Council
WI	Western Interconnection

REVIEW OF THE WECC EDT PHASE 2 EIM BENEFITS ANALYSIS AND RESULTS REPORT

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ABSTRACT

A region-wide Energy Imbalance Market (EIM) was recently proposed by the Western Electricity Coordinating Council (WECC). In order for the Western Area Power Administration (Western) to make more informed decisions regarding its involvement in the EIM, Western asked Argonne National Laboratory (Argonne) to review the EIM benefits study (the October 2011 revision) performed by Energy and Environmental Economics, Inc. (E3). Key components of the E3 analysis made use of results from a study conducted by the National Renewable Energy Laboratory (NREL); therefore, we also reviewed the NREL work. This report examines E3 and NREL methods and models used in the EIM study.

Estimating EIM benefits is very challenging because of the complex nature of the Western Interconnection (WI), the variability and uncertainty of renewable energy resources, and the complex decisions and potentially strategic bidding of market participants. Furthermore, methodologies used for some of the more challenging aspects of the EIM have not yet matured. This review is complimentary of several components of the EIM study. Analysts and modelers clearly took great care when conducting detailed simulations of the WI using well-established industry tools under stringent time and budget constraints. However, it is our opinion that the following aspects of the study and the interpretation of model results could be improved upon in future analyses:

- The hurdle rate methodology used to estimate current market inefficiencies does not directly model the underlying causes of sub-optimal dispatch and power flows. It assumes that differences between historical flows and modeled flows can be attributed solely to market inefficiencies. However, flow differences between model results and historical data can be attributed to numerous simplifying assumptions used in the model and in the input data. We suggest that alternative approaches be explored in order to better estimate the benefits of introducing market structures like the EIM.
- In addition to more efficient energy transactions in the WI, the EIM would reduce the amount of flexibility reserves needed to accommodate forecast errors associated with variable production from wind and solar energy resources. The modeling approach takes full advantage of variable resource diversity over the entire market footprint, but the projected reduction in flexibility reserves may be overly optimistic. While some reduction would undoubtedly occur, the EIM is only an energy market and would therefore not realize the same reduction in reserves as an ancillary services market. In our

opinion the methodology does not adequately capture the impact of transmission constraints on the deployment of flexibility reserves.

- Estimates of flexibility reserves assume that forecast errors follow a normal distribution. Improved estimates could be obtained by using other probability distributions to estimate up and down reserves to capture the underlying uncertainty of these resources under specific operating conditions. Also, the use of a persistence forecast method for solar is questionable, because solar insolation follows a deterministic pattern dictated by the sun's path through the sky. We suggest a more rigorous method for forecasting solar insolation using the sun's relatively predictable daily pattern at specific locations.
- The EIM study considered only one scenario for hydropower resources. While this scenario is within the normal range over the WI footprint, it represents a severe drought condition in the Colorado River Basin from which Western schedules power. Given hydropower's prominent role in the WI, we recommend simulating a range of hydropower conditions since the relationship between water availability and WI dispatch costs is nonlinear. Also, the representation of specific operational constraints faced by hydropower operators in the WI needs improvements.
- The model used in the study cannot fully capture all of the EIM impacts and complexities of power system operations. In particular, a primary benefit of the EIM is a shorter dispatch interval; namely, 5 minutes. However, the model simulates the dispatch hourly. Therefore it cannot adequately measure the benefits of a more frequent dispatch. A tool with a finer time resolution would significantly improve simulation accuracy.
- When the study was conducted, the rules for the EIM were not clearly defined and it was appropriate to estimate societal benefits of the EIM assuming a perfect market without a detailed specification of the market design. However, incorporating a more complete description of market rules will allow for better estimates of EIM benefits. Furthermore, performing analyses using specific market rules can identify potential design flaws that may be difficult and expensive to correct after the market is established.

Estimated cost savings from a more efficient dispatch are less than one percent of the total cost of electricity production. However, in our opinion all of these economic benefits would not be realized because of the cost to create and operate an electricity market. The analysis shows that the net societal benefit could potentially range from more than -1% (a net cost) to less than 1% of the total cost of electricity production. We are concerned if the precision of the models and methodologies used can accurately measure these small differences because many realities of WI system operations are not fully captured and market rules are not completely specified.

We conclude that there are many facets of the EIM study which may either over- or underestimate EIM benefits, the magnitude of which cannot be quantified without additional analysis. Because electricity is crucial to the economic health of the WI, it is our opinion that additional studies based on more clearly defined market rules, improved methodologies, and higher resolution models are warranted. We also recommend studying alternative market structures and cooperative frameworks in addition to the proposed EIM.

We hope that some of the issues and proposed improvements raised in this report will be considered as further EIM analyses are conducted. The Argonne staff has opened a dialogue with WECC, E3, NREL, and other interested parties to find solutions that best meet the needs of utilities and power consumers in the WI. We hope to continue the dialogue to advance the state of the art in modeling renewable generation in power systems and complex market structures like the EIM.

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EXECUTIVE SUMMARY

The Efficient Dispatch Toolkit (EDT) proposed by the Western Electricity Coordinating Council (WECC) consists of a system that is composed of two separate but related tools: namely, an Energy Imbalance Market (EIM) and an Enhanced Curtailment Calculator (ECC) (WECC 2011). The proposed EIM is a real-time energy market that would provide a region-wide, centralized generation dispatch. The market would operate on 5-minute time steps and incorporate real-time generation capabilities and transmission constraints. Currently, the dispatch in the Western Interconnection (WI) is performed hourly by each balancing authority (BA). Dispatchable units ramp from 10 minutes before to 10 minutes after the beginning of each hour. WECC security coordinators stationed at two reliability coordinator offices work with the BAs. Security coordinators monitor and direct actions to maintain system stability and security in the WI (WECC 2008).

Participation in the EIM is voluntary and would not replace existing markets, which are now based largely on bilateral contracts in much of the WI. Establishing an EIM will influence future bilateral prices and transmission flows for everyone in the WI regardless of their participation in the market. Market rules have not yet been defined in more detail, and the level of participation in the EIM is uncertain.

An analysis of the proposed 5-minute EIM was performed by Energy and Environmental Economics, Inc. (E3) on behalf of WECC (E3 2011). E3 used the GridView model (ABB 2011) combined with innovative methods for the treatment of renewable energy in system operations to evaluate EIM societal benefits. GridView, distributed by ABB, is an advanced optimization tool that simulates power system security-constrained economic dispatch (SCED). It also computes the cost of power production to serve grid loads. E3 estimated an EIM's societal benefits by computing the difference in power production costs in the WI between two cases: namely, the "Benchmark Case," which is the current mode of operation, and the "EIM Case," which is the proposed 5-minute EIM. The 5-minute EIM was modeled under the assumption that the proposed market would be adopted by all WI BAs except the California Independent System Operator (CAISO) and the Alberta Electric System Operator (AESO). These two BAs already have a centralized market structure.

The majority of E3's modeling assumptions and the methods used to optimize the economic dispatch of WI resources are consistent with standard practices, whereas other aspects, such as hydropower operations and the representation of flexibility reserves, are more advanced than those found in other similar models. The E3 analysis used results from supporting studies on operating reserve requirements performed by the National Renewable Energy Laboratory (NREL).

ES.1 Purpose and Intent of the Report

The Western Area Power Administration (Western), seeking to make more informed decisions, asked Argonne National Laboratory (Argonne) to review analyses related to EIM

societal benefits. Key portions of E3 analyses made use of results from a study conducted by NREL (Kirby et al. 2011); therefore, we also reviewed the NREL work. This report examines E3 and NREL methods, models, and model applications.

We realized that performing a cost-benefit analysis on the proposed EIM would present some significant challenges; for example, the methods and tools currently available to address many aspects of the analysis are not fully developed and/or universally accepted. The intent of this report is to identify areas that could be improved upon in future analyses.

This review was carried out based on an evaluation of the limited information available from presentations, reports, and communication with modelers and analysts involved in the EIM benefits study. Although it is complimentary of several components of the E3 study, it is critical of some aspects of the methodology and interpretation of model results. EIM study documents point out several analysis challenges and indicated if the assumptions and methods used in the analysis either over- or underestimated EIM cost savings. Many of these challenges along with others not mentioned in EIM reports are discussed in more detail in this report.

It should be pointed out that E3 conducted the analysis under both time and budget constraints which influenced how the analysis was conducted. Factors such as data availability, GridView model limitations, and recommendations from both WI utilities and the EDT Technical Review Subcommittee all played a role in the development and implementation of the study framework and the methodologies that were utilized by E3, WECC, and NREL staff. The reader should realize that the EIM study is very complicated and complex. Methodologies used for some of the more challenging aspects of the EIM are not yet in a mature state. Current knowledge gaps are challenging to overcome given that the future WI is projected to be very different from the past or current WI grid configurations. The reader should therefore keep the above factors in mind when reviewing this document and decisions that were made by EIM analysts and modelers.

ES.2 E3 Findings

The total production cost under the Benchmark Case was estimated by E3 for the year 2020 to be nearly \$20.9 billion as compared to about \$20.7 billion under the EIM Case (based on the primary set of assumptions for the EIM). The cost difference or savings of \$141.4 million was considered to be the benefit to society. These cost savings were about 0.68% of the total cost of electricity production. However, because the future is highly uncertain, E3 also performed sensitivity analyses, which estimated that societal benefits could range from \$53.6 million to \$232.6 million; that is, a savings of 0.26% to 1.12%. The net societal savings are lower; they are computed by subtracting the costs to establish and operate a central market from production cost savings.

Lower EIM production costs are realized under the EIM by dispatching and utilizing grid resources in the WI more efficiently through an all-encompassing systemic optimization of supply and demand components such that the transmission system operates within security constraints. E3 attributed these savings to the removal of energy market impediments and

reduced requirements for flexibility reserves under the EIM. Specific market barriers are not detailed in E3 documentation but may include limited coordination among market players, slow execution of bilateral trades, and trade agreements that incur several transmission charges (pancaking) when transported power (contractually) flows through multiple utility systems that have spare transmission resources (Stoft 2002; Kirschen and Strbac 2004).

In the future, flexibility reserves will augment conventional reserves to support the integration of new variable resources into the grid. The components of flexibility reserves, which are referred to by E3 as flex, spin, and supplemental, have different response time requirements ranging from seconds to 30 minutes, similar to the response times of the conventional reserve components of regulation, spinning, and supplemental. In contrast to the current BA-level dispatch, an EIM centralized dispatch over the entire EIM footprint would take advantage of variable resource diversity across a much larger region, thereby reducing flexibility reserve requirements. In addition, compared to an hourly dispatch, the 5-minute EIM dispatch interval will enable operators to reduce wind and solar forecast errors and allow operators to respond more quickly to changes in load and variable resource production.

Both energy market impediments and flexibility reserves affect the system dispatch and have interdependent influences on production costs. According to the E3 analysis, the removal of trade impediments accounts for \$41.8 million of the costs savings, that is, approximately 30% of total EIM societal benefits. The remaining 70% of the benefits is attributed to reduced flexibility reserve requirements under the EIM, which, according to the E3 analysis, allows for a more efficient dispatch of system resources. Total cost savings are based on differences between SCED model runs in the year 2020 for the Benchmark Case and the baseline EIM Case.

ES.3 Methods and Assumptions for Estimating the Cost of Market Barriers

E3 assumed that the current bilateral market structure in the WI has characteristics that impede the optimal unit dispatch of WI's grid resources and results in economic dispatch inefficiencies. To quantify these inefficiencies, E3 computed the difference in WI power production costs between the primary Benchmark and the EIM Cases. The GridView topology of the WI system includes approximately 16,000 buses, connecting transmission lines, and all generating units in the system. Buses are grouped into 24 zones.

When modeling the SCED dispatch with GridView for the year 2006 under the EIM Case, power flows among zones differ from recorded historical levels. To resolve historical differences and to calibrate the model, E3 introduced bidirectional hurdle rates on transmission lines that connect two different zones. Hurdle rates are essentially price adders for transporting energy between two connected points. In the E3 methodology, hurdle rates represent impediments to trade under the current market structure. A hurdle rate makes an interzonal energy flow more expensive relative to an energy flow within a zone. It therefore decreases the economic incentive to trade outside of a zone. Holding all other factors constant, higher hurdle rates lower both interzonal trading levels and energy transfers. Hurdle rates also alter the unit dispatch, tending to increase generation from units that are more expensive to operate while reducing output from those that are less costly. Under the Benchmark Case, E3 assigned interzonal hurdle rates such

that modeled zonal flows, which were *averaged* over time and space, were nearly identical to 2006 historical levels. In contrast, all hurdle rates in the EIM Case were set to zero, thereby simulating the removal of current market inefficiencies. When hurdle rates derived for the year 2006 were applied to interzonal flows in the 2020 Benchmark Case, the estimated WI dispatch costs increased by \$41.8 million (when discussed above, this amount was noted as a cost savings when trade impediments were removed).

The hurdle rate methodology does not directly model bilateral market inefficiencies identified in the literature. Instead, interzonal hurdle rates are used as a surrogate for market barriers that impede optimal economic energy transfers. By aligning modeled and historical flows, it is indirectly assumed that the historical but suboptimal dispatch will be obtained. It is our judgment that the hurdle rate methodology does not provide either a definitive measure or a full explanation of current WI energy market inefficiencies. Although economic efficiencies contribute toward zonal flow differences between the EIM Case and historically observed levels, flow differences are also attributed to numerous modeling simplifications and assumptions that were made by E3 regarding the transmission system, hydropower resources, cost curves for thermal generating unit production, bus-level loads, unit commitments, and resource availability. Actual historical outage data for 2006 was used for all the nuclear units and 13 of the largest coal plants. However, for the remaining power plants, the SCED uses a single set of unit outages from a single random outage draw based upon average outage statistics from the Generating Availability Data Set (GADS) for different unit categories. We were unable to determine how accurately the single random draw represented actual historical outages.

It also uses a simplified or linearized representation of power flows on the transmission system (oftentimes known as “dc power flow”) rather than a more rigorous, nonlinear representation (known as “ac power flow”). A linear representation of power flow may not allow the model to rigorously address the voltage stability issues that are prevalent in WI because of long line distances between generation resources and load centers.

In other words, even if the current bilateral market had no inefficiencies in 2006, modeled zonal flows would not match historical levels. It is very difficult (perhaps impossible) to untangle and quantify interactions among the huge numbers of variables in the dispatch model used in this analysis to identify how much of the estimated \$41.8 million in cost savings is an artifact of the modeling process and how much can be attributed to energy market inefficiencies.

E3 set hurdle rates such that the sum of annual differences between actual and modeled interzonal power flows in 2006 across all 17 monitored WI paths was less than 0.1%. Although annual average flow differences approached zero (<0.1%), the average absolute value of hourly differences was 29% with seasonal patterns of systematic over and under estimates. In its documentation, E3 (2011) states that: “[t]he differences are partially a reflection of inherent challenges in precisely simulating historical operations on an hour-by-hour basis” and “resolving some of these differences would require data granularity beyond the level permitted by the inputs available for the simulation.” We agree with these statements. We also find that calibrating GridView to a single criterion does not guarantee that the model produces accurate results for other metrics. For example, the simulated dispatch of some units is at times significantly different from historical levels, which leads to operating cost differences.

In addition, there are potentially numerous combinations of alternative hurdle rates that could match average historical transmission flows, and each of these combinations would likely lead to different results and conclusions in comparative case studies. In other words, the hurdle rate methodology does not lead to a unique and definitive solution. Furthermore, calibrating the Benchmark Case model run does not identify the root causes of the differences and therefore provide little insight into the problem.

On the basis of the level of accuracy in the GridView model runs made by E3, we cannot judge whether the societal benefit estimate is either too high or too low. We found several instances in which hourly hydropower plant production levels differed from historical levels, monthly thermal power plant generation levels differed from those reported by the Energy Information Administration (EIA) in EIA Form 906, and hourly thermal generation patterns deviated significantly from those typically practiced in the industry.

ES.4 Methods and Assumptions in Developing Flexibility Reserve Requirements

Flexibility reserves — which are referred to by E3 as flex, spin, and supplemental — will eventually be needed in addition to conventional reserves. E3 assumed that by 2020, a large amount of new variable resource capacity will be built, and flexibility reserves will be required to ensure reliable grid operations. Future requirements for flexibility reserves assumed by E3 were estimated by NREL based on projections of solar and wind production and the geographical diversity of variable resources (Kirby et al. 2011).

Flexibility reserves are needed because wind and solar forecasts are imperfect. In the NREL study, forecast errors for renewable energy production are based on short-term persistence forecasting: that is, it is assumed that the current variable resource production level will not change in the near future, typically a time period of one hour or less. NREL determined the flexibility reserve requirements on the basis of the statistical distributions of forecast errors, which were assumed to be a function of the variable resource production level. The statistical methodology used by NREL assumes that forecast errors are normally distributed. Given that the production levels of current variable resources change over time, flexibility reserves will need to be updated continuously. This practice differs from approaches used with conventional reserves, which typically remain constant over relatively long periods of time.

Under the Benchmark Case, E3 assumed that each zone would supply flexibility reserves to cover forecast errors within its own footprint. In contrast, flexibility reserve computations under the EIM Case are based on the aggregate forecast error over the entire EIM footprint. Because of the high degree of variable resource diversity over the footprint, the EIM forecast error is significantly lower than that of the sum of zonal areas' forecast errors, each of which exhibits much less diversity. This difference translates into lower flexibility reserve requirements under the EIM. The NREL analysis estimates that under the Benchmark Case, the average hourly requirement for combined flexibility regulation (flex) and spin services is 2,020 megawatts (MW). This requirement is approximately 1,000 MW in the EIM Case, that is, a reduction of approximately 50%. The Benchmark Case also requires about 2,145 MW of supplemental

flexibility reserves while the EIM requires only 1,180 MW. Whereas internal zonal resources satisfy flexibility reserves under the Benchmark Case, it is assumed that the zonal flexibility reserve requirements could be served by resources throughout the footprint in the EIM Case.

Although we agree with diversity concepts and the use of the statistical approach to compute the MW of flexibility reserves, the NREL methodology could be improved. A number of studies find that wind power forecasting errors do not typically follow a normal distribution (Lange 2005; Bludszuweit et al. 2008; Bessa et al. 2009; Hodge and Milligan 2011). Employing the persistence forecast method, we therefore computed hourly wind forecast errors in the Western Area Power Administration – Colorado-Missouri (WACM) Balancing Authority Area (BAA) using hourly variable resource production data contained in the GridView model output files. Our analysis shows that at low wind production levels, the forecast error distribution was highly skewed to the right; that is, over-projections of wind production are more likely than under-projections. In contrast, at high generation levels, the forecast error was moderately skewed to the left; that is, under-projections are more likely than over-projections. Only those forecasts in the moderate generation range had error distributions with skewness values that approached zero. We also found very similar skewness patterns when examining the EIM market footprint. Therefore, it is an oversimplification to assume that the forecasting error always follows a normal distribution. This finding will have implications for reserve requirement estimates. Furthermore, E3 used persistence forecasting for solar power. We suggest using a more rigorous method based on the fact that solar insolation, especially under clear-sky conditions, tends to follow a predictable pattern based on known seasonal and diurnal solar azimuth angles. Improvements in statistical forecast error methodologies will pave the way for more accurate estimates of flexibility reserve requirements.

NREL concludes that flexibility reserve requirements for the EIM Case are lower than amounts required under the Benchmark Case because variability resource diversity is greater over the entire EIM footprint compared to diversity within each individual BA. The underlying assumption in the NREL methodology is that power can always be sent to and received by any point in the EIM footprint. In reality, however, the transmission system becomes congested, especially at times of peak load, thereby limiting linkages among variable resources that may counteract each other.

This shortcoming is somewhat overcome by the E3 methodology since the GridView SCED accounts for transmission limitations. Hourly generation levels for each variable resource across the WI footprint are input to the model. However, it is our understanding that GridView does not fully account for the effects that uncertainty and forecast error have on the transmission system, because for the hourly dispatch the model “knows” with certainty loads and both variable resource power injections and units’ forced outages. It is also our understanding that the model did not accurately simulate the deployment of conventional and flexibility reserves in response to forecast errors and units’ forced outages.

Flex (regulation) reserves react to quick changes within a dispatch time interval and require automatic generation controls (AGCs). We expect that in order for the transmission system to operate within limits at all times slack may need to be reserved in the transmission system under the EIM Case in order to take full advantage of variable resource diversity across the market

footprint. No adjustments to transmission capacity components were made by E3 to accommodate these fast movements. It also appears that the modeling structure and methodology does not accurately represent constraints imposed by the capacity of the transmission system on the deployment of flex reserves.

We note that under Southwest Power Pool (SPP) market rules transmission capacity must be procured if conventional reserves are served by a resource outside a BA. It appears that no such transmission reserves are required under the EIM.

For the purpose of analyzing transmission issues we separate flexibility reserves into those that have response times that are either shorter or longer than the dispatch interval. Variable resource movements that are longer than the dispatch interval, such as spin and supplemental reserves, do not necessarily require AGC. However, transmission constraints may not allow grid operators to take full advantage of variable resource diversity. We note that the EIM Case specifies that EIM energy transactions would have the lowest priority and be curtailed if insufficient transmission exists in real-time; that is, the EIM can never displace other uses of the transmission system. Also, variable resource forecast errors may cause curtailments to occur if the grid is in a congested state. E3 neither simulated EIM curtailments due to forecast errors and system outages nor estimated the probability of EIM energy curtailment. In our opinion, actual BAA operations would need to carry additional reserves to account for EIM curtailments that are due to the combination of forecast errors, grid component outage events, and transmission congestion.

Under the EIM each BA operator would ultimately be responsible for maintaining a balance within its BAA. We also note the EIM is only an energy market. Yet the flexibility reserve reductions attributed to it in the E3 study would require a level of cooperation and coordination that extends far beyond an energy-only market. In reality, BA operators do not have perfect knowledge of production from variable resources and associated forecast errors across the WI. Flexibility reserve requirements are changing not only over time, but also with respect to physical location. It is our opinion that BAAs would be operated conservatively and would carry a higher level of flexibility reserves than those computed for the EIM Case. However, as the market matures, BA operators will gain experience under the EIM and would very likely reduce flexibility reserves below Benchmark Case levels. The exact level of flexibility reserve saving is difficult to assess, but methodologies that simulate EIM curtailments and imperfect BA operator knowledge could be constructed to gain a better appreciation of the magnitude of the savings. It should be noted that reductions in flexibility reserves as estimated by E3 account for about 70% of total EIM societal benefits and are therefore a critical component of the EIM analysis.

The E3 methodology ensured that adequate capacity was always online to cover all conventional reserves plus both flex and spin flexibility reserves. The GridView model accounts for all of these reserves in its unit commitment algorithm, but reserves are not assigned to units; that is, reserves as modeled by GridView do not affect either the maximum or minimum operation of units. In reality, units that are assigned these duties have reduced operational flexibility. Depending on the service provided, this is represented by some hourly dispatch models by either lowering the maximum allowable output and/or increasing the minimum allowable output levels of units that provide ancillary services. This enables units to rapidly

respond to grid-level load and resource changes. Some models “optimally” assign reserve to individual units such that system costs are minimized within model input parameters. These parameters may account for factors that go beyond cost minimization such as ensuring that unit assignments are geographically diverse while accounting for transmission limitations, forecast errors, uncertainty, and system reliability. Such assignments are particularly important in the EIM Case.

In addition to the reduced operational flexibility for resources that provide reserves, lower operational flexibility has a significant impact on system production costs. With a lower allowable maximum output, the number of units selling energy to the market increases. Compared to a situation where no reserves are provided, units that are relatively inexpensive to operate will produce less energy while more costly units will produce more energy. Also, a unit that provides regulation-down service typically generates above its technical minimum in order to respond to instantaneous increases in grid frequency, which are the result of either a decrease in system load or an increase in variable resource generation. Therefore it sometimes sells energy above the technical minimum even when market prices are less than production costs.

Lastly, E3 did not consider supplemental reserves in GridView production cost runs since it was assumed that adequate quick-start resources (i.e., mainly gas turbines) would always be available to provide this service. Therefore, the economic and grid implications of this function are not included in its study. However, it is important to take supplemental reserves into account when determining unit commitments, because under some conditions, quick-start units may already be committed to serve load and therefore would not be available to provide supplemental reserves.

We initially thought that flexibility reserve requirements were overestimated in the Benchmark Case because flexibility reserves must be served within the zone where variable resources were located; that is, it was assumed that no coordination or cooperation among BA operators would develop. To avoid this overestimation, we suggested that limited flexibility reserve sharing be allowed in the Benchmark Case to mimic current conventional sharing practices. However, we recognize that flexibility reserves are fundamentally different from conventional reserves and flexibility reserve sharing is technically more challenging under a Benchmark structure. In addition, guidance from the EDT Technical Review Subcommittee suggested that the analysis not utilize conventional resource reserve sharing groups, i.e., groups of BA operators, for variable resources.

ES.5 Modeling Hydropower Plant Operations

Typically, water deliveries within and between hydrological basins in the WI are primarily driven by nonpower considerations, including irrigation, recreation, environmental, industrial, and municipal uses — all of which are typically based on legal agreements among numerous affected parties. In contrast, the E3 representation of hydropower plant operations is based solely on power grid objectives using 2006 historical monthly generation levels for both 2006 and 2020.

According to the EIA, in 2006, hydropower plants accounted for almost 29% of the total generation from WI supply resources located in the United States (EIA 2008). Many of these power plants have limited operational flexibility, which could impact their participation in the proposed EIM. Stringent environmental operating criteria place limits on water releases and reservoir operations. Operating criteria are often complex and unique for each hydropower project placing hourly, daily, and monthly constraints on reservoir water levels. Interdependencies among cascaded water reservoirs and power plants compound operational complexities.

Because of the large number of hydropower plants and site-specific complexity of hydrological systems in WI, the hydropower representation in GridView is simplified. However, even though it has several shortcomings, it is superior to other similar models. It uses an iterative process to approximate hydrothermal coordination (HTC), given monthly energy, capacity, and operational ramping constraints. The HTC objective is to minimize locational marginal prices in the model. However, the HTC methodology was not universally applied to all hydropower resources. For some plants, hourly generation levels in the Benchmark and EIM cases in both 2006 and 2020 were set equal to actual hourly generation in 2006. That is, it was assumed that operations did not respond to the altered vector of market price signals simulated under the EIM, nor to the introduction of much greater amounts of variable generation, such as wind and solar. Presumably, generation levels for these plants were held fixed at historical 2006 levels stemming from the complexities of optimizing the dispatch of these resources.

It should also be noted that hydropower conditions in WI change considerably over both time and space, profoundly impacting thermal dispatch and transmission flows. Using a single “representative” hydropower condition may not typically produce average production cost results, as the influence of hydropower conditions on system economics is nonlinear. The marginal value of water used to generate power has a very high value during low hydropower conditions, whereas the opposite occurs when water is abundant and reservoir levels high.

We also noted that although E3 considers 2006 to be a year with average hydropower conditions, the Colorado River Storage Basin was in a prolonged drought that year. We therefore recommend that, at a minimum, the analysis be performed for a range of hydropower conditions that may occur across the WI. An analysis of several hydropower conditions that span a wide range of conditions is typically used by the Bureau of Reclamation (BOR) and Western (BOR 2007) and applied worldwide to systems with significant hydropower resources (Rebennack et al. 2010).

ES.6 Dispatch Model Granularity

The GridView model dispatches resources and serves load on an hourly basis; that is, it computes average unit generation over an hourly time span. Therefore, it cannot fully capture some of the benefits that may potentially be realized by dispatching the system every 5 minutes. In particular, it cannot model the advantages of following intra-hourly load fluctuations in the EIM. It also cannot fully assess real-time changes in flexibility reserve (flex) requirements given that the output from variable resources fluctuates over time.

This limitation is likely to lead to an underestimate of the potential EIM cost savings. We recommend that enhancements to the modeling process be made to better estimate implications for the EIM Case. Specifically, a more robust energy market simulation and optimization tool with a 5-minute time step would be extremely useful toward this end.

ES.7 Electricity Market Participation and Structure

E3 assumed that all generating resources in participating BAs (or zones) would always commit 100% of their dispatchable thermal resources and many hydropower units to the EIM. This very high level of participation will most likely not occur. For example, the Sierra-Nevada Region (SNR) of Western markets energy produced by several hydropower plants located in California's Central Valley Project. Although SNR participates in the California power market (CAISO), SNR's purchase and sales transactions in the CAISO balancing market are very low compared to all transactions. From 2010 to the present, less than 1% of all purchases are made through the CAISO, and sales are less than 10%. The primary reason that their CAISO balancing market transactions are small is the market price risk, especially with energy purchases in which SNR has chosen to minimize its exposure to real-time price volatility. In addition, SNR staff performed an analysis showing that their business strategy can be financially advantageous as compared to increasing their participation in the CAISO balancing market (Sanderson 2011). They analyzed purchases from bilateral parties between July 2009 and June 2010. The costs of power purchased from bilateral parties were compared to costs Western would have incurred for identical purchases made in the CAISO balancing market. Over the study period, Western's net savings from bilateral deals as opposed to using the balancing market was in the range of 1.5%.

Furthermore, because of environmental constraints and water delivery obligations, many hydropower producers have very limited operational flexibility, thereby affecting their ability to respond to EIM price signals. We also noted that the Southwestern Power Administration (SWPA), which has many similarities to Western and shares many of its objectives, did not join the energy imbalance service (EIS) market in the SPP. Of the 20 BAs in the SPP footprint, 16 participate in the EIS; these participants account for about 91% of the annual load in the SPP. Furthermore, market participants do not offer all of their resources to the EIS; approximately 80% to 85% of market participant resources are offered into the EIS market (Dillon 2011).

However, offering resources into an imbalance market does not mean they will be redispatched during market operation. The experience in SPP is that only about 10% of units offered into the EIS market are actually redispatched because of market operation.

If voluntary participation is low, the EIM's benefits would be significantly lower than those modeled. The E3 analysis shows that under the reduced BA Participation Case in which both Western and Bonneville Power Administration (BPA) do not join the EIM, savings would drop by more than 60% to \$53.6 million. However, many of the market operators' expenditures for start-up and operations would remain.

GridView's objective function minimizes production costs from a social surplus viewpoint based on unit-level marginal production costs. In an EIM, dispatch would most likely follow other U.S. market practices in which offers are submitted by market participants in terms of energy blocks with a corresponding bid price. In these markets, offers are not required to reflect actual unit production costs. In discussions with the SPP market monitor, we understood that the main role of the monitor is to ensure that participants do not exercise market power. SPP does not require participants to submit production cost bids similar to the assumption in the E3 analysis.

Although it is very difficult to verify, some historical offers appear to deviate significantly from production costs. Under some circumstances, grid conditions exist that present some participants with the opportunity to increase market clearing prices above production cost levels. If participants distort the market, the result may be a dispatch and corresponding price signals that significantly differ from the GridView results. These distortions could potentially more than erase cost savings realized from lower EIM production costs (i.e., the 0.2% cost savings attributed to more efficient zonal energy transfers). Therefore, a well-designed market that mirrors production costs with high participation and a strong monitoring function is essential to realizing social benefit gains from the EIM. This is consistent with the WECC Efficient Dispatch Toolkit Cost-Benefit Analysis report which states that "if market design is not carefully considered, the net benefits could be seriously degraded and costs could potentially overrun benefits" (WECC 2011).

We appreciate the rationale for conducting a cost/benefit analysis before market rules are fully defined to determine whether implementing an EIM will result in a net societal benefit. However, it is our opinion that market rules are important and followup studies should be performed to make a more accurate estimate of societal benefits after more specific rules have been developed. An analysis that includes specific market rules and approaches in a modeling framework would be very useful to avoid pitfalls in market design because market design flaws can be very difficult and expensive to modify after the market is established.

ES.8 Market Costs and Net Societal Benefits

Although many improvements could be made to the E3 analysis, the following discussion assumes that the benefits calculated for the Benchmark and primary EIM Cases are reasonably accurate. Utilicast was commissioned by WECC to estimate costs associated with operating and participating in the EDT (Utilicast 2011). On the basis of discussion with Western and information in the Utilicast report, nearly the entire EDT cost will be attributed to the EIM. Functions similar to those which are proposed under the ECC are currently being conducted by the WECC security coordinators with the webSAS tool, which calculates curtailment responsibilities on six qualified paths (Ackerman 2011; WECC 2011). The ECC would essentially expand the functions that webSAS performs over more paths on a source/sink level of granularity as opposed to the current zonal representation. Utilicast estimates ECC startup costs to range from \$0.3 million to \$0.4 million and annual operating costs to range from \$0.1 million to \$0.2 million (Utilicast 2011).

Because of the high degree of uncertainty about future expenditures, Utilicast EDT cost estimates have a wide range. Total societal costs for EIM startup range from \$66.61 million (i.e., EDT costs of \$66.91 million less ECC costs of \$0.3 million) to \$339.82 million (i.e., EDT costs of \$340.22 million less ECC costs of \$0.4 million). Annual operating costs range from \$80.26 million (i.e., EDT costs of \$80.36 million less ECC costs of \$0.1 million) to \$260.21 million (i.e., EDT costs of \$260.41 million less ECC costs of \$0.2 million). Ignoring startup costs and taking the midpoint of the annual market operating cost range yield a societal cost of about \$170.24 million. This amount exceeds the social benefits estimated for the primary EIM Case for the year 2020 by approximately \$28.8 million; that is, the EIM Case yields a negative social benefit. Adding startup expenditures would increase social losses by an even greater amount.

It should be noted that Utilicast estimates are separated into market operator and participant costs. Market operator costs for EIM operations range from \$33.9 million to \$128.9 million. The lower end of the range represents costs if an existing entity would operate the market. Assuming mid-range costs for participant costs and EIM operations by an existing entity, net societal benefits for the more efficient dispatch in 2020 would be approximately \$19 million (i.e., net production cost savings of less than 0.1%) when not considering any start-up costs. Considering results from the E3 sensitivity analyses, benefits could potentially be either lower or higher than the levels presented in this section.

ES.9 Conclusions and Recommendations

We conclude that E3 has made significant progress throughout the various analysis phases of the proposed EIM. It was brought to our attention that the analysis had to meet both time and budget constraints. It was also performed according to guidance from the EDT Technical Review Subcommittee and suggestions from EIM stakeholders on study assumptions and the data used. However, our opinion is that the current set of tools and available data could be improved to more accurately measure the total economic benefits of the EIM. We also note that the E3 results are based on a single set of unit outages, a single hydropower condition during one future year, and perfect market conditions. Sensitivity analyses can require considerable time and resources and we do not suggest that E3 simulate all possibilities in detail. However, we recommend that some sensitivity analyses be conducted on key assumptions for a small set of hours/situations (on-peak, off-peak, shoulder), to gain a better appreciation of the impact these assumptions have on the overall result. It is our opinion that hydropower is one area where sensitivity analysis is particularly important.

Furthermore, it is our opinion that once market rules are more clearly defined, EIM estimates of potential benefits and costs should be further refined. There are significant financial and equity implications of implementing the proposed EIM; therefore, its benefits should be investigated from a wider range of perspectives.

In addition to the proposed EIM structure, other market alternatives and cooperative programs could be examined with the goal of maximizing net social benefits while minimizing risks. Alternatives that could be investigated include the Dynamic Scheduling System (DSS)

which is a low-cost method to establish a dynamic signal between two BAs; the Area Control Error Diversity Interchange (ADI) which has been demonstrated to bring significant benefits at low cost; the Intra-Hour Transmission Scheduling (I-TS) which implements mid-hour scheduling; and the Intra-Hour Transaction Accelerator Program (I-TAP) which is a form of intra-hour scheduling currently being implemented in WI. In addition, the potential benefits of introducing more comprehensive centralized system operations, similar to the current ISO/RTO markets in the Eastern Interconnection and Texas, could also be considered.

We hope that some of the issues and proposed improvements raised in this report will be taken into consideration in the next phase of the EIM analysis.

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1 INTRODUCTION

The Efficient Dispatch Toolkit (EDT) proposed by the Western Electricity Coordinating Council (WECC) consists of a system that is composed of two separate but related tools: namely, an Energy Imbalance Market (EIM) and an Enhanced Curtailment Calculator (ECC) (WECC 2011). Under the EIM, optimal unit dispatch is performed by system operators every 5 minutes. In contrast, dispatch in the Western Interconnection (WI) is currently performed on an hourly basis. Whereas participation in the proposed future ECC will be mandatory, participation in the EIM will be voluntary. The Western Area Power Administration (Western), in order to make more informed decisions, asked Argonne National Laboratory (Argonne) to review analyses related to EIM societal benefits that were performed by Energy and Environmental Economics, Inc. (E3) and the National Renewable Energy Laboratory (NREL).

The proposed EIM would provide region-wide, centralized dispatch operating on a 5-minute time step over the EIM footprint. In contrast, the dispatch is currently performed separately by each balancing authority (BA). The EIM will optimize the overall dispatch, while incorporating real-time generation capabilities and transmission constraints. Market rules have not yet been defined fully. However, based on our review of the cost-benefit analysis of the proposed EIM in WI (WECC 2011), it appears that the intent and potential implementation of the market goes beyond simply matching small differences between BA schedules and actual operations. Instead, a market participant could potentially rely on the EIM to serve all of its loads and offer all of its generating resources for sale into the EIM. Therefore, the EIM may dispatch the majority of generating resources of market participants. If this type of market operation is implemented, it may be similar to the 5-minute Energy Imbalance Service (EIS) operated by the Southwest Power Pool (SPP), in which approximately 80% to 85% of market participant resources are offered into the EIS market (Dillon 2011). The EIM would not supersede the current bilateral market; however, the EIM will influence future bilateral prices and power flows on transmission lines.

An analysis of the proposed 5-minute EIM was performed by E3. An advanced security-constrained economic dispatch (SCED) model (i.e., the GridView model distributed by ABB) and innovative methods were used to evaluate the societal benefits of the EIM by computing the difference in total production costs to serve electricity demands within the EIM footprint for two cases. They are the “Benchmark Case,” which represents the current mode of operation, and the “EIM Case,” which assumes that the proposed 5-minute EIM would be adopted by all BAs in WI, excluding the California Independent System Operator (CAISO) and the Alberta Electric System Operator (AESO). These two BAs already have a central market structure. Both cases are consistent with the WECC Transmission Expansion Planning Policy Committee’s (TEPPC’s) 2020 planning case and utilize the best data available in the public domain.

The EIM would provide for a more efficient unit dispatch and utilization of WI resources through the all-encompassing systemic optimization of unit operations such that the transmission system operates within security constraints. E3 estimates that under its primary set of assumptions, the EIM would lower production costs by \$141.4 million in the year 2020. Savings are expected to result from the removal of energy market impediments and through the reduced flexibility reserve requirements that are anticipated under the EIM. Flexibility reserves will

augment current reserve requirements to support the integration of future variable (renewable) resources into the grid. In this report, the current set of reserve requirements required by WECC is referred to as “conventional reserves.”

This report summarizes and reviews the EIM benefits study performed by E3. It examines modeling tool applications and suggests areas where the analysis could be potentially improved. The review examines the following topics:

- (1) Assumptions and methods used to estimate the cost of current market trade barriers;
- (2) Assumptions and methods used to estimate the benefits from lower flexibility reserves;
- (3) Modeling methods for estimating hydropower plant operations;
- (4) The GridView model used to simulate the system operation in the WI concerning the model’s foresight, granularity, and the power market prices it produces;
- (5) Assumptions regarding the EIM structure and future participation levels; and,
- (6) Alternatives to the EIM.

This review was carried out based on an evaluation of the limited information available from presentations, reports, and communication with modelers and analysts involved in the EIM benefits study. Although it is complimentary of several components of the E3 study, it is critical of some aspects of the methodology and interpretation of model results. EIM study documents point out several analysis challenges and indicated if the assumptions and methods used in the analysis either over- or underestimated EIM cost savings. Many of these challenges along with others not mentioned in EIM reports are discussed in more detail in this report.

We realize that E3 conducted the analysis under both time and budget constraints. In addition, factors such as data availability, GridView model limitations, and recommendations from both WI utilities and the EDT Technical Review Subcommittee all played a role in the development and implementation of the study framework and the methodologies that were utilized by E3, WECC, and NREL staff. We also realize that the EIM study is very complicated and complex. Methodologies used for some of the more challenging aspects of the EIM are not yet in a mature state. Current knowledge gaps are challenging to overcome given that the future WI is projected to be very different from the past or current WI grid configurations. The reader should therefore keep the above factors in mind when reviewing this document and decisions that were made by EIM analysts and modelers. The intent of this report is to identify areas that could be improved and offer alternative methods that could potentially be used for future studies.

2 BENEFITS FROM REMOVING MARKET IMPEDIMENTS

This section of the report focuses on the benefits associated with the removal of trade impediments to improve energy market efficiency. E3 assumes that the current bilateral market structure in WI has inherent barriers that impede the optimal unit dispatch of WI's grid resources. Specific barriers are not detailed in E3 documentation. However, literature on this topic describes impediments that include, but are not limited to, the following: (1) imperfect information among market players concerning the state, status, and costs of footprint generation and transmission resources; (2) trade agreements that incur several transmission charges (pancaking) when transported power (contractually) flows through multiple utility systems that have spare transmission resources; (3) limited coordination; and (4) the time required to strike agreements among parties (Stoft 2002; Kirschen and Strbac 2004).

Although bilateral market inefficiencies can be described qualitatively, they are difficult to quantify. Bilateral agreement decisions made by utilities are based on factors such as the perceived reliability of deliveries, risk exposure, and trust among trading partners. It is difficult to estimate the value of these nonprice factors, but they play a role nonetheless in overall power grid operations and economics.

One of the principal goals of the EIM is to benefit society via a more efficient dispatch of generating resources in WI. E3 estimated that in 2020, the total production cost in the Benchmark Case will be almost \$20.9 billion as compared to about \$20.7 billion under the primary EIM Case. The cost difference or savings of \$141.4 million was considered by E3 to be the benefit to society. The production cost savings under the primary EIM Case is about 0.68% of the total cost of electricity production. Because the future is highly uncertain, E3 also performed sensitivity analyses, resulting in estimated societal benefits ranging from \$53.6 million to \$232.6 million, which is a savings of 0.26% to 1.12% of the total cost of electricity production. E3 estimated societal benefits based on analysis of results produced by the GridView model (ABB 2011), which optimizes the dispatch of generation resources in the WI to supply load under all primary and sensitivity cases.

Lower EIM production costs are realized by dispatching and utilizing grid resources in the WI more efficiently through the system-wide optimization of supply and demand components so that the transmission system operates within security constraints. E3 attributed these savings to the removal of energy market impediments and reduced requirements for flexibility reserves under the EIM. The removal of trade impediments accounts for \$41.8 million (i.e., 0.2% production cost savings), that is, approximately 30% of the total EIM societal benefit. The remaining 70% of EIM benefits is attributed to reduced requirements for flexibility reserves under the EIM, which allows for higher unit loadings. The remainder of this section focuses on the assumptions and methodology used to determine benefits arising from the removal of trade impediments.

2.1 Dispatch and Modeling Assumptions

As mentioned earlier, the GridView model was used to determine the dispatch for each case examined by E3. GridView is a least-cost, security-constrained unit commitment and economic dispatch model. It dispatches generators to serve loads chronologically with the objective of minimizing system-wide production cost given generator unit characteristics and transmission limits under both normal and contingency conditions.

Determining the optimal (i.e., least-cost) dispatch in a power grid is a formidable task. Therefore, simplifying assumptions are required to create a mathematical problem that is both manageable and solvable within a reasonable amount of time. These assumptions are important not only in terms of their validity and effect on model accuracy but also in terms of the conclusions that can be correctly drawn from model results. One simplification that GridView uses is that it represents each component in the system in the form of one or more linear equations. This approach allows it to employ linear programming (LP) techniques to find the optimal dispatch in WI. It also uses approximation methods (heuristics) to solve the unit commitment problem.

LP solvers are used extensively to find the optimal result for numerous types of mathematical problems, not only in the power industry but in many industries and disciplines. It is a widely accepted modeling approach. In fact, for very large and complex problems, such as the one we are presently addressing, it is the only technique that produces a solution that is guaranteed to be the mathematical optimum. However, a caveat of this approach is that approximations are typically required to make problems linear in order to apply LP solvers. Such approximations can have significant departures from the true performance of system components.

As would be the case when creating any WI-wide dispatch model, E3 made numerous assumptions when estimating the societal benefits of the EIM. Thus, on the basis of EIM documentation (E3 2011) and discussions with E3 staff (Moore 2011), it became apparent that modelers were very thorough in their depiction of the WI dispatch and economics. Optimization was conducted at a very refined level of granularity. The GridView topology of the WI system includes approximately 16,000 buses, connecting transmission lines, and all generating units in the system. Each bus was placed into one of 24 zones represented in the GridView. Most zones represent individual BAAs while others represent groups of BAAs.

In addition to their attention to detail, modelers also made very reasonable dispatch-related assumptions and approximations given study time and resource constraints. E3 also utilized the best set of data that were readily available, which was the WECC TEPPC 2020 planning case.

This attention to detail yields aggregate model results that are very similar to actual generation levels. Table 2.1 shows the generation breakdown by fuel technology type in 2006 for the portion of WI located in the United States for the Benchmark and EIM Cases as compared to actual data in the *Annual Energy Outlook 2008* (EIA 2008). Except for slight mismatches between data and model predictions for natural gas and hydropower, the Benchmark Case compares very closely to actual data in 2006.

Table 2.1 Generation Breakdown in 2006 for Portion of WI Located in the United States

Fuel/ Technology	Benchmark Case (%)	Annual Energy Outlook (%)
Coal	32.9	31.2
Natural Gas	27.7	25.6
Nuclear	9.6	9.4
Hydroelectric	24.6	28.8
Wind	1.2	1.4
Other	3.9	3.6
Total	100.0	100.0

Sources: EIA (2008) and E3 (2011).

At a more refined level, historical values and model results have significantly larger differences than would be suggested by aggregate statistics. We found several instances in which hourly hydropower plant production levels differed from historical levels (see Section 4.3), monthly thermal power plant generation levels differed from those reported by the Energy Information Administration (EIA) in EIA Form 906, and hourly thermal generation patterns deviated significantly from those typically practiced in the industry (see Appendix B). We don't expect modeled hourly generation to exactly match historical levels. However, we would expect that the patterns reasonably reflect physical operating constraints. We also found that plants/prime mover classes that are typically on the margin had the largest monthly generation error (i.e., 2006 monthly actual versus modeled generation). Correctly identifying marginal units are critical when estimating the differences in costs between two cases.

We also examined GridView marginal prices for the 2006 Benchmark Case at Palo Verde, which is typically used by Western as a representative price point (Appendix C). In our opinion, the prices were less expensive than we expected, especially during off-peak periods. Low prices may result when the model commits more units on-line than what occurred historically.

The following discussion highlights some potential factors leading to these differences. The comments below are not a criticism of the exemplary WI dispatch optimization performed by E3 modelers under time and budget constraints; rather, it draws attention to the interpretation of model results given the accuracy of model inputs and how the study represented the grid. It also points to alternative analytical methods that could potentially be used to improve future analyses.

Factors such as data availability, GridView model limitations, and recommendations from both WI utilities and study EDT Technical Review Subcommittee all played a role in the development and implementation of the study framework and the methodologies that were utilized by E3, WECC, and NREL staff. The reader should also realize that the EIM study is very complicated and complex. Methodologies used for some of the more challenging aspects of the EIM are not yet in a mature state. Current knowledge gaps are challenging to overcome given that the future WI is projected to be very different from past or current grid configurations. The

reader should therefore keep the above factors in mind when reviewing this document and decisions that were made by EIM analysts and modelers.

2.2 Review of Hurdle Rate Methodology

The topology used in the analysis divides the WI system into 24 zones with boundaries that roughly correspond to a BAA or a group of BAAs. When modeling the least-cost dispatch with GridView for the year 2006, power flows among zones differ from recorded historical levels. To resolve historical differences, E3 applied bidirectional hurdle rates on transmission lines that connect two different zones (E3 2011). Hurdle rates are essentially price adders for transporting energy between two connected points and are used by E3 to represent current impediments to trade between zones in WI.

A hurdle rate makes an interzonal energy flow more expensive relative to an energy flow within a zone. It therefore lowers the economic incentive to trade outside of a zone. Holding all other factors constant, higher hurdle rates lower both interzonal trading levels and energy transfers. Hurdle rates also alter the unit dispatch, tending to increase generation from units that are more expensive to operate while reducing output from those that are less costly.

The primary difference between the two cases, Benchmark and EIM, is that the Benchmark Case includes hurdle rates for power transfers among zones. Under the Benchmark Case, hurdle rates were determined by a heuristic method such that modeled 2006 flows among zones approximately equaled historically observed levels.

Since the intent of the EIM is to eliminate these economic inefficiencies associated with the current trading regime, all hurdle rates are set equal to zero in the EIM Case. Furthermore, hurdle rates were also set to zero for both scenarios on all transmission lines that connect two points within the same zone.

In both cases, GridView did not explicitly model bilateral contracts and existing CAISO and AESO markets. Under the EIM Case, it determined the most economical dispatch under idealistic market assumptions. E3 equated production cost differences between the two cases to market inefficiencies.

Although the hurdle rate methodology has been applied in other studies, and may be appropriate for those applications, in our opinion, it does not directly model many of the bilateral market inefficiencies identified in the literature. Instead, interzonal hurdle rates are used as a surrogate for market barriers that impede economically optimal energy transfers. By aligning modeled and historical flows, it is indirectly assumed that the historical suboptimal unit dispatch will be obtained. Furthermore, it is indirectly assumed that differences between the Benchmark and EIM Cases in dispatch cost are solely attributable to inefficiencies in the current market structure.

In reality, modeled interzonal differences are attributable not only to market inefficiencies but also to data granularity issues and to simplifications that are required to solve for the

mathematical optimum SCED in a reasonable amount of computer run time. Therefore, it is our judgment that the hurdle rate methodology does not yield an accurate measure of WI market inefficiencies. Although economic efficiencies may contribute toward zonal flow differences between the EIM Case and historically observed levels, flow differences can also be attributed to the numerous simplifying assumptions that were made when modeling unit commitments and the economic dispatch. Inaccurate data exacerbates these differences. In other words, even if the current bilateral market had no inefficiencies in 2006, modeled zonal flows would not match historical levels. Model simplifications and data inaccuracies that lead to interzonal flow differences fall into the following categories:

- (1) **Hydropower Resources:** Simplified representation of hydropower resources, which currently comprise about one-third of WI supply resources;
- (2) **Thermal Generating Resources:** Lack of unit-specific granularity on fuel costs and generic representation of heat rate curves;
- (3) **Load:** Use of identical normalized chronological shapes at all load buses within a BAA;
- (4) **Linearization:** Approximations that are used to transform nonlinear grid characteristics into linear approximations, which are required in the LP modeling framework;
- (5) **Transmission Load Flow:** Use of a simplified, linear representation of power flows on the transmission system (a “dc power flow”) rather than a more rigorous, nonlinear representation (an “ac power flow”);
- (6) **Unit Commitments:** Simplifications that are used to predetermine which units will be operational during the next optimized day; and
- (7) **Resource Availability:** Methods employed to determine what transmission lines and generating resources will be out of service as a result of both scheduled and forced outages. Random outages of units are based a single random draw.

Appendix A provides a more detailed discussion on each of the modeling assumptions listed above.

We find little fault with the assumptions that E3 uses, which are common (standard practice) when optimizing scheduling and economic dispatch. Some aspects of the dispatch model, such as the hydropower optimization, go beyond other models of its type. The issue is that the modeling process and simplifications contributes to differences between the EIM modeled power and actual flows. That is, differences do not emerge merely as a result of market inefficiency. Therefore, it is not appropriate to assign the cost differences between the EIM and Benchmark cases solely to economic inefficiency.

In addition, modeling simplifications may easily overshadow flow differences that result from market trade impediments. Expert judgment was used by E3 to estimate the direction and, in some cases, the general magnitude of each contributing factor. However, it is very difficult

(perhaps impossible) to untangle and quantify interactions among the huge number of variables in GridView. In addition, it is highly probable that for specific transmission lines, some model assumptions may increase flows in one direction while others may contribute to counterflows. It is therefore difficult to judge whether the E3 methodology produces a cost estimate that is either too high or too low.

We commend E3 staff who took great care to set hurdle rates such that the sum of differences between actual 2006 and modeled flows across all 17 monitored WECC paths in the Benchmark Case was less than 0.1%. Assigned values were determined via an iterative methodology that successively lowers the average difference between modeled and historic flow levels. In contrast, all hurdle rates in the EIM Case were set to zero, thereby removing power transfer cost impediments among zones. When hurdle rates derived for the year 2006 were applied to interzonal flows in the 2020 Benchmark Case, dispatch costs in WI increased by \$41.8 million.

Although 2006 annual average flow differences across all 17 monitored WI transmission paths between historical levels and Benchmark Case results approached zero (<0.1%), the average absolute value of hourly differences was 29%, with seasonal patterns of systematic over- and underestimates. Regarding this difference, the E3 document (E3 2011) states that “[t]he remaining differences are partially reflective of inherent challenges in precisely simulating historical operations on an hour-by-hour basis” and “resolving some of these differences would require data granularity beyond the level permitted by the inputs available for the simulation.” We agree with these statements. Note that the \$41.8 million estimate of social costs is only 0.2 percent of the total dispatch cost (i.e., roughly \$41.8 million divided by \$20,876 million). This small difference pales in comparison to the level of accuracy of the GridView model, case assumptions, and supporting data.

We also note that the Benchmark Case model run was calibrated to match a single historical criterion (i.e., interzonal flows). There are potentially a very large number of combinations of alternative hurdle rates that could match average historical transmission flows, and some combinations would likely lead to different results and conclusions in comparative case studies. In other words, the hurdle rate methodology does not lead to a unique and definitive solution.

Calibrating the model to a different or additional criterion would most likely produce a different result than that determined by E3. For instance, the model could also be calibrated to match historical 2006 generation at the plant or zonal level. Historical plant/prime mover data are reported by the EIA in EIA Form 906.

Hurdle rates determined for 2006 were used for both the 2006 and 2020 Benchmark model runs. Applying hurdle rates to transmission lines in 2020 yields several technical inaccuracies. Placing a hurdle rate on a line affects flows throughout the grid, especially for nonradial grids such as the one in WI. A power transaction between any two points (i.e., source and sink) affects not only the line (or path) that directly connects the two points but other lines, as well. That is, not all of the power flows on the direct link — some of it flows to the sink via indirect pathways, creating inadvertent flows. Holding all other factors constant, a topology change, such as the addition of new lines or the injection of energy from new power sources that may be built in WI

between 2006 and 2020, will change flow levels on both the direct and indirect pathways. Other topology changes that may occur by 2020 include the elimination of some pathways and the retirement of existing generation resources. Even if all loads, generation, and hurdle rates are identical, an altered transmission topology produces a different transmission flow, both within and between zones. Therefore, hurdle rate calibrations performed for a (known) 2006 topology will not have the same effect on power flows in the 2020 topology.

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3 BENEFITS FROM LOWER FLEXIBILITY RESERVE REQUIREMENTS

Because variable resource production can have large and rapid changes over time, BA operators will face many challenges if the wind and solar resource projections made by E3 and NREL are realized in 2020. One BAA operated by Western is the Western Area Power Administration – Colorado-Missouri (WACM). Figure 3.1 shows wind production projections for the WACM BAA from March 14 to March 20, 2020. The figure also shows the percent of BAA hourly load served by wind (on the secondary y-axis), and changes in wind production from the previous hour (i.e., wind production hourly ramp). Hourly wind production ranges from zero to the maximum installed wind capacity in the BAA, and the percent of load served by wind varies from zero to almost 40%. The maximum hourly increase in wind production is about 470 MW, and the maximum hourly decrease is almost 310 MW. It is projected that other types of variable resources; namely solar, will not be operating in the WACM BAA in 2020.

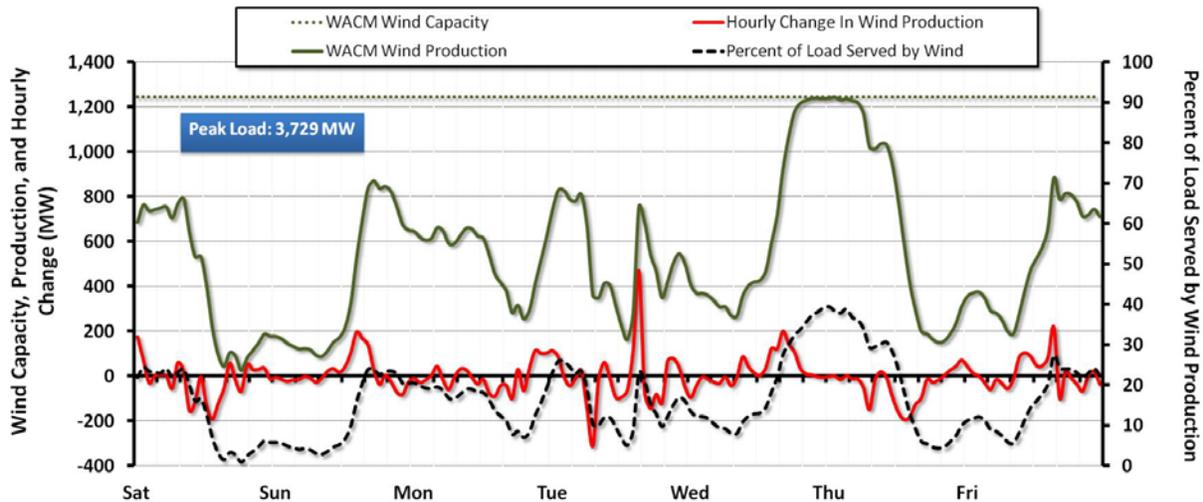


Figure 3.1 E3 Projections of Wind Production for WACM BAA from March 14 to March 20, 2020

Total WACM BAA system loads and net loads (i.e., load less wind production) are shown in Figure 3.2 for the same time period. The figure shows that loads follow a consistent daily double peak pattern within a fairly narrow range, whereas net loads are characterized by a much larger range and a more erratic daily pattern. There is also very rapid net load ramping, especially on Thursday, as wind production decreases in the morning while loads simultaneously increase. Coping with rapid and large-scale changes, along with variable resource forecast inaccuracies, will be difficult if the WACM BA must rely solely with its own internal resources to balance supply and demand. This figure highlights the need for new grid operating criteria, procedures, and structures.

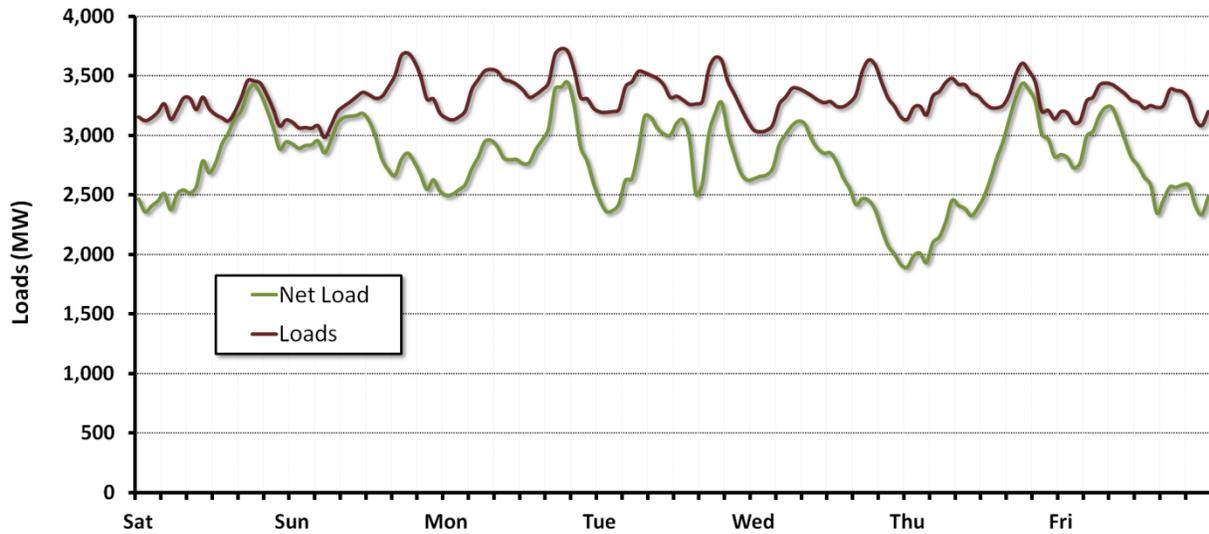


Figure 3.2 E3 Projections of Loads and Net Loads for WACM BAA from March 14 to March 20, 2020

It is generally accepted that a high penetration of renewable energy, as shown in Figures 3.1 and 3.2, changes the need for operating reserves in the power system. Several approaches have been proposed to estimate the additional reserves required to handle additional uncertainty and variability from variable resources (Doherty and O'Malley 2005; Ortega-Vazquez and Kirschen 2009; Matos and Bessa 2011). In wind integration studies, there has been an evolution of approaches for operating reserves (Ela et al. 2010; Ela et al. 2011).

NREL used the methodology developed for the Eastern Wind Integration Study (EWITS) (EnerNex 2011) to estimate the requirements for regulation and reserves in the current EIM analysis. This methodology entails the use of flexibility reserves, which are categorized by E3 as flex, spin, and supplemental.¹ These flexibility reserves supplement conventional reserves to ensure reliable operations in 2020 when a relatively high penetration of variable resource capacity is predicted to be installed as electric power generation from renewable sources matures.

Requirements for flexibility reserves for both the Benchmark and EIM Cases, in terms of megawatts (MW), were estimated by NREL (Kirby et al. 2011) for the year 2020. Estimates are based on solar and wind power forecast errors and the geographical diversity of variable resources. Forecast errors for variable resource energy production in the NREL analysis are based on the assumption of short-term persistence forecasting; that is, the current variable resource production level will not change in the near future, typically a time period of one hour or less.

Since flexibility reserves were neither needed nor required in 2006 because variable generation levels were relatively low, this requirement was set to zero for the E3 2006 model

¹The NREL analysis (Kirby et al. 2011) uses the terms regulation, spin, and non-spin for the same categories.

runs. In 2020, flexibility reserve requirements are added to “conventional” regulation and operating reserve requirements that respond to instantaneous changes in load and help keep the grid in balance when a grid component unexpectedly fails.

Unlike conventional ancillary services, which tend to be set for relatively long periods, flexibility reserves will be updated hourly on the basis of current variable resource output levels. The flexibility reserve requirements have been estimated by NREL using a statistical approach. The method employed is tailored for each type of flexibility reserve that is needed to keep the grid in balance.

Under the Benchmark Case in 2020, it is assumed that each zone would supply flexibility reserves to cover forecast errors within its own footprint. Recall that zonal boundaries roughly follow the area of one or more BAAs. In contrast, flexibility reserve computations under the EIM Case are based on the aggregate forecast error over the entire EIM footprint. Because of the high degree of variable resource diversity over the EIM footprint, the EIM forecast error is significantly lower than the sum of zonal area forecast errors, each of which exhibits much less diversity. Therefore, the EIM Case has much lower flexibility reserve requirements than the Benchmark Case.

Resource diversity is advantageous because there tends to be a negative correlation in levels of variable resource production across areas in the EIM footprint (Milligan et al. 2010). Forecasting errors in different BAAs are therefore likely to cancel out to some extent (Giebel et al. 2007), resulting in lower flexibility reserve requirements than would be the case if each area carries its own reserves. This effect is captured in the EIM Case given that the reserve calculations are performed for the entire EIM footprint. However, congestion in the network may prevent transferring power among regions, as will be discussed in more detail in Section 3.7.

E3 estimates that reductions in flexibility reserve requirements under the primary EIM Case would achieve societal benefits that account for 70% of the \$141.4 million total benefit. The levels of flex and spin reserves estimated by NREL were input into GridView for economic evaluation under both the Benchmark and primary EIM Cases. The difference in total production costs between the two was \$99.6 million. These savings related to flexibility reserves are composed of two components, namely, approximately \$90.0 million for reduced flexibility reserve requirements and \$9.6 million for EIM footprint-wide procurement of these requirements.

In addition, forecast errors and uncertainty about wind production during the next day should be taken into account when determining unit commitments (Botterud et al. 2011). It is of note that even when wind production is known with certainty, changes in wind production may require thermal power plants to have more startups and shutdowns during the day than they would otherwise have in the absence of wind turbines. Note that in Figure 3.2, all days in the time period have net load ranges that are significantly greater than the range of total system load.

3.1 Flex Reserve Requirements

This section discusses flex reserves, which are also referred to in this report as flexibility regulation. Flex reserves are similar to conventional regulation service in that both are used to compensate for (or react to) very short-term (in the range of seconds to minutes) changes in the grid through the use of unit automatic generation controls (AGCs). Because these changes occur very quickly, the time needed to balance the grid via system re-dispatch is insufficient.

Using EIM study data for wind and solar production in 2020, NREL determined the amount of flexibility regulation (“flex”) that would be required to fully cover 10-minute power movements 99.7% of the time. It is assumed that deviations stem from variable resource forecast errors, which are a function of the output level produced by a variable resource generator. These distributions change as a function of variable resource production level and would need to be updated every 5 to 10 minutes.

Despite substantial improvements in wind power forecasting accuracy over many years, it is still very difficult to develop a method of predicting wind production in the next 5 to 10 minutes that is better than simply assuming persistence, that is, production 5 to 10 minutes into the future is identical to the current level (Monteiro et al. 2009). Therefore, NREL’s wind production forecast error is set to be equal to the production level at any point in time minus production levels that actually occurred 10 minutes earlier.

Flex reserve requirements are based on standard statistical techniques to ensure that sufficient flexibility regulation is available to cover short-term forecasting errors 99.7% of the time; that is, three standard deviations or sigma from the mean of the forecast error distribution. Based on personal communication with NREL staff, we confirmed that the three sigma level has been adopted by some U.S. power systems and therefore appears to be a reasonable assumption for this analysis. The statistical methods are applicable under the following conditions:

- (1) The forecast error follows a normal distribution; and
- (2) The wind and solar forecast errors at very short time scales are not correlated.

However, several studies indicate that wind power forecasting errors do not follow a normal distribution (Lange 2005; Bludszweit et al. 2008; Bessa et al. 2009; Hodge and Milligan 2011). We also found in this study that there are conditions under which hourly forecast errors are either positively or negatively skewed depending on the state of the current wind production.

NREL estimated that the hourly average flexibility regulation requirement under the Benchmark Case is on the order of 950 MW. Consistent with diversity concepts and previous studies, flexibility reserves under the EIM Case are significantly lower; that is, 430 MW on average is needed — or roughly half the amount under the Benchmark Case.

3.2 Flexibility Spin Reserves Requirements

Flexibility spin reserves accommodate variable resource forecasting errors over a 10-minute time horizon. This service is similar to conventional spinning reserves, because the units that provide the service must be synchronized to the grid and respond to grid events within a 10-minute time frame. The requirement was set such that flexibility spin reserves would sufficiently cover 68% (1 sigma) of all forecast errors that occur in less than 1 hour. The percentage values presented above are based on the assumption that wind and solar are normally distributed and independent. As noted in the section above, the normal distribution assumption does not always hold. Also, NREL's assumption that wind and solar forecast errors are statistically dependent may not be accurate in all cases. Variable resource integration studies (GE Energy 2010) have shown that during the morning when solar output increases (error underestimates occur based on persistence), wind resources tend to decrease (error overestimate occurs based on persistence). The opposite tends to occur during evening hours. During the night, the solar error is zero while wind forecast error persists. These complex interactions should be investigated further. When forecasting errors are dependent, a positive correlation in errors gives rise to higher reserve requirements, whereas a negative correlation has the opposite effect as forecasting errors from wind and solar tend to cancel out.

Similar to the flexibility regulation requirement, NREL uses the persistence approach to estimate forecast errors for spinning and nonspinning reserve forecasts. However, the forecast error is based on a 1-hour time interval. The error is therefore almost always much greater than the 10-minute error.

Although we agree with using the simple persistence method for wind forecasts, better methods could be used for solar forecasts, especially for photovoltaic (PV) forecasts in at least some parts of WI. Solar insolation under clear-sky conditions follows a predictable daily pattern at a given location since seasonal and diurnal solar azimuth angles are known. The use of diurnal solar insolation along with PV performance characteristics (e.g., efficiency curves) may work particularly well in areas where clouds are scarce and humidity is low — conditions that prevail in much of the Western Area Power Administration – Lower Colorado (WALC) footprint, which includes parts of Arizona and southern portions of both Nevada and California.

When solar insolation decreases because of cloud cover or high humidity, a clear-sky adjustment factor ranging from 0.0 to under 1.0 could potentially be applied. This factor is computed each hour based on actual conditions and applied to the next forecast period; that is, the adjustment factor is expected to persist in the next forecast period, not the total PV production. In addition, PV production would be adjusted for temperature changes, which also affect PV performance. It helps that temperature, in contrast to wind speed, can be predicted with a relatively high degree of accuracy. PV production is also much less sensitive to temperature as compared to the sensitivity of wind production to wind speed.

Although we have not researched or tested the method described above, it appears that this simple approach would perform better than traditional persistence when examining hourly PV in the graphs presented in Section 3.6. We present it here in the spirit of potentially improving forecasting techniques for the purpose of refining estimates of EIM benefits. NREL may want to

explore this and/or other solar forecasting methodologies, because more accurate solar forecasts will lower the spin and supplemental flexibility reserve requirements.

For concentrated solar power (CSP), there is significant inertia in the technology which significantly smooths out or eliminates short-term fluctuations. When combined with energy storage, such as molten salts, CSP resources have a limited, but significant dispatch capability. Therefore, at worst, the forecast error for CSP is significantly less than both wind and PV and in some cases it is negligible for periods of an hour or less.

An hourly average flexibility spin requirement under the Benchmark Case is on the order of 980 MW, whereas roughly 610 MW on average are needed under the primary EIM Case. That is an average reduction of about 370 MW.

3.3 Flexibility Supplemental Reserves Requirements

Last, supplemental flexibility reserves have a 30-minute response requirement and do not have to be synchronized to the grid. These requirements are similar to conventional nonspinning reserves. According to the NREL documentation, supplemental reserves, for example, would respond to variable resource ramping error events (Kirby et al. 2011). It also insures that adequate reserve capacity is available to respond to large hourly reductions in variable resource production levels.

The supplemental reserves would cover 98% (two sigma) of movements of less than one hour, that is, two standard deviations from the mean of the forecast error distribution. In combination, flex, spin, and supplemental reserves would cover 99.7% of all of the movements in less than one hour.

An hourly average flexibility supplemental reserve requirement under the Benchmark Case is on the order of 2,260 MW, whereas roughly 1,220 MW on average are needed under the primary EIM Case.

3.4 Representation of Flexibility and Conventional Reserves in GridView

The GridView model finds the optimal dispatch in terms of average hourly grid operations; that is, the model operates on an hourly time step. It therefore cannot solve for movements at subhourly intervals, such as instantaneous changes in load, production drops as cumulus clouds move over PV cells, and minute-by-minute changes in wind farm production levels. Therefore, simplifying assumptions need to be made when representing grid requirements, such as flexibility and conventional reserves.

In GridView conventional regulation and spinning reserves along with flexibility regulation and spin reserves are modeled as a committed capacity constraint, meaning that the capacity committed during the day-ahead commitment cycle must be greater than or equal to the load plus reserve requirement for each hour (Mizumori 2012). Note that from an energy dispatch

standpoint, GridView makes no distinction among any of these services; that is, the online capacity in the unit commitment algorithm is simply increased by the sum of all services.

There is some debate as to whether or not flexibility reserves need to be added on top of conventional reserves or if there are synergies between the two. E3 chose the more conservative approach and added them together. We agree with this “additive” approach at the current level of knowledge and experience with integration of variable resources. This approach is also consistent with current reliability standards from the North American Electric Reliability Corporation (NERC); the standards provide limited ability to use contingency reserves to balance wind ramping events (FERC 2010).

NREL computed flexibility supplemental reserve requirements which would be used to cover longer-term (i.e., 30 minute movements). E3 assumed that this service along with conventional nonspinning reserves would be adequately covered by quick-start gas turbines, and was therefore excluded from the representation of flexibility reserves. Therefore, the economics and grid implications of this function are not included in its study.

3.5 Case Study 1 – Analysis of Flexibility Reserve Requirements for WACM

NREL determines flexibility reserve requirements on the basis of statistical distributions of forecast errors. These distributions change as a function of variable resource production level. The statistical methodology used by NREL assumes that forecast errors are distributed normally. It recognizes that reserve requirements are limited because wind and solar generation cannot go below zero or above rated output. In general, this assumption tends to be true over large regions, such as that of the EIM footprint, during moderate production levels. However, it may not always be the case during both high and low variable resource production events and for smaller footprints, such as a BAA or zone.

To investigate the normal distribution assumption more thoroughly, we performed a statistical analysis on the WACM BAA, which is operated by Western. Employing the persistence forecast method, we computed hourly wind forecast errors in the WACM BAA by using hourly variable resource production data contained in GridView model output files. The analysis accounts for geographical variable resource diversity within a BAA. Computations are based on a probabilistic treatment of wind production forecast error and an operating risk level input by users. Developed specifically for this paper, it employs the same basic principles as the methodology developed by NREL. The method described here can determine both “up” and “down” reserves.

Using hourly wind generation data shown in the EIM model results, we computed an hourly forecast error for wind in the WACM BAA using the persistence forecast method. Figure 3.3 shows the forecast error standard deviation changes as a function of production level. Standard deviations were determined by the following procedure. First, each actual production level is assigned to a class in which each class spans 20 MW. The first class is 0 MW to 20 MW, the second is 20 MW to 40 MW, the third is 40 MW to 60 MW, etc., until the wind capacity in the BAA is reached. Next, we calculate the standard deviation of all observations in each class. For

example, the class that includes observations from 0 MW to 20 MW has a one-sigma forecast error of about 5 MW (primary y-axis) based on 114 observations (secondary y-axis). Note that the data point on the graph is placed in the middle of the class range — in this case at 10 MW.

At low power production, the forecast error is relatively small, approximately 5 MW, increasing to a maximum of about 100 to 110 MW when power production is in the 500 to 750 MW range. The forecast error then decreases as the production level further increases. This mound shape is very similar to the one presented by NREL (King et al. 2011).

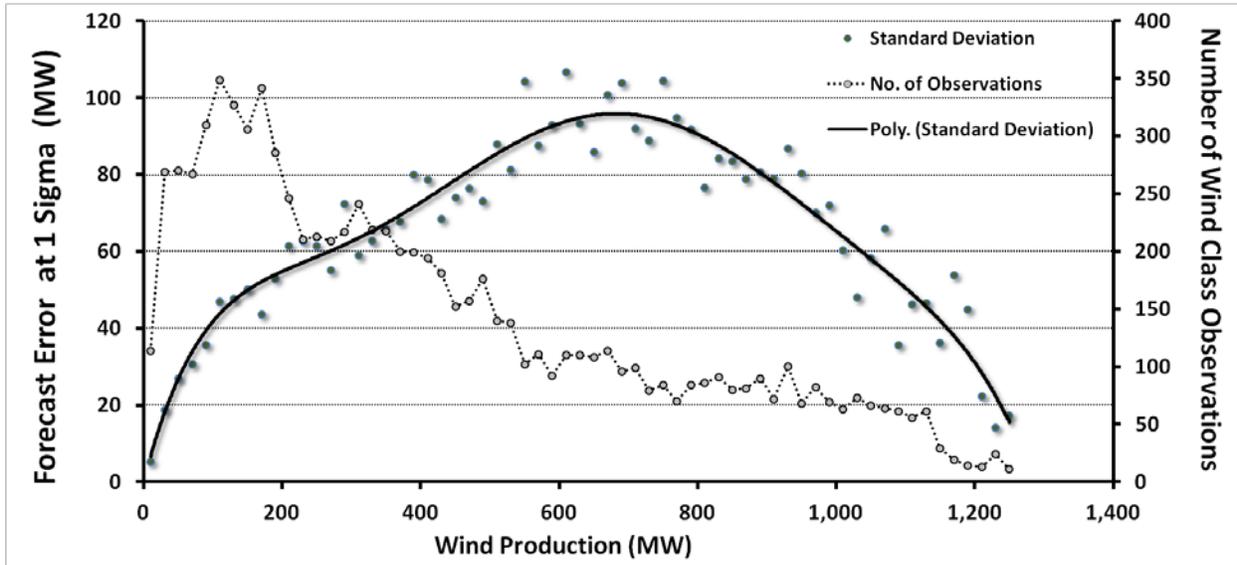


Figure 3.3 Standard Deviation of the WACM BAA Hourly Forecast Error Distribution as a Function of Wind Production

Figure 3.4 displays forecast error statistics and trend lines. It shows that the mean and median error values are very close to zero. Consistent with the trend in forecast error sigma, the range of errors is relatively small at both low and high power production levels.

Figure 3.5 indicates that at low wind production levels, the forecast error distribution is highly skewed to the right (i.e., +3.0); that is, over-projections of wind production are more likely than under-projections. In contrast, at high generation levels, the forecast error was moderately skewed to the left (i.e., -1.5); that is, under-projections are more likely than over-projections. Only those forecasts in the moderate generation range had error distributions with skewness values that approach zero.

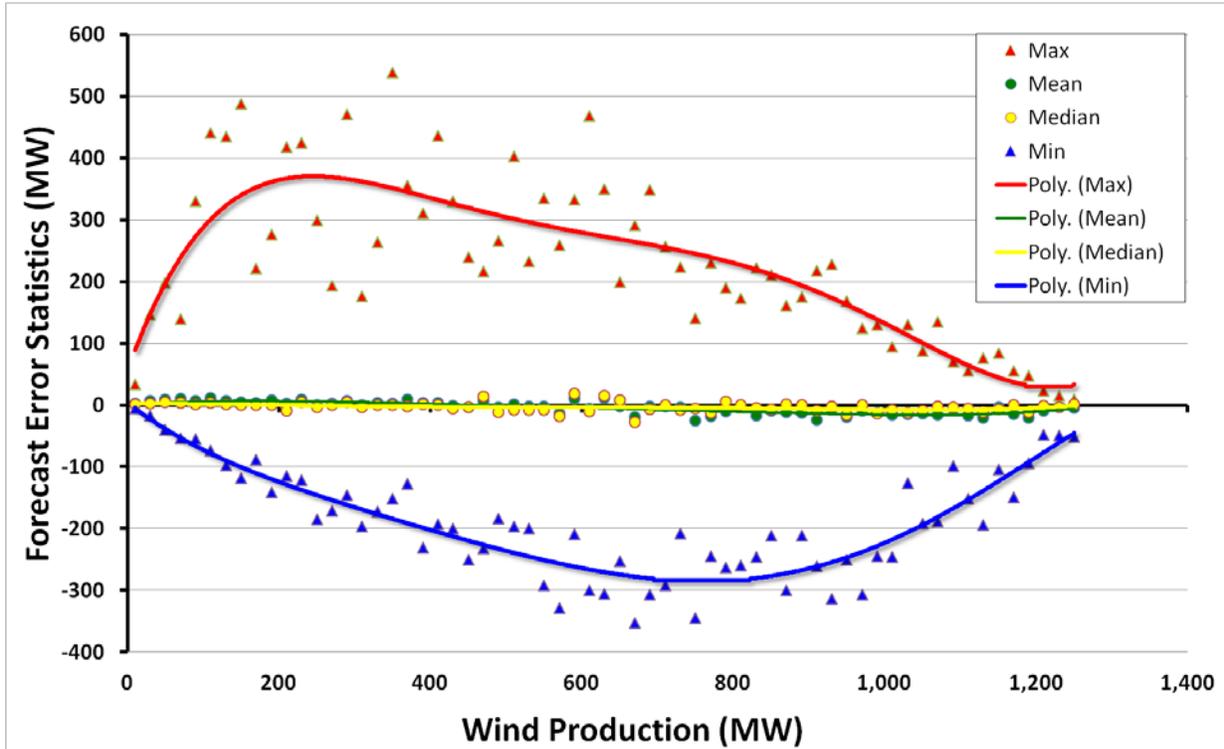


Figure 3.4 Forecast Error Distribution Statistics and Trend Lines

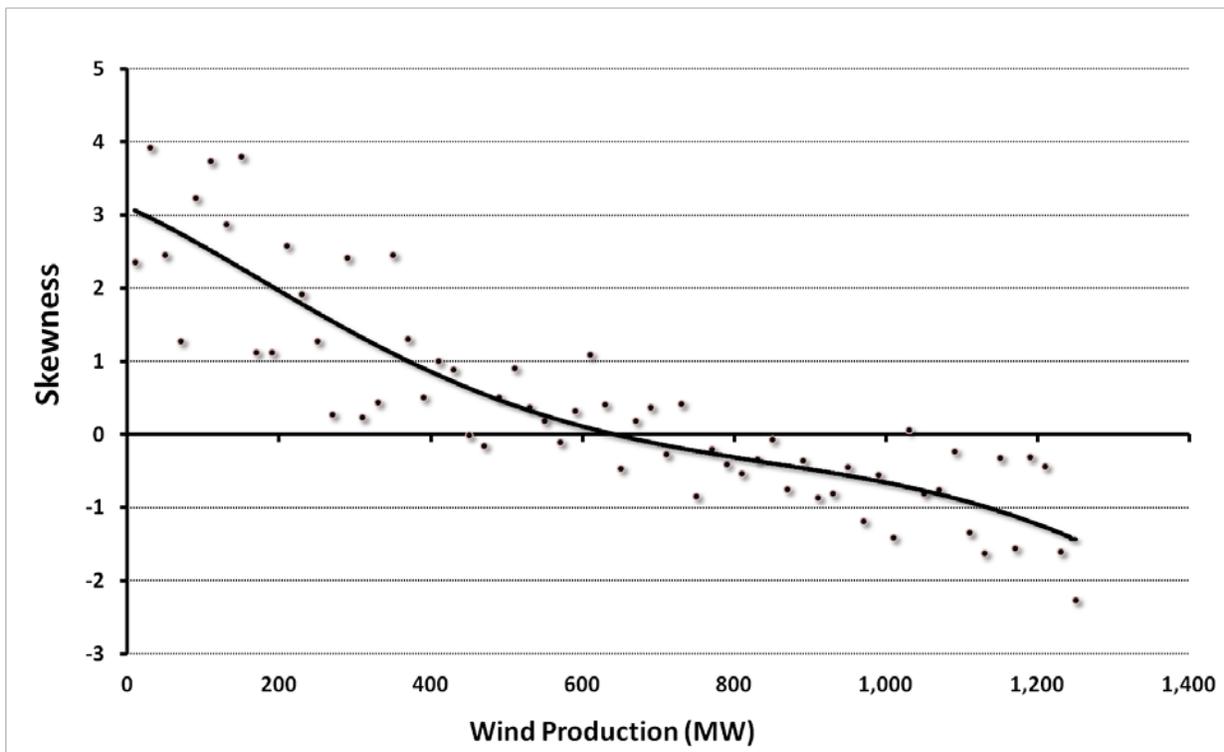


Figure 3.5 Skewness for the WACM BAA Hourly Forecast Error Distribution as a Function of Wind Production

This skewness trend, which decreases as wind production levels increase, is clearly shown in the series of charts that follow. Figure 3.6 shows that when wind production is in the 20- to 40-MW range, there are many occurrences when the wind error is small. Using persistence forecasting, it obviously cannot be overestimated by more than 40 MW. However, if there is a big increase in wind speed, power production could theoretically increase in the next hour up to the total wind turbine capacity. This case would result in a very large under-projection of wind production. Because large increases in wind occur only on rare occasions, the distribution is skewed to the right.

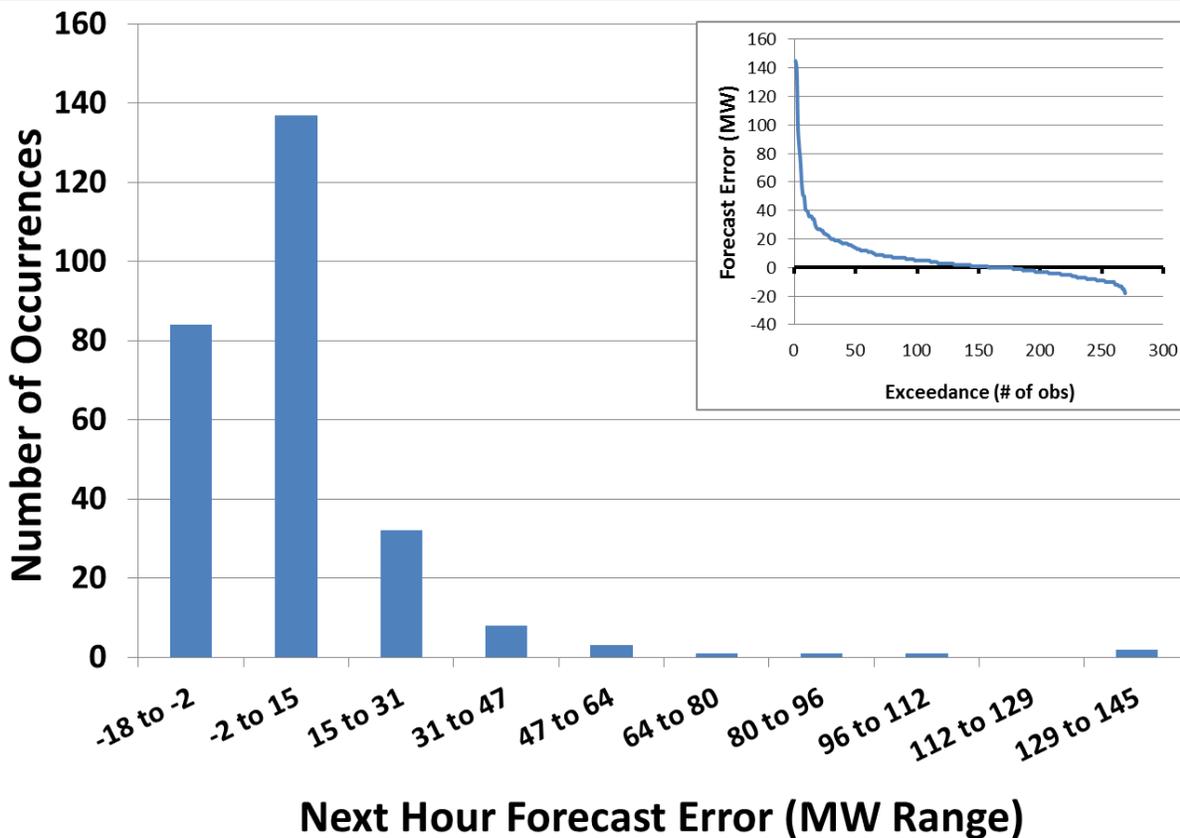


Figure 3.6 Forecast Error Distribution for the 20-MW to 40-MW Wind Production Class

Figure 3.7 shows that when the wind production level is in the 1,000- to 1,020-MW range, there are many occurrences when the wind error is also relatively small. In this case, the wind power forecast under estimate cannot exceed the wind capacity in the BA (i.e., 1,244 MW) minus 1,000 MW, resulting in 244 MW. On the other hand, if there is a sudden decrease in wind speed, power production could theoretically decrease to zero in the next hour, resulting in an over-projection of up to 1,020 MW. Another cause of a large decrease in wind production is when the wind speed goes above the turbine cut-off speed and the wind turbine shuts down for

safety reasons. Because large reductions in wind do occur only on rare occasions, the distribution is skewed to the left.

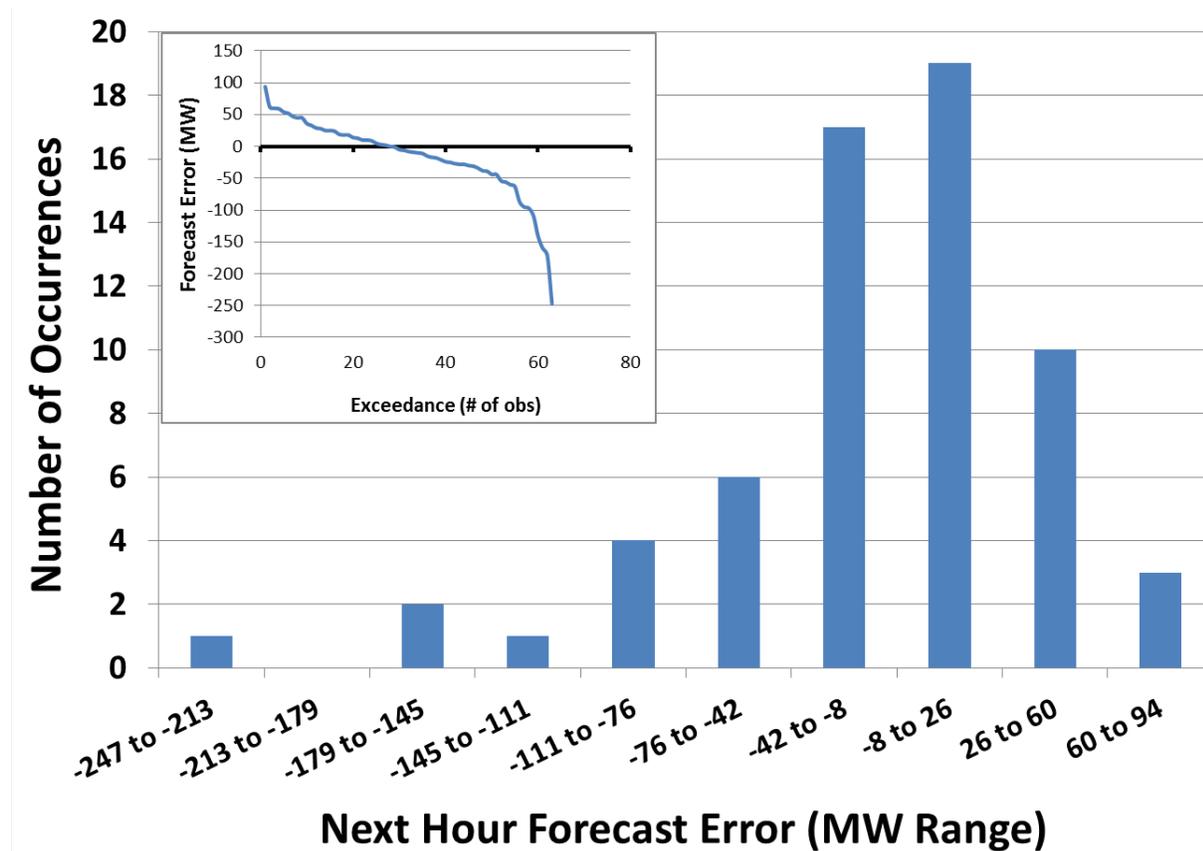


Figure 3.7 Forecast Error Distribution for the 1,000-MW to 1,020-MW Wind Production Class

Figure 3.8 shows that at a moderate production level, such as 540 MW, the wind forecast error is small. However, wind power production can potentially increase or decrease by significant amounts in the next hour, resulting in a symmetrical error distribution centered at an approximate error of zero, that is, the shape that is not skewed.

The last statistic computed is kurtosis, which relates the height and sharpness of the distribution's peak to the rest of the data. A normal distribution has zero kurtosis. Higher values indicate a higher, sharper peak and, in this case, lower forecast errors than would be found in a normal distribution. Negative values indicate a lower, less distinct peak than would be found in a normal distribution. Kurtosis as a function of wind production is shown in Figure 3.9.

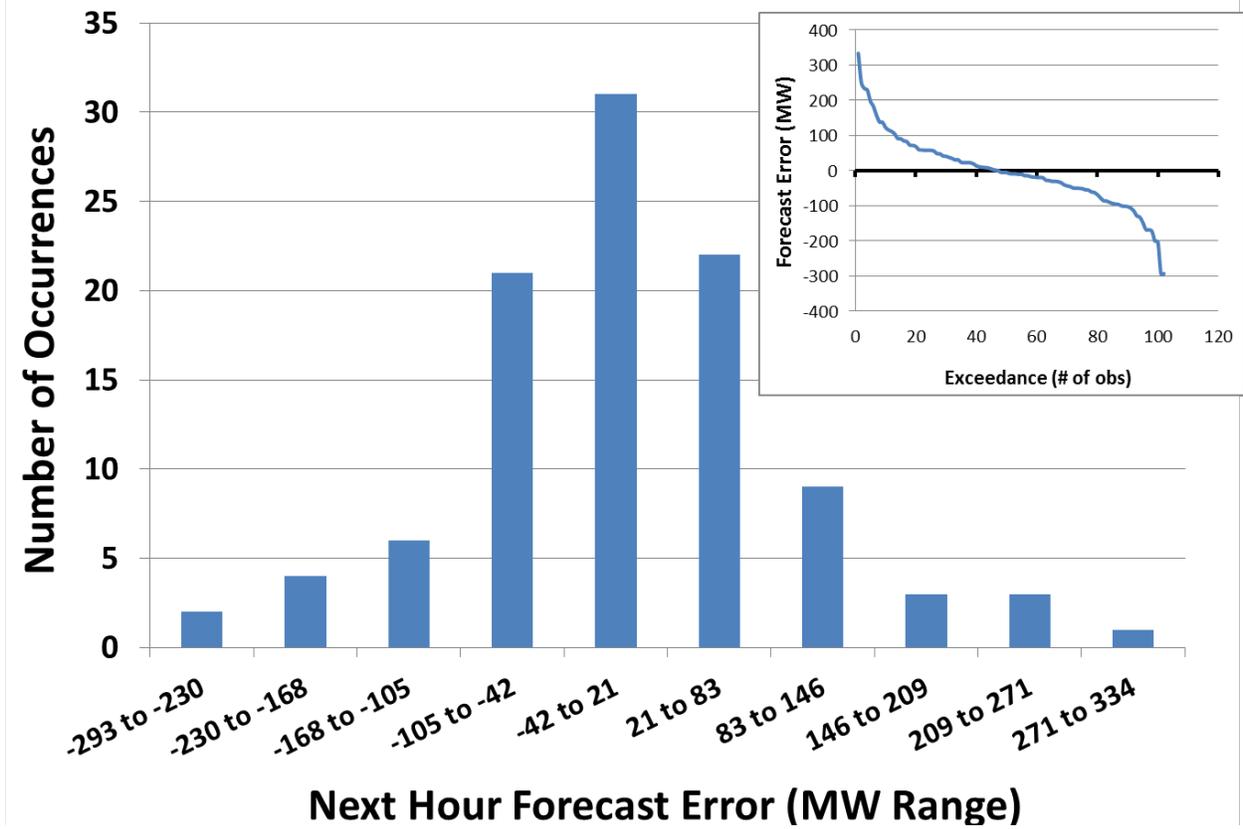


Figure 3.8 Forecast Error Distribution for the 540-MW to 560-MW Wind Production Class

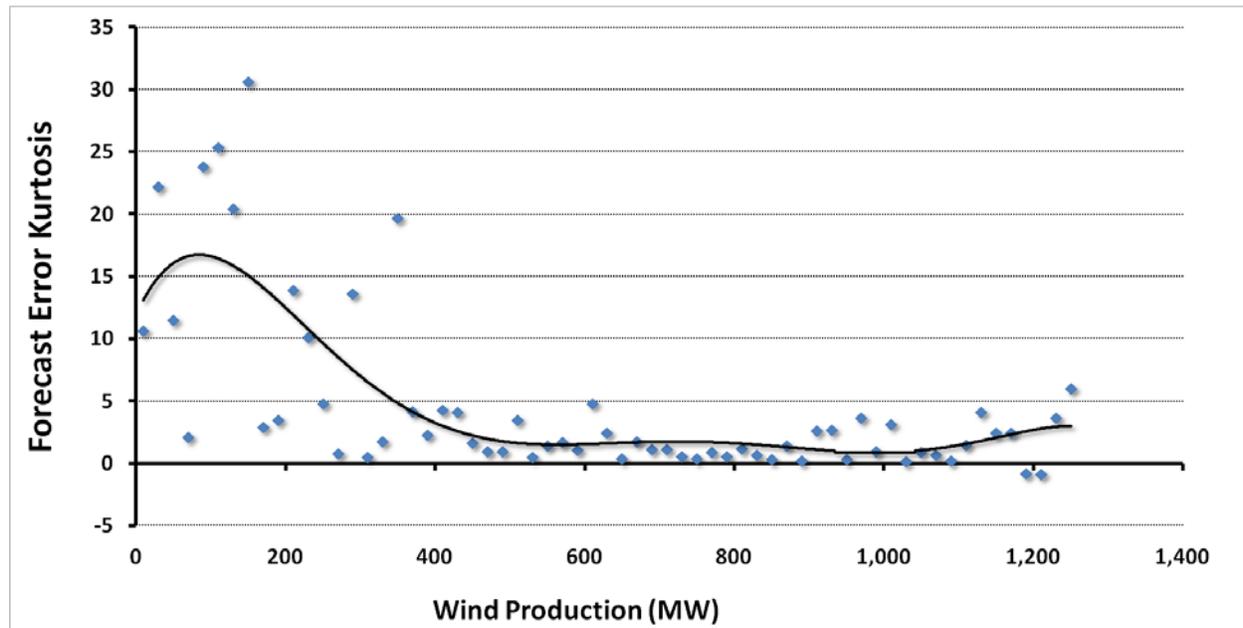


Figure 3.9 Kurtosis for the WACM BAA Hourly Forecast Error Distribution as a Function of Wind Production

The statistical distributions shown above are based on a relatively small sample size within each 20 MW bin. This could potentially result in distorted within-bin distributions. Therefore, we tested different bin sizes and found that the solution is robust — meaning that we obtain similar results for different bin ranges (e.g., 20 MW, 40 MW, 60 MW, 80 MW, 100 MW). At this point, we would like to emphasize intent of the above Argonne example was not to set actual flexibility reserves for a BA operator but instead to illustrate an improved methodology for determining reserves in both the up and down directions. We contend that this methodology would provide a better understanding of the problem and yield a higher level of accuracy. Probability distributions for real-world applications would need to be supported by a larger and richer data set. We suggest that other parametric distributions should also be considered to describe the forecasting error in reserve calculations. Argonne has recently developed statistical algorithms that estimate state-dependent nonparametric forecast distributions that could also potentially be used for this purpose.

Future refinements to the statistical methods described above could potentially provide greater insights to the problem. For example, statistics could be generated for stratified data sets (i.e., data separated by category) that meet a specific set of criteria, such as season or meteorological condition (e.g., ranges of atmospheric pressure). A stratified approach would require a much larger data set.

3.6 Case Study 2 – WALC PV Patterns

Unlike the WACM BAA, which E3 projects will have only wind capacity in 2020, the WALC BAA is projected to have only PV capacity. Figure 3.10 shows PV production from March 14, 2020, to March 20, 2020. That is also the same time period shown in Figures 3.1 and 3.2 for the WACM BAA. An examination of the variable resource production for the two BAAs shows distinctly different patterns. Wind generation tends to be significantly more erratic during both the night and day. On the other hand, PV production only occurs during the daytime in a more regular pattern compared to wind.

As briefly discussed in Section 3.2, alternative approaches for PV solar would probably achieve more accurate predictions than the simple persistence method that is applied to wind. Forecast error probability distributions and exceedance curves could then be constructed for PV solar, similar to those produced for wind as described in the previous section. These distributions along with the risk level would be used to determine flexibility reserve requirements.

In addition to forecast error, we find that grid issues associated with PV solar integration will differ from wind. Figure 3.11 shows loads and net loads (i.e., loads minus PV production) for the WALC BAA. Note that the minimum daily net load occurs at approximately noon each day.

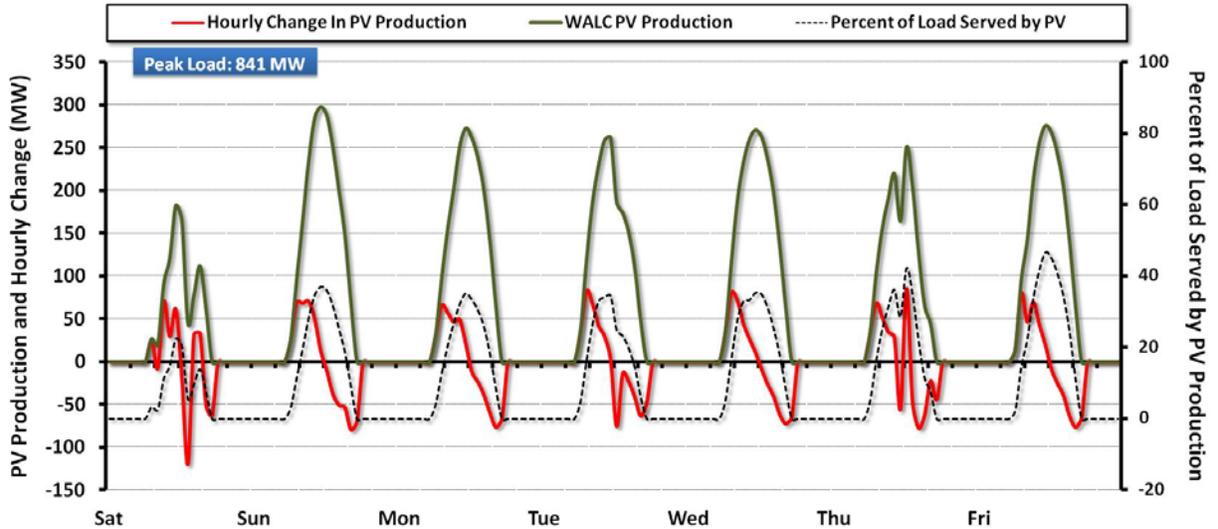


Figure 3.10 E3 Projections of PV Production for WALC BAA from March 14 to March 20, 2020

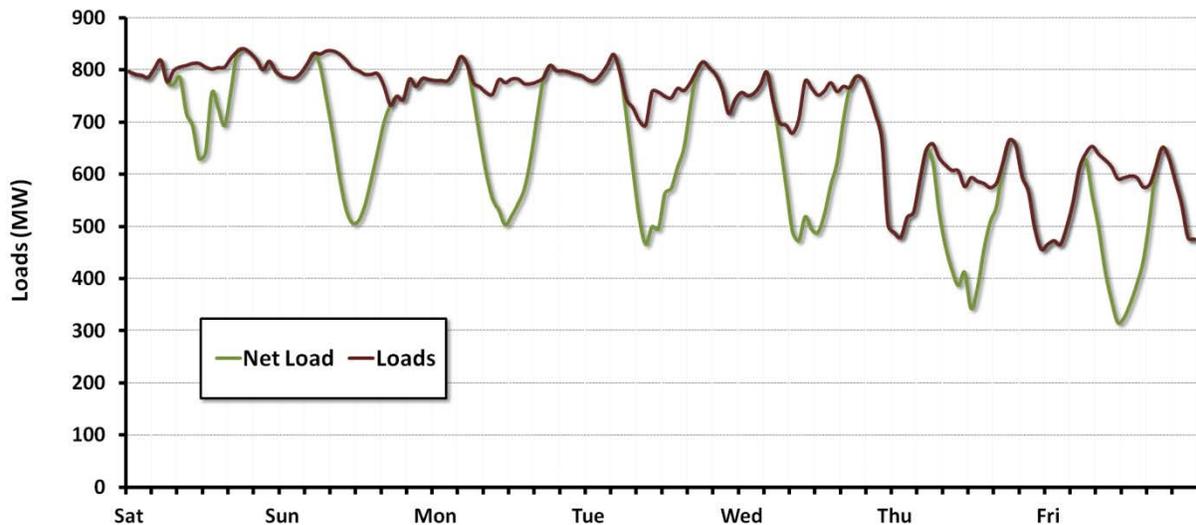


Figure 3.11 Projections of Loads and Net Loads for WALC BAA from March 14 to March 20, 2020

It is also of note that PV solar in the WALC BAA is highly dependent on the time of year with peak production occurring in the early summer. However, the GridView model output contains counterintuitive results. Figures 3.12 and 3.13 are for the third week in June 2020 (i.e., the summer solstice period). We anticipated that June should have higher PV solar generation levels than any other month, because the days are the longest and the sun's rays are most direct. However, when comparing PV generation, the data in Figures 3.10 and 3.12 are contradictory. They show that there is more generation during the week in March than there is in

June. Two possible explanations for this discrepancy would be either more cloud cover in summer than spring or less generation due to higher ambient temperatures in summer than spring. We recognize that higher ambient temperatures can reduce solar output from PV units. However, a nearly 7% drop in generation in summer compared to winter and an 18% drop in generation in summer compared to spring appears to be counterintuitive and should be investigated further.

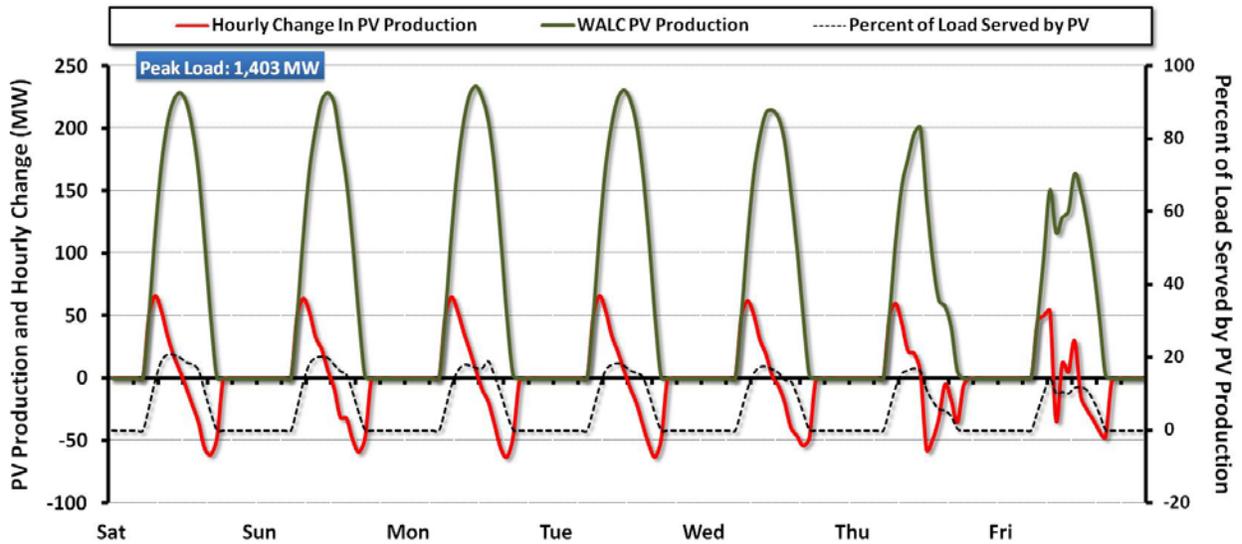


Figure 3.12 E3 Projections of PV Production for WALC BAA from June 20 to June 26, 2020

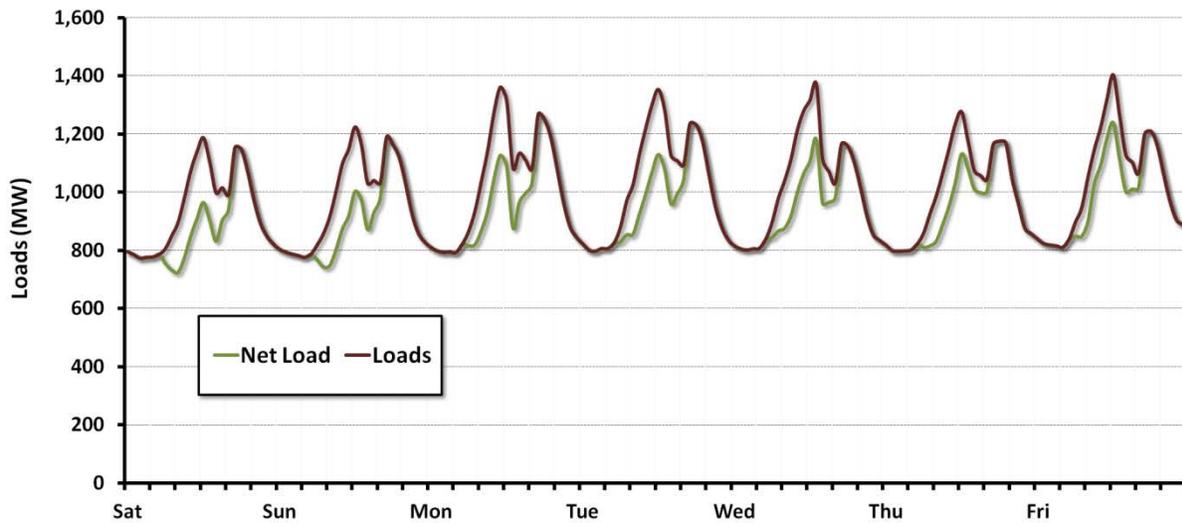


Figure 3.13 E3 Projections of Loads and Net Loads for WALC BAA from June 20 to June 26, 2020

An examination of the monthly PV solar production for the WALC BAA, shown in Figure 3.14, further illustrates unexpected PV solar projections. First, the WALC BAA has no concentrated solar power (CSP) plants; thus, there are no results to plot in Figure 3.14 for these types of technologies. The CSP0 designation indicates plants with no thermal storage, and the CSP6 designation indicates plants with 6 hours of thermal storage.

A similar trend is also seen for the monthly PV solar production plot for the entire EIM footprint. Figure 3.15 shows monthly production for three types of solar. The PV solar production in the summer months of June, July, and August is no greater than it is in a number of winter months. Conversely, the plots for CSP plants show that production is significantly higher in the summer months than in the winter months.

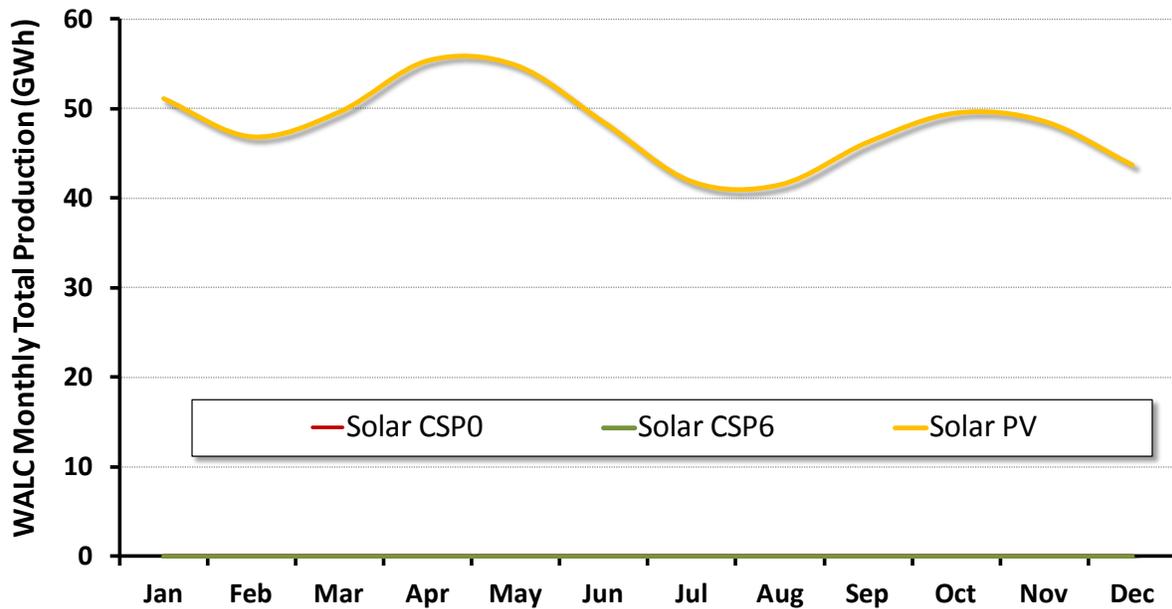


Figure 3.14 Monthly PV Solar Production in the WALC BAA in 2020 (Note: there are no CSPs in the WALC BA)

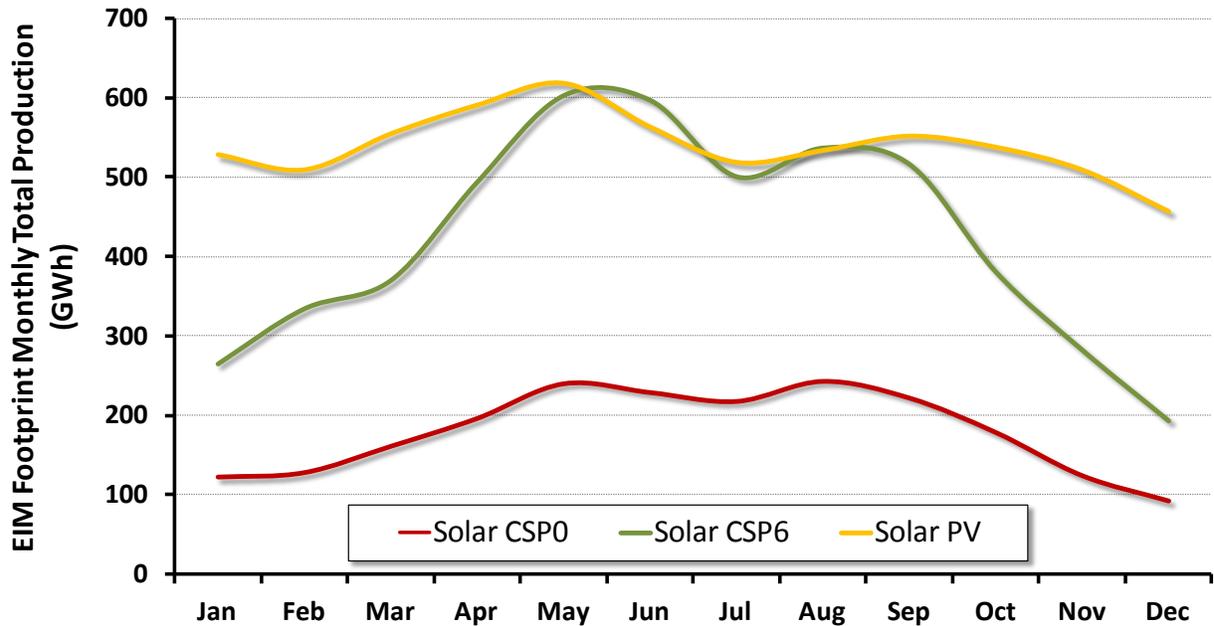


Figure 3.15 Monthly Variable Resource Production and Load in the Entire EIM Footprint in 2020

3.7 Alternative Representation of Flexibility Regulation and Reserves

The E3 methodology ensured that adequate capacity was always online to cover all conventional reserves plus both flex and spin flexibility reserves. The GridView model accounts for all of these reserves in its unit commitment algorithm, but reserves are not directly assigned to units. In reality, units that are assigned these duties have reduced operational flexibility. The TEPPC database does not contain information about which ancillary services can be provided by each generator and therefore unit-level reserves were not modeled. However, given the importance of this issue on the estimation of EIM benefits, it is our opinion that a greater appreciation for the cost of providing these services would be gained if generic data were used and reserves applied to units instead of omitting ancillary service assignments. We note that generic data are used for several other input data values elsewhere in the model.

An alternative approach to the one used in GridView for the EIM Case is to assign reserves directly to individual units as shown in Figure 3.16. Since actual values are not available, generic input data based on unit classification could be used. The capacity available for serving scheduled loads and/or for offer into the market is lowered. The spare capacity enables a unit to rapidly respond to grid-level load and resource changes. We propose that both conventional regulation and flexibility reserves should also further restrict the scheduled operational range by increasing (adding to) minimum resource schedule. The proposed approach separates both conventional and flexibility reserves into “up” and “down” components. More detail about each service is provided below.

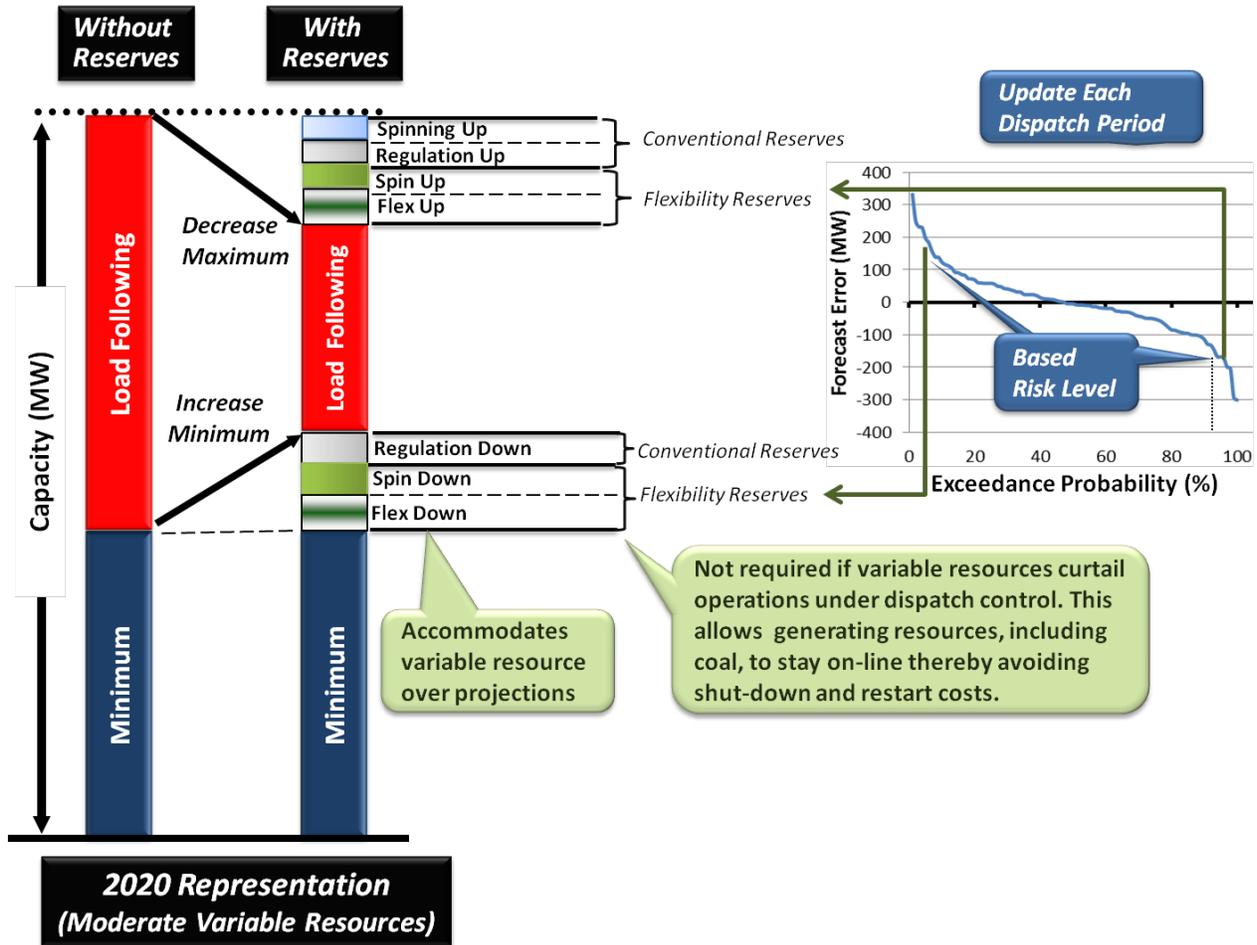


Figure 3.16 Alternative Representation of Flexibility Regulation and Reserves

Conventional “regulation up” lowers a generator’s maximum schedule, whereas conventional “regulation down” increases the minimum schedule. This adjustment allows for adequate generator capabilities to respond to instantaneous decreases and increases in load, respectively. Similarly, generator capabilities need to be reserved for flex services (i.e., flexibility regulation) in order for the machine to respond to short-term (e.g., less than 10-minute) variable resource forecast error. Similar to conventional regulation, this service is separated into up and down components. These flex services are needed in addition to conventional regulation because each serves a specific purpose. However, as noted earlier, this additive approach may be somewhat conservative. Instantaneous load changes and short-term variable resource forecast error are not correlated, providing additional “random diversity” and perhaps reducing the total regulation requirement (i.e., conventional plus flex).

Unlike regulation, conventional spinning reserves affect only the maximum scheduled amount because generator response is always in the positive direction; that is, generation is increased when unexpected resource outages occur. Therefore, conventional spinning reserves

fill supply “voids” when a unit is unexpectedly forced out of service or a transmission line outage requires higher output from generators in specific locations. Similarly, flexibility spin “up” reserves are needed to fill voids that result from a forecast that overestimates variable resource production levels. In some respects, the forecast error is analogous to a thermal unit that randomly fails — in both cases a supply void must be filled. However, unlike thermal generating stations, where controls on the machine prevent generation from randomly increasing, output from variable resources can increase, that is, the forecast was underestimated. Our approach, therefore, reserves some machine capability above the minimum schedule to provide for flexibility spin down.

This “down” service can be served by directly controlling production from variable technologies. That would curtail variable resource production when forecasts underestimate production levels. If “spilling” wind and solar is unacceptable or financially unattractive to owners/operators of a variable resource, the service could be served by curtailing hydro and thermal power resources. This situation may arise if a production tax credit is given to a variable resource in the future and/or if owners are paid a set price for production under a firm contract, regardless of the value of the energy to the grid.

Even though flexibility “down” reserves should be relatively inexpensive to accommodate in grid operations, this reserve is still very important to ensure adequate system flexibility to respond at times of low demand when thermal and hydropower plants tend to operate at the technical (e.g., thermal) and/or mandatory (e.g., hydro) minimums.

Because forecast errors do not always have a normal distribution, the entire error distribution, along with risk levels for different services, is used in our proposed approach to determine separate up and down flexibility requirements. As illustrated in the inset graph of Figure 3.8, an exceedance curve of forecast error probability is created. Positive forecast errors result from variable resource over-projections, and negative forecast errors are due to under-projections. The largest over-projected forecast error is never exceeded and is assigned an exceedance probability of zero. At the other extreme, variable resource generation is always higher than the lowest forecasted level and assigned an exceedance value of 100 percent.

Assuming that the probability exceedance curve, which is based on historical data, applies to the future condition, flexibility reserve requirements can be determined for a specific risk level. For example, reserves for flexibility regulation (flex) down would be determined simply by setting the exceedance probability to the risk tolerance level (e.g., 1%) and finding the corresponding MW of forecast error. For flex service up, the reserve level is determined by subtracting the risk tolerance level from 100 and finding the corresponding MW forecast error. For example, if the risk tolerance for flex up is 1%, the reserve requirement is based on the 99% exceedance level.

Note that there is a unique probability exceedance curve for each forecast time horizon (e.g., 5-minute, 10-minute, and 1-hour), current variable production level, and region (i.e., BAA or group of BAAs). As we discussed concerning the WACM BAA, forecast error distributions for low, medium, and high wind production levels differ significantly. Therefore, flexibility reserves will need to be updated as time unfolds, preferably at the shortest practical time interval.

Probabilistic forecasts can be estimated based on historical forecasting errors. For instance, one method based on kernel-density estimation is proposed in Bessa et al. (2012). Such probabilistic forecasts can also be used to estimate flexibility reserves and as input to unit commitment models, as discussed in Botterud et al. (2011).

In addition to the reduced operational flexibility for resources that provide reserves, lower operational flexibility has a significant impact on system production costs. With a lower allowable maximum output, the number of units selling energy to the market increases. Compared to a situation where no reserves are provided, units that are relatively inexpensive to operate will produce less energy while more costly units will produce more energy. Also, a unit that provides regulation-down service typically generates above its technical minimum in order to respond to instantaneous increases in grid frequency, which are the result of either a decrease in system load or an increase in variable resource generation. Therefore it sometimes sells energy above the technical minimum even when market prices are less than production costs.

The statistical analyses presented above may offer some improvements over those used in the E3 analysis. However, even at the BAA level, it is inadequate because it does not consider transmission constraints and other risk factors. The flexibility reserve calculation must address deliverability issues, for example, by reserving transmission capacity specifically for flexibility reserves. In addition, diversity among the resources providing flexibility services needs to be addressed. For example, reliability is significantly higher when small amounts of services are provided by many geographically dispersed sources (from a grid connectivity perspective) than when provided from a single source. If the single reserve source is forced out of service or if a critical transmission line goes down, then all reserves may be lost, placing grid security at risk. The single reserve approach is attractive from a purely economic perspective if reliability issues are ignored. However, it is important that all risks and rewards be taken into account when making flexibility reserve decisions.

Some models “optimally” assign system-level reserve to individual units such that system costs are minimized within model input parameters. Optimization may also include factors that go beyond cost minimization such as ensuring that unit assignments are geographically diverse while accounting for transmission limitations, forecast errors, uncertainty, and system reliability. It is our opinion that such assignments are particularly important in the EIM Case, since transmission limitations will play a vital role in how and when reserves are deployed.

3.8 Grid Transmission Considerations

The importance of properly managing transmission congestion in a power system with a high penetration of variable resources was discussed in a report by Jones (2011). The report states that “[h]igher penetration of wind power in the grid can introduce new patterns in the flow of power in the transmission and distribution networks. These unexpected flows could overload some transmission lines, causing new operating limits and congestion in the system.” When examining variability and uncertainty at various time horizons ranging from sub-zero seconds to one day, the report states that:

Within these critical time frames, wind variability and uncertainty have the most significant impact on operation grids and on decision support tools and processes in the control room. Examples of processes and tools that time frames affect include: scheduling of generation and transmission capacity; allocation of different types and levels of generation for reserves; unit commitment and load following; and real-time dispatch of resources that keep the system balanced.

The report also points out that “[c]ongestion can be managed in different ways and there is still no consensus on the best approach.” It highly recommends that more research be conducted “to transparently and cost effectively deal with congestion, while simultaneously accommodating integration of more wind generation.”

The WI transmission system becomes congested, especially at times of peak load, thereby limiting linkages among variable resources that may counteract each other. Incidences of transmission congestion affecting wind generation have already occurred in WI under the conditions of relatively low penetration of variable resources. In the Bonneville Power Administration (BPA) service territory, BPA has instructed wind turbine operators to curtail energy production because there was inadequate transmission capacity available to export excess energy out of the region while still maintaining hydropower operations within environmental constraints² (Rogers et al. 2010). However, on December 7, 2011, the Federal Energy Regulatory Commission (FERC) ruled that the BPA decision to curtail wind power was discriminatory under the Federal Power Act, Section 211A, but noted that if more transmission capacity had been available, BPA could have transported some of the excess to other systems (Runyon 2011). We anticipate that as more variable resources are built in the future, transmission congestion issues and perhaps conflicts such as the one between BPA and wind plant owners will increase.

NREL estimates that flexibility reserve requirements for the EIM Case are lower than amounts required under the Benchmark Case because variability resource diversity is greater over the entire EIM footprint compared to diversity within each individual BA. For example, if wind generation in New Mexico suddenly decreases while at the same time wind generation in Washington state increases rapidly, the net WI generation change could potentially be zero. However, if transmission pathways are congested, system operators may not be able to take advantage of this diversity. For the purposes of analyzing transmission issues we separate flexibility reserves into those that have response times that are either shorter or longer than the dispatch interval.

Flex (regulation) reserves react to quick changes within a dispatch time interval and require AGC. We expect that in order for the transmission system to operate within limits at all times slack may need to be reserved in the transmission system under the EIM Case in order to take

² According to BPA staff, spilling water would have increased dissolved gases to levels above those which cause harm to fish, such as the native salmon (PowerNews 2011). However, those opposed to curtailing wind production disagree and say that spilling water, if done carefully, is the safest solution to the salmon. Spilling water can aid fish migration and increase survival rates. Opponents also say that there are no data that show levels of dissolved gases above the Washington state standard are harmful to fish (Del Franco 2011).

full advantage of variable resource diversity across the market footprint. No adjustments to transmission capacity components were made by E3 to accommodate these fast movements. We note that under SPP EIS market rules transmission capacity must be procured if conventional reserves are served by a resource outside a BAA. It appears that no such transmission reserves are required under the EIM.

Although the NREL determination of flexibility reserves does not account for transmission limits, the GridView SCED includes a detailed representation of the transmission system. Hourly generation levels for each variable resource along with loads across the WI footprint are input to the model. However, it is our understanding that GridView does not fully account for the effects that uncertainty and forecast error have on the transmission system, because the hourly dispatch model “knows” with certainty the system loads, variable resource power injections, and units’ forced outages. It is also our understanding that the model did not simulate the deployment of conventional and flexibility reserves in response to forecast errors and unit outage events.

Spin and supplemental reserves do not necessarily require AGC. However, transmission constraints may not allow grid operators to take full advantage of variable resource diversity. We note that the EIM Case specifies that EIM energy transactions would have the lowest priority and be curtailed if insufficient transmission exists in real-time; that is, the EIM can never displace other uses of the transmission system. Also, variable resource forecast error may cause curtailments to occur if the grid is in a congested state. E3 neither simulated EIM curtailments due to forecast errors and system outages nor estimated the probability of EIM energy curtailment. In our opinion, actual BA operations would need to carry additional reserves to account for EIM curtailments that are due to the combination of forecast errors, grid component outage events, and transmission congestion.

Under the EIM each BA operator would ultimately be responsible for maintaining a balance within its BAA. We also note the EIM is only an energy market. Yet the flexibility reserve reductions attributed to it in the E3 study would require a level of cooperation and coordination that extends far beyond an energy-only market. In reality, BA operators do not have perfect knowledge of production from variability resources and associated forecast error across the WI. Flexibility reserve requirements are changing not only over time, but also with respect to physical location. It is our opinion that BAAs would be operated conservatively and would carry a higher level of flexibility reserves than those computed for the EIM Case. However, as the market matures, BA operators will gain experience under the EIM and would likely reduce flexibility reserves below Benchmark Case levels. The exact level of flexibility reserve saving is difficult to assess, but methodologies that simulate EIM curtailments and imperfect BA operator knowledge could be constructed to gain a better appreciation for the magnitude of the savings. It should be noted that reductions in flexibility reserves as estimated by E3 accounts for about 70% of total EIM societal benefits and are therefore a critical component of the EIM analysis.

In the large independent system operator (ISO)/regional transmission organization (RTO) markets in the Eastern Interconnection, the interaction between transmission constraints and operating reserves has been addressed by introducing zones for operating reserves within the ISO/RTO footprint. A similar approach, with modifications for local conditions (e.g., voltage considerations), could potentially be used in WI. Hence, the NREL “footprint” case used for the

EIM dispatch in GridView is probably overstating the reduction in operating reserve requirements. The NREL “regional” case may therefore provide a more realistic estimate of future needs for flexibility reserves. However, in using zonal operating reserve requirements, some benefits of spreading forecasting errors across a geographically diverse region would be lost. Table 3.1 shows that if the NREL regional reserves had been used for the EIM Case, reductions in reserve capacity relative to the Benchmark Case would have been about 45% lower (see the last two columns in Table 3.1). E3 did not perform a dispatch run using the NREL “regional” flexibility reserve case; therefore, the economics of this case are unknown.

Table 3.1 Reserve Requirement (MW) Computed by NREL

Flexibility Reserve	Business-as-Usual (BAU)	Regional	EIM Footprint	BAU Minus Regional	BAU Minus EIM Footprint
Flex	948	669	429	279	519
Spin	1,072	801	590	271	482
Supplemental	2,144	1,601	1,181	543	963

Source: Kirby et al. (2011).

In the terminology used by NREL, Business-as-Usual (BAU) refers to the case in which each zone or BA operator supplies its own flexibility reserve requirements. These requirements are input to GridView when performing Benchmark Case production cost optimization.

We initially thought that flexibility reserve requirements were overestimated in the Benchmark Case because flexibility reserves must be served within the zone where variable resources were located; that is, it was assumed that no coordination or cooperation among BA operators would develop. To avoid this overestimation, we suggested that limited flexibility reserve sharing be allowed in the Benchmark Case to mimic current conventional sharing practices. However, we recognize that flexibility reserves are fundamentally different from conventional reserves and flexibility reserve sharing is technically more challenging under a Benchmark structure. In addition, guidance from the EDT Technical Review Subcommittee suggested that the analysis not utilize conventional resource reserve sharing groups for variable resources.

Another aspect of the transmission system that needs more study is voltage stability and reactive power issues that limit power transfers in WI. As more variable resources are integrated into the WI, these issues may intensify. The aforementioned report by Jones (2011) states that

...wind plants are known to cause voltage stability problems in power systems with insufficient reactive power support. Having the proper tools to assess system voltage stability in real-time becomes even more critical with higher wind penetration levels ...

Newer wind turbines are capable of voltage control. It was assumed that wind farms added to the system in the future will either be Type 4 wind turbines with dynamic voltage or a more

advanced technology that will continue to have dynamic voltage. The GridView model does not directly consider voltage and reactive power requirements in its calculations and therefore cannot assess the attributes of newer turbines on grid operations. Therefore, we suggest that E3 test the validity of GridView results by simulating various situations (e.g., seasonal peak and off peak hours) with a more rigorous, nonlinear power flow model (or “ac power flow”) to directly assess voltage stability issues under both the Benchmark and EIM Cases.

3.9 Supplemental Flexibility Reserves and Ramping Events

Supplemental flexibility reserves are nonspinning resources that need to be available within a 30-minute time frame. Because it was assumed that this service is similar to conventional nonspinning reserves, E3 did not commit units in GridView production cost runs for this function. Therefore, the economic and grid implications of this function are not included in its study. Presumably, units (mainly gas turbines) providing this service must also be able to start and synchronize to the grid very quickly. However, it is important that supplemental reserves be taken into account when determining unit commitments, because under some conditions, quick-start units may already be committed to serve load and therefore would not be available to provide supplemental reserves. For zones without adequate quick-start capacity, this service and transmission capacity must be procured outside of the BAA under the Benchmark Case.

According to NREL documentation, flexibility supplemental reserves would respond to variable resource ramping error events (Ela et al. 2011). In order to assess the magnitude of variable resource ramping, we created ramp exceedance curves for the hour-ahead forecast error in 2020. The curve shown in Figure 3.17 is for wind ramping events in the WACM BAA. In the year 2020, no solar resources are located in WACM; therefore the exceedance curve is a function of the wind resources only. Note that ramping events range from over-projections of more than 535 MW to under-projections of almost 355 MW. In addition, 5% of the time, over-projections are more than 105 MW and are underestimated at the same level 5% of the time.

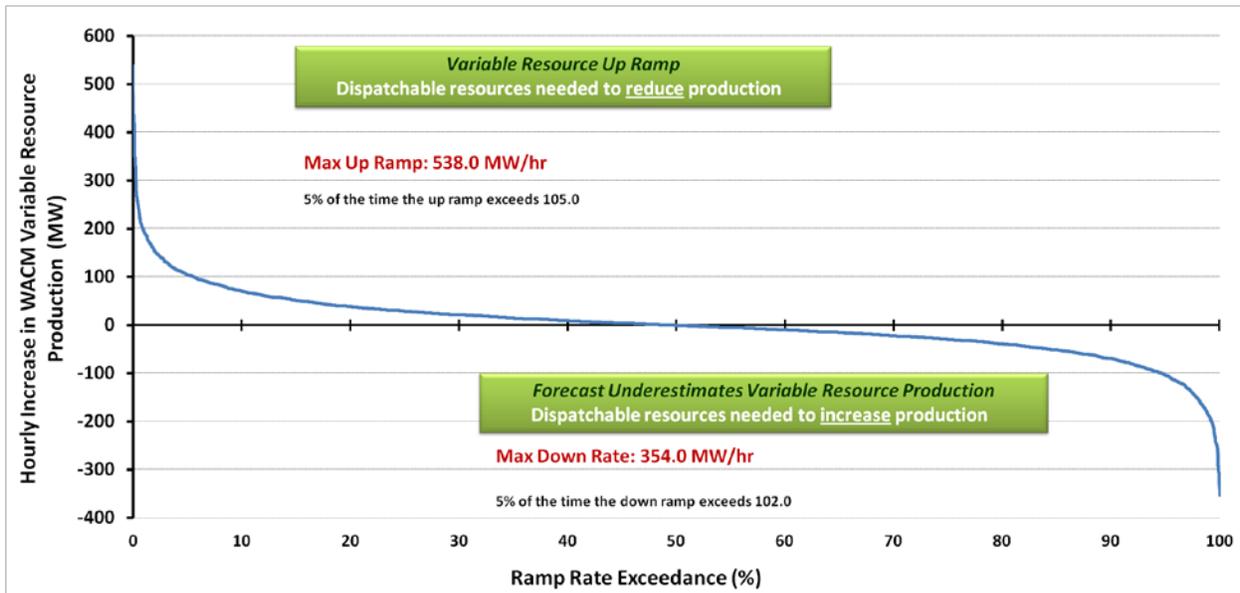


Figure 3.17 Ramping Event Exceedance Curve for Variable Resources (All Wind) in the WACM BAA

A five-minute re-dispatch of the system would help alleviate some transmission issues associated with these slower-moving (e.g., 30-minute) events; however, it is important that these uncertainties be taken into account in the unit commitment and dispatch. Without a mechanism to ensure that enough up-ramping capacity is available in the system, the EIM dispatch may fall short when variable resources are over-forecasted. It should not be assumed that quick-start units will be available, because several base load units may be placed off-line under the assumption that quick-start units would be committed to follow the load during the day. It is also important that there is adequate flexibility on the “down” side when determining unit commitments to accommodate situations when the wind is much greater than projected.

If the amount of capacity and generation from renewables expands greatly in the future, alternative scheduling strategies, in addition to the one used by E3, for energy and reserves should be considered to better account for variable resource uncertainties. For instance, the approach of using probabilistic wind power forecasting as input to unit commitment decisions, either for determination of dynamic operating reserves or as input to a stochastic unit commitment formulation, has been explored in Wang et al. (2011) and Botterud et al. (2011). Such alternative approaches could also be considered in future studies of the integration of renewable energy in general, and of the EIM in particular.

In contrast to the WACM BAA, which in 2020 is projected to have wind as the only variable resource, the WALC BA is projected to have only PV resources. Ramping events exceedance for the WALC is provided in Figure 3.18. Ramping events range from over-projections of more than 165 MW to under-projections of almost 105 MW. In addition, 5% of the time, over-projections are more than 60 MW and are underestimated at the same level 5% of the time. Most zero ramps occur at night when PV resources produce no power.

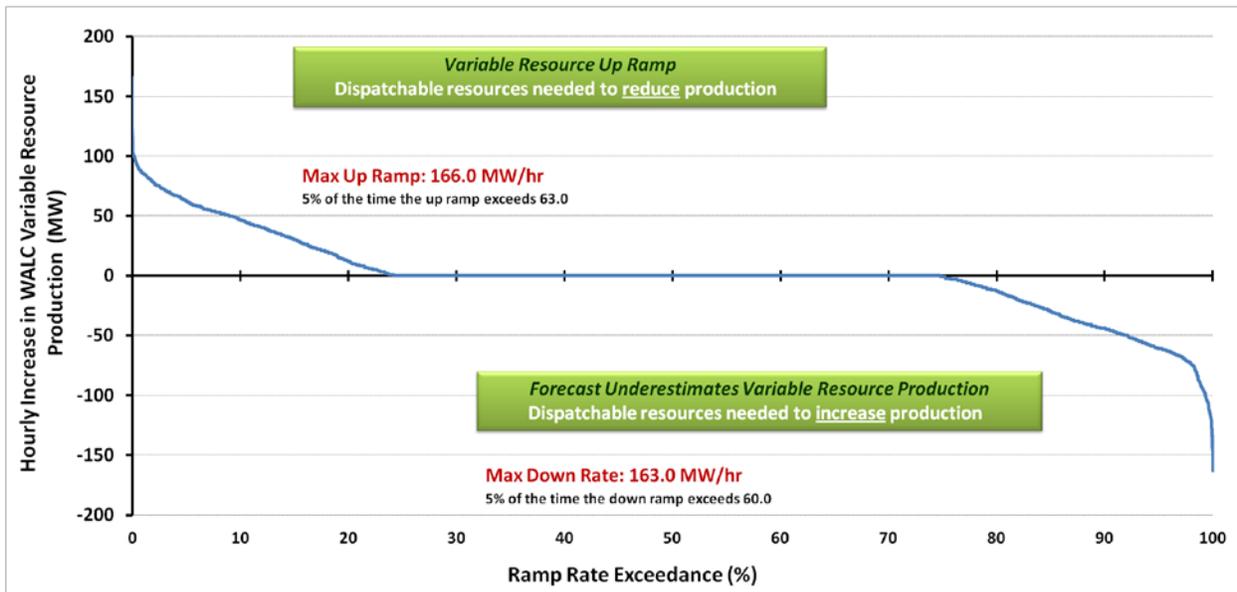


Figure 3.18 Ramping Event Exceedance Curve for Variable Resources (All PV) in the WALC BAA

4 MODELING HYDROPOWER

Water deliveries within and between hydrological basins in WI are primarily driven by nonpower considerations, including those for irrigation, recreational, environmental, industrial, and municipal uses — all of which are typically based on legal agreements among numerous affected parties (BOR 2009). In contrast, the E3 representation of hydropower plant operations is based solely on power grid objectives using 2006 historical monthly generation levels for both 2006 and 2020.

According to the EIA, in 2006, hydropower plants accounted for almost 29% of the total generation from WI supply resources located in the United States (EIA 2008). Many of these power plants have limited operational flexibility, which could impact their participation in the proposed EIM. Stringent environmental operating criteria place limits on water releases and reservoir operations. Operating criteria are often complex and unique for each hydropower project and serve to place hourly, daily, and monthly constraints on reservoir water levels. Interdependencies among cascaded water reservoirs and power plants compound operational complexities.

Because of the large number of hydropower plants and the site-specific complexity of hydrological systems in WI, the hydropower representation in GridView is simplified. However, even though it has several shortcomings, it is superior to other similar models. It uses an iterative process to approximate hydrothermal coordination (HTC), given monthly energy, capacity, and operational ramping constraints. The HTC objective is to minimize locational marginal prices (LMPs) in the model. However, the HTC methodology was not universally applied to all hydropower resources. For some plants, hourly generation levels in the Benchmark and EIM Cases in both 2006 and 2020 were set equal to actual hourly generation in 2006. That is, it was assumed that operations did not respond to the altered vector of market price signals simulated under the EIM, nor to the introduction of much greater amounts of variable generation, such as wind and solar. Presumably, generation levels for these plants were held fixed at historical 2006 levels stemming from the complexities of optimizing the dispatch of these resources.

This section will compare and contrast how groups of hydropower resources in four regions in WI were modeled in both 2006 and 2020. The four groups of hydropower resources surveyed are located in the Colorado River Storage Project (CRSP), the Loveland Area Project (LAP), the Sierra Nevada Region (SNR), and the Bonneville Power Administration (BPA). It will also discuss how the time and spatial variability of hydropower can impact thermal dispatch and transmission flow.

4.1 Colorado River Storage Project

This study used the hydrology levels in 2006 as the basis for hydropower operation in WI in 2020. However, 2006 may not be the most representative year for modeling the hydroelectric conditions for CRSP resources because that year was one of the driest on record. Annual water releases from the Glen Canyon Dam during the 2006 calendar year were only 8.39 million acre-feet (MAF), and the average forebay elevation was about 3,610 feet above sea level, as shown in

Form PO&M-59 (BOR 2006). This water release was only slightly above the minimum release required by law, which is 8.23 MAF, and the elevation is more than 104 feet below the reservoir's crest elevation, which results in very low water-to-power conversion rates throughout the year. Glen Canyon represents approximately 75% of the CRSP capacity and energy resources. Furthermore, other CRSP resources, such as the Aspinall Cascade, experienced below-average hydropower production levels.

An examination of GridView results reveals that E3 bounded (i.e., forced) the model to produce results that very closely match actual 2006 hourly generation levels. Argonne compared GridView hourly generation results to supervisory control and data acquisition (SCADA) data for all of the CRSP power plants published on Western's Web site (<http://www.wapa.gov/crsp/opsmaintersp/scada.htm>). With the exception of a few minor differences, model results exactly matched those recorded and stored in SCADA systems. The hourly historical values were used not only for 2006, but also for the year 2020 for both the Benchmark and primary EIM cases.

4.2 Loveland Area Project

For many plants in Western's LAP system, hourly hydropower generation patterns produced by the GridView model differed greatly from actual data in 2006. Argonne compared actual 2006 LAP hourly generation data with those produced by GridView. Actual data are compiled and stored at the CRSP Office located in Montrose, Colorado, in its energy management system (EMS). The graphs in the figures below compare actual generation to GridView model results.

Figure 4.1 compares Yellowtail plant generation data used by the GridView model with actual data for the month of July 2006. The two plots correspond very closely.

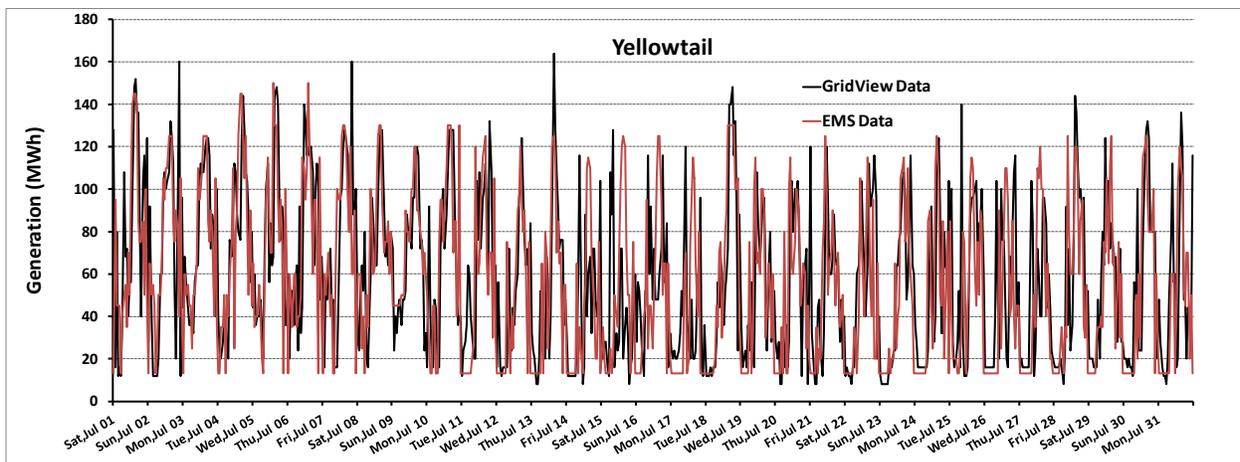


Figure 4.1 Comparison of Modeled and Actual Plant Generation at Yellowtail in July 2006

However, GridView model results for other plants, such as Seminoe, do not correspond closely as can be seen in Figures 4.2 and 4.3 for the months of July 2006 and December 2006, respectively. The E3 report did not explain why generation at some LAP dams matched actual

2006 generation whereas generation at others did not. The reason for the generation pattern mismatch for some dams in LAP should be resolved.

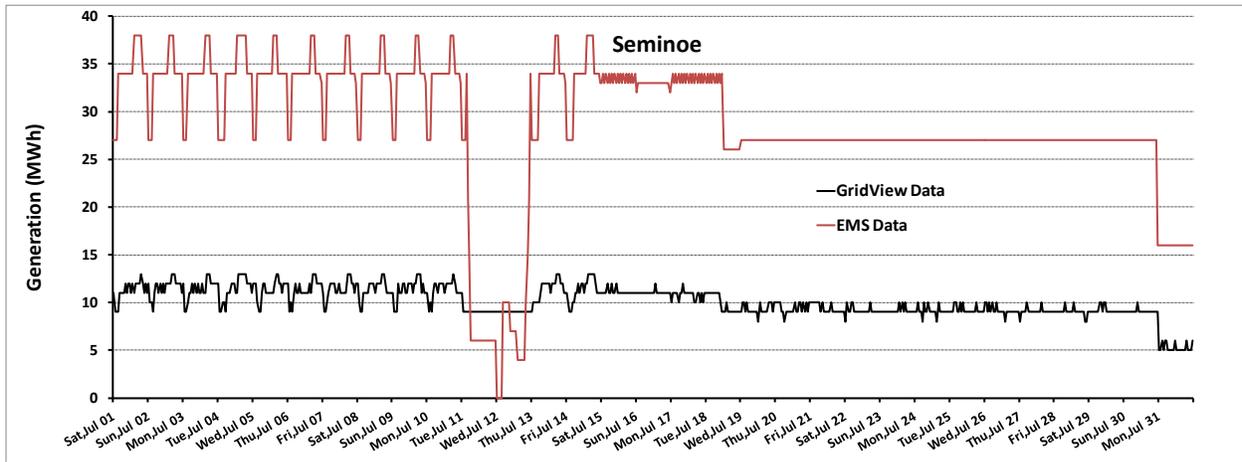


Figure 4.2 Comparison of Modeled and Actual Plant Generation at Seminoe in July 2006

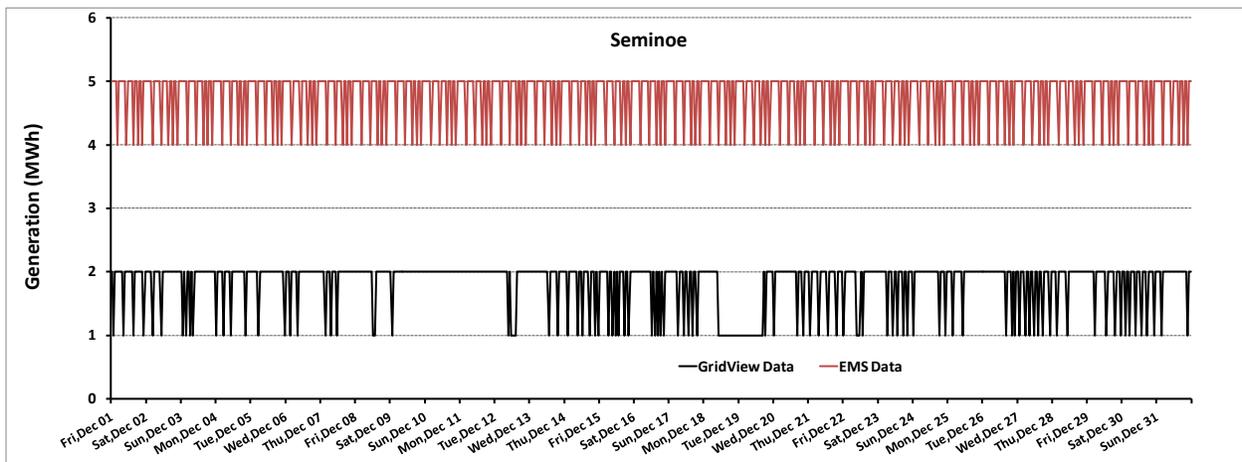


Figure 4.3 Comparison of Modeled and Actual Plant Generation at Seminoe in December 2006

Similar to CRSP, GridView hourly generation from LAP hydropower resources in 2020 were constrained to produce 2006 hourly levels. To use 2006 hydroelectric power data for both CRSP and LAP resources in 2020, an adjustment had to be made that would correctly match the date with the day of the week. An adjustment was necessary because 2020 begins on a Wednesday, while 2006 began on a Sunday. To match days of the week correctly between both years, data from January 4 to 7, 2006, were used to represent January 1 to 4, 2020. Data from January 8 to March 4, 2006, represented January 5 to February 29, 2020. Finally, data from February 26 to December 28, 2006, represented March 1 to December 31, 2020. Using hourly 2006 generation data again in 2020 is a potential shortcoming in the methodology because it is

improbable that such low hydropower conditions will occur in both CRSP and LAP again in 2020.

Furthermore, hourly GridView generation results were the same for both the Benchmark and EIM Cases. No changes in model results between the two cases were observed for either the CRSP or LAP systems. This result implies that even though it was assumed that Western's CRSP and LAP will participate in the EIM, neither system will alter dispatch schedules in response to the proposed EIM. It also suggests that CRSP and LAP hydropower resources do not have the ability to accommodate fluctuations in wind and solar output. While it is correct that CRSP and LAP hydropower resources have many environmental and institutional limitations, it is also true that under some, but not all, hydropower conditions at certain locations, such as the Blue Mesa and Morrow Point plants, Western may have some limited flexibility to respond to market price signals.

4.3 Sierra Nevada Region

Hydropower data discrepancies, similar to those in the LAP, also occurred for plants in Western's SNR. Again, Argonne compared actual 2006 SNR monthly generation data, collected by an EMS, with those produced by GridView. The graphs in the figures below compare actual generation to GridView model results.

Figure 4.4 compares J.F. Carr plant generation data produced by the GridView model with actual data for the month of September 2006. The two plots correspond fairly closely.

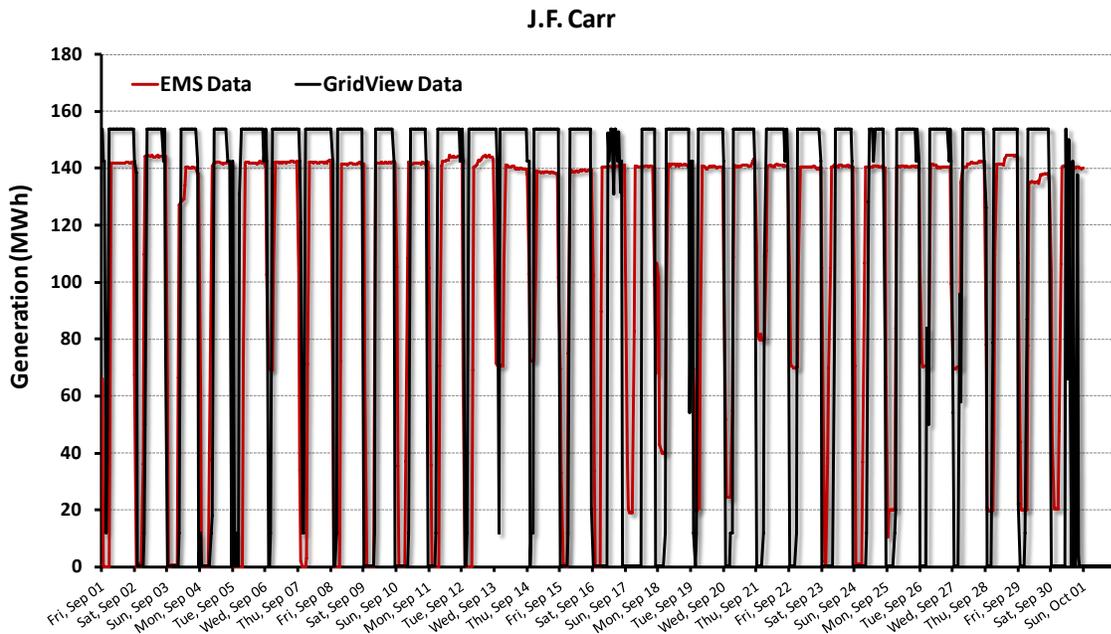


Figure 4.4 Comparison of Modeled and Actual Plant Generation at J.F. Carr in September 2006

However, historical operations and GridView model results for other plants, such as Shasta, which is the largest hydropower plant in the SNR, and Whiterock do not correspond closely as can be seen in Figures 4.5 and 4.6. The E3 report did not explain why generation at some SNR dams matched actual 2006 generation whereas generation at others did not. The reason for the generation pattern mismatch for some hydropower plants in SNR should be resolved.

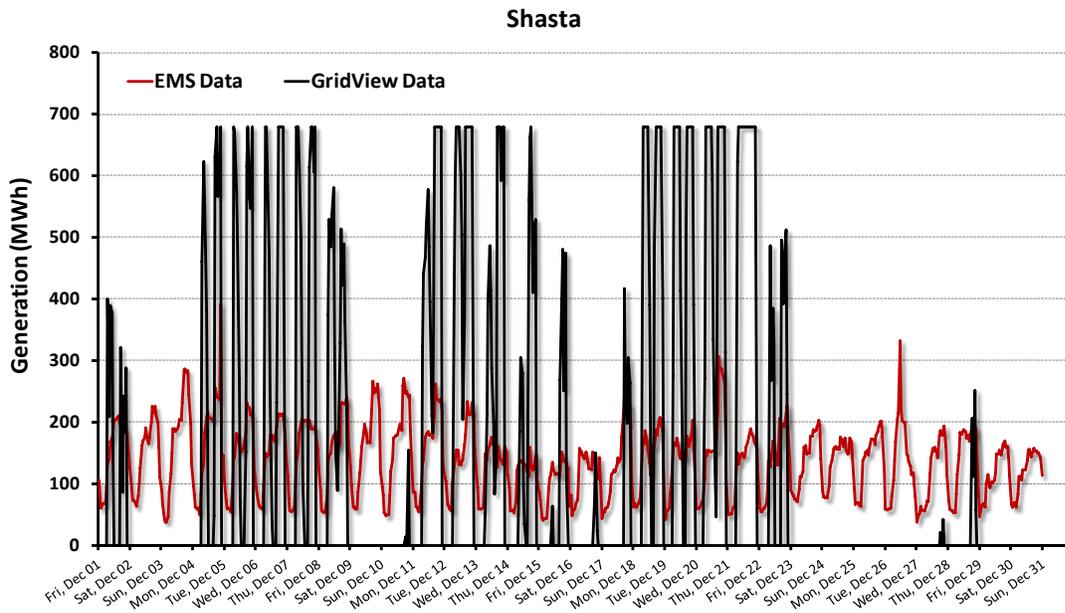


Figure 4.5 Comparison of Modeled and Actual Plant Generation at Shasta in December 2006

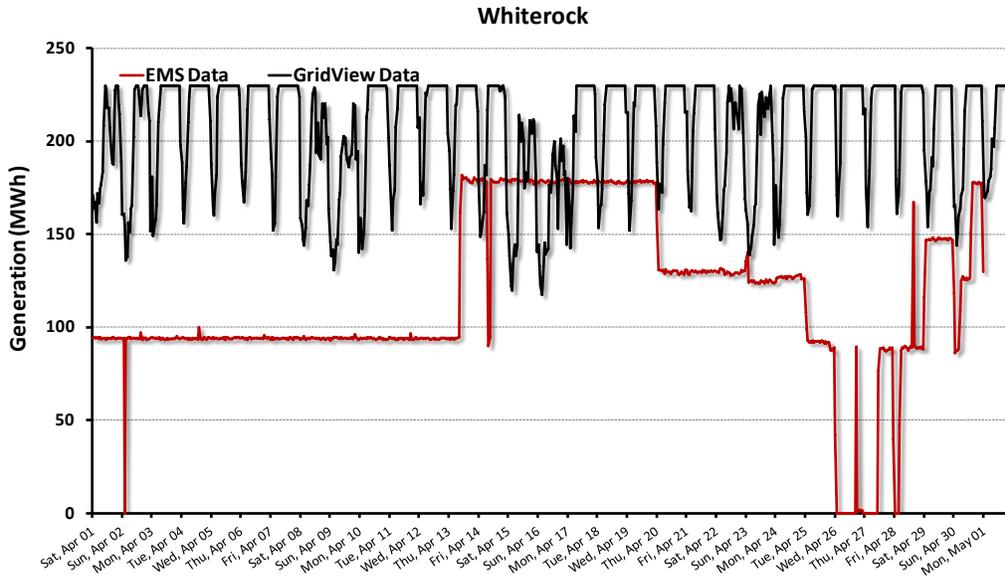


Figure 4.6 Comparison of Modeled and Actual Plant Generation at Whiterock in April 2006

4.4 Bonneville Power Administration

Unlike hydropower generation at CRSP and LAP, which showed no response to the EIM, GridView model results for conventional hydropower dispatch in the BPA BAA show a significant response to the introduction of the EIM. Figures 4.7 and 4.8 compare BPA results for the Benchmark and EIM Cases in both April 2020 and October 2020, respectively. The disparity between results in which BPA is allowed to alter operations while other hydropower plants do not (e.g., those in CRSP) appears to arise solely as a result of the modeling process used in GridView. We assume that in the case of the BPA BA, hydropower plants were modeled using an iterative process to approximate HTC, given monthly energy, capacity, and operational ramping constraints. On the other hand, we assume that historical hourly generation levels were simply input into the model for the CRSP and LAP resources. In this case, it appears that this historical pattern does not change over time (i.e., in 2020) and between scenarios.

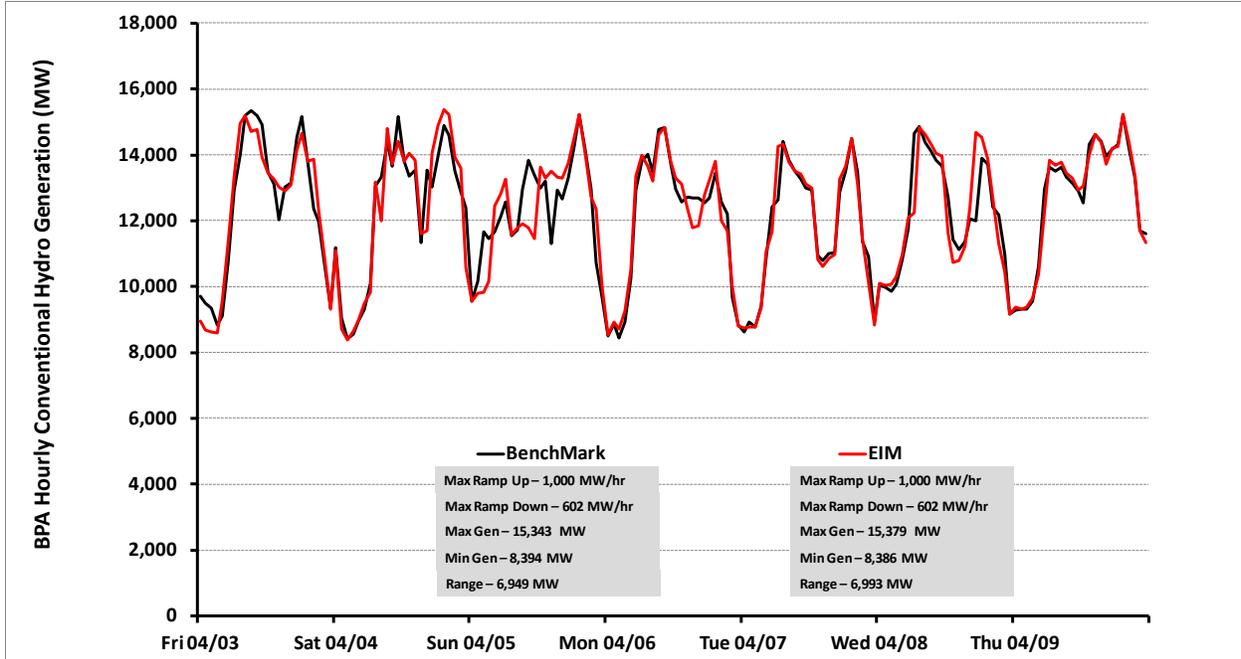


Figure 4.7 Comparison of Total BPA Hydroelectric Generation under Benchmark and EIM Cases in April 2020

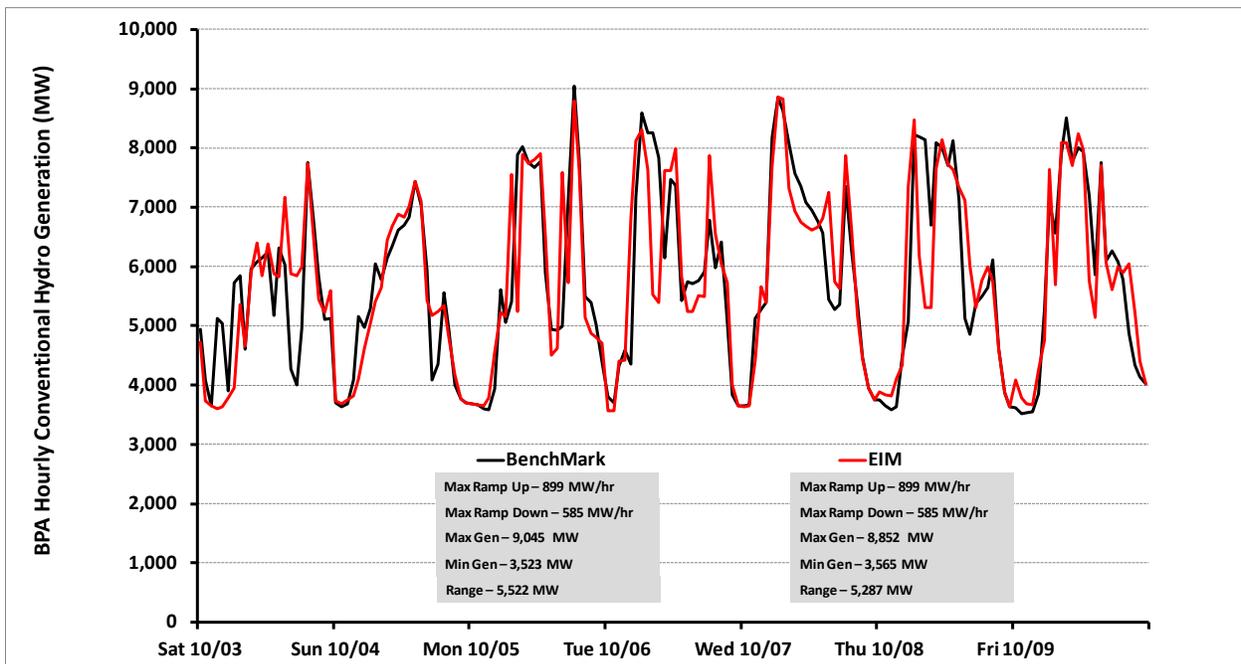


Figure 4.8 Comparison of Total BPA Hydroelectric Generation under Benchmark and EIM Cases in October 2020

4.5 Hydropower Variability

It should also be noted that hydropower conditions change considerably over time and space, profoundly impacting thermal dispatch and transmission flows. Using a single set of “representative” hydropower conditions may not produce average dispatch production cost results because hydropower conditions have a large influence on system economics that are nonlinear. The marginal value of water used to generate power has a very high value during low hydropower conditions, whereas the opposite result is obtained when water is very plentiful.

Figure 4.9 shows the historical changes in WI hydropower and an “average” future projection (Veselka et al. 2007). Note that at one time, hydropower served more than half of WI loads. However, because future hydropower capacity expansion is expected to be minimal, hydropower’s percent contribution to the total supply is expected to decrease over time.

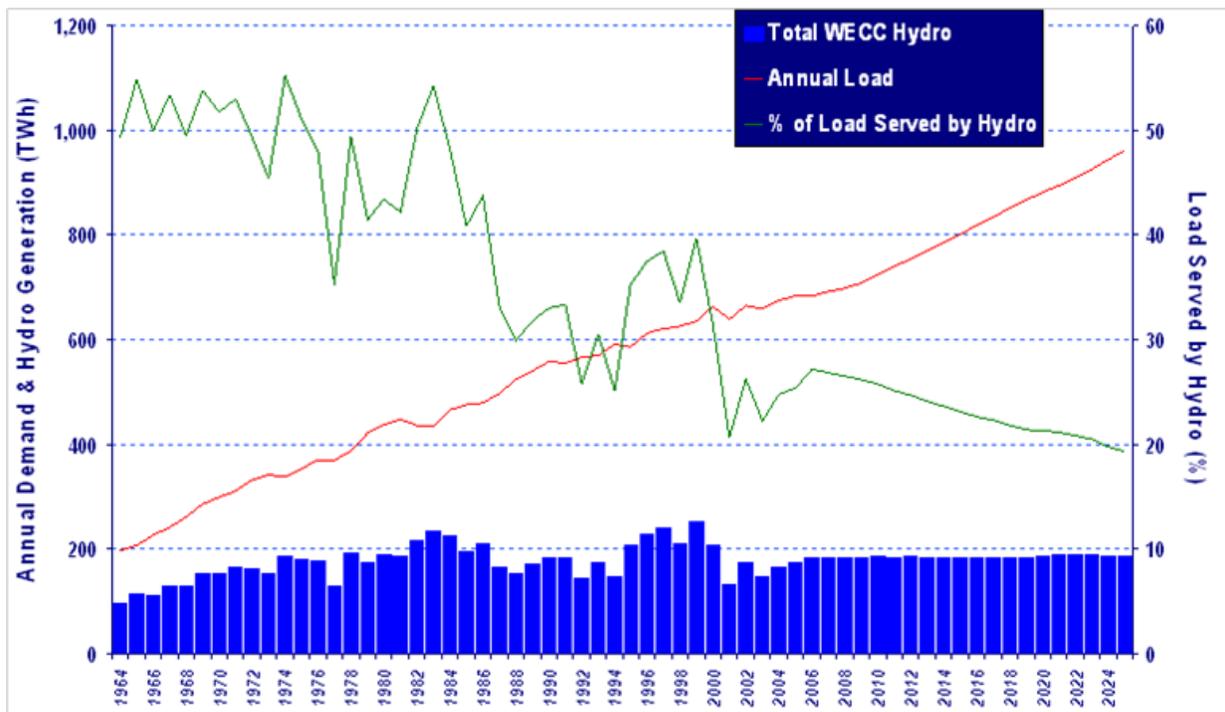


Figure 4.9 Hydropower’s Supply Contribution in WI (Veselka et al. 2007)

At the basin and power plant levels, production displays a much larger degree of variability. For example, annual production levels at Glen Canyon Dam vary by more than a factor of 2.6 (Veselka et al. 2010). We also noted that, although E3 considered 2006 to be average in terms of hydropower conditions, the Colorado River Storage Basin was in a prolonged drought during that year.

Therefore, we recommend that E3 analyses be performed for a range of hydropower conditions that may occur across the WI. An analysis of several hydropower conditions that span a wide range of conditions is typically used by the Bureau of Reclamation (BOR) and Western (BOR 2007) and applied to many systems worldwide that have a significant percent of load served by hydropower resources (Rebennack et al. 2010).

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5 GRIDVIEW MODEL TIME STEP

This section reviews the GridView model time granularity in terms of dispatch interval and how it may affect the model results. A simple case study is then presented comparing the market behavior for a 5-minute dispatch interval and a 1-hour dispatch interval.

5.1 Granularity of the Dispatch Interval in the GridView Model

In the EIM study, the GridView model dispatches resources and serves load on an hourly basis; that is, it computes the average grid value for each hour. Therefore, it cannot fully capture some of the benefits that may potentially be realized by updating the system dispatch every 5 minutes. In particular, it cannot model the advantages of following intra-hourly load fluctuations in the EIM. It also cannot fully assess real-time changes in flexibility regulation as output from variable resources fluctuates over time.

5.2 Case Study – Comparing Results of a Simple Dispatch Model with 5-Minute and 1-Hour Dispatch Intervals

Argonne developed a very simple spreadsheet to compare a 1-hour dispatch to one with a 5-minute interval. We emphasize that this spreadsheet is only for illustrative purposes. In general, when the system is dispatched every 5 minutes, operations are much more responsive to variations in loads and resources than they are in a system dispatched every hour. Responsiveness to generation fluctuations is especially important for a system that has a large penetration of variable resources, such as wind and solar, because the generation output from these sources can be highly variable even over short time periods. Less regulation is required when the amount of generation dispatched is closer to the actual load.

The spreadsheet made use of hourly load forecasts by WI zone for 2020. The spreadsheet illustrates the response for two cases: namely, a case with no variable resources and another with variable resources at a specific hourly forecast value. Stochastic elements are factored into the spreadsheet for both forecasted loads and forecasted variable generation by the use of a random number generator that arbitrarily produces short-term, 5-minute forecast errors. The magnitude of the error every 5 minutes is equal to some fraction of the maximum error input by the user. Load and variable generation forecast errors over the forecast hour (i.e., a longer-term error trend) may be specified by the user. Short-term errors and a longer-term error trend were added to the forecast load and variable generation to determine the actual load or wind generation. Again, we emphasize that the purpose of the spreadsheet is to illustrate the advantages of a 5-minute dispatch and is overly simplistic.

Figures 5.1 and 5.2 show the results of the spreadsheet in the WACM BAA over a 1-hour time period where: (1) the load is decreasing; (2) the forecasted wind for that hour is 600 MW; (3) the 5-minute and 1-hour load errors are 2 and 20 MW, respectively; and (4) the 5-minute and

1-hour wind errors are 20 and -80 MW (i.e., the actual energy provided by wind power is less than forecasted), respectively.

Figure 5.1 compares a 1-hour dispatch to a 5-minute dispatch interval over an hour period that has no wind generation. To simplify the comparison, load forecast error is assumed to be negligible. For the 1-hour dispatch, generation is adjusted in the first and last 10 minutes of an hour. At the beginning of the hour, the generation decreases from the value at the beginning of the hour to a value that is halfway to the load forecast value at the end of the hour (BOR 1995). It should be noted that the slopes of the dispatch at the beginning and end of the hour are not necessarily equal. That is because the adjustments made to the generation depend upon the previous hour for the first 10 minutes and on the next hour for the last 10 minutes.

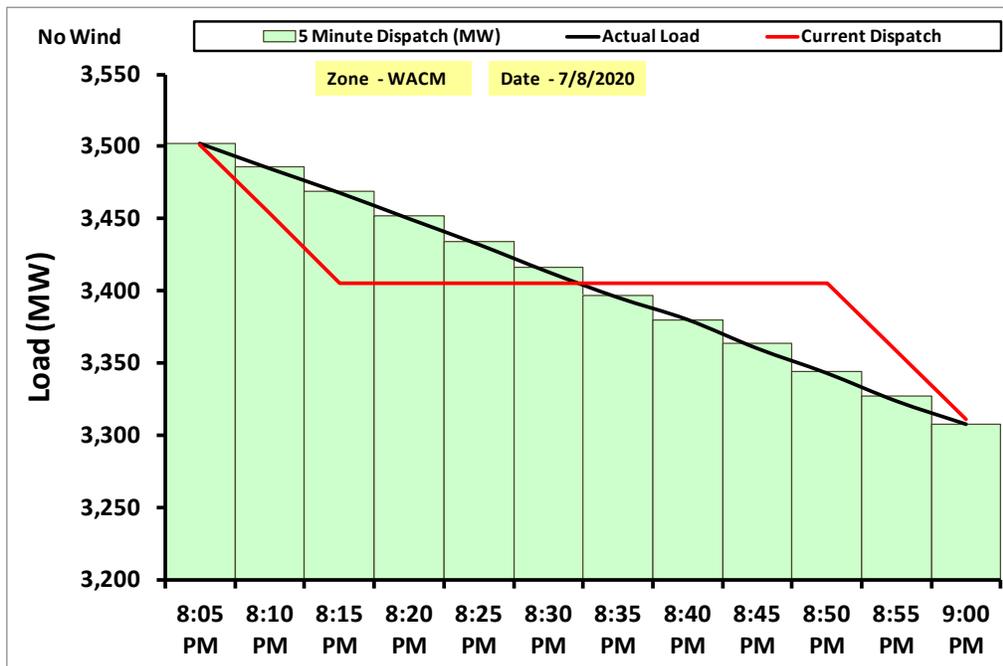


Figure 5.1 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Decreasing Load and No Wind Generation

The graph also shows the actual load. The 5-minute dispatch requires much less regulation than does the 1-hour dispatch. Regulation required in the 1-hour dispatch is the difference between the current dispatch (red) line and the actual load, whereas regulation in the 5-minute dispatch is the difference between the 5-minute (green) values and the actual load.

Figure 5.2 compares the two dispatch regimes for a case that has 600 MW of wind power forecasted in that hour. This figure also shows the wind variability during the hour. Again, the 5-minute dispatch requires much less regulation than does the 1-hour dispatch. The maximum amount by which the 5-minute dispatch overestimates the load (i.e., regulation down) in any 5-minute period is 26 MW, as compared to 4 MW for the 1-hour dispatch. However, the

maximum amount by which the 5-minute dispatch underestimates the load (i.e., regulation up) in any 5-minute period is 12 MW, as compared to 94 MW for the 1-hour dispatch.

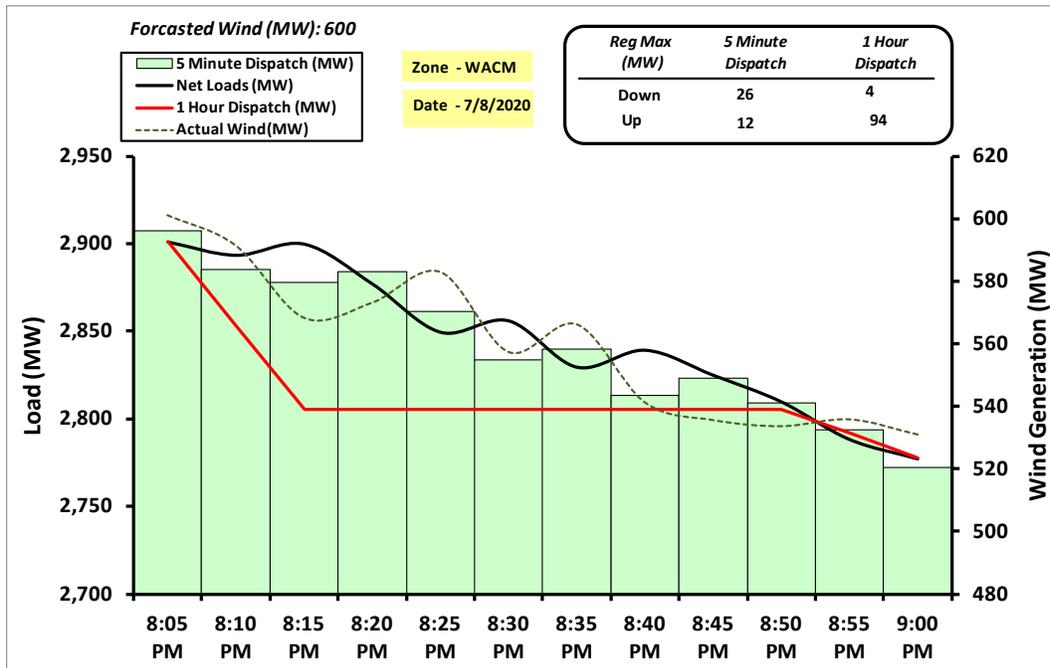


Figure 5.2 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Decreasing Load and 600 MW of Forecasted (but Variable) Wind

Another example of the responsiveness of the 5-minute dispatch is illustrated in Figures 5.3 and 5.4. In this example, the load is increasing while the wind is decreasing from a forecast value of 600 MW for that hour. Figure 5.3, which is the “no wind” case, again shows that significantly less regulation is needed for the 5-minute dispatch as compared to the 1-hour dispatch. Figure 5.4 also shows that 5-minute dispatch requires much less regulation than does the 1-hour dispatch. The maximum amount by which the 5-minute and 1-hour dispatches overestimate the load is about 23 MW. However, the 1-hour dispatch can significantly underestimate the load in any 5-minute period. The maximum regulation up required in the 5-minute dispatch is 19 MW as compared to 85 MW for the 1-hour dispatch.

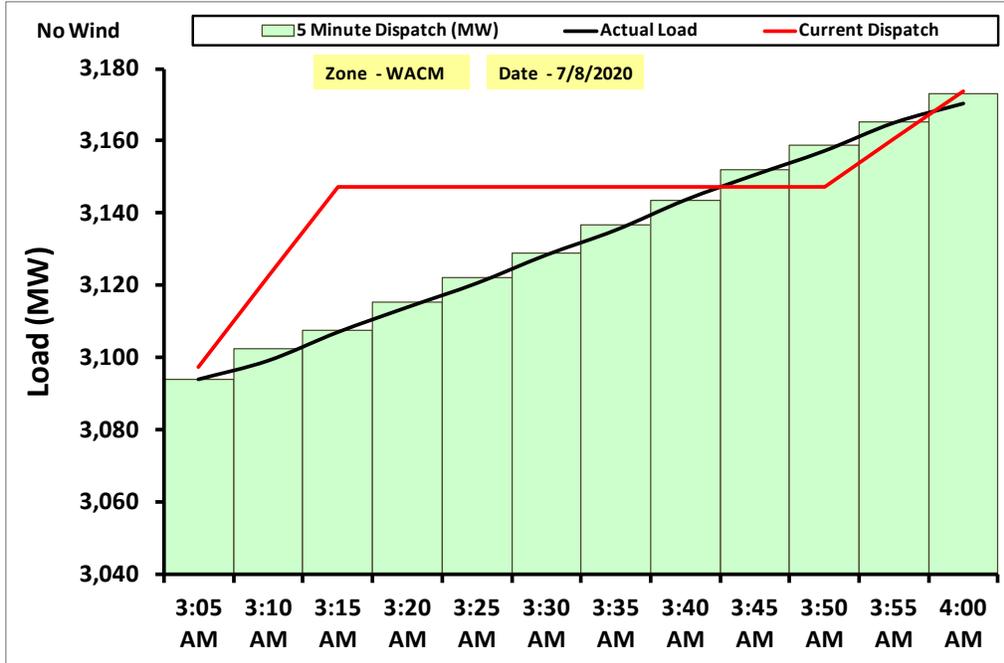


Figure 5.3 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Increasing Load and No Wind Generation

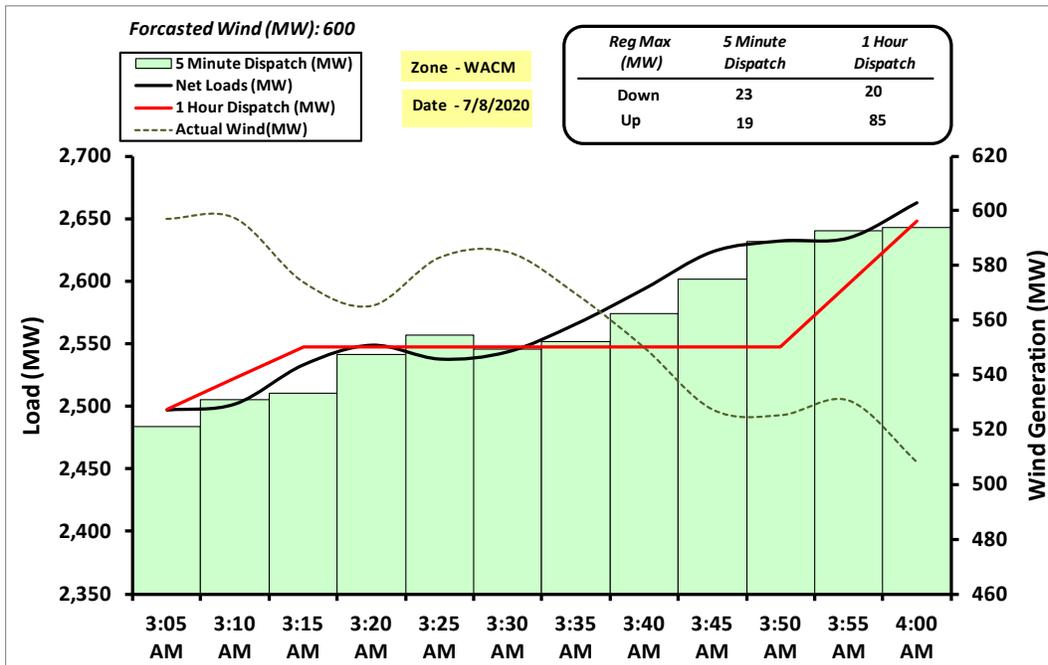


Figure 5.4 Comparison of 1-Hour and 5-Minute Dispatch Interval over an Hour with Increasing Load and 600 MW of Forecasted (but Variable) Wind

It should be noted that in scenarios *with* variable resources, graphs display significantly more 5-minute ramping than those *without* variable resources. More frequent ramping will have operational and maintenance implications for both thermal and hydropower units. Higher costs are anticipated for hydro units because they may be required to operate for short periods of time in rough zones, which is a generation range with excessive powerhouse vibration resulting in accelerated turbine runner cavitation and component wear and tear. As discussed in Section 3, variable resource diversity across the EIM footprint should reduce ramping requirements, although there must be adequate transmission capacity in the system to take advantage of this diversity.

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6 MODELING THE ELECTRICITY MARKET

This section discusses the nature of and assumptions made about the electricity market in the EIM benefit analysis. It discusses how the assumption of a 100% commitment of resources by a BA could overestimate societal benefits in the primary EIM Case and discusses how participant behavior can result in an imperfect market, adversely affecting market prices.

6.1 Balancing Authority Participation in the Market

The \$141.4 million societal benefits estimate in the 2020 EIM Case was based on the assumption that all WI BAs other than those in CAISO and AESO would participate in the market. Because participation in the EIM will be voluntary, future participation levels are highly uncertain at this time. Therefore, E3 performed a sensitivity run with a lower BA participation level. Under the “Reduced BA Participation Case,” production cost savings were only \$53.6 million as compared to a cost savings of \$141.4 million under the primary EIM Case. However, much of the market operator expenditures for start-up and operations would remain. In addition, there are risks when participants drop out of the market when it is operational.

E3 assumed that all generating resources in participating BAs (or zones) would always commit 100% of their dispatchable thermal resources and many hydropower units to the EIM. This very high level of participation will most likely not occur and is not reflected in the CRSP and LAP hydropower dispatch discussed in Sections 4.1 and 4.2, in which there were no differences in hydropower dispatch between alternatives. It also differs from Western’s market participation in the CAISO. The following example illustrates that market participation will be overestimated if it is assumed market participants will commit all of their dispatchable resources. Western’s SNR Office markets energy produced by several hydropower plants located in California’s Central Valley Project (CVP). It is required to participate in the California power market, which also allows for bilateral agreements. Table 6.1 summarizes SNR’s purchase and sales transactions in the CAISO balancing market as compared to all transactions. The balance of the transactions (total minus CAISO) is for bilateral agreements.

Table 6.1 SNR Purchases Made in the CAISO As Compared to Total Power Purchases, Including Bilateral Contracts

	Purchase (MWh)			Sales (MWh)		
	CAISO	Total	%Total	CAISO	Total	%Total
2010	0	171,189	0.0	19,186	199,904	9.6
YTD 2011	824	120,049	0.7	13,571	145,347	9.3

Source: McCoy (2011).

SNR’s purchase and sales transactions in the CAISO balancing market relative to all transactions are very low. Since 2010, less than 1% of all purchases are made through the CAISO, and sales are less than 10%. The primary reason that CAISO balancing market

transactions are small is market price risk. SNR makes few energy purchases in order to minimize its exposure to real-time price volatility. In addition, SNR staff performed an analysis showing that their business strategy can be financially advantageous as compared to greater participation in the CAISO balancing market (Sanderson 2011). They analyzed purchases from bilateral parties between July 2009 and June 2010 on behalf of customers whose entire load is served by Western. The study results are shown in Table 6.2. The costs of power purchased from bilateral parties were compared to costs Western would have incurred for identical purchases made in the CAISO spot market. Over the study period, Western saved over \$85,600 from bilateral deals; the largest single monthly saving was almost \$27,200 in June 2010. This savings would be passed along directly to customers receiving the power.

Table 6.2 Comparison of Bilateral Contract Costs versus Spot Market Costs Incurred by SNR

Month/Year	Cost of Power Western Purchased for Customers via Bilateral Contracts (\$)	Cost of Power if Purchased on CAISO Market (\$)	Savings from Bilateral Purchases (\$)	Savings (%)
June 2010	319,198	346,358	27,160	7.8
May 2010	434,132	443,975	9,843	2.2
April 2010	1,114,285	1,124,889	10,605	0.9
March 2010	520,882	535,469	14,587	2.7
Feb. 2010	519,397	519,679	282	0.1
Jan. 2010	537,676	542,804	5,127	0.9
Dec. 2009	588,914	581,919	-6,995	-1.2
Nov. 2009	69,612	60,149	-9,463	-15.7
Oct. 2009	506,608	516,914	10,306	2.0
Sept. 2009	349,995	363,311	13,315	3.7
Aug. 2009	459,683	468,327	8,644	1.8
July 2009	273,800	276,035	2,235	0.8
Totals	5,694,182	5,779,828	85,647	1.5

SNR is not alone regarding its approach to market risk exposure. Western's CRSP Office markets energy and capacity from hydropower resources in the upper Colorado River Basin. It also schedules hydropower energy production from these resources on a day-ahead basis and in real time to fulfill its energy delivery obligations under long-term firm contracts. CRSP has chosen to limit its exposure to bilateral market price fluctuations primarily by scheduling its resources to meet customer hourly energy requests. This approach differs from other marketing strategies, which reduce hydropower generation during the nighttime while at the same time purchasing power to serve load. The "stored" energy is then sold during on-peak periods when prices tend to be higher.

It should also be noted that Western has very limited flexibility in its operations, potentially impacting its ability to participate in the proposed EIM and respond to EIM price signals. It has firm noncontingent hourly energy delivery obligations based on binding long-term contracts with

its customers. Stringent environmental regulations with complex operating criteria place limits on water releases and reservoir operations. In addition, daily or monthly reservoir water releases are dictated by the BOR on the basis of several nonpower considerations, including irrigation, recreational, environmental, industrial, and municipal uses.

Looking at the SPP EIS market, we also find that not all of the market participant resources are offered into the market. About 80% to 85% of participants' resources are bid into the EIS. In addition, not all entities that are eligible to participate in the EIS have joined. Of the 20 BAs in SPP, 16 participate in the EIS market (Wech 2011), and they account for about 91% of the annual load in the SPP (SPP 2010).

However, offering resources into an imbalance market does not mean they will be redispatched during market operation. The experience in SPP is that only about 10% of units offered into the EIS market are actually redispatched because of market operation.

A notable nonparticipant in the EIS market is the Southwestern Power Administration (SWPA), which has many similarities to Western and shares many of its objectives. The EIS market has negatively impacted transmission flows and congestion on its system, and it incurs additional costs that are not reimbursed (Wech et al. 2011).

A general observation based on the discussions above is that while companies in WI may need to change their current scheduling and trading practices before a fluid and efficient EIM can unfold, it is not necessarily reasonable to assume that such changes can or will be made in all cases.

6.2 Behavior of Market Participants

A key assumption of the GridView production cost optimization model is a "perfect" electricity market. That is, no one market participant influences market prices or engages in direct collusion (through communication and coordinated activities with other participants) or implicit collusion (through the observation of other participants). Furthermore, all market participants behave rationally and submit bids into the marketplace that reflect the marginal cost of production.

In an "imperfect" market, participants can influence market prices. Market imperfections could potentially arise when there is insufficient market competition to keep prices in check and when transmission constraints result in the fragmentation of the larger marketplace into smaller isolated sets of players. Market fragmentation most often occurs under high load periods when the transmission system becomes congested. Transmission congestion severely restricts (or eliminates) competitors outside of the congested area from delivering power. Such market imperfections provide some players with the opportunity to profit by raising prices. In a perfect market, there is no financial incentive to bid above production costs as there are many other market participants that would supply power if a participant raised its bid price.

In an EIM, dispatch would most likely follow other U.S. market practices, including the SPP EIS, in which offers are submitted by market participants in terms of energy blocks with a corresponding bid price. In these markets, offers are not required to reflect actual unit production costs. Although it is very difficult to verify, some historical offers appear to deviate significantly from production costs.

The following are examples from the PJM Interconnection market where day-ahead energy offers do not appear to reflect marginal production costs. Figure 6.1 shows a bid in July 2010 where a small quantity of energy is offered at a price much higher than lower bid blocks. Bid blocks below 140 MW are low, about \$30/MW. However, bidding on blocks above 140 MW increases to \$1,000/MW, which is the PJM market limit.

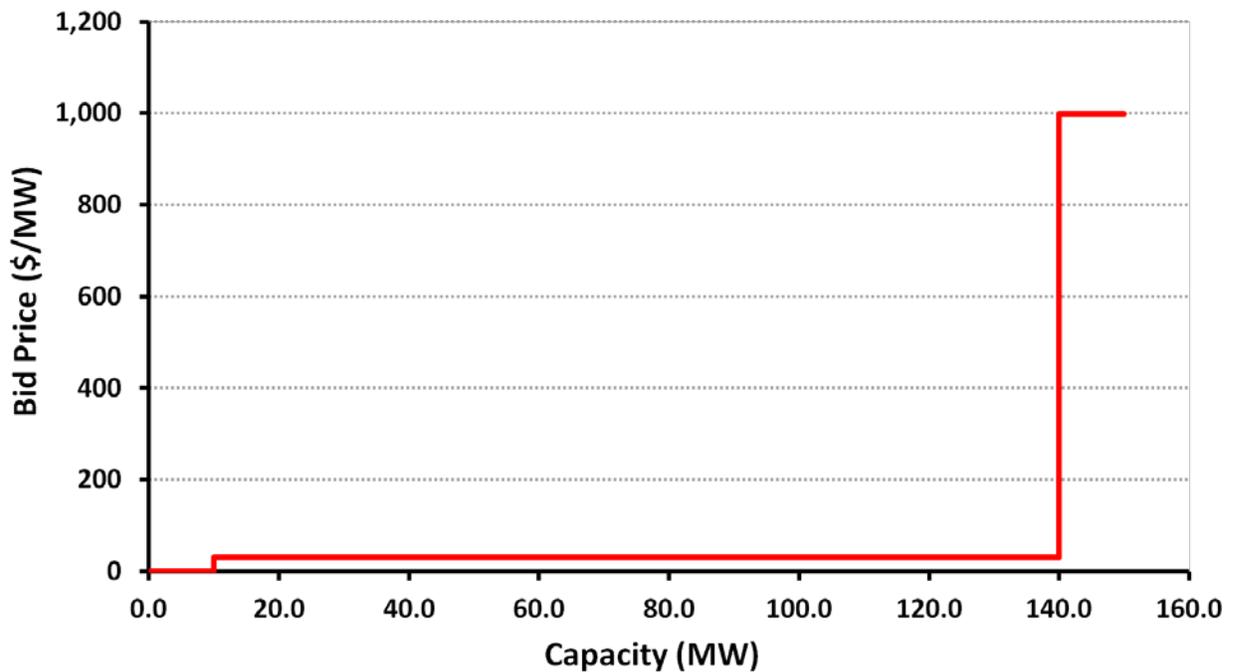


Figure 6.1 Example of a Hockey-Stick Bid Profile Submitted to PJM for a Unit in July 2010

Figure 6.2 is an illustration of a bid submitted to PJM in July 2010, in which all of the bid capacity is offered at the maximum allowable bid price.

Finally, suppliers can submit bids that have large daily offer price fluctuations. Figure 6.3 is an example of this type of bid submitted to the PJM market. The figure shows that on three consecutive days in July 2010, the bid prices for the last block of capacity (from 140 to 166 MW) varied from a low of \$114/MW to a high of \$300/MW. It is difficult to believe that the production cost could vary that widely on three consecutive days.

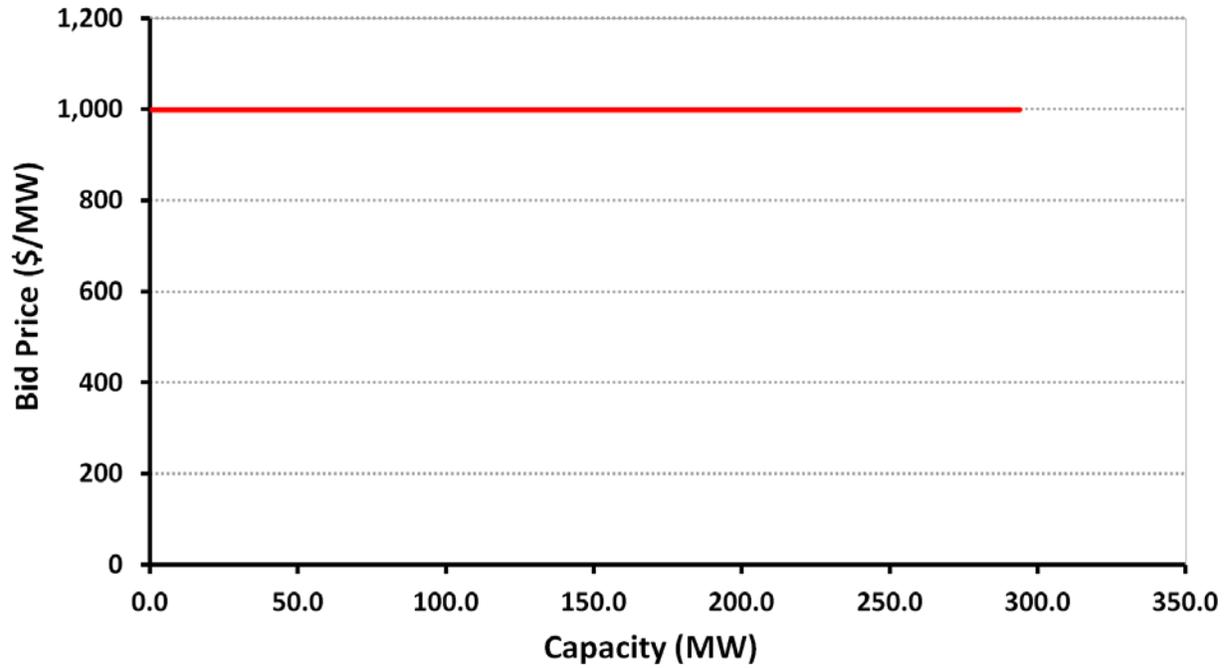


Figure 6.2 Example of an Economic Withholding Strategy Bid Submitted to PJM for a Unit in July 2010

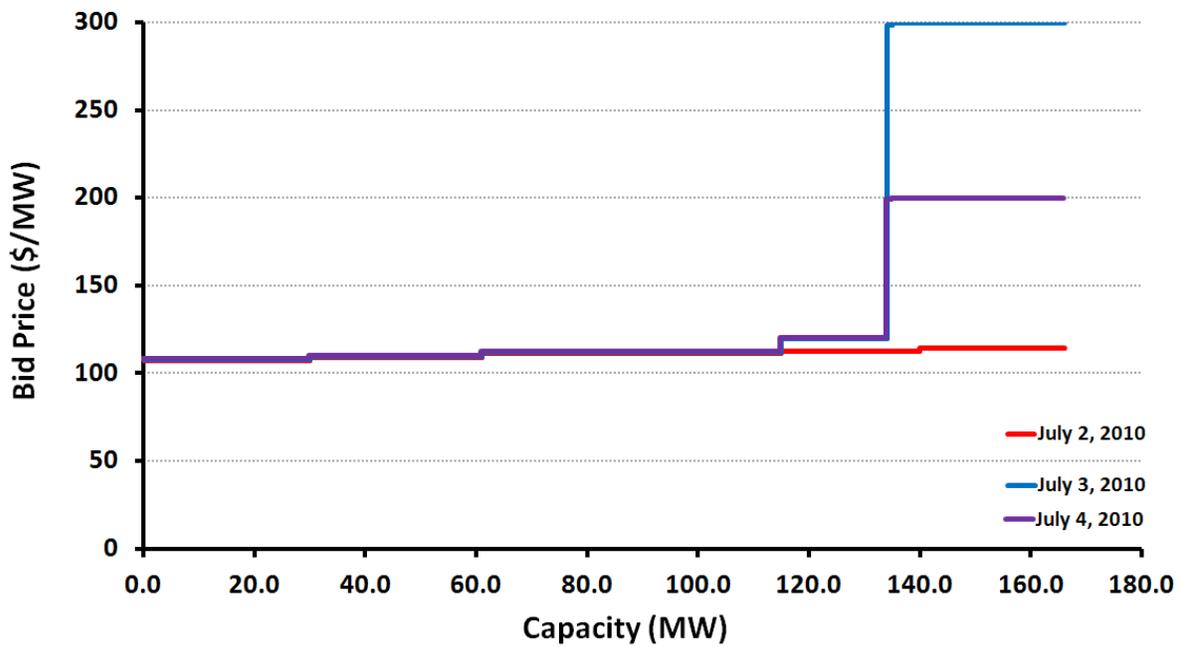


Figure 6.3 Example of Offers with Large Daily Bid Price Fluctuations Submitted to PJM in July 2010

6.3 Importance of Explicitly Specifying Market Rules

The EIM will have wide-reaching consequences that transcend the circumstances of individual market participants. Modeling the perfect market is a good initial step. However, the analysis should be refined when EIM rules are fully defined to assess the “potential” for market participants to exercise market power under specific sets of rules. Potentially, market distortions could more than erase cost savings from lower EIM production costs (i.e., the 0.2% cost savings attributed to more efficient zonal energy transfers). Therefore, a well-designed market that mirrors production costs with high participation and a strong monitoring function is essential to realizing the societal benefit gains projected to result from the EIM. The *WECC Efficient Dispatch Toolkit Cost-Benefit Analysis* report states that “if market design is not carefully considered, the net benefits could be seriously degraded and costs could potentially overrun benefits” (WECC 2011).

Low hydropower conditions, transmission congestion resulting from high levels of variable resources production, unit and transmission line outages, highly concentrated markets, and low reserve margins are just a few of the many factors that can lead to conditions that may allow one or more participants to exercise market power. The ability to exercise market power is not static but can change rapidly over time (in the case of the proposed EIM, every 5 minutes) as the load and resource balances change. In discussions with the SPP market monitor, we understood that the primary role of the monitor is to ensure that participants do not exercise market power. SPP does not require participants to submit production cost bids similar to the assumption in the E3 analysis.

Methods for assessing market power can range from the very simple, such as the Herfindahl-Hirschman Index (HHI)³ applied by the U.S. Department of Justice and FERC, which measures market concentration levels, to the very sophisticated, such as agent-based model systems (ABMSs), which mimic potential behaviors of autonomous interacting agents (i.e., utility systems) in a simulated market (Conzelmann et al. 2004).

We appreciate the rationale for conducting a cost/benefit analysis before market rules are more clearly defined to determine whether implementing an EIM will result in a net societal benefit. However, it is our opinion that market rules are important and followup studies should be performed to make a more accurate estimate of societal benefits after more specific rules have been developed. An analysis that includes specific market rules and approaches in a modeling framework would be very useful to avoid pitfalls in market design because market design flaws can be very difficult and expensive to modify after the market is established.

6.4 Risks to Those Not Participating in a Market

Organizations that are not participating in any electricity market can still be exposed to adverse risks. This section describes two instances where agencies within the U.S. Department of

³ For a definition, see: http://fraser.stlouisfed.org/publications/frb/page/33101/download/66351/33101_1990-1994.pdf.

Energy's Power Marketing Administration were adversely affected by regional electricity markets in which they did not participate.

The first instance occurred during the California "energy crisis" from 2000 to 2001. Although Western's CRSP office did not participate in the deregulated California market, all suppliers throughout WI had an opportunity to provide energy to California.

Figure 6.4 shows a timeline of maximum and minimum market prices at the Palo Verde hub during the 2000–2001 California energy crisis, in which large price spikes began in the spring of 2000 and lasted through the middle of 2001 (Veselka et al. 2010; Joskow 2001). This hub is representative of the market prices for Western's spot market transactions. Although there were many contributing factors to the crisis, poor market design permitted market participants to raise prices above economic levels. As a result of the crisis, Western had no alternative but to purchase energy at very high prices to fulfill its contractual obligations to serve its customers' hourly requests for energy.

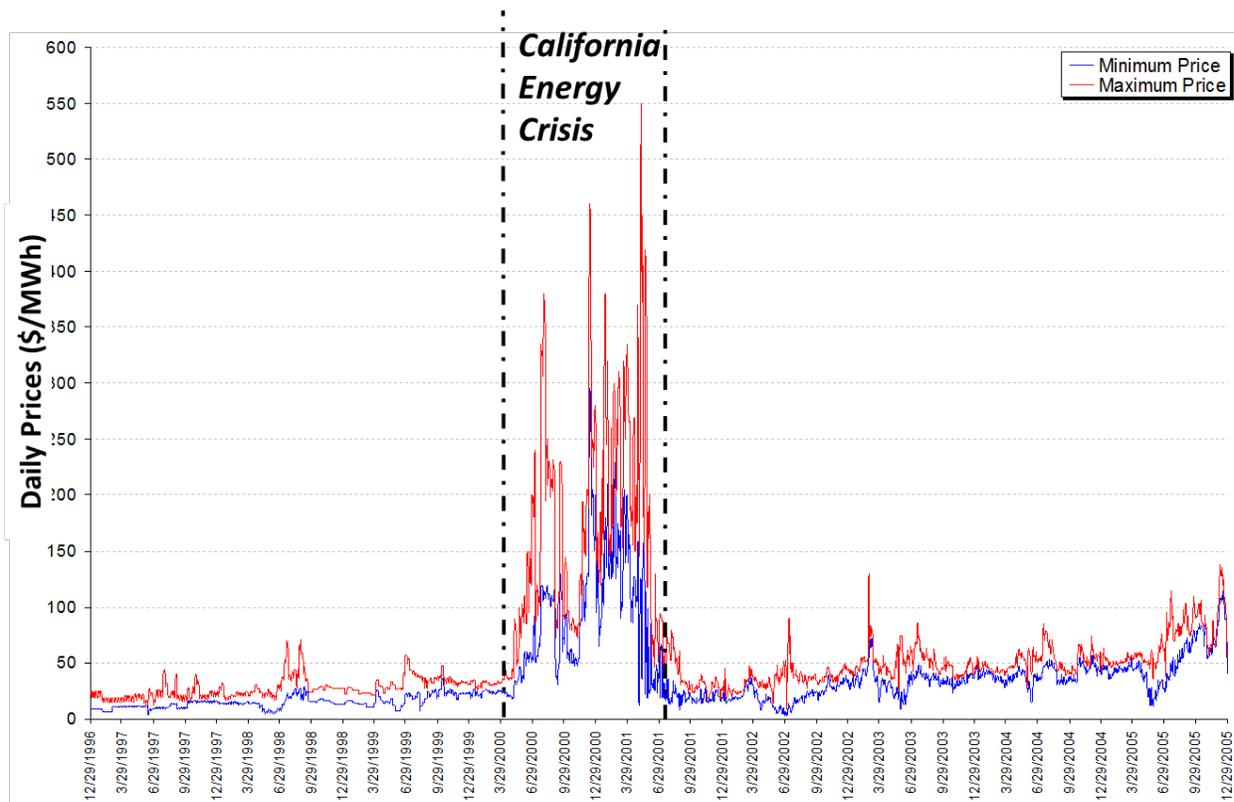


Figure 6.4 Maximum and Minimum Market Prices at the Palo Verde Hub from 1996 to 2005 (Veselka et al. 2010)

The events leading to the California energy crisis are well understood; however, the reasons that caused it are not as clear. The crisis clearly illustrated the influence of markets on

nonparticipants and the need for well-designed markets with strong market monitoring, an early warning system, and vigorous enforcement of market rules.

Another instance of market impacts on nonparticipants involves the effect of the EIS market within the SPP. SWPA is not a participant in that market; yet, after the EIS market was implemented in 2007, SWPA discovered that transmission flows changed significantly from what they were prior to the EIS market. Transmission congestion increased significantly on SWPA-owned lines. To maintain system reliability, SWPA was often forced to reduce generation from its hydroelectric power plants. This reduction in hydro generation required SWPA to purchase power at market prices to serve customers with which it had purchase contracts. Although SWPA had sufficient power at its facilities to serve its customers, it was unable to deliver their power. Because SWPA did not participate in the EIS market, it was not reimbursed for the extra expense of purchasing power to serve its customers (Wech et al. 2011). A more detailed analysis would be needed to determine how Western's ability to serve its customers may be affected by instituting an EIM in WECC.

7 NET SOCIETAL BENEFITS

Although many improvements could be made to the E3 analysis, the following discussion assumes that E3 benefits for the Benchmark and primary EIM Cases are reasonably accurate. Utilicast was commissioned by WECC to estimate the costs of deploying the EDT for both the market operator and market participants (Utilicast 2011). Based on discussion with Western and information in the Utilicast report, it is our judgment that nearly the entire EDT cost will be attributed to the EIM. Functions similar to those that are proposed under the ECC are currently being conducted by the WECC security coordinators with the webSAS tool, which calculates curtailment responsibilities on six qualified paths (Ackerman 2011; WECC 2011). The ECC would essentially expand the functions that webSAS performs over more paths on a source/sink level of granularity as opposed to the current zonal representation. Utilicast estimates ECC startup costs to range from \$0.3 million to \$0.4 million and annual operating costs to range from \$0.1 million to \$0.2 million (Utilicast 2011).

Because of the high degree of uncertainty about future expenditures, Utilicast's EDT cost estimates range widely. Total societal costs for EIM startup range from \$66.61 million (i.e., EDT costs of \$66.91 million less ECC costs of \$0.3 million) to \$339.82 million (i.e., EDT costs of \$340.22 million less ECC costs of \$0.4 million). The annual operating cost ranges from \$80.26 million (i.e., EDT costs of \$80.36 million less ECC costs of \$0.1 million) to \$260.21 million (i.e., EDT costs of \$260.41 million less ECC costs of \$0.2 million). Ignoring startup costs and taking the midpoint of the annual market operating cost range yields a societal cost of about \$170.24 million. This amount exceeds the societal benefits estimated for the primary EIM Case for the year 2020 by approximately \$28.8 million; that is, the EIM Case yields a negative societal benefit. Adding startup expenditures would increase societal losses even more.

It should be noted that Utilicast estimates are separated into market operator and participant costs. Market operator costs for EIM operations range from \$33.9 million to \$128.9 million. The lower end of the range would be the approximate cost for an existing entity to operate the market. Assuming a midrange value for participant costs and the cost of EIM operations by an existing entity, net societal benefits for the more efficient dispatch in 2020 would be approximately \$19 million, excluding start-up costs (i.e., net production cost savings of less than 0.1%). Based on the E3 sensitivity analyses, benefits could potentially be either lower or higher than the levels presented here.

The WECC cost/benefit study also analyzed economics in terms of net present value (NPV). If the Reduced BA Participation Case is ignored because it has the lowest estimated benefits, the study estimates that EDT net societal benefit ranges from a net benefit of \$941 million to a net cost of \$1,250 million. The NPV calculation covers the time period starting in the beginning of 2012 through the end of 2024. During the first three years, it was assumed that the market would not operate, but EDT startup costs were incurred. At the high end of the range, benefits from the CO₂ Sensitivity Case (highest benefit case), in combination with the low end of the cost range, were used. At the other end of the spectrum, the primary EIM Case is paired with the high-cost range.

Examining the NPV of EDT net benefits for the primary EIM Case, the range is from a net benefit of \$333 million to a net cost of \$1,250 million. The midpoint of the range is a net cost of about \$459 million.

8 ALTERNATIVES TO AN EIM

In addition to the proposed EIM structure, we highly recommend that other market alternatives and cooperative programs be examined with the goal of maximizing net societal benefits with low risks. A current activity in the WI region that is developing and implementing a number of transmission scheduling alternatives is the Joint Initiative Program (JIP). The JIP is a collaborative effort by Columbia Grid, Northern Tier Transmission Group, and WestConnect to develop high value market solutions. Four potential alternatives that may be less expensive than an EIM and yield considerable cost savings are the Dynamic Scheduling System (DSS), Area Control Error Diversity Interchange (ADI), Intra-Hour Transmission Scheduling (I-TS), and the Intra-Hour Transaction Accelerator Program (I-TAP), as briefly outlined below. The benefits of these techniques were not included in the Benchmark Case. The potential benefits of balancing area consolidation and employing more centralized coordination of the scheduling and dispatch of system-wide resources (similar to current procedures in ISO/RTO markets in other parts of the United States) should also be considered in the overall evaluation of deploying different market alternatives within WI.

8.1 Dynamic Scheduling System

The DSS facilitates a more efficient method of establishing a dynamic signal between two BAs. After establishing a communication link to the central DSS server, a participant can share a dynamic signal with any other participant who has a link to the DSS server. This approach allows participants to avoid extensive set-up costs and the time (typically months) required to establish a dynamic schedule with each entity with whom they want to share a dynamic signal. The DSS is currently being used by 18 utility companies in WI (Montoya 2011).

8.2 Area Control Error Diversity Interchange

The ADI method distributes the diversity of the individual participants' area control error (ACE) among the group to cancel opposing ACE values and reduce the amount of generation unit control movement that would be required for each participant to meet the generation control requirement independently (VanCoevering 2008). Pooling the positive and negative ACE values limits the amount of regulation deployed to maintain NERC Control Performance Standards. ACE diversity interchange programs are already used by several participants within WI. There is a pilot program under way in the WI that includes eleven (11) participating BAs. The results of their initial tests have been very positive (Austin 2011).

8.3 Intra-Hour Transmission Scheduling

The I-TS is an effort by BAs and transmission providers to modify existing business practices so as to implement mid-hour scheduling. Any new schedules, or changes to existing schedules, must be submitted 15 minutes after the hour so the new schedule can begin on the half

hour. This initiative is not intended to create a 30-minute bilateral market but rather to address the occasional need for intra-hour balancing energy that can result from large changes in loads or resources. Currently, many BAs in WI have updated their business practices, but I-TS usage has been very limited (Montoya 2011).

8.4 Intra-Hour Transaction Accelerator Program

The Intra-Hour Transaction Accelerator Program, which is currently being implemented in parts of WI, is an Internet-accessible bulletin board “hub” or meeting place that links existing trading systems via the new I-TAP hub software and hardware to enable high-speed, real-time transactions (Joint Initiative Products and Services Strike Team 2009). The I-TAP system will provide an enhanced level of transaction speed and efficiency while providing a unique and broad view of power products available throughout WI. It should also be noted that the I-TAP uses OASIS (the Open Access Same-time Information System) to ensure that capacity is available on a transmission pathway between where the buyer and seller are located on the grid (Ackerman 2011). I-TAP is not intended to be a centralized market. All participation is voluntary, and all transactions are bilateral deals between the individual parties.

I-TAP will facilitate intra-hour trading among participating entities and thereby contribute to lowering the cost of integrating variable resources, helping meet reliability standards and avoiding expensive sanctions, and lowering the need for imbalance energy and associated charges (Joint Initiative Products and Services Strike Team 2009).

8.5 ISO/RTO Market Structure

The potential benefits of introducing more comprehensive centralized system operations, similar to the current ISO/RTO markets in the Eastern Interconnection and Texas, should also be considered. When it comes to integration of renewable energy, these benefits include large balancing authority areas, centralized unit commitment and scheduling, frequent dispatch of resources, and locational market incentives through LMPs (Botterud et al. 2010).

It is worth noting that the neighboring SPP system is currently moving toward implementing a day-ahead market with improved system-wide unit commitments (SPP 2012); this market structure is similar to that of the PJM market. In the current EIS market structure, BAs are required to have adequate capacity online at all times to meet load. This requirement somewhat diminishes the economics of the SPP EIS, because plants sometimes operate at minimum generation levels while EIS purchases serve load.

9 CONCLUSIONS AND RECOMMENDATIONS

There is a subtle yet very important distinction between how the GridView model is applied in the E3 study as compared to the method that is used in other types of modeling applications (e.g., BOR 2007). Because resolving differences between actual and modeled operations is extremely difficult, the impacts of an alternative operational scenario are often estimated by comparing an “imperfectly” modeled reference scenario to an “imperfectly” modeled change case. In effect, it is a measure of the system’s sensitivity to the changed operation in an “apples-to-apples” comparison. In the EIM study, benefits are based on a Benchmark model run that is calibrated to match a single historical criterion (i.e., interzonal flows). Because in many respects the Benchmark run does not accurately reflect actual conditions, it should not be used as the starting point from which alternative cases are measured.

The analysis conducted by E3 estimates a potential savings of about 0.68% that could be attributed to EIM improvements in grid operation. At this point, we argue that the estimate is highly uncertain given the modeling assumptions that were made and the methods that were employed in conducting the analysis. Furthermore, it is difficult to assess whether the estimate is too high or too low, given all of the complexities involved. To compute the EIM’s net societal benefits, the costs to create, administer, and operate the market are subtracted from the savings. This net societal benefit should be weighed against the risks associated with introducing the EIM.

In this report we point to several improvements that could be made to the EIM analysis. The current set of tools and available data are a good step towards this goal. However, in our opinion, enhancements to the modeling process can be made that will improve these estimates; namely, a better representation of flexibility reserves and a more robust energy market simulation and optimization tool with a 5-minute time step. However, even with a 5-minute time step, some major issues will take significant time and resources to resolve. We note that many of the issues described in this report were discussed in EIM documents authored by E3 but simplifications were needed in order to complete the analysis under both time and budget constraints.

The need for additional studies is highlighted by the fact that only a very high-level conceptualization of the EIM had been formulated at the time the analysis was conducted. In order to assess the EIM and associated risks more accurately, the scope of the market(s) (e.g., how flexibility reserves will be handled) and specific market rules need to be clearly defined and adequately represented in the modeling process wherever possible. It is our opinion that once market rules are more clearly defined, EIM estimates of potential benefits and costs should be reevaluated.

We also suggest that sensitivity analyses be conducted to verify the validity of key modeling assumptions. We realize that sensitivity analyses can take a lot of time and resources and we do not suggest that all possibilities be simulated in detail. However, we recommend that some sensitivity analyses be conducted on key assumptions for a small set of hours/situations (on-peak, off-peak, shoulder), to gain a better appreciation for the impact of an assumption on the

overall result. It is our opinion that hydropower is one area where sensitivity analysis is particularly important.

The EIM evaluation process also needs to increase the involvement of BA operators, schedulers, and marketers so that a clearer picture of the day-to-day issues that they face can be more clearly understood in the context of the EIM. Although modeling challenges exist, models can still be very useful and should not be abandoned. When applied and interpreted properly, models provide a means of learning and gaining insights into potential problems that would not otherwise be uncovered. However, we should not put too much emphasis in the exact numbers that the models produce; rather, emphasis should be placed on the insights that emerge through the modeling process. Ultimately, the decision to implement an EIM will boil down to a judgment call that should involve all stakeholders, including the individuals who are responsible for keeping the grid whole. To this end, modeling will help make more informed decisions.

In short, there are substantial economic and equity implications of the proposed EIM; therefore, decision makers should not adopt it in haste before it is fully investigated from a wide range of perspectives. We hope that some of the issues and proposed improvements raised in this report will be taken into consideration in the next phase of the EIM analysis.

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APPENDIX A:

**MODELING ASPECTS THAT MAY CONTRIBUTE TO ZONAL FLOW
DIFFERENCES BETWEEN EIM MODELED AND ACTUAL 2006 ZONAL FLOWS**

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APPENDIX A:

MODELING ASPECTS THAT MAY CONTRIBUTE TO ZONAL FLOW DIFFERENCES BETWEEN EIM MODELED AND ACTUAL 2006 ZONAL FLOWS

Some portion of the differences between modeled and observed 2006 flows among Western Interconnection (WI) zones defined in the cost/benefit analysis of the Western Electricity Coordinating Council's (WECC) proposed Energy Imbalance Market (EIM) is attributed to the models, methods, and data that were used to estimate the societal benefits that could occur if the EIM were implemented. Therefore, the flow differences should not all be assigned to market inefficiencies under the current bilateral market structure. Model simplifications that can lead to differences in interzonal flows are described in detail below.

A.1 Linear Representation

GridView primarily uses linear programming (LP) modeling techniques to determine the least-cost dispatch in WI. This modeling framework requires that all model components of an LP problem formulation are represented as a set of continuous linear equations. This set of equations includes generation, transmission, and demand components. Because most aspects of individual grid elements and the behavior of the system as a whole are nonlinear, LP models use linear approximations, including key representations, such as heat-rate curves of thermal power plants and power flows through transmission lines.

Typically, thermal power plants operate most efficiently when running at the designed capacity. At lower levels of operation, the plants run less efficiently and therefore have higher production costs. In order to approximate heat-rate curves, GridView divides the unit into a maximum of seven capacity blocks, with each capacity block assigned a unique heat rate.

In addition, heat-rate curves are not static but change as a function of variables, such as atmospheric temperature and pressure. Gas-turbine technologies are especially sensitive to atmospheric conditions. GridView did not take these heat-rate factors into consideration in any of the simulated cases.

Furthermore, thermal generators, especially those that utilize steam as the primary mover, cannot generate power below a minimum level. Therefore, the unit must either be off or operate at or above the minimum level. Once a unit is turned off, the time and expense it takes to return that unit to an operational state are important economic variables. This noncontinuous technical limitation cannot be represented in a model that is strictly formulated with linear equations.

In order to keep solution times reasonable, GridView uses heuristics to determine when each unit will be in an operational mode during the next simulated day; that is, it predetermines which units will be operating at or above the minimum generation level in any hour prior to the final dispatch run. Although a well-designed heuristic method provides a reasonable unit commitment result, it is not guaranteed to produce the best mathematical solutions. It should be noted that simplifying assumptions need to be made when optimizing unit commitments during actual

operations. Tools used for this purpose have typically been developed, applied, and improved upon over years of actual operational experience. Therefore, GridView uses a nonlinear approximation methodology to estimate future unit commitments, that is, when each unit will be either on or off during a specified (e.g., 24-hour) period. The unit commitment schedule is then used to constrain the GridView LP dispatch. For each hour, units that are online are constrained to generate at a minimum or maximum generation level, whereas units that are off-line do not generate power.

Finally, because an LP technique is used to optimize a security-constrained dispatch that accounts for transmission constraints and contingencies, the transmission system is modeled using a simplified or linearized representation of power flows (oftentimes known as “dc power flow”) rather than a more rigorous, nonlinear representation (known as “ac power flow”). A linear power flow representation cannot rigorously address voltage stability issues that arise when power systems have long transmission line distances between generation resources and load centers.

Further complicating the situation is the fact that grid operators alter the topology of the transmission system to relieve transmission congestion by opening and closing a multitude of circuits — typically on lower voltage lines. Modeling the decisions for relieving congestion is a very difficult task; it can be modeled by using integer programming techniques but not LP techniques.

A.2 Unit Production Costs

GridView performs a unit dispatch based on costs (or bids) and limitations placed on both unit and transmission components. Unit-level production costs input to GridView are the sum of fuel costs and nonfuel variable operation and maintenance costs, including costs to operate pollution control devices (i.e., their energy usage and/or reagent costs). Fuel costs, which are dependent on a unit’s heat-rate curve and fuel price, typically account for the majority of the total production cost. In addition to the fuel consumed while they are operating, some units (e.g., coal-fired steam technologies) may consume considerable amounts of fuel during startup and to keep them warm while in an “off” state.

Consistent with LP formulations, GridView disaggregates a generating unit into a maximum of seven capacity blocks. The first block, which is set to the minimum generation level, is the least efficient. Each successive block is assigned a single efficiency such that the efficiency is increasingly higher (i.e., has a lower heat rate than that of the previous block) and therefore is less expensive to operate as production levels increase. It should be noted the GridView uses incremental heat rates for each block. The end product is a piecewise linear function that approximates the actual heat-rate curve.

In addition to the challenges in modeling heat-rate curves, there are significant challenges associated with obtaining heat-rate data for thermal units. Much of the unit-specific heat-rate and fuel price data are proprietary. Therefore, E3 used generic heat rates and regional fuel costs. This approach results in a model with “lumpy” zonal supply curves in which a small change in market prices under some circumstances may result in a rather large swing in zonal energy transfers. On

the other hand, under some conditions, relatively large changes in prices may result in little or no change in zonal energy transfers. In reality, diversity among generation units within a zone leads to supply curves that are typically smoother than the ones represented in the EIM analysis.

A.3 Unit Commitment Data

As stated above, GridView uses a nonlinear approximation methodology to determine when each unit will be either operational or taken off-line in the optimal LP dispatch. Typical unit commitment algorithms require information about both warm and cold start-up costs, shut-down costs, and both minimum up and down times. Similar to fuel prices, these data at the unit level are usually proprietary. Therefore, GridView uses generic information. However, in actual operations, these parameters can vary widely among units that fit into the same category (e.g., large coal-steam).

A.4 Resource Availability

GridView uses a single Monte Carlo draw to simulate forced outages during generation and transmission. Forced outage rates are assigned to units on the basis of information contained in the Generating Availability Data Set (GADS), which is available through the North American Electric Reliability Corporation (NERC). The outage rate that is assigned to a generating unit is based on the general category into which it falls. This methodology is commonly used in economic dispatch models.

A GADS outage rate assigned to a unit may differ from the actual 2006 rate because GADS values are representative for a generator category; that is, it is not the actual outage rate for an individual unit. Using the GADS information, a suitably selected random draw will yield statistics that are consistent with historical outages within and across each category. However, it is highly unlikely that it will produce outage times and dates that actually occurred in 2006. Differences in unit outages between historical events and model simulations contribute to flow differences in zones. For the nuclear plants and the 13 largest coal plants, E3 used actual historical outages for 2006 rather than a random draw based on outage rates for the hurdle rate benchmarking process.

In addition to forced outages, units are also taken off-line for scheduled maintenance. GADS also contains statistics on these events by generation category. The same observations made above for forced outages apply to scheduled outages. However, these outage events are “scheduled” by GridView and are not based on a random draw. Typically, these outages are scheduled during periods of the year that have lower demand, for example, spring and autumn. From a modeling standpoint, the optimal economic schedule over the entire EIM footprint requires coordination among all units in the grid, such that the increased annual dispatch cost from taking units off-line is minimized. In reality, many other scheduling issues, such as the availability of parts, skilled crews, and equipment, are also important. In addition, maintenance schedules are determined at the company level to meet corporate objectives. These factors often conflict with an outage schedule that is optimized for the larger footprint, which implies that all resource operators would cooperate in maintenance scheduling.

The Transmission Expansion Planning Policy Committee (TEPPC) base case, which is used for the E3 analysis, does not include transmission outages. TEPPC documents indicate that maintenance outages typically occur during off-peak hours, with minimal impact on market prices, and forced outages occur infrequently.

A.5 Hydropower Representation

Hydropower generation accounts for about one-third of total power production in WI. In WI's northwest region, almost two-thirds of the generation is produced by hydropower. On the other hand, hydropower accounts for only 9% of the generation mix in the Desert Southwest Region. Hydropower is therefore a key component of grid operations in WI. This heavier reliance on hydropower represents a challenge to modelers because the characteristics of hydropower production differ significantly as compared to those of thermal power production.

Hydropower operations are a function of the amount of water stored behind the dam and temporal inflow variations. Each hydropower plant is unique in that it is subject to site-specific constraints related to not only the physical characteristics of the dam and power plant but also the associated reservoir characteristics (where applicable) and downstream environmental objectives. In addition, water basins and reservoirs are multipurpose resources that include nonpower uses, such as flood control, irrigation, municipal and industrial use, and recreation. Management of water resources for these nonpower uses is typically given a high priority.

Unlike most thermal units, generation produced by a hydropower plant is limited by water availability. Optimization of hydropower resources therefore involves the release of limited water supplies when it has the highest value to the grid. These releases are constrained by numerous limitations and operational practices, which are imposed on the dam and power plant and in downstream river channels. Each hydropower plant and associated reservoir is unique.

The hydropower representation in GridView is relatively simplistic. However, it is superior to most other similar models. It uses an iterative process to approximate hydrothermal coordination (HTC) given monthly energy, capacity, and operational ramping constraints. The HTC objective is to minimize locational marginal prices (LMPs) in the model.

However, the HTC methodology was not universally applied to all hydropower resources. For the Colorado River Storage Project (CRSP), hourly generation levels for all major hydropower plants were set equal to the actual 2006 hourly generation in both 2006 and 2020 and in both the Benchmark and EIM Cases. That is, it was assumed that generation did not respond to the altered vector of market price signals simulated under the EIM, nor to the introduction of much greater amounts of variable generation, such as wind and solar.

This methodological approach may have been taken by E3 given that the modeling of reservoirs, such as Glen Canyon Dam, is very complex. Reservoir operating constraints include two different minimum release levels (one for daytime hours and another for nighttime), maximum up and down hourly ramp rates, and restrictions on the daily range of releases.

The CRSP system also contains a tightly coupled cascade whereby operation among power plants is highly interdependent; that is, releases from one hydropower plant affect the operation of other plants in the cascade, not only at a given instant but over time. The CRSP Aspinall Cascade has generating units at the Blue Mesa, Morrow Point, and Crystal Reservoirs. Releases from Crystal are mandated to be constant for downstream water requirements. It also has a relatively small reservoir that is subject to stringent water-level constraints that span several days. These restrictions constrain operations at Morrow Point, the upstream power plant, in order to ensure that inflows into Crystal keep reservoir elevations within specified limits.

Another complicated operational regime is at the CRSP Flaming Gorge Power Plant located on the Green River in Northern Utah. Not only does it have operational constraints imposed on water releases in terms of minimums and hourly ramping, but it is also constrained by downstream environmental objectives. Hourly releases must be made such that water levels at a gauge located more than 60 miles downstream in Jensen, Utah, remain within a 0.1-meter range each day. This constraint is further complicated by the Yampa River water flows that empty into the Green River between the reservoir and gauge.

The CRSP system exemplifies operational limitations and modeling challenges that affect the WI dispatch. Armed with actual detailed information and a long history of operational experience, it is challenging for an operator to optimize a single hydropower plant or project. GridView must optimize all hydropower plants in the entire EIM footprint while simultaneously accounting for thermal system interactions and transmission constraints. Therefore, by necessity, simplifying assumptions were made in GridView.

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APPENDIX B:

**COMPARISON OF 2006 MONTHLY THERMAL POWER PLANT
GENERATION AND GRIDVIEW MODELED RESULTS**

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**COMPARISON OF 2006 MONTHLY THERMAL POWER PLANT
GENERATION AND GRIDVIEW MODELED RESULTS**

Energy and Environmental Economics, Inc. (E3) calibrated the GridView run for the Benchmark Case such that the overall average annual power flow on 17 monitored WECC transmission paths were very similar (within 0.1%) to actual 2006 values. This single calibration criterion may not be sufficient. We found several instances in which monthly thermal power plant generation levels differed from historical levels.

In order to make historical comparisons, we first calculated total unit-level GridView monthly generation using hourly model results for the year 2006. Next, we examined historical 2006 generation contained in the Energy Information Administration (EIA) Form EIA-906 (EIA Form 906). This form provides historical plant-level generation by fuel type and primary mover. The final step in the process adds GridView monthly results for units that match EIA-906 prime mover descriptions.

We did not perform an exhaustive comparison of all thermal power plants in WI. Instead, we focused on a few power plants with locations that are either in balancing authorities (BAs) operated by the Western Area Power Administration (Western) or are directly relevant to Western's operation. Western operates both the Western Area Power Administration – Lower Colorado (WALC) BAA and the Western Area Power Administration – Colorado-Missouri (WACM) BAA. We also examined a few power plants outside these two BAAs. This review included plants that are associated with the Western power exchange with Salt River Project (SRP) and the Palo Verde Nuclear Generating Station, which is located at a major electricity trading hub used by Western.

We also graphed hourly GridView generation results for a few other thermal generating units. Although we do not have historical hourly generation for any thermal unit, we note that operations at some units have generation patterns that appear to differ significantly from standard operations.

Figures B.1 through B.19 show historical and monthly comparisons, along with modeled hourly generation patterns produced by GridView. In general, we find that for those unit types examined, the historical and modeled monthly generation levels are in relatively close agreement for large coal-fired units. These units typically have relatively low production costs and are therefore loaded first in the dispatch order. Smaller units and those that primarily consume natural gas are more expensive to operate and therefore are loaded after large inexpensive coal-fired units. When the operation of these units is modeled, monthly generation often differs from historical levels.

There were several instances where unit generation patterns differed significantly from standard operations. The first instance is shown in Figure B.2 for unit 2 of the Palo Verde Nuclear Power Station. The simulated output during a week in January 2006 for this unit shows

several large ramping events in excess of 500 MW in just two hours. Such large spikes occurred in several months in 2006; namely, January, February, November, and December. Nuclear power plants would not and cannot be operated with large power swings in a short time period.

We don't expect modeled hourly generation to exactly match historical levels. However, we would expect that the patterns reasonably reflect physical operating constraints. We also found that plants/prime mover classes that are typically on the margin had the largest monthly generation error (i.e., 2006 monthly actual versus modeled generation). Correctly identifying marginal units are critical when estimating economic costs between two cases. Additional evidence should be given to verify the claim that overall societal benefits are expected to be relatively accurate. Also, in this application marginal changes in societal benefits are more important than overall benefits.

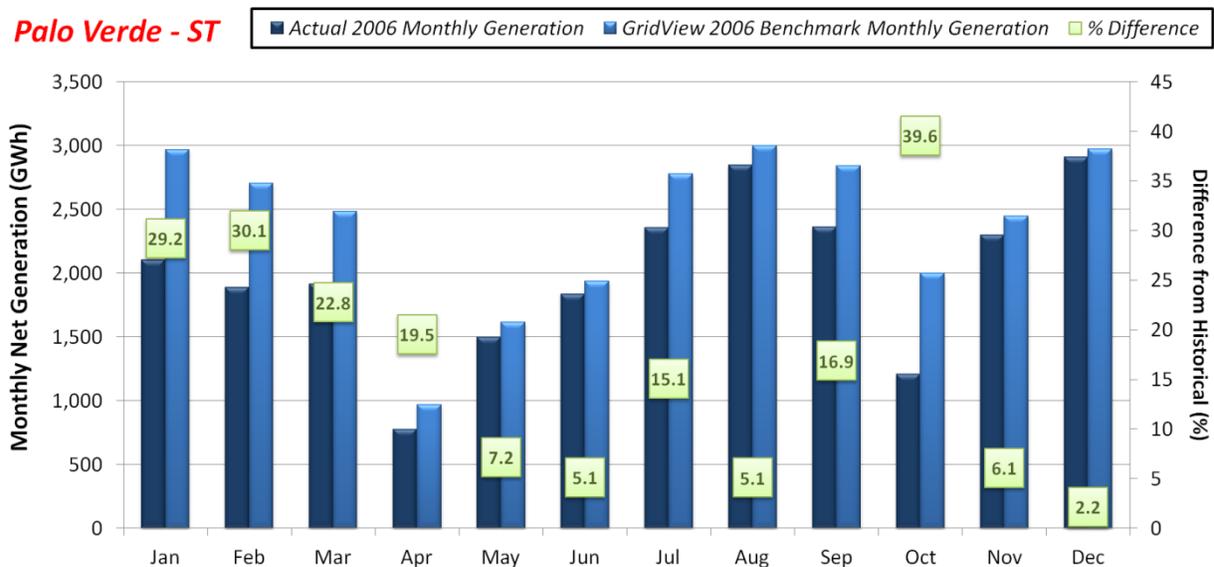


Figure B.1 Actual versus GridView Modeled 2006 Net Monthly Generation for Palo Verde Large Nuclear Steam (ST) Units (Major Trading Hub Used by Western)

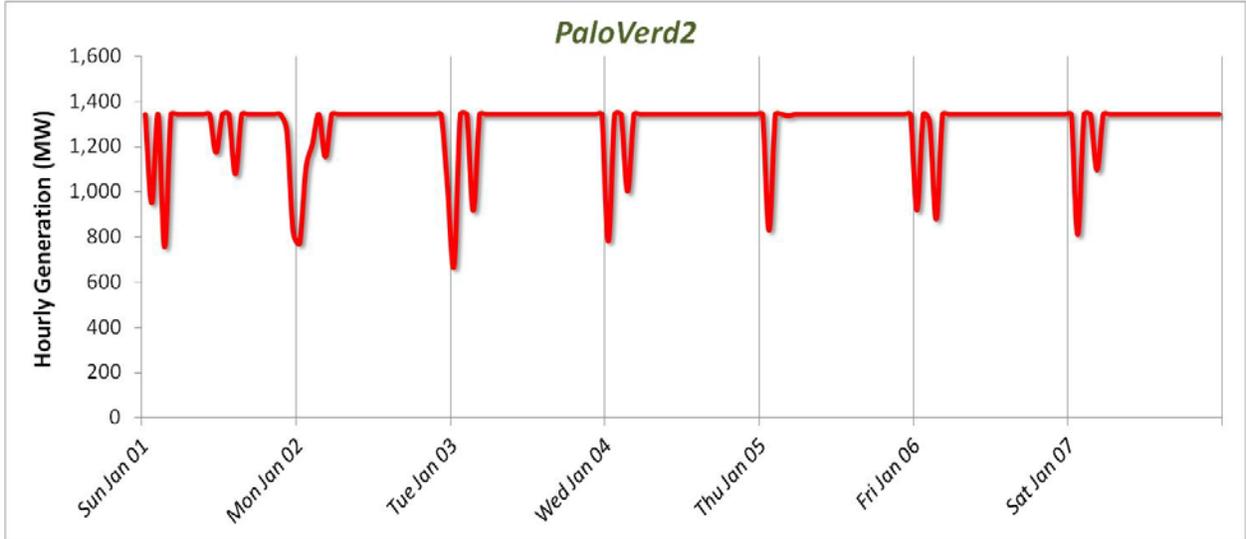


Figure B.2 Palo Verde Nuclear Unit 2 Modeled Hourly Generation for a Week in January 2006

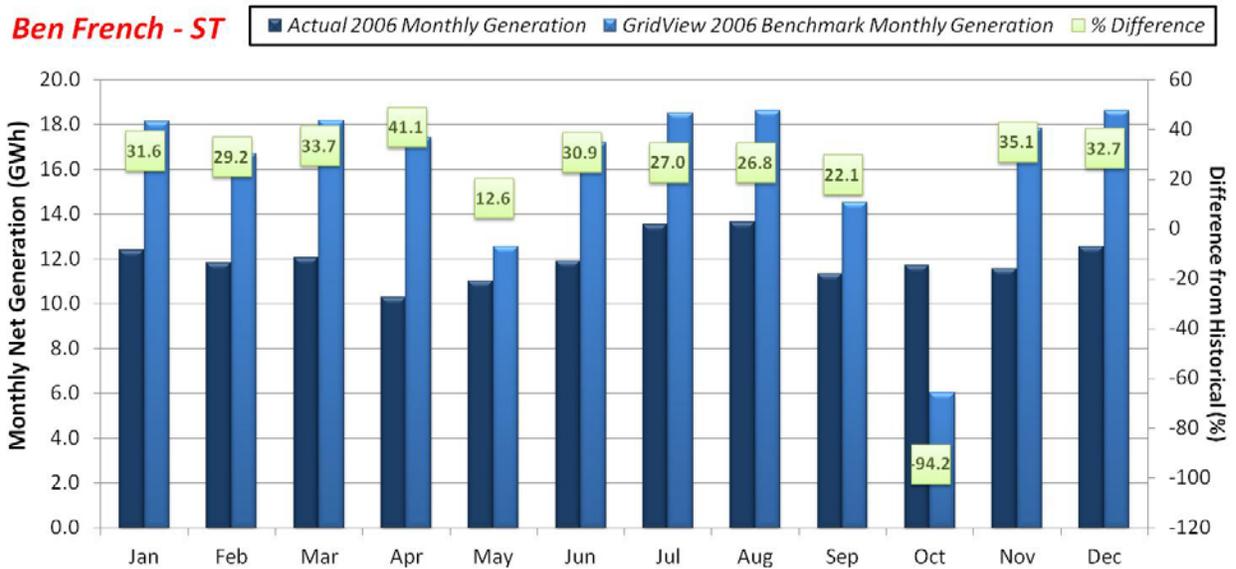


Figure B.3 Actual versus GridView Modeled 2006 Monthly Net Generation for the Ben French Small Coal-fired Steam Unit Located in the WACM BA

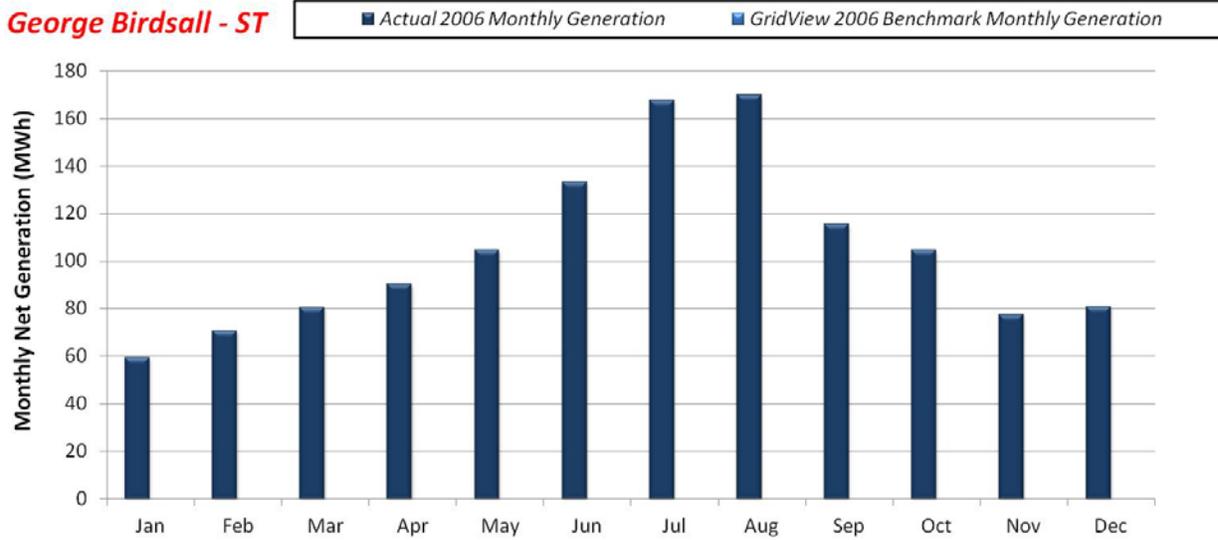


Figure B.6 Actual versus GridView Modeled 2006 Monthly Net Generation for George Birdsall Small Natural Gas-fired Steam Units Located in the WACM BA

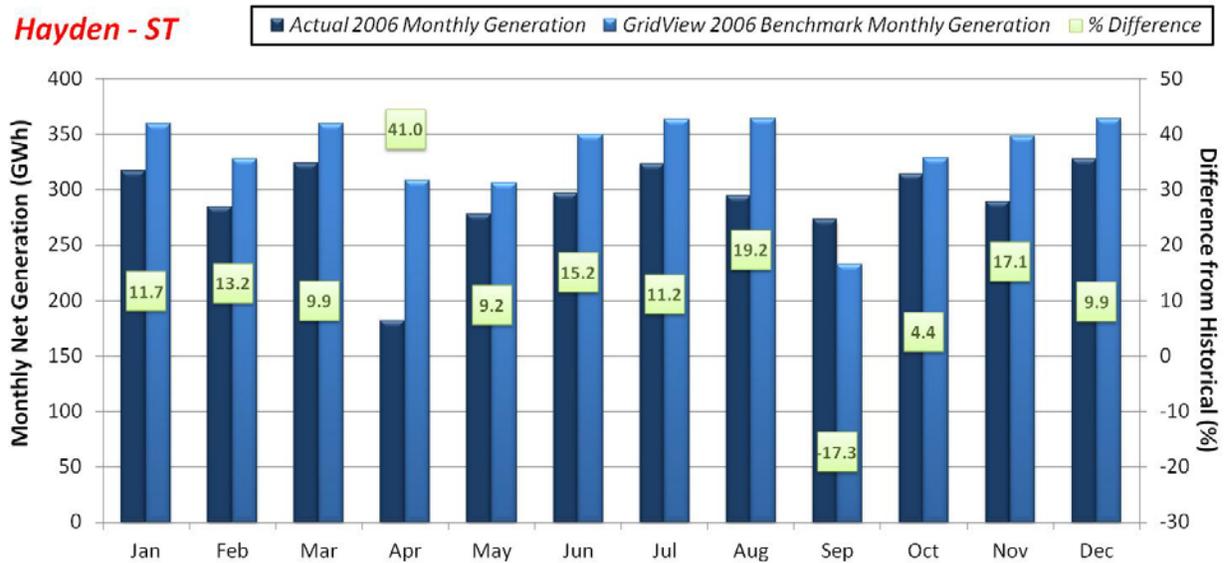


Figure B.7 Actual versus GridView Modeled 2006 Monthly Net Generation for Hayden Large Coal-fired Steam Units Located in the WACM BA

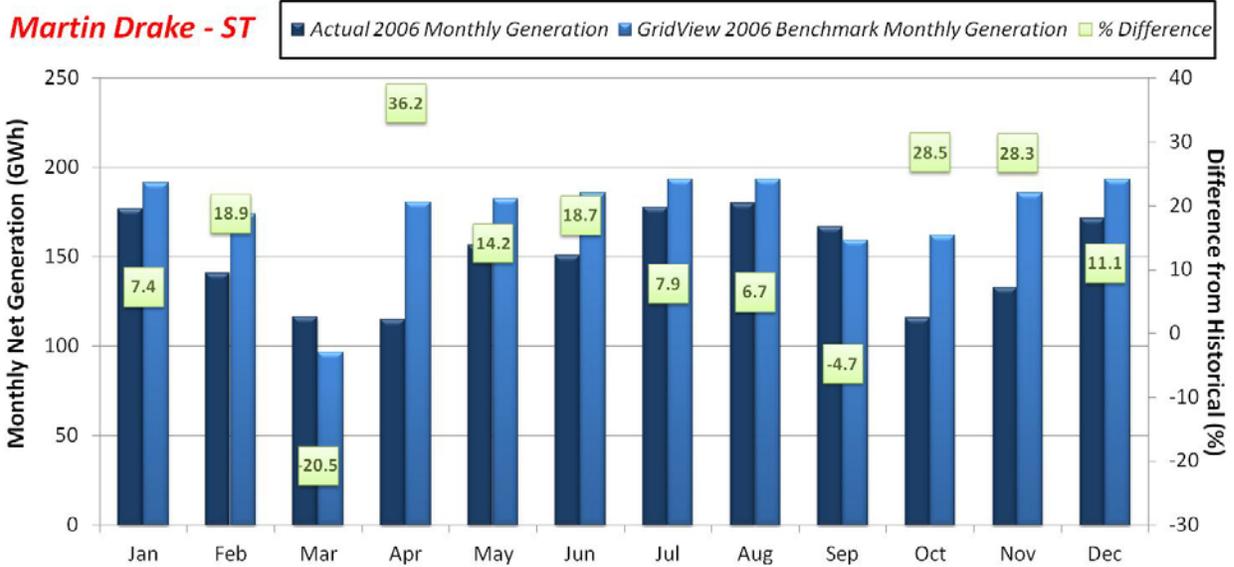


Figure B.8 Actual versus GridView Modeled 2006 Monthly Net Generation for Martin Drake Small Coal-fired Steam Units Located in the WACM BA

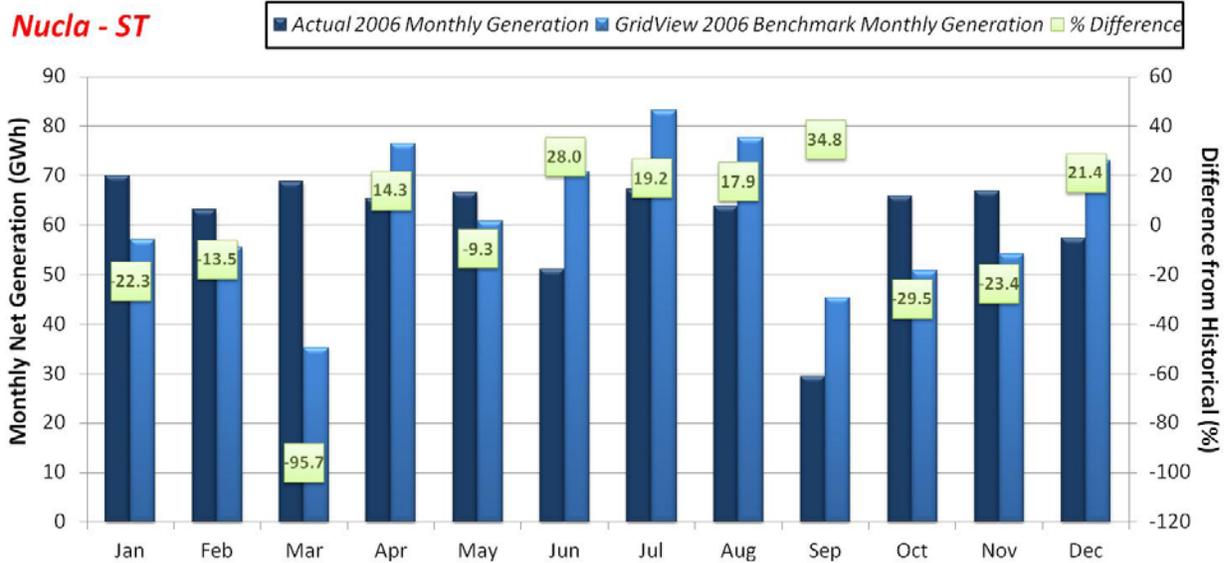


Figure B.9 Actual versus GridView Modeled 2006 Monthly Net Generation for Nucla Small Coal-fired Steam Units Located in the WACM BA

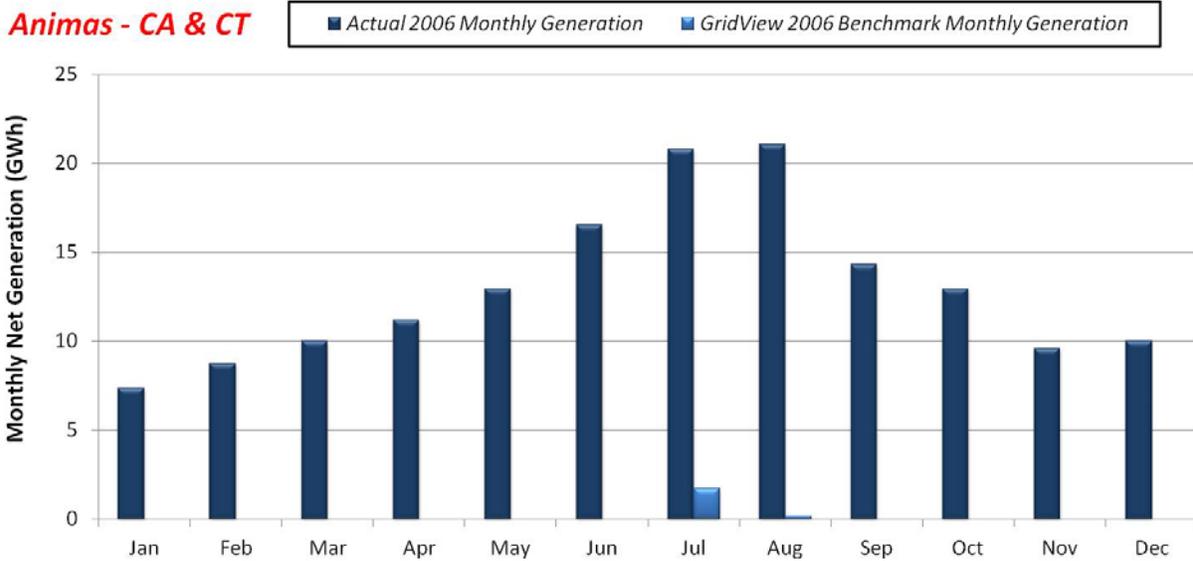


Figure B.12 Actual versus GridView Modeled 2006 Monthly Net Generation for the Animas Combined Cycle Unit Located in the WALC BAA that includes Steam Turbine (CA) and Combustion Turbine (CT) Components

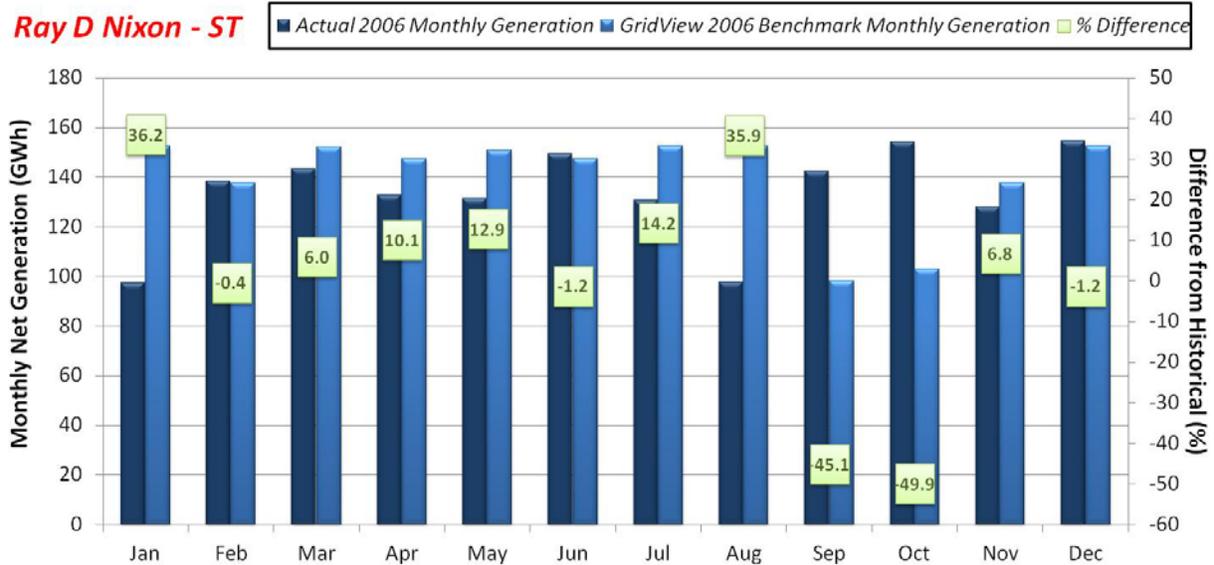


Figure B.13 Actual versus GridView Modeled 2006 Monthly Net Generation for the Ray D. Nixon Large Coal-fired Steam Unit Located in the WACM BA

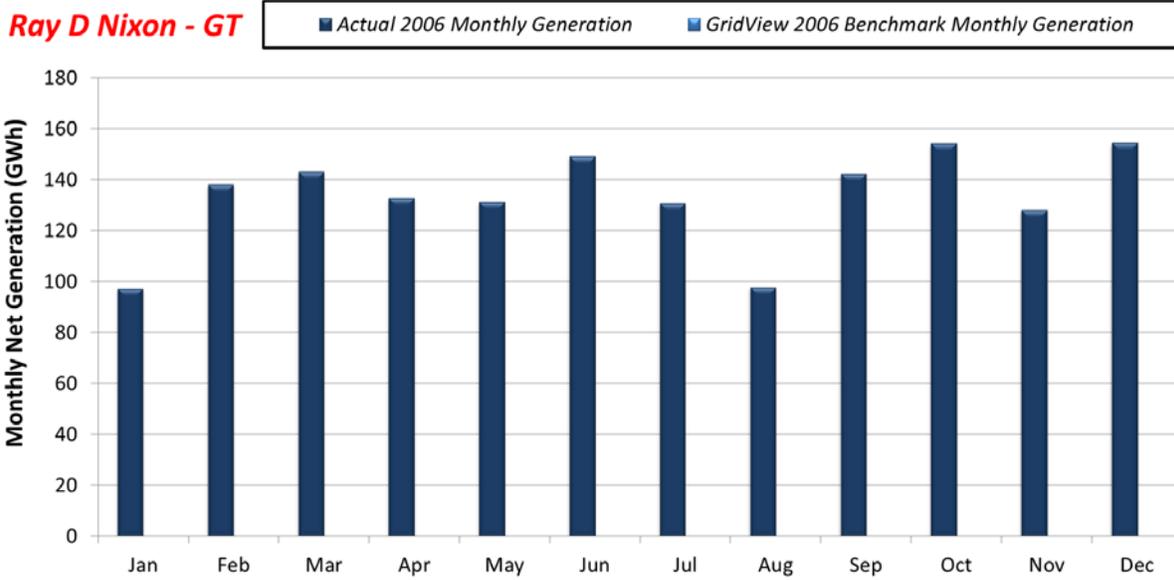


Figure B.14 Actual versus GridView Modeled 2006 Monthly Net Generation for the Ray D. Nixon Natural Gas-fired Gas Turbine Unit Located in the WACM BA

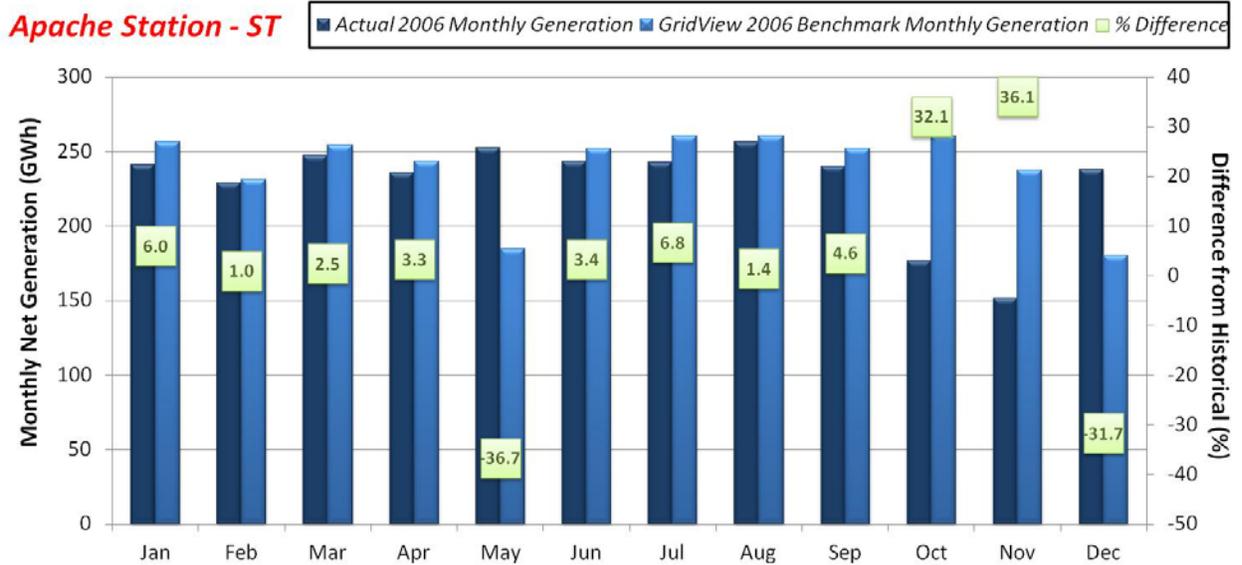


Figure B.15 Actual versus GridView Modeled 2006 Monthly Net Generation for Apache Station Large Coal-fired Steam Units Located in the WALC BA

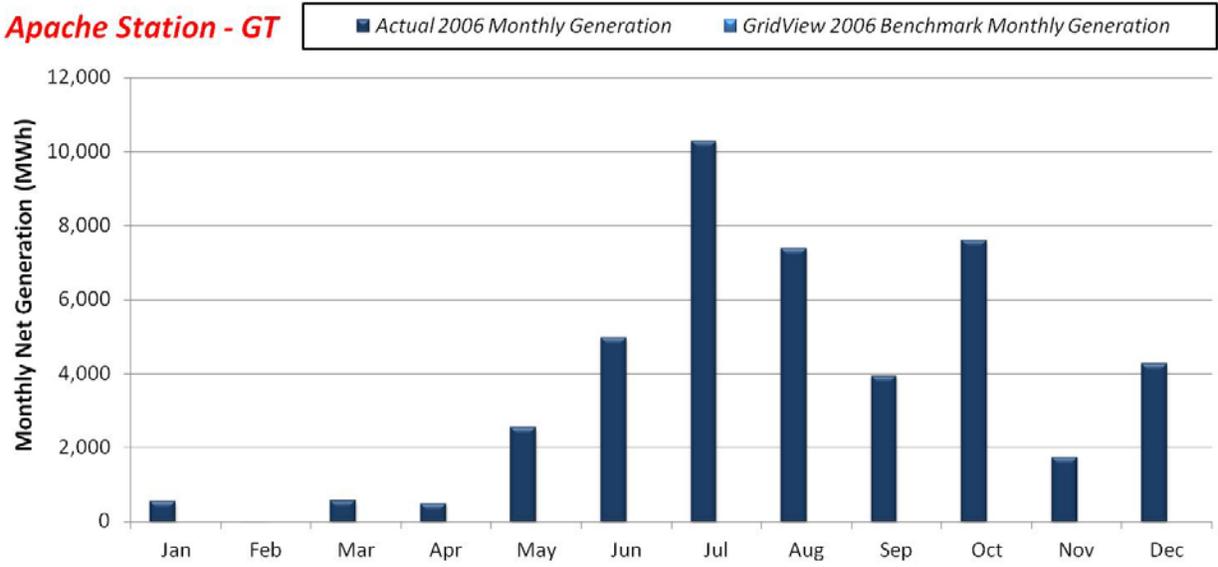


Figure B.16 Actual versus GridView Modeled 2006 Monthly Net Generation for the Apache Station Gas Turbine Unit Located in the WALC BA

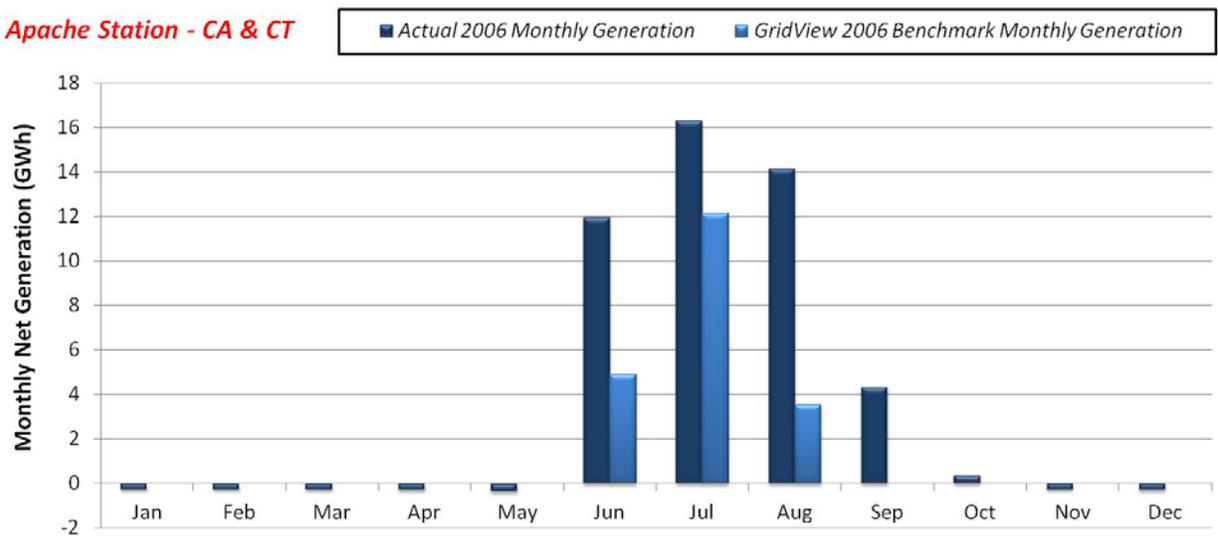


Figure B.17 Actual versus GridView Modeled 2006 Monthly Net Generation for the Apache Station Combined Cycle Unit Located in the WALC BA

Blythe Energy LLC - CA & CT

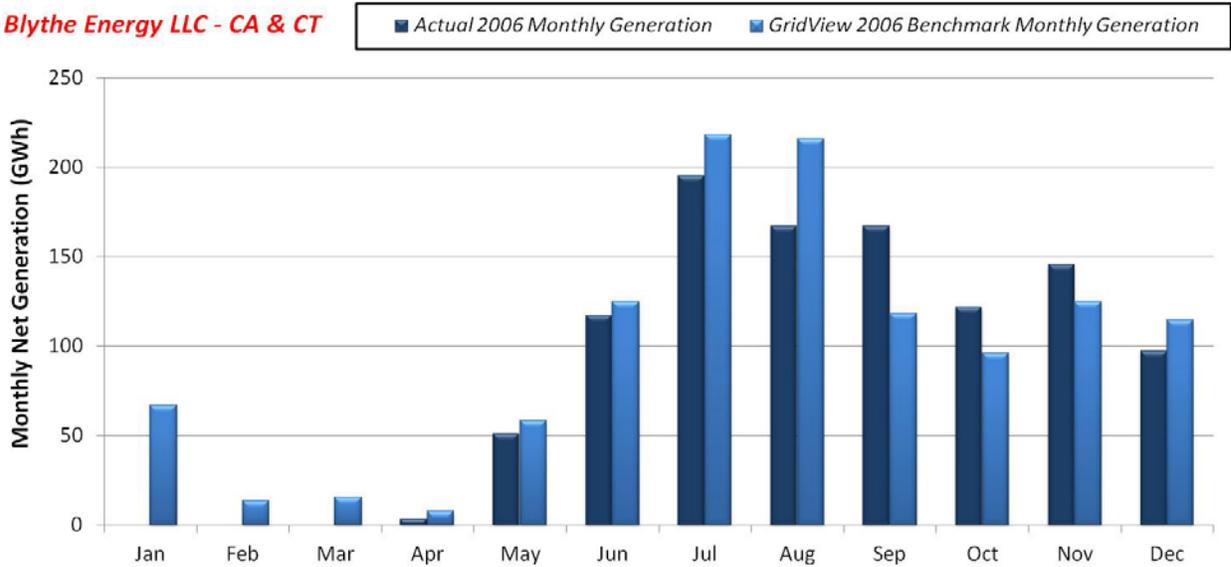


Figure B.18 Actual versus GridView Modeled 2006 Monthly Net Generation for the Blythe Energy LLC Combined Cycle Unit Located in the WALC BA

Four Corners - ST

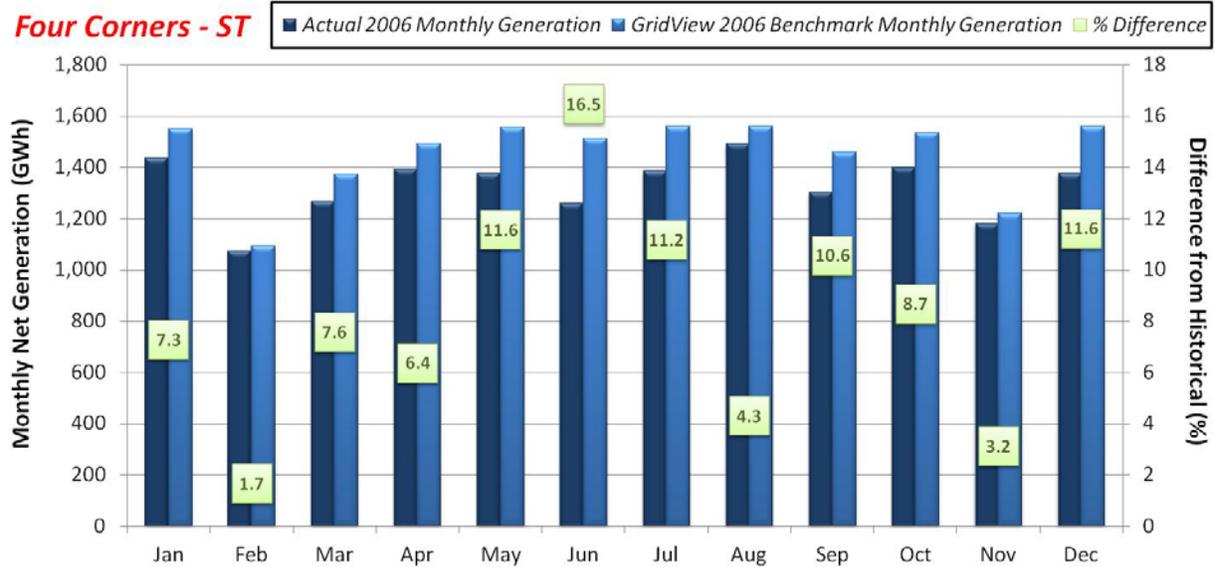


Figure B.19 Actual versus GridView Modeled 2006 Monthly Net Generation for Four Corners Large Coal-fired Units (Used for SRP Power Exchanges)

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APPENDIX C:
BENCHMARK CASE MONTHLY ELECTRICITY PRICES

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APPENDIX C:

BENCHMARK CASE MONTHLY ELECTRICITY PRICES

This appendix examines the monthly marginal electricity prices in 2006 determined by the GridView model for the Benchmark Case. The GridView model calculated prices for more than 2,600 buses; however, the bus chosen was Palo Verde because it is the location at which a substantial amount of wholesale electricity trading takes place and is reported in the trade press. In addition, the Western Area Power Administration (Western) uses the electricity price at Palo Verde as a benchmark, because it is the closest trading hub to Glen Canyon Dam, which is one of the largest hydroelectric power plants operated by Western.

Figures C.1 to C.12 show the hourly price for each month in 2006 computed by the GridView model for the Benchmark Case. In general, the trends in prices are as expected, that is, the prices at peak demand hours are highest in the summer (June, July, August) and winter (December, January, February) months and lowest in the spring and fall months. However, the lowest daily prices seem too low. In many months, the lowest price is at \$20/MWh or below — which does not correspond to the off-peak prices historically observed.

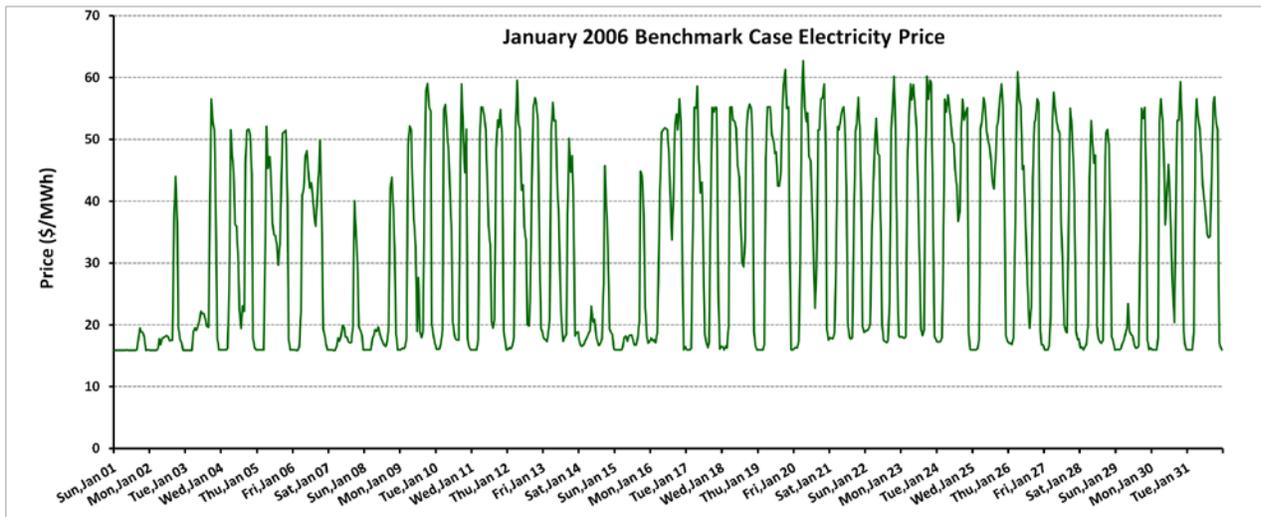


Figure C.1 January 2006 Electricity Price at Palo Verde Bus

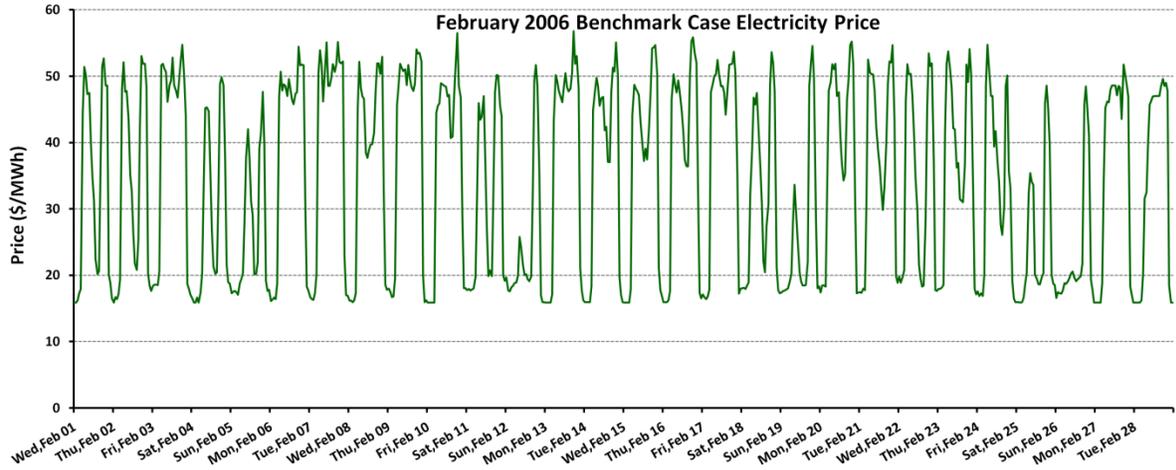


Figure C.2 February 2006 Electricity Price at Palo Verde Bus

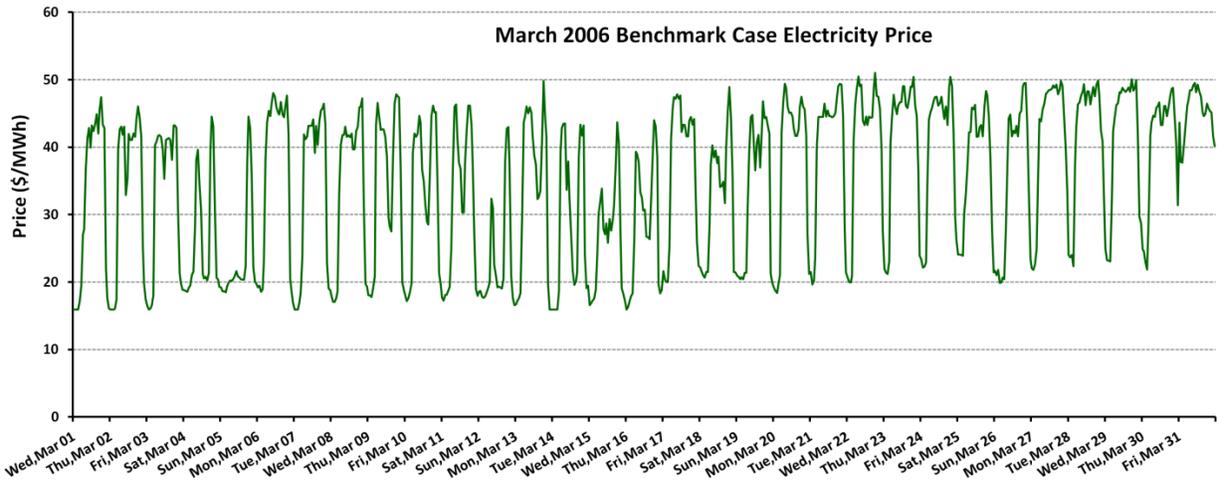


Figure C.3 March 2006 Electricity Price at Palo Verde Bus

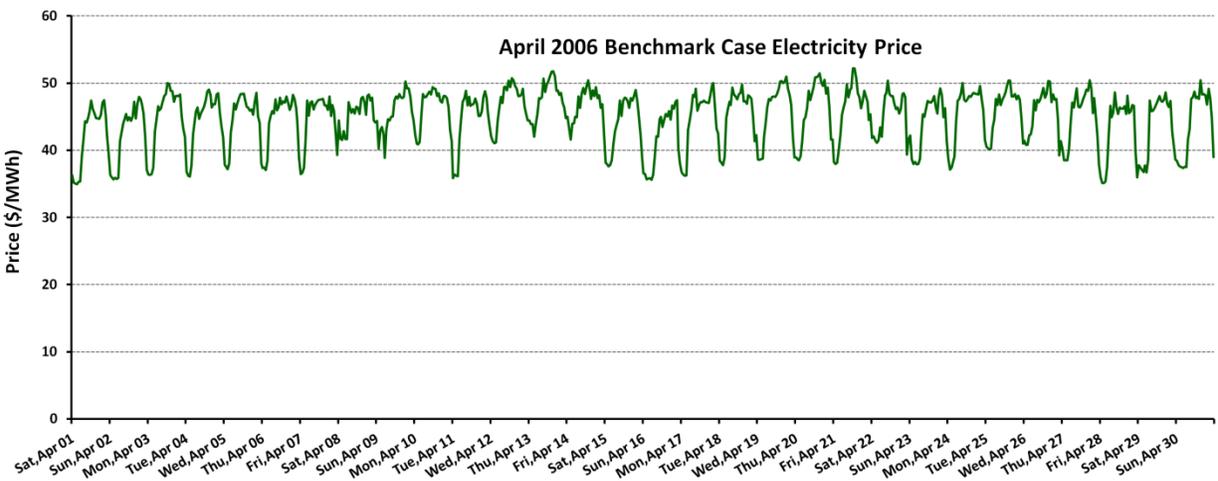


Figure C.4 April 2006 Electricity Price at Palo Verde Bus

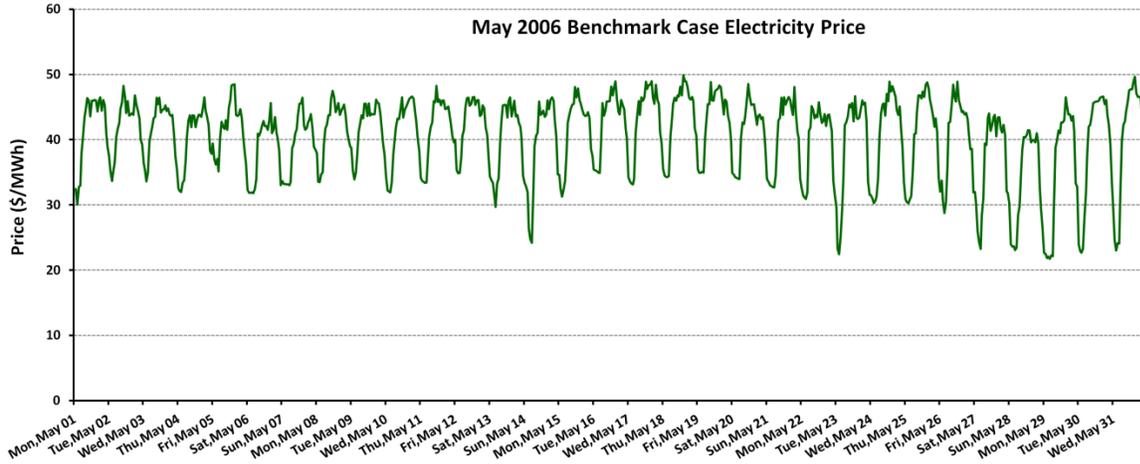


Figure C.5 May 2006 Electricity Price at Palo Verde Bus

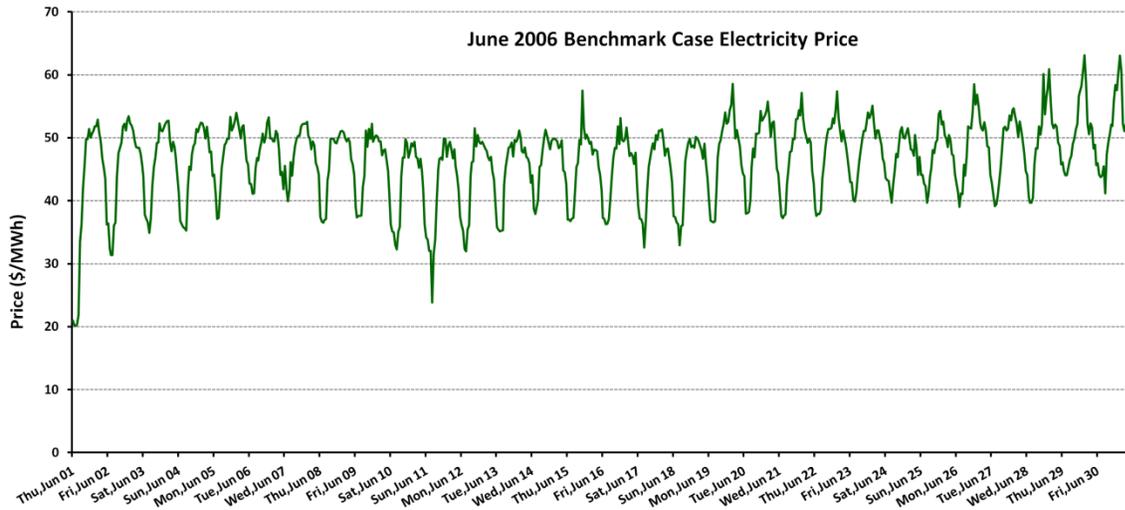


Figure C.6 June 2006 Electricity Price at Palo Verde Bus

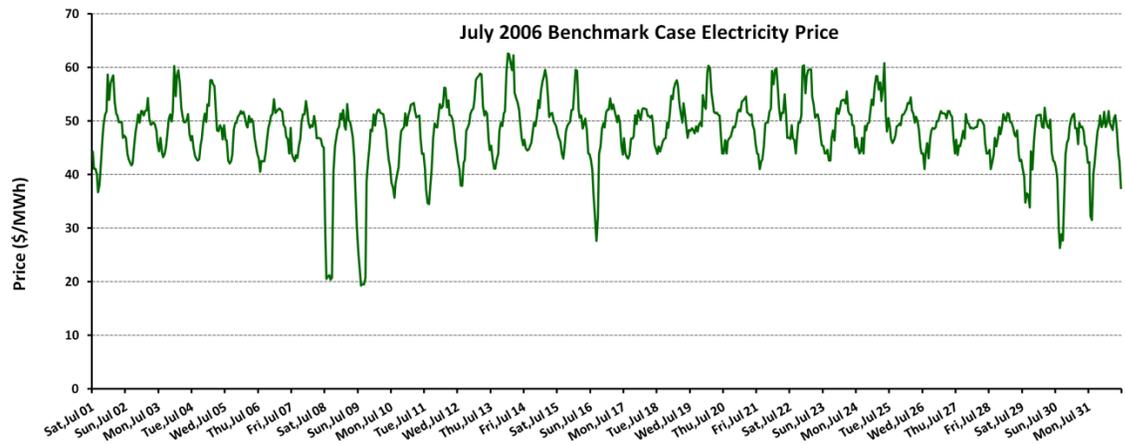


Figure C.7 July 2006 Electricity Price at Palo Verde Bus

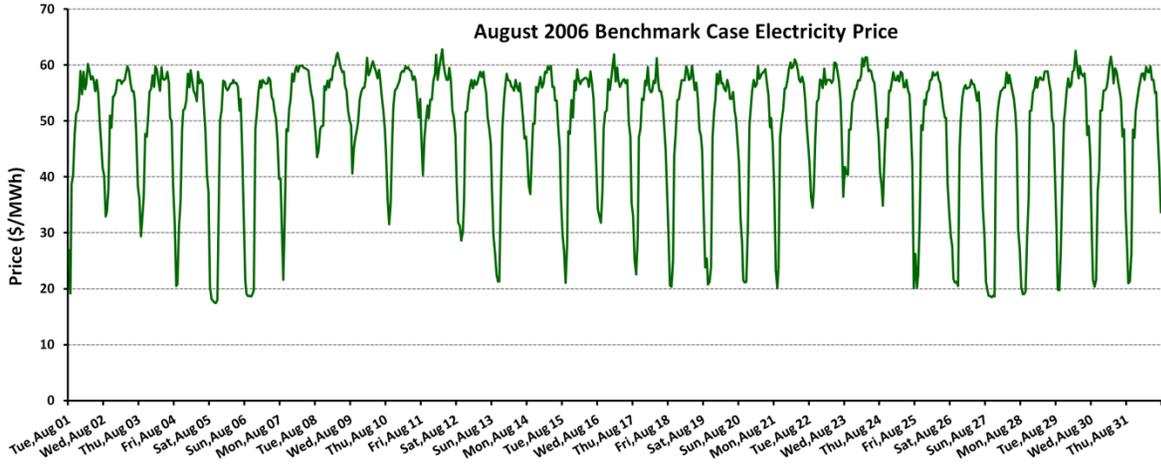


Figure C.8 August 2006 Electricity Price at Palo Verde Bus

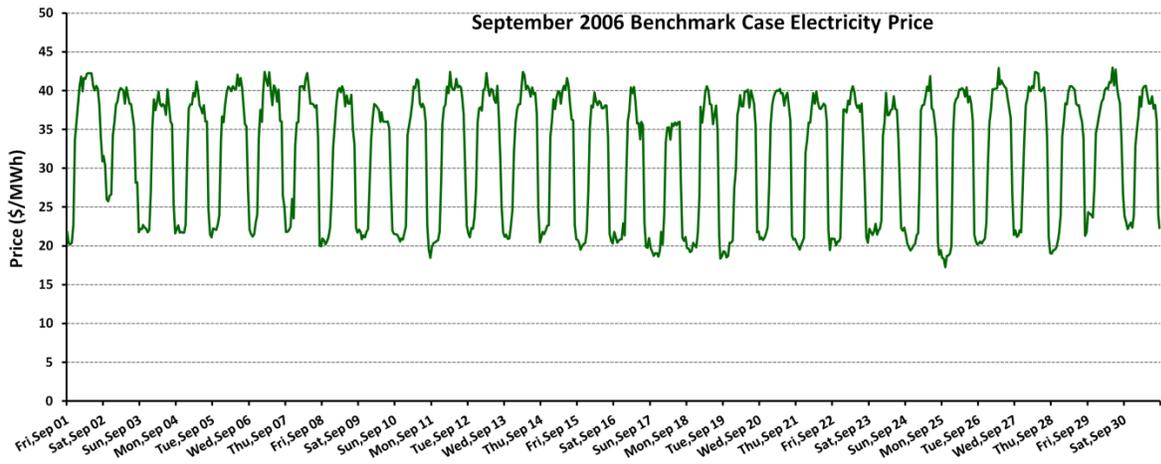


Figure C.9 September 2006 Electricity Price at Palo Verde Bus

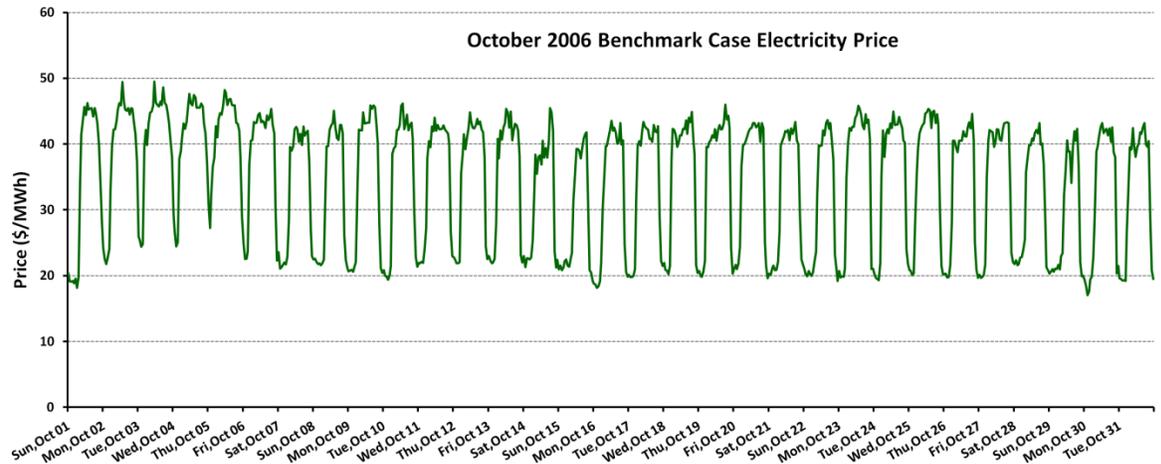


Figure C.10 October 2006 Electricity Price at Palo Verde Bus

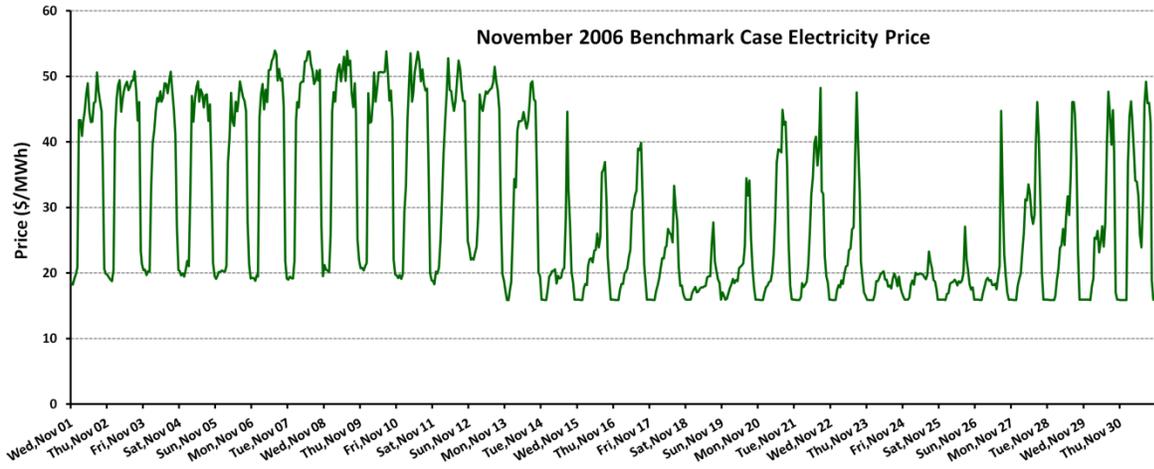


Figure C.11 November 2006 Electricity Price at Palo Verde Bus

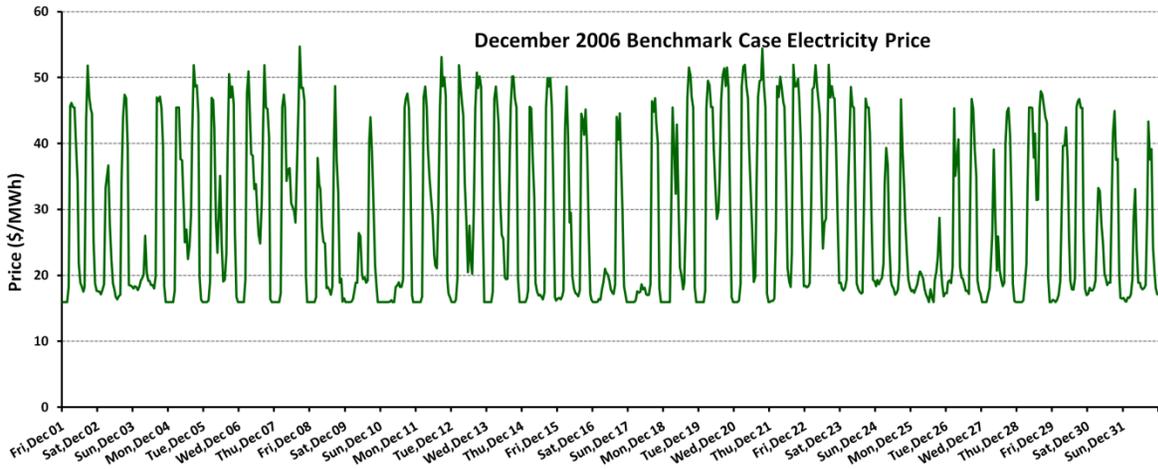


Figure C.12 December 2006 Electricity Price at Palo Verde Bus

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