Document name	**Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling**
Category	( ) Regional reliability standard ( ) Regional criteria ( ) Policy ( ) Guideline (x) Report or other ( ) Charter
Document date	March 29, 2013
Adopted/approved by	WECC Variable Generation Subcommittee
Date adopted/approved	March 29, 2013
Custodian (entity responsible for maintenance and upkeep)	WECC Variable Generation Subcommittee
Stored/filed	Physical location: Web URL:
Previous name/number	(if any)
Status	( ) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by ________________________ ( ) other _________________________________ ( ) obsolete/archived)

Final Technical Report

Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling

DOE Award DE-EE0001376, 02:10 – 12:12

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March 29, 2013

Acknowledgment: This report is based upon work supported by the U. S. Department of Energy under Award No. DE-EE0001376.

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List of Acronyms

ACE:	Area Control Error
AESO:	Alberta Electric System Operator
APS:	Arizona Public Service
AS:	Ancillary Service
AVA:	Avista Corporation
BA:	Balancing Authority
BANC:	Balancing Authority of Northern California
BCTC:	British Columbia Transmission Corporation
BPA:	Bonneville Power Administration
BTU:	British Thermal Unit
CAISO:	California Independent System Operator
CC:	Combined Cycle
CFE:	Comisión Federal de Electricidad (México)
CHPD:	PUD No 1 of Chelan County
CO_2:	Carbon Dioxide
COTP:	California-Oregon Transmission Project
CPS:	Control Performance Standard
CT:	Combustion Turbine
DA:	Day-ahead
DC:	Direct Current
DC-OPF:	Direct Current Optimal Power Flow
DOE:	US Department of Energy
DOPD:	PUD No 1 of Douglas County
DR:	Demand Response
ED:	Economic Dispatch
EIM:	Energy Imbalance Market
EPS:	El Paso Electric
FAR EAST:	IPC Region Far East
GCPD:	PUD No 1 of Grant County
GWh:	Gigawatt-hour
HA:	Hour-ahead
IID:	Imperial Irrigation District
IPC:	Idaho Power Company
ISO:	Independent System Operator
LADWP:	Los Angeles Department of Water and Power
LLC:	Limited Liability Company
MAGIC:	IPC Region Magic Valley
mmBTU:	Million BTU
MW:	Megawatt

MWh: Megawatt-hour
NEVP: Nevada Power
NOx: Nitrous oxides
NREL: National Renewable Energy Laboratory
NWMT: Northwest Energy
PACE: PacifiCorp East
PACE_ID: PacifiCorp East Region Idaho
PACE_UT: PacifiCorp East Region Utah
PACE_WY: PacifiCorp East Region Wyoming
PACW: PacifiCorp West
PG&E_BAY: Pacific Gas & Electric Region Bay
PG&E_VLY: Pacific Gas & Electric Region Valley
PGN: Portland General Electric
PNM: Public Service Company of New Mexico
PNNL: Pacific Northwest National Laboratory
PSC: Public Service Company of Colorado
PSE: Puget Sound Energy
PUC: Public Utility Commission
RFP: Request for Proposal
RSG: Reserve Sharing Group
RT: Real Time
SCE: Southern California Edison
SCED: Security-Constrained Economic Dispatch
SCL: Seattle City Light
SCUC: Security-Constrained Unit Commitment
SDGE: San Diego Gas & Electric
SO_2: Sulfur Dioxide
SPPC: Sierra Pacific Power
SRP: Salt River Project
SWPL: Southwest Power Link
TEP: Tucson Electric Power
TEPPC: Transmission Expansion Planning Policy Committee
TID: Turlock Irrigation District
TPWR: Tacoma Power
TREAS: IPC Region Treasure Valley
UC: Unit Commitment
USE: Un-served Energy
VG: Variable Generation
VGS: Variable Generation Subcommittee
WACM: WAPA – Colorado Missouri Region

WALC:	WAPA – Lower Colorado Region
WAUW:	WAPA – Upper Great Plains West
WECC:	Western Electricity Coordinating Council
WI:	Western Interconnection
WIEB:	Western Interstate Energy Board
WWSIS:	Western Wind and Solar Integration Study

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Executive Summary

The electric grid in Western North America, known as the Western Interconnection (WI), serves over 70 million people in 14 states, two Canadian Provinces, and a portion of Mexico. It is managed by 37 Balancing Authorities (BAs) of various ownership structures and operating paradigms. These areas are each responsible for balancing generation to load on a real-time basis. Ever increasing levels of wind and other naturally time-variant generation has placed an increased burden on the resources used for balancing.

As part of a US Department of Energy (DOE) grant, WECC assembled a project team from its Variable Generation Subcommittee (VGS) to investigate innovative, regionally-applied Balancing Area concepts that can facilitate the integration of increasing levels of wind and other variable generation resources. With support from the DOE, WECC sought to advance understanding of how different balancing cooperation arrangements affect regional reliability and reduce integration costs.

The overall objective of this study was to understand, Interconnection-wide, the financial benefit (in reduced production costs) of intra-hour scheduling compared to hourly scheduling. The study also sought to analyze how that benefit would change by altering input assumptions in different scenarios. To assist with the study, WECC contracted with Energy Exemplar, LLC (formerly known as PLEXOS Solutions, LLC) to perform the production cost simulations. Under the guidance and review of the VGS, Energy Exemplar performed the simulations and helped provide analyses of the resulting data.

This study did not investigate the costs of implementing intra-hour scheduling processes.

Three scenarios were modeled and analyzed using the PLEXOS production cost modeling software:

- **PNNL Scenario**. This scenario had 11 percent VG penetration and used data assumptions from the PNNL BA Cooperation Study[1].
- **PUC EIM Scenario**. This scenario had 11 percent VG penetration and used the same data and assumptions from the NREL PUC EIM Study[2].

[1] Pacific Northwest National Laboratory (PNNL) Balancing Authority (BA) Cooperation Study.

[2] National Renewable Energy Laboratory (NREL) Public Utility Commission (PUC) Energy Imbalance Market (EIM) Study.

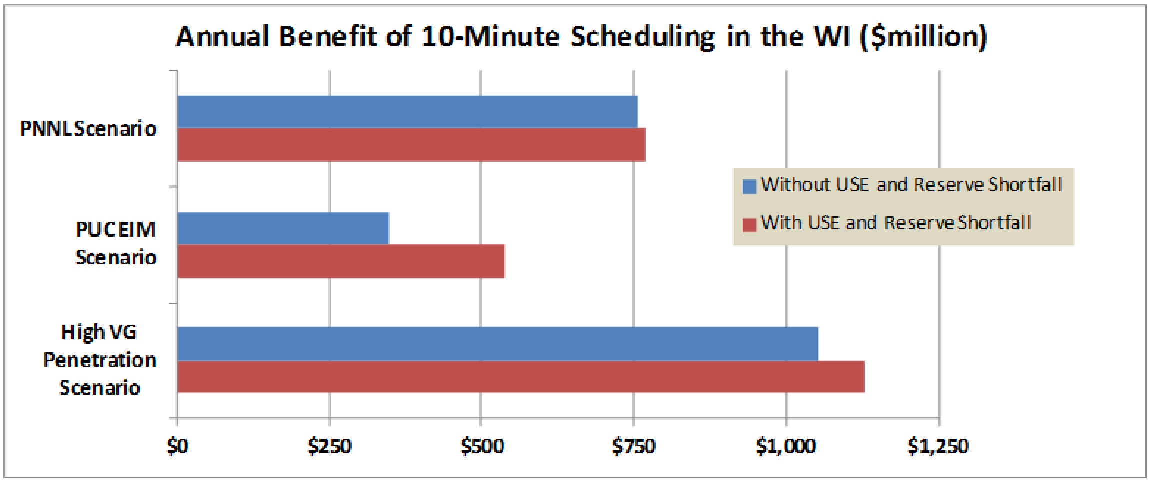
- **High VG Penetration Scenario**. This scenario had 27 percent Variable Generation (VG) penetration and used data assumptions from the PNNL BA Cooperation study.

To model the difference in system production costs between hourly scheduling and intra-hour scheduling, two cases were simulated and compared in each scenario:

- Hourly Case (hourly scheduling).
- 10-Minute Case (10-minute scheduling).

The difference in production costs between the Hourly Case and the 10-Minute Case was taken as the estimate of the benefits of intra-hour scheduling for each scenario, based on the assumptions contained in each scenario. The results of the simulations for each scenario are shown in Figure 1.

Figure 1: Annual Benefit of 10-Minute Scheduling



All of the scenarios show substantial financial benefits to intra-hour scheduling. The benefit estimates change depending on whether a penalty price for Un-served Energy (USE) and reserve shortfalls was considered. These benefits should be considered as aggregate social benefits to the WI.

Including a penalty price for Un-served Energy and reserve shortfalls in each scenario increased the estimated of benefits of the 10-Minute Case over the Hourly Case. Also, the benefit of 10-minute scheduling increased with additional VG penetration. Because key assumptions differed between the scenarios, care must be taken when comparing the results between scenarios.

Both the PNNL Scenario and the PUC EIM Scenario showed a slight increase in emissions in their respective 10-Minute Case compared to their Hourly Case. This was a result of increased coal generation and decreased gas generation during real time. However, given the current and expected restrictions on coal generation, it may be difficult to achieve increased power production from coal resources.

Conversely, the High VG Penetration Scenario showed a slight decrease in emissions between the Hourly Case and 10-Minute Case due to reduced wind and solar power curtailment in the 10-Minute Case.

The increase or decrease in emissions shown in this study are only when comparing the 10-Minute Case to the Hourly Case for the study scenarios. These emission comparisons should not be confused with an estimate of emission changes between present day operation (2012) and future day operation (2020) of the study scenarios. The increase in coal generation during shorter scheduling periods can also indicate that pre-schedule arrangements between BAs may not have reflected the trading, remote ownership, dynamic schedules, and exchanges that take place presently on the system. Additional studies could be performed to examine this relationship.

While the purpose of modeling is to calculate results that are as realistic as possible, there are always inherent limitations to any simulation study.

It is difficult to precisely represent and account for all of the details in the Bulk Electric System of the WI. For example, there may be existing commercial arrangements and operating methods used by BAs in the WI that are not modeled precisely. Incorrectly accounting for commercial agreements and operating methods currently in use may understate the current “efficiency” of hourly scheduling, and thus overstate the benefit of intra-hour scheduling. The study results should be considered in light of data and model limitations.

Introduction

The electric grid in the Western North America, known as the Western Interconnection (WI) serves over 70 million people in 14 states, two Canadian Provinces, and a portion of Mexico. It is managed by 37 distinct Balancing Authorities (BAs) of various ownership structures and operating paradigms (Figure 2). These BAs are each responsible for balancing generation to load on a real-time basis. Ever increasing levels of wind and other naturally time-variant generation has placed an increased burden on the resources used for balancing.

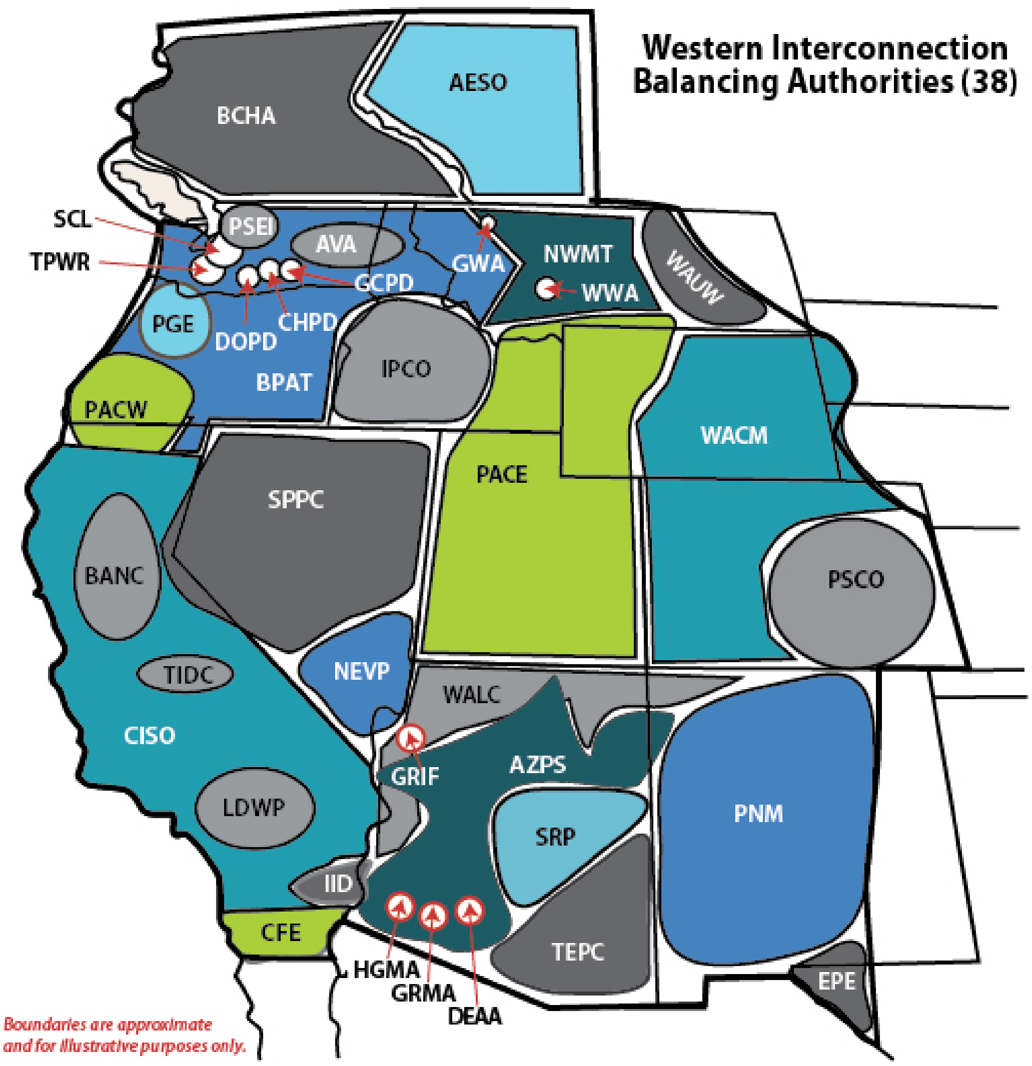
There is a need among utilities, state, and Regional Entities in the WI to deliver wind and other renewable energy from distant areas to load centers. The fact that variable generation is located in another BA than the load, often hundreds of miles away, poses issues for Balancing Authorities at the load, generator, and in-between. In addition, hourly bilateral markets are prevalent in the West. These limit the options entities have to balance variable generation within the hour.

The current method of providing balancing services in non-Independent System Operator (ISO) areas of the Western Interconnection is that the BA where the variable generation is located is required to provide this service.[3] The variable generator then pays for the "imbalance services" as agreed to in the transmission service tariff. There is often no method for the variable generator to secure these services from entities other than the BA or to transfer this burden to the entity that is purchasing the energy. It has been demonstrated that this method creates inefficient operations, drives up integration costs, and limits the amount of wind and other variable generation that can be connected to the system in a region.

There are opportunities for novel balancing options available to variable generator operators, BAs, and Load-Serving Entities. Some, such as Area Control Error (ACE) Diversity Interchange, have been shown to reduce balancing costs. Yet, in part due to reliability and market equity concerns, it is only currently being implemented over small, contiguous regions. Other examples of novel solutions to increasing balancing options include wind-only Balancing Areas and dynamic scheduling. However, in all these cases, there has not been an examination of Interconnection-wide balancing options and their impact on reliability and integration costs.

[3] An example of an exception is Iberdrola self-supply project with BPA. More information can be found at http://www.iberdrolarenewables.us/rel_10.09.22.html.

Figure 2: Map of WECC Balancing Authorities



AESO - Alberta Electric System Operator
AZPS - Arizona Public Service Company
AVA - Avista Corporation
BANC - Balancing Authority of Northern California
BPAT - Bonneville Power Administration - Transmission
BCHA - British Columbia Hydro Authority
CISO - California Independent System Operator
CFE - Comision Federal de Electricidad
DEAA - Arlington Valley, LLC
EPE - El Paso Electric Company
GRMA - Gila River Power, LP
GRIF - Griffith Energy, LLC
IPCO - Idaho Power Company
IID - Imperial Irrigation District
LDWP - Los Angeles Department of Water and Power
GWA - NaturEner Power Watch, LLC
NEVP - Nevada Power Company
HGMA - New Harquahala Generating Company, LLC
NWMT - NorthWestern Energy
PACE - PacifiCorp East
PACW - PacifiCorp West
PGE - Portland General Electric Company
PSCO - Public Service Company of Colorado
PNM - Public Service Company of New Mexico
CHPD - PUD No. 1 of Chelan County
DOPD - PUD No. 1 of Douglas County
PSEI - Puget Sound Energy
SRP - Salt River Project
SCL - Seattle City Light
SPPC - Sierra Pacific Power Company
TPWR - City of Tacoma, Department of Public Utilities
TEPC - Tucson Electric Power Company
TIDC - Turlock Irrigation District
WACM - Western Area Power Administration, Colorado-Missouri Region
WALC - Western Area Power Administration, Lower Colorado Region
WAUW - Western Area Power Administration, Upper Great Plains West
WWA - NaturEnur Wind Watch, LLC

11272012:hr

In response to a US Department of Energy (DOE) solicitation,[4] WECC assembled a project team from its Variable Generation Subcommittee (VGS) to investigate innovative, regionally applied Balancing Area concepts that can facilitate the integration of increasing levels of wind and other variable generation resources. With support from the DOE, WECC sought to advance understanding of how different balancing cooperation arrangements affect regional reliability and reduce integration costs. It was hoped that this collaborative effort will support key federal, regional, state, and utility decisions that will last for decades. WECC, the Regional Reliability Organization for the Western Interconnection, was uniquely suited to ensuring success in this endeavor.

Study Objectives

The overall objective of this study was to understand, on an Interconnection-wide basis, the effects intra-hour scheduling compared to hourly scheduling. Moreover, the study sought to understand how the benefits of intra-hour scheduling would change by altering the input assumptions in different scenarios.

To solicit a contractor to provide production cost modeling support, WECC issued a competitive Request for Proposal (RFP). The RFP was issued on February 1, 2011 and four respondents submitted proposals. After a review of all the proposals, Energy Exemplar, LLC (formerly known as PLEXOS Solutions, LLC) was chosen to be the contractor.

Through a related DOE funding opportunity, PNNL obtained a sister grant to perform studies related to BA Cooperation, while WECC was contracted separately to perform studies related to intra-hour scheduling requiring real time simulations performed by Energy Exemplar. The PNNL work related to BA Cooperation is included in a separate document. This report solely addresses the WECC scope of Intra-hour Scheduling.

To ensure broad stakeholder involvement, the study team provided quarterly updates in the VGS meetings throughout the study. In addition, a technical review committee, made up of a smaller group of WECC members, was formed to help provide input into the study methodology and assumptions.

[4] Funding Opportunity Announcement Number: DE-PS36-09GO99009; Issue Date: 12/30/2008

Study Scenarios

This report describes results of three separate scenarios with differing key assumptions and comparing the production costs between hourly scheduling and 10-minute scheduling performance. The different scenarios were chosen to provide insight into how the estimated benefits might change by altering input assumptions. Several key assumptions were different in the three scenarios, however most assumptions were similar and/or unchanged among the scenarios.

Table 1 outlines some of the differences among the scenarios. Further descriptions of assumptions and methodologies are provided later in this report.

PNNL Scenario

The PNNL Scenario was based on the Transmission Expansion Planning Policy Committee (TEPPC) PC0 case with some modifications provided by PNNL. The modifications include higher resolution wind and solar generation profiles, different operating reserve calculations, and different BA definitions.

The term “PNNL” in PNNL Scenario is meant to indicate that the assumptions are the same as those used in the PNNL Study on BA cooperation concepts.

PUC EIM Data Scenario

The PUC EIM Scenario was also based on the TEPPC PC0 data set. However, the data set was different from that used in the PNNL Scenario. Some of the key differences include hurdle rate assumptions, operating reserve calculations, and simulation algorithm.

The PUC EIM Scenario was based on the data set used by NREL in a study for the State-Provincial Steering Committee (SPSC).

High VG Penetration Scenario

The High VG Penetration Scenario is almost exactly the same as the PNNL Scenario, with the main difference being that higher wind and solar generation values were assumed. All the other assumptions (including the simulation algorithm) were kept consistent with the PNNL Scenario.

Table 1: High Level Comparison of Key Scenario Assumptions

Assumption	PNNL	PUC EIM	High VG Penetration
Wind Penetration	8%	8%	21%
Solar Penetration	3%	3%	6%
Overall Renewable	18%	18%	32%

Table 1: High Level Comparison of Key Scenario Assumptions			
Assumption	**PNNL**	**PUC EIM**	**High VG Penetration**
Energy Penetration			
Simulation Algorithm	PLEXOS 3-Stage	NREL 2-Stage	PLEXOS 3-Stage
Fuel (gas) Prices	$7.28/MMBtu	$7.28/MMBtu	$7.28/MMBtu
Hurdle Rates	$10/MWh	Interface-specific	$10/MWh

All of the data for the scenarios were translated into PLEXOS format to be able to run with the PLEXOS software.

General Simulation Approach

Intra-hourly BA exchange

With renewable generation penetration levels increasing, it is assumed to be beneficial if the BAs in the WI support each other by sharing the generation exchange at an intra-hourly schedule interval, rather than hour schedule, to manage the renewable generation variability and uncertainty. As the current "business as usual" operation in the WI is typically hourly BA scheduling, the purpose of this study is to evaluate the benefit from having BA scheduling at 10-minute intervals compared to hourly intervals. This study describes the hypothetical benefits of achieving 10-minute scheduling but does not describe or quantify the methods and costs to implement such.

To calculate those benefits, this study looked at two simulations cases for each scenario:

- Hourly Case (hourly scheduling).
- 10-Minute Case (10-minute scheduling).

The difference in production cost between these two simulations provided an estimate of the aggregate benefits of intra-hour scheduling in the WI, given the assumptions in the scenario. In all of the scenarios the respective hurdle rates were kept constant in both the Hourly Case and the 10-Minute Case.

In the Hourly Case, current operations are modeled by requiring actual interchange over the hour to be within the L_{10} tolerance of the scheduled interchange for the hour.

For intra-hour scheduling, new scheduled interchange values are calculated in the model and held between the BAs over the intra-hour scheduling period. For example, for 15-minute scheduling, scheduled interchange between BAs to be held over the 15-

minute period would be reset each 15 minutes. This allows for BAs to better optimize bilateral exchanges from hour schedules by taking advantage of reduced forecast error for load and variable generation.

The 10-Minute Case is not meant to approximate an Energy Imbalance Market (EIM). In an EIM, Energy Imbalance Service is automatically exchanged over the hour where real-time Actual Interchange deviates from Scheduled Interchange.

The 10-Minute Case is also not meant to approximate a virtual BA consolidation. Rather, it is meant to reflect current bilateral markets using a shorter scheduling interval than one hour.

Simulation Algorithms

Among the three study scenarios, there were two separate simulation algorithms used.

For the PNNL Scenario and the High VG Penetration Scenario, Energy Exemplar used the PLEXOS 3-stage sequential simulation approach (described below). For the PUC EIM Scenario, Energy Exemplar used the 2-stage methodology from the PUC EIM Study performed by NREL (described below). Table 2 summarizes some of the differences between the algorithms.

The reason for using different methodologies on the different scenarios was to have a basis for comparison with other studies that have used those respective methodologies. The assumptions and methodology for the PNNL Scenario and the High VG Penetration Scenario were chosen to be the same as those used by PNNL in their BA Cooperation Study. The assumptions and methodology for the PUC EIM Scenario was chosen to be the same as those used by NREL for the PUC EIM Study. The goal of having methodologies in common with other studies was to assist in comparing results across multiple research efforts.

Table 2: Comparison of Simulation Methodologies

Input	**PLEXOS 3-Stage**	**NREL 2-Stage**
BAs Modeled	32	24
Hurdle Rates	$10/MWh (fixed for all interchange)	$0.96 – $40
Simulation Sequence	DA-HA-RT	DA-RT
Simulation Software	PLEXOS	PLEXOS
Operating Reserve Calculation Methodology	PNNL Swinging Door	NREL flex reserve
Forecast Method and wind forecast error method	PNNL provided the Day-ahead (DA) and Hour-Ahead (HA) load/wind/solar forecasts	NREL provided the DA wind/solar forecasts

Table 2: Comparison of Simulation Methodologies

Input	PLEXOS 3-Stage	NREL 2-Stage
BAs operated together in preschedule and real time	No	No
Remote owned units represented	Within geographically sited BA	Hoover: both energy and capacity ownership is modeled Colstrip: capacity ownership is modeled
Hurdle Rates	$10/MWh	BA boundary-specific
Scheduled Interchange determination	In the Hourly Cases, BA exchange from the HA simulation is honored without L_{10} band in the Real-Time simulation. In the 10-Minute Cases, BA exchange can be re-scheduled.	Hurdle-rate determined
L_{10} allowed	Yes, in the Hourly Cases	N/A
Hydro Model and Hydro Reserves	Hydro can provide reserves	Hydro can provide reserves
Hydro-Thermal Coordination (HTC)	Hydro dispatch similar to HTC	Hydro dispatch similar to HTC
Hydro Water Year Assumption	2006	2006

Limitations

While the purpose of modeling is to calculate results that are as realistic as possible, there are always inherent limitations to any simulation study.

It is difficult to precisely represent and account for all of the details in the Bulk Electric System of the WI. For example, there may be existing commercial arrangements and operating methods used by BAs in the WI that are not modeled precisely. Some of these may include the following:

- Long- and short-term contracts
- Remote ownership of generators in other BAs
- Interchange scheduling
- Ancillary services provided through dynamic schedules and pseudo-ties
- Power exchanges
- Coordinating agreements
- Hydro generation
- Dedicated transmission facilities connecting generation to loads without “hurdle rates”

Incorrectly accounting for such commercial agreements and operating methods currently in use may understate the current “efficiency” of hourly scheduling, and thus overstate the benefit of intra-hour scheduling.

The study results should be considered in light of data and model limitations.

Simulation Results and Analysis

This section contains the results from the three scenarios that were modeled. Care must be used in comparing results because of the differing assumptions:

- PNNL Scenario
- PUC EIM Scenario
- High VG Penetration Scenario

PNNL Scenario

Simulation Assumptions

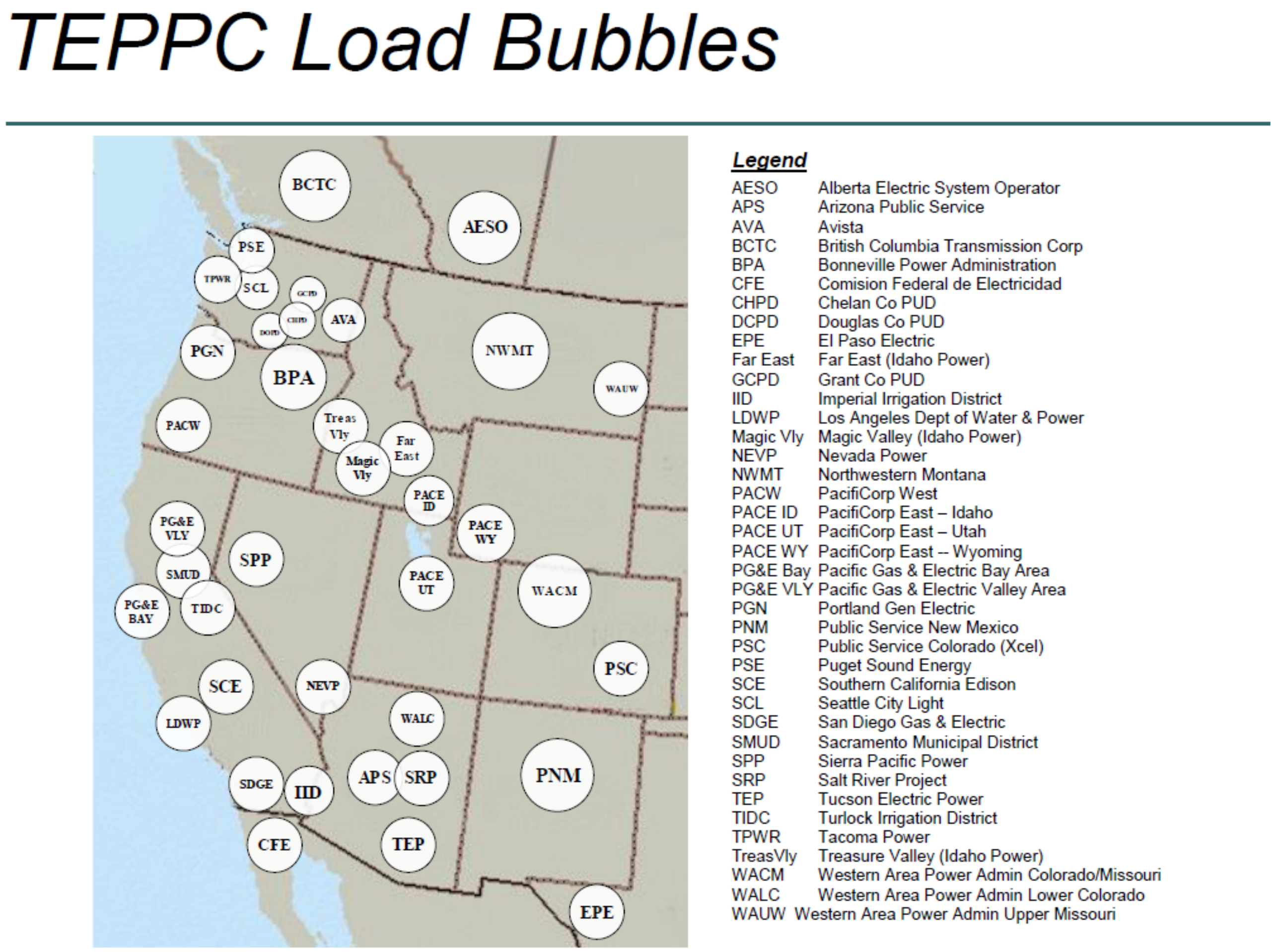
The WI system used for the PNNL Scenario was translated from the WECC TEPPC PC0 database for year 2020.

The network model includes the following:

- Over 17,500 nodes.
- Over 2,200 generators.
- Over 22,590 transmission lines and transformers.
- Over 1,000 transmission lines and transformer limits are enforced in the simulations.
- 44 phase shifters that are modeled as control variables in the simulations.
- 127 interfaces whose limits are enforced in the simulations.
- 18 Nomograms that are honored in the simulations.
- 39 load regions (“bubbles”).

A map of the TEPPC load regions is shown in Figure 3.

Figure 3: Diagram of the WI Load Regions



The load regions specified in the database are listed in Table 3.

Table 3: Load Regions in the Western Interconnection	
Load Region	**Name**
AESO	Alberta Electric System Operator
APS	Arizona Public Service
AVA	Avista
BCTC	British Columbia Transmission Corporation
BPA	Bonneville Power Administration
CFE	Comisión Federal de Electricidad (México)
CHPD	PUD No 1 of Chelan County
DOPD	PUD No 1 of Douglas County

Table 3: Load Regions in the Western Interconnection	
Load Region	**Name**
EPS	El Paso Electric
FAR EAST	IPC Region Far East
GCPD	PUD No 1 of Grant County
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
MAGIC	IPC Region Magic Valley
NEVP	Nevada Power
NWMT	Northwest Energy
PACE_ID	PacifiCorp East Region Idaho
PACE_UT	PacifiCorp East Region Utah
PACE_WY	PacifiCorp East Region Wyoming
PASW	PacifiCorp West
PG&E_BAY	Pacific Gas & Electric Region Bay
PG&E_VLY	Pacific Gas & Electric Region Valley
PGN	Portland General Electric
PNM	Public Service Company of New Mexico
PSC	Public Service Company of Colorado
PSE	Puget Sound Energy
SCE	Southern California Edison
SCL	Seattle City Light
SDGE	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
SPPC	Sierra Pacific Power
SRP	Salt River Project
TEP	Tucson Electric Power
TID	Turlock Irrigation District
TPWR	Tacoma Power
TREAS	IPC Region Treasure Valley
WACM	WAPA - Colorado Missouri Region
WALC	WAPA - Lower Colorado Region
WAUW	WAPA - Upper Great Plains West

PLEXOS 3-Stage Sequential Simulation Methodology

The PLEXOS 3-Stage Sequential Simulation Methodology was used for the PNNL Scenario and the High VG Penetration Scenario.

PNNL Scenario and High VG Penetration Scenario Assumptions

While there are currently 37 BAs in the WI, the PNNL Scenario modeled only 32 BAs, based closely on the geographic boundaries of the actual BAs (excluding the generation-only BAs). Table 4 lists the 32 BAs modeled in the simulations. The BAs were formed from the 39 TEPPC load regions shown above.

Table 4: Balancing Authority Areas Modeled in the Western Interconnection

BA	Regions Encompassed
AESO	AESO
APS	APS
AVA	AVA
BANC	SMUD
BCTC	BCTC
BPA	BPA
CAISO	PG&E_BAY, PG&E_VLY, SCE, SDGE
CFE	CFE
CHPD	CHPD
DOPD	DOPD
EPE	EPEC
GCPD	GCPD
IID	IID
IPC	FAR EAST, MAGIC, TREAS
LDWP	LADWP
NEVP	NEVP
NWMT	NWMT
PACE	PACE_ID, PACE_UT, PACE_WY
PACW	PACW
PGN	PGN
PNM	PNM
PSC	PSC
PSE	PSE

Table 4: Balancing Authority Areas Modeled in the Western Interconnection	
BA	**Regions Encompassed**
SCL	SCL
SPP	SPPC
SRP	SRP
TEP	TEP
TIDC	TID
TPWR	TPWR
WACM	WACM
WALC	WALC
WAUW	WAUW

Additional Assumptions

- The contingency (spinning) reserve of 4 percent BA load was modeled for all BAs. The flexibility up/down and regulation up/down reserves were modeled at the BA level. A uniform hurdle rate of $10/MWh for power exchange between any two adjacent BAs was used for both the PNNL Scenario and High VG Penetration Scenario.
- The Henry Hub gas price of $7.28/mmBTU (in 2010 dollars) was used to derive the regional monthly gas prices.
- The penalty prices for the Un-served Energy, reserve shortfalls, and over-generation in the production cost modeling are listed in Table 5.

Table 5: Penalty Prices for Product Shortfalls and Over-Generation in the Mixed Integer Programming Problem Formulations

Product Shortfall	Penalty Price	Notes
Un-served Energy	$500/MWh	In the production cost calculation, an indicative price of Combustion Turbine (CT) generation ($85/MW) is used
Over-generation	-$1000/MWh	
Spinning Reserve Shortfall	$250/MWh	In the production cost calculation, an indicative price of CT generation
Regulation and Flexibility up Reserve Shortfall	$250/MWh	

Table 5: Penalty Prices for Product Shortfalls and Over-Generation in the Mixed Integer Programming Problem Formulations		
Product Shortfall	**Penalty Price**	**Notes**
Regulation and Flexibility down Reserve Shortfall	$250/MWh	($85/MW) is used

For the PNNL Scenario, the requirements for flexibility and regulation reserves were provided by PNNL, based on BA load and renewable energy variability and uncertainty.[5] In addition, the forecasted and actual renewable generation profiles, as well as the forecasted and actual load profiles, were provided by PNNL and use one-minute-interval interpolated wind and load data. These data assumptions were kept consistent with the PNNL study on BA Cooperation.

Simulation Settings

- Day-ahead (DA) simulation was performed at hourly intervals within the 24-hour energy-Ancillary Service (AS) co-optimization window. The DA-forecasted load and renewable energy production were used. DA optimization was performed within each BA individually with loads and generation in the physical footprint.
- Hour-ahead (HA) simulation was performed at hourly intervals within the one-hour plus five-hour look-ahead energy-AS co-optimization window. The HA-forecasted load and renewable energy production were used. The commitment for the long- and medium-startup generators from the DA simulation was used. HA optimization was performed within each BA individually.
- For the Hourly Case, the hourly BA interchange from the HA simulation was frozen within the L_{10} tolerance bands in the Real-Time (RT) simulation.
- For the 10-Minute Case, the BA interchange schedule was reset in each of the RT 10-minute simulation periods.

PLEXOS SCUC/ED algorithm

The PNNL Scenario used the PLEXOS Security Constrained Unit Commitment (SCUC) and Economic Dispatch (ED) algorithm.

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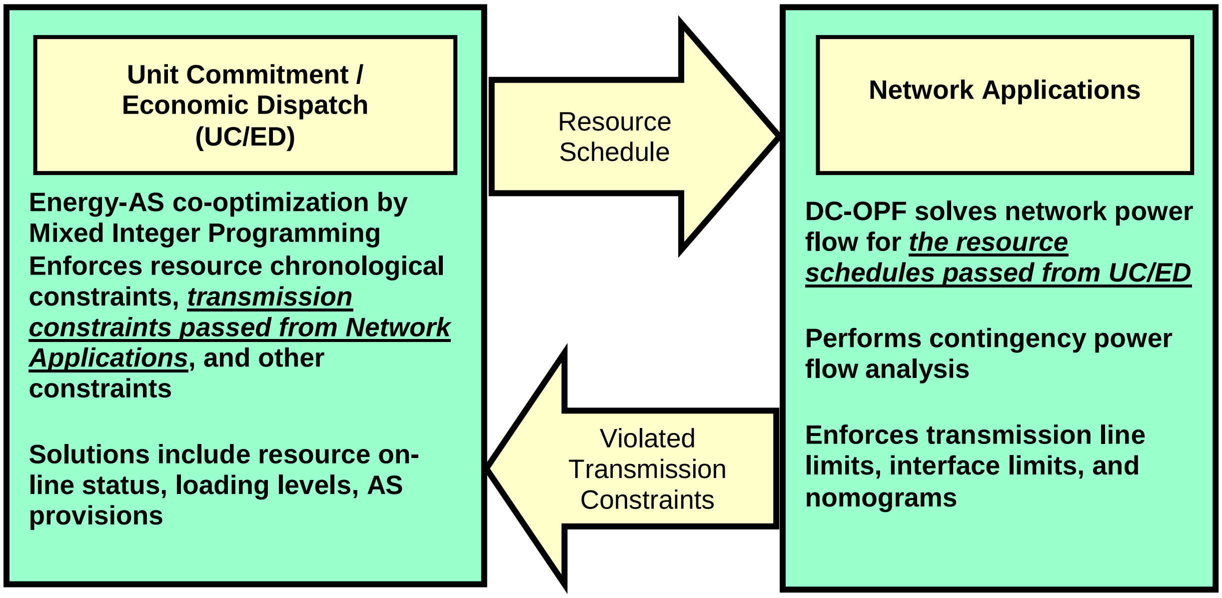
[5] For more information on the PNNL Methodology of calculating operating reserve requirements, see the white paper “PNNL Methodology for Simulation of BA Balancing Functions” located at http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/Shared%20Documents/BA%20Cooperation%20Study/Reserves%20Assumptions/PNNL%20Balancing%20Reserve%20Analysis%20Methodology.docx.

PLEXOS' SCUC algorithm consists of two major logics: Unit Commitment using Mixed Integer Programming and Network Applications. The SCUC/ED simulation algorithm can be better described in Figure 4.

Figure 4: PLEXOS Security-Constrained Unit Commitment and Economic Dispatch Algorithm



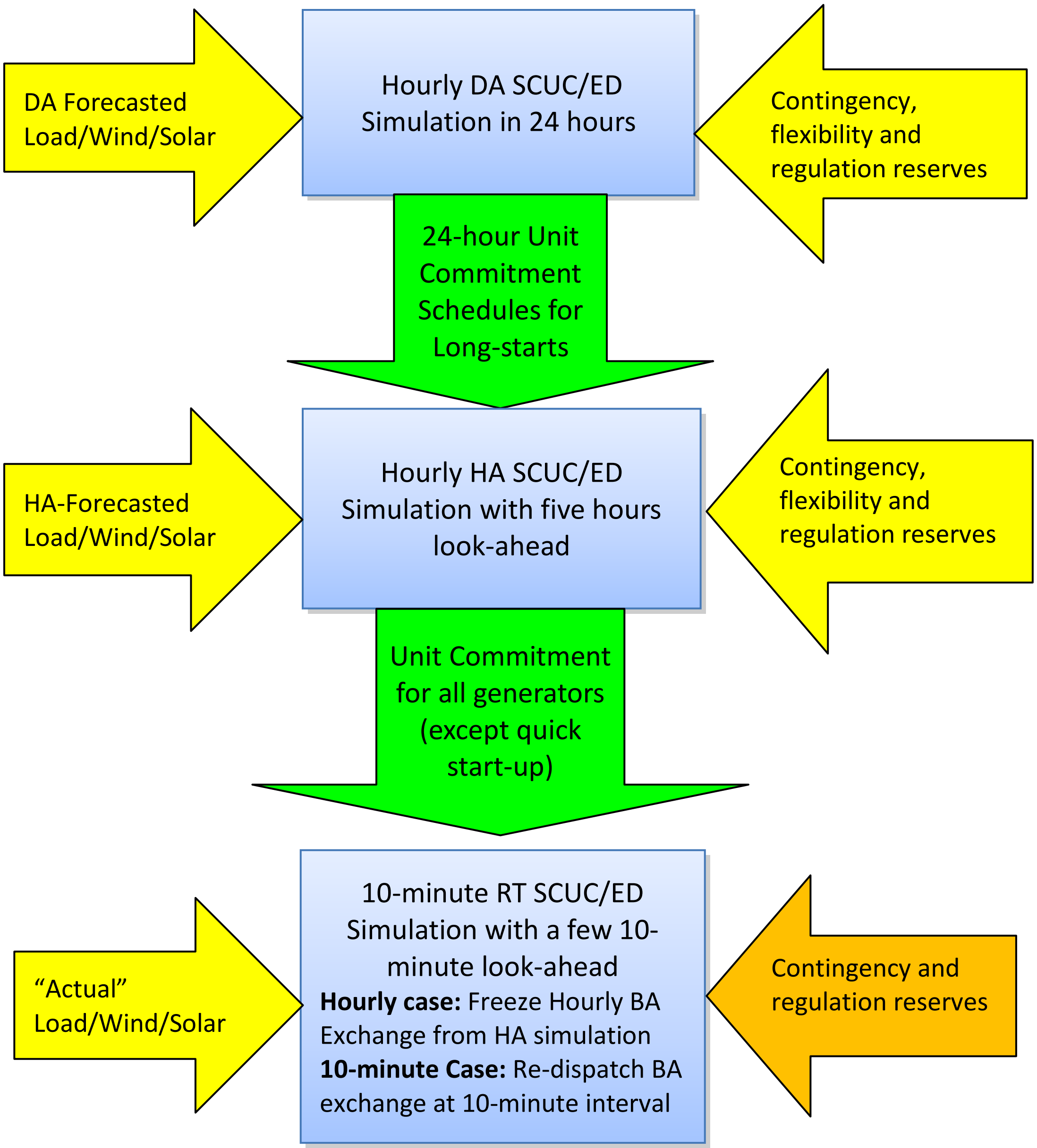
The Unit Commitment and economic dispatch (UC/ED) logic performs the Energy-AS co-optimization using Mixed Integer Programming enforcing all resource and operation constraints. The UC/ED logic commits and dispatch resources to balance the BA energy demand and meet the BA reserve requirements.

The resource schedules from the UC/ED are passed to the Network Applications logic. The Network Applications logic solves the Direct Current Optimal Power Flow (DC-OPF) to enforce the power flow limits and nomograms. The Network Applications logic also performs the contingency analysis, if the contingencies are defined. If there are any transmission limit violations, these transmission limits are passed to the UC/ED logic for the re-run of UC/ED. The iteration continues until all transmission limit violations are resolved. Thus the co-optimization solution of Energy-Ancillary Service-Direct Current Optimal Power Flow is reached.

3-stage Sequential Simulation Approach

The simulation approach adopted in this study for the PNNL Scenario and High VG Penetration Scenario was a 3-stage sequential simulation: DA-HA-RT. The 3-stage sequential simulations approach is illustrated in Figure 5.

Figure 5: 3-Stage DA-HA-RT Sequential Simulation Approach



A summary of the data flow and simulation algorithms in each stage of the 3-stage sequential simulations is briefly described below. The details of the assumptions are provided in the next few subsections.

In the DA simulation:

- Day-ahead forecasted load/wind/solar generation time series are used;
- The SCUC/ED optimization window is 24 hours with hourly interval;
- The Contingency, Flexibility up/down, Regulation up/down reserves constraints are met.

In the HA simulation:

- The Hour-ahead forecasted load/wind/solar generation time series are used;
- The SCUC/ED optimization window is one hour plus five-hour look-ahead with hourly interval;
- The Unit Commitment patterns from the DA simulation are frozen for generators with Min Up/Down Time greater than five hours;
- The Contingency, Flexibility up/down, Regulation up/down reserves constraints are met.

In the RT simulation:

- The actual 10-minute load/wind/solar generation time series are used.
- The Security-Constrained Economic Dispatch (SCED) optimization window is 10-minute plus five 10-minute look-ahead with 10-minute interval.
- The Unit Commitment patterns from the HA simulation are frozen;
- The Contingency, Regulation up/down reserves are modeled. However, the flexibility up/down reserves constraints are relaxed in RT. The implication is that the capacity held in the HA simulation for the flexibility reserves is deployed to cover the load and renewable generation variability and uncertainty at the 10-minute interval.

The transmission network was modeled at the nodal level in the DA, HA, and RT stages. The optimization calculations were done WECC wide at the BA level.

In the Hourly Case, the hourly BA interchange values from the HA simulation were fixed within the CPS2 L_{10} band and held over each real-time modeling period (10 minutes) in the hour to the HA value. This means that each BA must meet its own load, generation reserves, and interchange by changing generation within its BA, holding Interchange Schedules within L_{10} limits at the HA level.

In the 10-Minute Case, the BA exchanges were free to be rescheduled at 10-minute intervals and in the model optimized on a WECC-wide basis.

Results and Analysis

The 3-stage DA-HA-RT sequential simulations were performed for the PNNL Scenario for year 2020. Two RT simulations were performed: Hourly Case and 10-Minute Case. The energy generation by technology from these two RT simulations is listed in Table 6.

Table 6: Comparison of Generation by Technology (PNNL Scenario)						
	Hourly Case		10-Minute Case		Difference	
Technology	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)
Biomass	16,009	2%	16,758	2%	749	0.07%
CC	191,738	19%	177,896	17%	(13,842)	-1.35%
Coal	277,648	27%	292,224	28%	14,576	1.42%
CT	43,844	4%	40,868	4%	(2,975)	-0.29%
DR	206	0%	132	0%	(74)	-0.01%
Geo-Thermal	36,062	4%	36,171	4%	109	0.01%
Hydro	245,624	24%	246,994	24%	1,370	0.13%
Nuclear	77,010	7%	77,805	8%	794	0.08%
Other	5,579	1%	5,487	1%	(91)	-0.01%
Pumped Storage	4,550	0%	4,550	0%	-	0.00%
Pumping Load	0	0%	-	0%	(0)	0.00%
Small Hydro	7,897	1%	7,987	1%	90	0.01%
Solar	31,836	3%	31,836	3%	0	0.00%
Steam	7,399	1%	6,732	1%	(667)	-0.06%
Wind	82,013	8%	82,013	8%	0	0.00%
Total	**1,027,414**	**100%**	**1,027,454**	**100%**	**39**	**0.00%**

The values in the green colored rows are counted toward Renewable Portfolio Standards. While the generation from wind and solar resources is around 11 percent, the total generation from all renewable resources[6] is closer to 18 percent.

The simulation solution of the 10-Minute Case shows that generation from coal, hydro, and nuclear increased while the generation from Combined Cycle (CC) and Combustion Turbine (CT) were reduced. This indicates that the coal, nuclear, and hydro generation make up the load net renewable generation over-forecast (i.e., the actual load net renewable generation is less than the forecasted). The CC and CT generation are backed down when the load net renewable generation is under-forecasted (i.e., the

[6] For this study, renewable resources are defined as biomass, geothermal, small hydro, wind, and solar. These technologies are frequently considered to be RPS-eligible energy sources in the majority of Renewable Portfolio Standards in the United States. While large hydro generation is counted as renewable energy in some jurisdictions, it is not counted as renewable energy for the purposes of this study.

actual load net renewable generation is greater than the forecasted). However, given the current and expected restrictions on coal generation, it may be difficult to achieve increased power production from coal resources.

The annual total production cost for the two cases are listed in Table 7. In the Hourly Case, the annual total production cost was $20.5 billion. In the 10-Minute Case, the annual production cost was reduced to $19.8 billion, for a production cost savings of $755 million.

There was 39 GWh of Un-served Energy (USE) and 178 GWh of reserve shortfalls in the Hourly Case. In the 10-Minute Case, the USE was reduced to zero and the reserve shortfall was reduced to 42 GWh. When counting the USE and reserve shortfalls priced at $85/MWh, the production cost saving was bumped up to $769 million.

The reduction of the Un-served Energy and reserve shortfall indicates that some BAs do not have enough flexible capacity to cover the renewable generation variability and uncertainty. When BAs share the flexibility capacity, the WI can accommodate the 11 percent VG.

There was no dumped energy in either of the cases.

Table 7: Comparison of Production Costs in the PNNL Scenario								
	Hourly Case			10-Minute Case			Cost Difference without USE and Reserve Shortfall	Cost Difference with USE and Reserve Shortfall
Month	Total Generation Cost ($000)	USE (GWh)	BA Reserve shortfall (GWh)	Total Generation Cost ($000)	USE (GWh)	BA Reserve shortfall (GWh)	Total Generation Cost Savings ($000)	Total Generation Cost Savings ($000)
January, 2020	1,670,538	8	17	1,586,502	-	2	84,036	86,019
February, 2020	1,441,907	7	9	1,366,067	-	0	75,840	77,137
March, 2020	1,557,121	4	16	1,470,918	-	8	86,203	87,196
April, 2020	1,305,689	0	6	1,227,986	-	0	77,702	78,202
May, 2020	1,419,684	1	5	1,343,319	-	0	76,365	76,875
June, 2020	1,605,440	1	4	1,545,612	-	0	59,828	60,222
July, 2020	2,242,510	1	21	2,200,083	-	0	42,427	44,260
August, 2020	2,249,477	1	11	2,209,799	-	0	39,678	40,690
September, 2020	1,920,468	1	19	1,882,876	-	4	37,591	38,935
October, 2020	1,738,323	1	13	1,695,283	-	4	43,039	43,839
November, 2020	1,553,546	6	18	1,487,920	-	1	65,626	67,563
December, 2020	1,786,875	10	39	1,720,057	-	23	66,818	69,043
Total	**20,491,576**	**39**	**178**	**19,736,422**	**-**	**42**	**755,154**	**769,981**

The comparison of the production cost by BA between the Hourly Case and 10-Minute Case is listed in Table 8. The production cost by BA includes only the total generation costs in the BAs and does not include the BA exchange costs and revenues.

While Table 8 shows the difference in production costs between the Hourly Case and the 10-Minute Case by BA, it should not be considered as a list of estimated benefits for each BA. The figures do not take into account additional revenues or savings from scheduled power transactions or Energy Imbalance Service between BAs to accommodate the change in the overall generation mix.

Table 8: Production Cost Comparison by BA (PNNL Scenario)

BA	Hourly Case Total Production Cost ($k)	10-Minute Case Total Production Cost ($k)	Total Production Cost Difference (10-Minute Case - Hourly Case)	
			($k)	Difference %
AESO	2,916,319	2,823,942	(92,377)	-3%
APS	1,123,879	1,184,621	60,742	5%
AVA	117,013	117,357	344	0%
BANC	462,107	494,081	31,974	7%
BCTC	237,042	233,923	(3,119)	-1%
BPA	1,257,969	1,223,088	(34,881)	-3%
CAISO	5,459,794	5,101,305	(358,489)	-7%
CFE	787,344	787,181	(163)	0%
CHPD	610	0	(610)	-100%
DOPD	-	-	-	0%
EPE	262,639	218,165	(44,474)	-17%
GCPD	-	-	-	0%
IID	171,918	162,661	(9,258)	-5%
IPC	92,543	75,306	(17,236)	-19%
LDWP	470,127	417,299	(52,828)	-11%
NEVP	1,121,631	1,034,254	(87,377)	-8%
NWMT	188,743	211,280	22,537	12%
PACE	839,794	892,911	53,117	6%
PACW	384,752	327,111	(57,642)	-15%
PGN	464,093	441,341	(22,753)	-5%
PNM	438,787	451,878	13,090	3%
PSC	1,022,757	891,950	(130,807)	-13%
PSE	492,097	421,779	(70,318)	-14%
SCL	-	-	-	0%

Table 8: Production Cost Comparison by BA (PNNL Scenario)				
BA	Hourly Case Total Production Cost ($k)	10-Minute Case Total Production Cost ($k)	Total Production Cost Difference (10-Minute Case - Hourly Case) ($k)	Difference %
SPP	227,050	240,595	13,545	6%
SRP	909,400	891,653	(17,747)	-2%
TEP	304,346	320,731	16,385	5%
TIDC	109,379	106,999	(2,380)	-2%
TPWR	-	-	-	0%
WACM	479,791	521,019	41,228	9%
WALC	149,651	143,993	(5,658)	-4%
WAUW	-	-	-	0%
Total	**20,491,576**	**19,736,422**	**(755,154)**	**-4%**

The following three tables list the comparisons of the CO_2, NOx, and SO_2 emissions by technology between the Hourly Case and 10-Minute Case.

Table 9: CO_2 Emission Comparison by Generator Type (PNNL Scenario)				
Technology	Hourly Case Total CO_2 Production (ton)	10-Minute Case Total CO_2 Production (ton)	CO_2 Production Difference (10-Minute Case - Hourly Case) (ton)	(%)
CC	83,006,401	76,945,778	(6,060,623)	-7%
Coal	282,446,710	298,295,060	15,848,349	6%
CT	26,405,777	24,776,222	(1,629,555)	-6%
Other	2,446,269	2,371,767	(74,503)	-3%
Steam	3,693,887	3,299,352	(394,535)	-11%
Total	**397,999,044**	**405,688,178**	**7,689,134**	**2%**

Table 10: NOx Emission Comparison by Generator Type (PNNL Scenario)				
Technology	Hourly Case Total NOx Production (ton)	10-Minute Case Total NOx Production (ton)	NOx Production Difference (10-Minute Case - Hourly Case)	
			(ton)	(%)
CC	78,295	71,725	(6,570)	-8%
Coal	546,543	580,488	33,944	6%
CT	30,217	28,118	(2,099)	-7%
Other	1,055	963	(92)	-9%
Steam	5,220	5,075	(145)	-3%
Total	**661,331**	**686,369**	**25,038**	**4%**

Table 11: SO_2 Emission Comparison by Generator Type (PNNL Scenario)				
Technology	Hourly Case Total SO_2 Production (ton)	10-Minute Case Total SO_2 Production (ton)	SO_2 Production Difference (10-Minute Case - Hourly Case)	
			(ton)	(%)
CC	3,397	3,075	(321)	-9%
Coal	436,971	462,367	25,396	6%
CT	2,585	2,338	(247)	-10%
Other	261	251	(10)	-4%
Steam	749	688	(61)	-8%
Total	**443,963**	**468,720**	**24,756**	**6%**

Emissions for CO_2, NOx, and SO_2 all increased in the 10-Minute Case. This is due to the increased coal generation in the 10-Minute Case.

PUC EIM Scenario

PUC EIM Scenario Assumptions

The WECC EIM data set also uses the TEPPC 2020 database, but with modified assumptions. The WI was represented by 39 load regions, 24 BAs, and seven Contingency Reserve Sharing Groups (RSG).

- The load forecasts were defined for 39 load regions. The Contingency reserves were defined as 4 percent of the RSG loads for each RSG.

- The transmission hurdle rates were defined between BA and are fine-tuned so that the major interface power flows match the historical power flows (see Appendix D).
- The joint-owned generator Hoover was modeled for the owner's Unit Commitment and energy delivery. The joint-owned generator Colstrip was modeled for the owner's Unit Commitment.
- Minor transmission network revisions were performed to model the transmission rights for the following lines:
    - Balancing Authority of Northern California's (BANC) right on the California-Oregon Transmission Project (COTP) (Path 66),
    - California Independent System Operator's (CAISO) right on the Pacific Northwest DC-tie (Path 65),
    - CAISO's right on the Intermountain DC-tie (Path 35), and
    - Imperial Irrigation District's (IID) right on the Sunrise Power Link (SWPL).

For further details of the PUC EIM study assumptions, please refer to the study report when it is published.

NREL 2-Stage Sequential Simulation Methodology

The NREL 2-Stage Sequential Simulation Methodology was used for the PNNL Scenario and the High VG Penetration Scenario.

PUC EIM Scenario Methodology

The PUC EIM Scenario utilized the production cost modeling dataset and methodology used by NREL for the PUC EIM study.

For the PUC EIM simulation, a 2-Stage DA-RT sequential simulation approach was used, as described below.

The DA simulation performed 24-hour SCUC at the hourly interval with the forecasted renewable generations. The Unit Commitment from the DA simulation was passed to the 10-minute RT simulation with the actual renewable generation.

Input data included:

- Forecasted wind generation profiles
- Actual load and solar profiles, i.e., perfect forecasts
- Detailed generator characteristics
- Contingency reserve, regulation reserve, and flexibility reserve for each specified BA or group of BAs
- Transmission hurdle rates between BAs

- Detailed nodal transmission network of the WI

The DA SCUC simulation resulted in an hourly Unit Commitment and resource schedule for the entire Interconnection. Each BA separately committed enough on-line capacity to cover its own load and reserve requirement at any hour.

For hourly cases, the RT SCED optimized over the hour with no look ahead. For the 10-Minute Cases, the RT SCED optimized over 10 minutes with a look ahead of five 10-minute intervals. Input data for both included:

- The actual load, wind, and solar profiles
- Unit commitment schedules from the DA SCUC
- Detailed generator characteristics
- Contingency reserve, regulation reserve, and flexibility reserve for each specified BA or group of BAs
- Transmission hurdle rates between BAs
- Detailed nodal transmission network of the WI

The RT SCED simulation resulted in either an hourly or a 10-minute dispatch for the Interconnection.

The flexibility reserves to cover the renewable variability and uncertainty were included in both the DA SCUC and the RT SCED. The flexibility reserves were defined at the BA level.

Results and Analysis

The 2-stage DA-RT sequential simulation was performed using the PUC EIM study database. Two RT simulations were performed: Hourly Case and 10-Minute Case. The energy generation by technology from these two RT simulations is listed in Table 12.

Table 12: Comparison of Generation by Technology (PUC EIM)

Technology	Hourly Case		10-Minute Case		Difference	
	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)
Biomass	16,009	2%	16,758	2%	749	0.07%
CC	191,738	19%	177,896	17%	(13,842)	-1.35%
Coal	277,648	27%	292,224	28%	14,576	1.42%
CT	43,844	4%	40,868	4%	(2,975)	-0.29%
DR	206	0%	132	0%	(74)	-0.01%
Geo-Thermal	36,062	4%	36,171	4%	109	0.01%
Hydro	245,624	24%	246,994	24%	1,370	0.13%

Table 12: Comparison of Generation by Technology (PUC EIM)						
	Hourly Case		10-Minute Case		Difference	
Technology	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)
Nuclear	77,010	7%	77,805	8%	794	0.08%
Other	5,579	1%	5,487	1%	(91)	-0.01%
Pumped Storage	4,550	0%	4,550	0%	-	0.00%
Pumping Load	0	0%	-	0%	(0)	0.00%
Small Hydro	7,897	1%	7,987	1%	90	0.01%
Solar	31,836	3%	31,836	3%	0	0.00%
Steam	7,399	1%	6,732	1%	(667)	-0.06%
Wind	82,013	8%	82,013	8%	0	0.00%
Total	1,027,414	100%	1,027,454	100%	39	0.00%

The values in the green colored rows are counted toward Renewable Portfolio Standards. While the generation from wind and solar resources is around 11 percent, the total generation from all renewable resources is closer to 18 percent, just as in the PNNL Scenario.

The annual total production cost values for the cases are listed in Table 13. In the Hourly Case, the annual total production cost was $19.6 billion. In the 10-Minute Case, the annual production cost was reduced to $19.2 billion. The production cost savings was $349 million.

There was 1,581 GWh of USE and 848 GWh of reserve shortfalls in the Hourly Case. In the 10-Minute Case, the USE was reduced to 1 GWh and the reserve shortfall was reduced to 216 GWh. When counting the USE and reserve shortfalls priced at $85/MWh, the production cost savings was bumped up to $537 million.

Table 13: Comparison of Production Costs in the PUC EIM Scenario								
	Hourly Case			10-Minute Case			Cost Difference without USE and Reserve Shortfall	Cost Difference with USE and Reserve Shortfall
Month	Total Generation Cost ($000)	USE (GWh)	BA Reserve shortfall (GWh)	Total Generation Cost ($000)	USE (GWh)	BA Reserve shortfall (GWh)	Total Generation Cost Savings ($000)	Total Generation Cost Savings ($000)
January, 2020	1,535,528	45	85	1,499,141	-	19	36,387	45,819
February, 2020	1,312,783	202	65	1,280,194	0	19	32,589	53,604
March, 2020	1,427,724	199	94	1,396,068	0	25	31,656	54,486
April, 2020	1,183,321	125	75	1,151,663	-	27	31,658	46,292
May, 2020	1,312,527	135	62	1,287,646	0	21	24,881	39,862
June, 2020	1,526,415	91	48	1,501,255	0	12	25,160	35,957
July, 2020	2,218,096	222	56	2,191,369	0	9	26,727	49,595
August, 2020	2,229,174	104	56	2,200,318	1	13	28,856	41,191
September, 2020	1,892,066	61	56	1,869,363	0	16	22,703	31,351
October, 2020	1,721,765	65	88	1,684,847	0	17	36,918	48,490
November, 2020	1,495,151	133	77	1,470,244	0	22	24,906	40,901
December, 2020	1,734,370	199	86	1,707,432	0	16	26,939	49,850
Total	**19,588,919**	**1,581**	**848**	**19,239,539**	**1**	**216**	**349,380**	**537,399**

The comparison of the production cost by region between the Hourly Case and the 10-Minute Case is listed in Table 14. The production cost by region includes only the total generation costs in the regions and does not include the region exchange costs and revenues.

While Table 14 shows the difference in production costs between the Hourly Case and the 10-Minute Case by BA, it should not be considered as a list of estimated benefits for each BA. The figures do not take into account additional revenues or savings from scheduled power transactions or Energy Imbalance Service between BAs to accommodate the change in the overall generation mix.

Table 14: Production Cost Comparison by BA (PUC EIM Scenario)

BA	Hourly Case Total Production Cost ($k)	10-Minute Case Total Production Cost ($k)	Total Production Cost Difference (10-Minute Case - Hourly Case)	
			($k)	Difference %
AESO	1,257,233	1,236,377	(20,857)	-2%
APS	209,224	215,325	6,102	3%
AVA	1,017,595	1,055,367	37,772	4%
BANC	3,017,281	3,035,612	18,331	1%
BCTC	382,743	354,340	(28,403)	-7%
BPA	901,579	903,290	1,711	0%
CAISO	333,105	323,797	(9,308)	-3%
CFE	162,113	161,867	(247)	0%
CHPD	2,736	3,032	296	11%
DOPD	22,598	21,951	(648)	-3%
EPE	-	-	-	0%
GCPD	601,089	525,637	(75,451)	-13%
IID	356,473	360,316	3,842	1%
IPC	267,390	262,315	(5,075)	-2%
LDWP	122,977	108,976	(14,001)	-11%
NEVP	1,060,337	1,047,661	(12,676)	-1%
NWMT	1,808,234	1,794,411	(13,823)	-1%
PACE	446,489	461,122	14,633	3%
PACW	63,638	64,766	1,129	2%
PGN	704,572	696,809	(7,763)	-1%
PNM	154,177	133,433	(20,744)	-13%
PSC	354,424	340,972	(13,453)	-4%
PSE	2,002,538	1,958,531	(44,007)	-2%
SCL	665,704	667,775	2,071	0%

Table 14: Production Cost Comparison by BA (PUC EIM Scenario)				
BA	Hourly Case Total Production Cost ($k)	10-Minute Case Total Production Cost ($k)	Total Production Cost Difference (10-Minute Case - Hourly Case) ($k)	Difference %
SPP	167,002	153,812	(13,190)	-8%
SRP	164,153	150,720	(13,434)	-8%
TEP	445,367	464,019	18,651	4%
TIDC	1,504	-	(1,504)	-100%
TPWR	-	-	-	0%
WACM	-	-	-	0%
WALC	217,283	208,707	(8,576)	-4%
WAUW	360,167	333,145	(27,022)	-8%
Total	**423,785**	**403,331**	**(20,455)**	**-5%**

The following three tables list the comparisons of the emissions for CO_2, NOx, and SO_2 by technology between the Hourly Case and the 10-Minute Case using the WECC EIM study database.

Table 15: CO_2 Emission Comparison by Generator Type (PUC EIM)				
Technology	Hourly Case Total CO_2 Production (ton)	10-Minute Case Total CO_2 Production (ton)	CO_2 Production Difference (10-Minute Case - Hourly Case) (ton)	(%)
CC	82,206,138	81,411,355	(794,783)	-1%
Coal	302,239,236	306,020,155	3,780,919	1%
CT	15,898,166	15,539,739	(358,426)	-2%
Other	2,174,604	2,262,857	88,253	4%
Steam	3,137,124	2,445,377	(691,747)	-22%
Total	**405,655,267**	**407,679,483**	**2,024,216**	**0.5%**

Table 16: NOx Emission Comparison by Generator Type (PUC EIM)				
Technology	Hourly Case Total NOx Production (ton)	10-Minute Case Total NOx Production (ton)	NOx Production Difference (10-Minute Case - Hourly Case) (ton)	(%)
CC	82,093	82,020	(73)	0%
Coal	587,700	595,083	7,383	1%
CT	16,791	16,366	(426)	-3%
Other	437	441	4	1%
Steam	4,621	4,373	(248)	-5%
Total	**691,643**	**698,283**	**6,641**	**1.0%**

Table 17: SO_2 Emission Comparison by Generator Type (PUC EIM)				
Technology	Hourly Case Total SO_2 Production (ton)	10-Minute Case Total SO_2 Production (ton)	SO_2 Production Difference (10-Minute Case - Hourly Case) (ton)	(%)
CC	4,030	4,053	23	1%
Coal	471,078	478,037	6,959	1%
CT	1,122	1,110	(12)	-1%
Other	27	26	(1)	-4%
Steam	619	550	(69)	-11%
Total	**476,876**	**483,776**	**6,900**	**1.4%**

High VG Penetration Scenario

One of the goals of the study was to determine how the benefits of intra-hour scheduling would be affected by high levels of VG that may exist in the future.

Simulation Assumptions

The simulation assumptions and methodology were the same as used for the PNNL Scenario, with one exception: resource definition. The High VG Penetration Scenario had more wind and solar resources included in the generation profile. A complete breakdown of the generators used in this scenario can be found in Appendix B.

Resource Definition

For this study, the high VG penetration scenario used was the same scenario used as the high wind/low solar case in the NREL Western Wind and Solar Integration Study (WWSIS), Phase 2. While the wind and solar resource definition of this High VG Scenario indicate increased generation in most BAs, it is not just a simple scaled up version of the PNNL Scenario or PUC EIM wind and solar resources.

Transmission Expansion

The transmission in the existing TEPPC 2020 PC0 network was not adequate to accommodate the High VG Penetration Scenario, so some transmission expansion assumptions had to be made. The transmission expansion assumptions were added to allow the simulations to deliver the renewable energy at the high VG penetration level. Without the transmission expansion assumptions, the simulation would not have been able to solve and generate results for the High VG Penetration Scenario.

Given that this study is not a transmission expansion study, it is important to note that the transmission expansion methodology was simplistic. The transmission expansion methodology did not include detailed economic or reliability analyses. Nor did it take into account issues such as rights of way, environmental concerns, policy constraints, or any other factor that might normally be considered in detailed transmission planning activities.

The project team took the following steps to create the transmission expansion assumptions:

1. Perform PLEXOS nodal simulation with the renewable generation at the high VG penetration level.
2. For any congested transmission line with the yearly average shadow price greater than $5/MWh, build a parallel transmission with the exact same characteristics of the congested transmission line, and reducing the path impedance.
3. For a congested transmission interface with the yearly average shadow price greater than $5/MWh, increase the transmission interface rating by 500 MW and build a parallel transmission line in the transmission interface if necessary.
4. Re-perform PLEXOS nodal simulation and repeat the process until all monitored transmission lines and interfaces are less than $5/MWh.

The transmission expansion and interface expansion results are listed in Appendix A. The solutions of the transmission expansion indicate that there is more transfer capacity needed to deliver the renewable generation to the load centers under the High VG Penetration Scenario.

Results and Analysis

After finalizing the resource definitions and transmission expansion, the 3-stage DA-HA-RT sequential simulation was performed for the High VG Penetration Scenario for year 2020. Two RT simulations were performed: Hourly Case and 10-Minute Case. The generation by technology from these two RT simulations is listed in Table 18.

Table 18: Comparison of Generation by Technology (High VG Penetration Scenario)

	Hourly Case		10-Minute Case		Difference	
Technology	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)	Total Generation (GWh)	Total Generation (%)
Biomass	13,714	1%	12,881	1%	(833)	-0.08%
CC	129,971	13%	117,610	11%	(12,361)	-1.20%
Coal	192,676	19%	186,577	18%	(6,099)	-0.59%
CT	63,459	6%	60,830	6%	(2,629)	-0.25%
DR	195	0%	143	0%	(52)	-0.01%
Geo-Thermal	34,658	3%	34,853	3%	195	0.02%
Hydro	238,075	23%	241,743	23%	3,668	0.36%
Nuclear	67,847	7%	66,063	6%	(1,784)	-0.17%
Other	5,941	1%	5,742	1%	(200)	-0.02%
Pumped Storage	8,339	1%	8,290	1%	(50)	0.00%
Pumping Load	-	0%	-	0%	-	0.00%
Small Hydro	7,626	1%	7,732	1%	106	0.01%
Solar	59,247	6%	60,630	6%	1,384	0.13%
Steam	8,210	1%	7,375	1%	(835)	-0.08%
Wind	202,422	20%	221,915	21%	19,493	1.89%
Total	**1,032,381**	**100%**	**1,032,384**	**100%**	**4**	**0.00%**

The values in the green colored rows are counted toward Renewable Portfolio Standards. While the generation from wind and solar resources is around 27 percent, the total generation from all renewable resources is closer to 32 percent.

At the high VG penetration level, 33,514 GWh of renewable generation was curtailed in the Hourly Case. In the 10-Minute Case, the renewable generation curtailment was reduced by 20,877 GWh to 12,638 GWh. Table 19 lists the details of the renewable generation curtailments by BA.

Table 19: Comparison of VG Curtailment (High VG Penetration Case)

	Renewable Generation Curtailment (GWh) for the Hourly Case				Renewable Generation Curtailment (GWh) for the 10-Minute Case				Curtailment Reduction (GWh)
Region	CSP	PV	Wind	Total	CSP	PV	Wind	Total	Total
AESO	0	0	648	648	0	0	117	117	531
APS	56	120	160	335	17	44	49	111	224
AVA	0	1	508	509	0	0	89	89	421
BANC	0	0	42	42	0	0	34	34	8
BCTC	0	11	294	305	0	0	1	1	304
BPA	0	0	6	6	0	0	0	0	6
CFE	0	0	0	1	0	0	0	0	1
EPEC	0	0	1	1	0	0	0	0	1
FAR EAST	0	30	55	85	0	1	1	3	82
GCPD	0	66	235	301	0	2	5	7	294
IID	137	87	0	223	2	1	0	4	220
LADWP	0	0	0	0	0	0	0	0	0
MAGIC	36	34	58	127	5	5	2	12	115
NEVP	0	9	2,842	2,851	0	0	397	397	2,453
NWMT	0	15	535	550	0	3	105	108	442
PACE	0	0	1,158	1,159	0	0	285	285	874
PACW	0	0	4	5	0	0	0	0	4
PG&E	0	0	0	0	0	0	0	0	0
PGN	27	114	4,221	4,362	4	29	1,442	1,475	2,887
PNM	1	2	1,339	1,342	0	0	1,313	1,313	29
PSC	0	0	785	785	0	0	553	553	233
PSE	21	2	10	32	2	0	0	2	31
SCE	0	0	0	0	0	0	0	0	0
SCL	0	1	1	1	0	0	0	0	1
SDGE	0	5	50	55	0	0	0	0	55
SPPC	0	67	518	586	0	12	113	124	461
SRP	202	85	16	303	0	0	0	0	302
TEP	0	9	56	64	0	0	5	5	60
TID	0	0	0	0	0	0	0	0	0
TPWR	0	0	0	0	0	0	0	0	0

Table 19: Comparison of VG Curtailment (High VG Penetration Case)									
	Renewable Generation Curtailment (GWh) for the Hourly Case				Renewable Generation Curtailment (GWh) for the 10-Minute Case				Curtailment Reduction (GWh)
Region	**CSP**	**PV**	**Wind**	**Total**	**CSP**	**PV**	**Wind**	**Total**	**Total**
TREAS	0	0	0	0	0	0	0	0	0
WACM	0	550	17,025	17,574	0	323	7,322	7,645	9,930
WALC	77	96	523	696	3	21	60	84	611
WAUW	0	2	564	566	0	1	268	269	296
Total	556	1,306	31,652	33,514	34	444	12,159	12,638	20,877

In addition to the renewable generation curtailment, there was 8,919 GWh of hydro generation curtailment in the Hourly Case, and 5,251 GWh of hydro generation curtailment in the 10-Minute Case.

Along with the renewable and hydro generation curtailment, there was also over-generation (dumped power) in both the Hourly Case and the 10-Minute Case. Table 20 shows the over-generation by BA. The over-generation was reduced from 2,800 GWh in the Hourly Case to 1,953 GWh in the 10-Minute Case.

Table 20: Comparison of Over-Generation (High VG Penetration Case)				
	Hourly Case	10-Minute Case	Difference	
BA	**Total Over-Generation (GWh)**	**Total Over-Generation (GWh)**	**(GWh)**	**Diff %**
AESO	43	6	(37)	-86%
APS	12	6	(6)	-50%
AVA	24	24	(0)	0%
BANC	0	-	(0)	0%
BCTC	34	4	(30)	-88%
BPA	32	57	25	78%
CAISO	2	0	(1)	-50%
CFE	-	-	-	0%
CHPD	2	2	0	0%
DOPD	-	-	-	0%
EPE	-	0	0	0%

Table 20: Comparison of Over-Generation (High VG Penetration Case)				
	Hourly Case	10-Minute Case	Difference	
BA	Total Over-Generation (GWh)	Total Over-Generation (GWh)	(GWh)	Diff %
GCPD	5	5	0	0%
IID	0	-	(0)	0%
IPC	35	54	19	54%
LDWP	3	1	(2)	-67%
NEVP	1	0	(1)	-100%
NWMT	31	4	(27)	-87%
PACE	47	46	(1)	-2%
PACW	149	107	(43)	-29%
PGN	0	1	1	0%
PNM	109	35	(75)	-69%
PSC	1,313	1,313	0	0%
PSE	134	44	(90)	-67%
SCL	13	5	(7)	-54%
SPP	14	7	(6)	-43%
SRP	0	0	(0)	0%
TEP	0	-	(0)	0%
TIDC	-	-	-	0%
TPWR	14	4	(10)	-71%
WACM	722	216	(506)	-70%
WALC	7	3	(4)	-57%
WAUW	54	8	(47)	-87%
Total	**2,800**	**1,953**	**(847)**	-30%

In PSC and WACM, the over-generation numbers are particularly pronounced. This is because of the many must-run coal units that are not flexible enough to cover the variability and uncertainty of wind generation.

Comparing the generation by technology (shown in Table 18), it is evident that the reduced renewable and hydro generation curtailment in the 10-Minute Case are accompanied with reduced thermal generation. The resultant production cost differences are presented in Table 21.

Table 21: Comparison of Production Costs (High VG Penetration Case)								
	Hourly Case			10-Minute Case			Cost Difference without USE and Reserve Shortfall	Cost Difference with USE and Reserve Shortfall
Month	Total Generation Cost ($000)	USE (GWh)	BA Reserve shortfall (GWh)	Total Generation Cost ($000)	USE (GWh)	BA Reserve shortfall (GWh)	Diff. Total Generation Cost ($000)	Diff. Total Generation Cost($000)
January, 2020	1,415,137	0	163	1,309,079	-	128	106,058	109,057
February, 2020	1,249,868	0	96	1,159,502	-	66	90,367	92,961
March, 2020	1,298,013	1	189	1,203,044	-	135	94,969	99,643
April, 2020	1,119,838	0	111	1,042,105	-	-	77,733	87,198
May, 2020	1,263,403	0	248	1,180,966	-	-	82,437	103,548
June, 2020	1,456,627	0	131	1,375,248	-	-	81,379	92,523
July, 2020	1,990,569	2	225	1,898,761	0	149	91,808	98,336
August, 2020	1,964,478	0	166	1,878,809	-	112	85,669	90,281
September, 2020	1,646,738	1	161	1,568,160	-	109	78,578	83,043
October, 2020	1,498,881	0	114	1,420,617	-	81	78,264	81,055
November, 2020	1,336,670	0	220	1,246,698	-	187	89,972	92,777
December, 2020	1,533,949	1	155	1,437,631	-	120	96,317	99,307
Sum	**17,774,171**	**6**	**1,979**	**16,720,620**	**0**	**1,089**	**1,053,551**	**1,129,729**

The total production cost savings in the Western Interconnection was $1.05 billion without considering the USE and reserve shortfall. With the USE and reserve shortfall priced at $85/MWh, the total production cost saving was approximately $1.13 billion.

The comparison of the production cost saving by BA is listed in Table 22. The production cost by BA includes only the total generation costs in the BAs and does not include the BA exchange costs and revenues.

While Table 22 shows the difference in production costs between the Hourly Case and the 10-Minute Case by BA, it should not be considered as a list of estimated benefits for each BA. The figures do not take into account additional revenues or savings from scheduled power transactions or Energy Imbalance Service between BAs to accommodate the change in the overall generation mix.

Table 22: Production Cost Comparison by BA (High VG Penetration Case)

BA	Hourly Case Total Production Cost ($k)	10-Minute Case Total Production Cost ($k)	Total Production Cost Difference (10-Minute Case - Hourly Case) ($k)	Diff %
AESO	2,361,997	2,279,594	(82,403)	-3%
APS	1,067,634	1,092,274	24,640	2%
AVA	191,281	154,518	(36,763)	-19%
BANC	411,958	368,773	(43,184)	-10%
BCTC	217,795	208,920	(8,875)	-4%
BPA	801,953	793,705	(8,248)	-1%
CAISO	4,330,636	4,047,888	(282,748)	-7%
CFE	585,466	562,045	(23,422)	-4%
CHPD	22	-	(22)	-100%
DOPD	-	-	-	0%
EPE	228,253	190,793	(37,460)	-16%
GCPD	-	-	-	0%
IID	199,522	184,778	(14,744)	-7%
IPC	125,842	107,926	(17,917)	-14%
LDWP	343,849	317,387	(26,462)	-8%
NEVP	1,009,307	894,391	(114,916)	-11%
NWMT	183,829	171,247	(12,582)	-7%
PACE	889,448	872,793	(16,655)	-2%
PACW	306,986	253,738	(53,248)	-17%

Table 22: Production Cost Comparison by BA (High VG Penetration Case)				
BA	Hourly Case Total Production Cost ($k)	10-Minute Case Total Production Cost ($k)	Total Production Cost Difference (10-Minute Case - Hourly Case)	
			($k)	Diff %
PGN	405,188	407,751	2,563	1%
PNM	497,235	474,245	(22,990)	-5%
PSC	812,737	701,051	(111,685)	-14%
PSE	481,083	429,263	(51,820)	-11%
SCL	-	-	-	0%
SPP	333,704	315,112	(18,592)	-6%
SRP	615,152	587,782	(27,369)	-4%
TEP	242,555	242,407	(148)	0%
TIDC	95,246	89,111	(6,135)	-6%
TPWR	-	-	-	0%
WACM	609,230	590,337	(18,894)	-3%
WALC	426,265	382,791	(43,474)	-10%
WAUW	-	-	-	0%
Total	**17,774,171**	**16,720,620**	**(1,053,551)**	**-6%**

In the 10-Minute Case, the Un-served Energy was reduced from six GWh to nearly zero GWh.

At the high VG penetration level, there were excessive reserve shortfalls in both the Hourly Case and the 10-Minute Case. Table 24 shows the comparison of the USE and reserve shortfalls by BA by product. In the 10-Minute Case, the USE was reduced to zero and the overall reserve shortfalls were reduced by 890 GWh.

These high reserve shortfalls indicate that more flexible resources are necessary to meet this high level of VG penetration. More generators able to provide flexibility reserves would need to be added to the aggregate WI generation portfolio.

For the 10-Minute case, the maximum instantaneous reserve capacity shortfall was more than 1800 MW, compared to more than 1900 MW in the Hourly Case. Table 23 compares the reserve shortfall capacity at different levels between the two cases.

Table 23: Reserve Shortfall Capacity Comparison		
	Hourly Case	**10-Minute Case**
Maximum	1910 MW	1814 MW
99th Percentile	926 MW	637 MW
90th Percentile	477 MW	291 MW
50th Percentile	151 MW	81 MW

For this study, the $85/MWh penalty for reserve shortfall in the production cost calculation is indicative of the cost of generation for a CT providing reserve capabilities. This penalty addition to the production costs is meant to approximate the cost impact of having to run additional generators to serve the reserve needs. Considering this cost attribution, the overall benefit calculation of $1.13 billion is more likely compared to the benefit calculation of $1.05 billion, which does not consider reserve shortfall. But both of these numbers need to be considered carefully, given that the dataset didn't provide for sufficient reserve generation in the High VG Penetration Scenario.

The BAs with the most reserve shortfalls were NWMT, PACW, and WACM (see Table 24). This fact indicates there are capacity shortages or ramp capacity shortages in these regions because of the high VG penetration in these regions. The shortfalls are reduced substantially in the free 10-minute BA exchange re-dispatch.

Table 24: Comparison of Un-served Energy and Reserve Shortfalls (High VG Penetration Case)												
	Production Shortfall (GWh) for the Hourly Case					Production Shortfall (GWh) for the 10-Minute Case					Shortfall Reduction (GWh) for the 10-Minute Case	
BA	USE	Spin	Reg-up	Reg-down	Total	USE	Spin	Reg-up	Reg-down	Total	Total	%
AESO	1	6	7	2	16	-	3	1	1	5	11	67%
APS	0	0	0	0	1	-	-	-	-	-	1	100%
AVA	0	9	23	16	49	-	2	8	12	22	27	56%
BANC	2	3	6	1	11	0	-	0	1	1	10	89%
BCTC	0	0	2	-	2	-	1	0	-	1	1	47%
BPA	-	1	0	0	1	-	-	-	0	0	1	95%
CAISO	1	-	-	-	1	-	-	-	-	-	1	100%
CFE	2	0	0	4	6	-	-	-	-	-	6	100%
CHPD	-	-	-	-	-	-	-	-	0	0	(0)	0%
DOPD	-	0	0	0	0	-	-	-	0	0	0	57%
EPE	-	0	0	0	0	-	-	-	-	-	0	100%
GCPD	-	-	-	-	-	-	-	-	-	-	-	0%
IID	-	4	18	1	23	-	-	-	0	0	23	99%
IPC	-	0	0	-	0	-	-	-	-	-	0	100%
LDWP	-	5	2	0	7	-	-	-	-	-	7	100%
NEVP	-	1	1	0	2	-	-	-	0	0	2	98%
NWMT	-	38	158	108	303	-	25	89	98	212	91	30%
PACE	-	0	0	0	0	-	-	-	-	-	0	100%
PACW	0	237	476	404	1,117	-	160	346	391	896	221	20%
PGN	-	0	0	0	0	-	-	-	-	-	0	100%
PNM	-	13	46	31	90	-	4	14	28	46	44	49%

Table 24: Comparison of Un-served Energy and Reserve Shortfalls (High VG Penetration Case)												
	Production Shortfall (GWh) for the Hourly Case					Production Shortfall (GWh) for the 10-Minute Case					Shortfall Reduction (GWh) for the 10-Minute Case	
BA	USE	Spin	Reg-up	Reg-down	Total	USE	Spin	Reg-up	Reg-down	Total	Total	%
PSC	0	0	0	-	0	-	-	-	-	-	0	100%
PSE	-	7	5	4	16	-	2	1	0	4	12	76%
SCL	-	-	-	-	-	-	-	-	1	1	(1)	0%
SPP	-	1	2	0	4	0	-	0	0	0	3	94%
SRP	-	3	0	0	3	-	-	-	-	-	3	100%
TEP	-	0	0	1	1	-	-	-	-	-	1	100%
TIDC	-	5	0	0	5	-	4	0	-	4	1	20%
TPWR	-	-	0	0	0	-	-	-	0	0	(0)	0%
WACM	-	39	113	134	286	-	32	80	133	245	41	14%
WALC	-	7	27	7	40	-	2	6	5	14	27	66%
WAUW	-	-	-	-	-	-	-	-	-	-	-	0%
Total	**6**	**381**	**888**	**711**	**1,985**	**0**	**235**	**546**	**670**	**1,451**	**534**	**27%**

The following three tables list the comparisons of the emission productions for CO_2, NOx, and SO_2 by technology between the Hourly Case and the 10-Minute Case.

Table 25: CO_2 Production Cost Comparison by Generator Type (High VG Penetration Case)

Technology	Hourly Case Total CO_2 Production (ton)	10-Minute Case Total CO_2 Production (ton)	CO_2 Production Difference (10-Minute Case - Hourly Case) (ton)	(%)
CC	56,812,308	51,514,146	(5,298,163)	-9%
Coal	196,513,150	190,771,769	(5,741,381)	-3%
CT	38,666,220	37,133,068	(1,533,152)	-4%
Other	2,235,292	1,917,680	(317,612)	-14%
Steam	4,536,615	4,138,891	(397,724)	-9%
Total	**298,763,586**	**285,475,553**	**(13,288,032)**	**-4%**

Table 26: NOx Production Cost Comparison by Generator Type (High VG Penetration Case)

Technology	Hourly Case Total NOx Production (ton)	10-Minute Case Total NOx Production (ton)	NOx Production Difference (10-Minute Case - Hourly Case) (ton)	(%)
CC	50,482	45,196	(5,285)	-10%
Coal	382,740	372,801	(9,939)	-3%
CT	44,244	42,428	(1,817)	-4%
Other	1,435	1,229	(206)	-14%
Steam	5,823	5,356	(467)	-8%
Total	**484,724**	**467,010**	**(17,714)**	**-4%**

Table 27: SO_2 Production Cost Comparison by Generator Type (High VG Penetration Case)

Technology	Hourly Case Total SO_2 Production (ton)	10-Minute Case Total SO_2 Production (ton)	SO_2 Production Difference (10-Minute Case - Hourly Case) (ton)	(%)
CC	2,007	1,792	(215)	-11%
Coal	302,532	295,691	(6,841)	-2%
CT	3,722	3,538	(184)	-5%
Other	537	488	(49)	-9%

Table 27: SO_2 Production Cost Comparison by Generator Type (High VG Penetration Case)				
Steam	1,193	1,098	(95)	-8%
Total	**309,991**	**302,607**	**(7,384)**	**-2%**

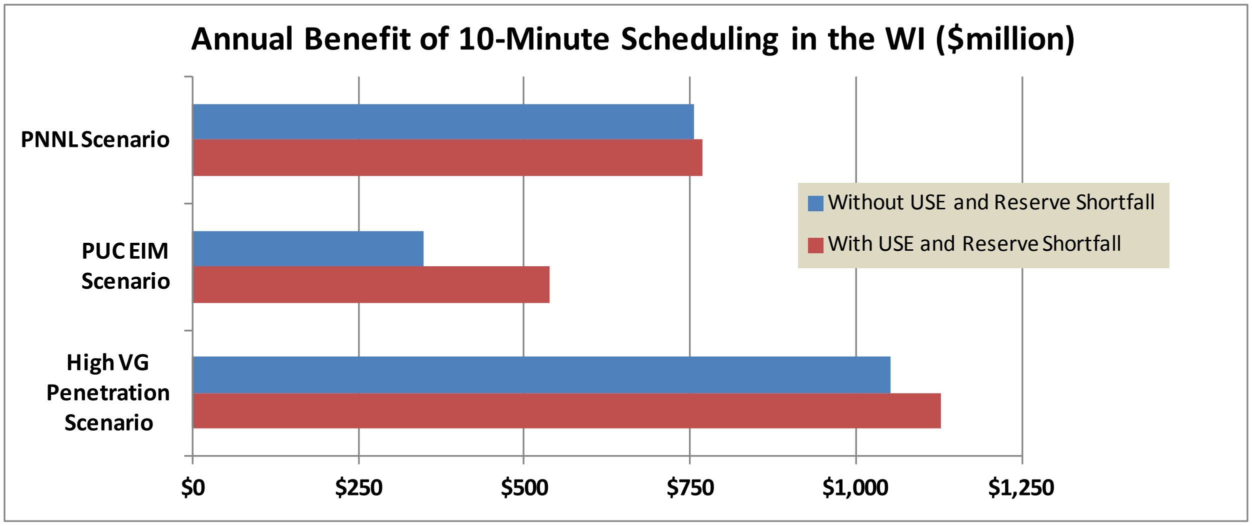
In the 10-Minute Case, less renewable curtailment yields less thermal generation. This results in reduced emissions.

Comparing the Scenarios

Production Cost Benefits

The benefit results of intra-hour scheduling compared with hour scheduling and for the respective assumptions used in each of the scenarios is presented in Figure 6.

Figure 6: Annual Benefit of 10-Minute Scheduling



All of the scenarios show substantial benefits to intra-hour scheduling. These benefits should be considered as aggregate social benefits to the WI.

Considering the Un-served Energy and reserve shortfalls in each scenario served to increase the estimated of benefits of the 10-Minute Case over the Hourly Case. Also, the benefit of 10-minute scheduling appears to increase with increased VG penetration.

Emissions

Both the PNNL Scenario and the PUC EIM Scenario showed a slight increase in emissions in the 10-Minute Case compared to the Hourly Case. This was a result of increased coal generation and decreased gas generation. However, given the current and expected restrictions on coal generation, it may be difficult to achieve increased power production from coal resources.

Conversely, the High VG Penetration Scenario showed a slight decrease in emissions due to reduce wind and solar power curtailment in the 10-Minute Case.

It should be clarified that the increase or decrease in emissions shown in this study are only when comparing the 10-Minute Case to the Hourly Case for the study scenarios. These emission comparisons should not be confused with an estimate of emission changes between present day operation (2012) and future day operation (2020) of the study scenarios.

Limitations

As mentioned earlier, it is difficult to precisely represent and account for all of the details in the Bulk Electric System of the WI. To the extent that the model and datasets incorrectly accounted for commercial agreements and operating methods currently in use, the results may have understated the current “efficiency” of hourly scheduling, and thus overstated the benefit of intra-hour scheduling. The study results should be considered in light of data and model limitations.

Conclusions

A summary of observations and findings are summarized for each scenario below.

PNNL Scenario

1. The production cost saving was $755 million for the entire Western Interconnection from the Hourly Case to the 10-Minute Case ($770 million considering USE and reserve shortfall).
2. The Un-served Energy was reduced from 39 GWh to zero GWh in the 10-Minute Case. This indicates that, when BAs support each other at the 10-minute interval, the BAs can reduce the amount of reserves needed and better share renewable generation variability and uncertainty.
3. The reserve shortfall was reduced from 178 GWh in the Hourly Case to 42 GWh in the 10-Minute Case. Further investigation of the reserve shortfalls in the 10-Minute Case would be necessary to see if the reserve requirements are adequately defined or if there is a shortage of ramp capacity in the WI.
4. In the 10-Minute Case, coal generation was increased and the CC and CT generation was reduced. This may indicate that the coal generation covers the renewable generation over-forecast (i.e., the actual renewable generation is less than the forecasted renewable generation), and the CC and CT generation backs down when actual renewable generation is greater than the forecasted renewable generation. This could also be in large part because efficiencies now obtained from long term contracts, remotely owned generation, trading and exchanges between BAs in the pre-schedule period and reflected in Interchange Schedule obligations were not modeled to the extent they currently are utilized. Further detailed analysis may be needed.
5. Due to coal generation increase and CC and CT generation reductions in the 10-Minute Case, CO_2, NOx, and SO_2 emissions increased in the entire WI relative to the hourly scheduling case.

PUC EIM Scenario

1. The production cost saving was $349 million for the entire Western Interconnection from the Hourly Case to the 10-Minute Case ($537 million considering USE and reserve shortfall).
2. The Un-served Energy was reduced from 1,581 GWh to 1 GWh in the 10-Minute Case.
3. The reserve shortfall was reduced from 848 GWh in the Hourly Case to 216 GWh in the 10-Minute Case. Further investigation of the reserve shortfalls in the 10-Minute Case would be necessary to see if the reserve requirements are adequately defined or if there is a shortage of ramp capacity in the WI.
4. In the 10-Minute Case, coal generation was increased and the CC and CT generation was reduced. This may indicate that the coal generation covers the renewable generation over-forecast (i.e., the actual renewable generation is less

than the forecasted renewable generation), and the CC and CT generation backs down when actual renewable generation is greater than the forecasted renewable generation. This could also be in large part because efficiencies now obtained from long term contracts, remotely owned generation, trading and exchanges between BAs in the pre-schedule period and reflected in Interchange Schedule obligations were not modeled to the extent they currently are utilized. Further detailed analysis may be needed.

5. Due to coal generation increase and CC and CT generation reductions in the 10-Minute Case, CO_2, NOx, and SO_2 emissions increased in the entire WI relative to the hourly scheduling case.

High VG Penetration Scenario

1. The total production cost saving was $1.05 billion from the Hourly Case to the 10-Minute Case ($1.13 billion considering USE and reserve shortfall). But both of these numbers need to be considered carefully, given that the dataset didn't provide for sufficient reserve generation in the High VG Penetration Scenario.
2. The Un-Served energy was reduced from 6 GWh in the Hourly Case to zero GWh in the 10-Minute Case.
3. At the high VG Penetration level, the simulations of both cases showed substantial amount of renewable and hydro generation curtailment. The renewable generation curtailment was reduced from 33,514 GWh in the Hourly Case to 12,638 GWh in the 10-Minute Case. The hydro generation curtailment is reduced from 8,919 GWh in the Hourly Case to 5,251 GWh in the 10-Minute Case.
4. Though there was substantial renewable and hydro generation curtailment, dumped power occurred in both cases. The dumped power was reduced from 2,800 GWh in the Hourly Case to 1,953 GWh in the 10-Minute Case.
5. There was a substantial amount of reserve shortfalls in both cases. The reserve shortfall was reduced from 1,979 GWh in the Hourly Case to 1,089 GWh in the 10-Minute Case. Further investigation of the reserve shortfalls in the Hourly Case would be necessary to see if the reserve requirements are adequately defined or if there is a shortage of ramp capacity in the WI.
6. Due to less renewable and hydro generation curtailment, thermal generation from all technologies was reduced. Consequently, CO_2, NOx, and SO_2 emissions increased in the entire WI.

Areas for Additional Study

As with most research efforts, this study has revealed areas that could be further analyzed to build upon the findings of this report.

As shown by the different numbers in each scenario, the estimated benefits of 10-minute scheduling are dependent upon the assumptions and simulation methodology employed. There are many assumptions that could be modified to determine how sensitive the results are to those assumptions. The following is a short list of examples:

- Representation of the efficiencies produced by pre-arrangements in the pre-schedule periods
- Hurdle rates
- Regulation and load following reserve levels and requirements
- Variable Generation forecasting methods.
- Penalty prices for Un-served Energy, reserve shortfall, and over generation
- Fuel prices
- Resource definitions (location, generation profile, maximum capacity, fuel costs, tax adders, etc.)
- BA participation
- Other intra-hour schedule intervals
- Effects of L_{10} relaxation and Reliability Based control
- Hydro modeling and water year assumptions
- Dynamic Transfer Capacity increases, and other transmission expansion effects

While this study analyzed 10-minute scheduling time steps, other entities across North America have been interested in other intra-hour time steps, such as 5-minute, 15-minute, and 30-minute. Taking the scenarios from this study, similar simulations could be run to analyze the impact of different scheduling intervals compared to hourly scheduling.

As was indicated for the High VG Penetration Scenario, this study did not engage in a full transmission expansion study when defining necessary transmission to allow for the High VG Penetration simulation to run. Moreover, the results indicate that the High VG Penetration Scenario needed more reserve generation in the resource portfolio. A more detailed transmission expansion study would be able to provide more accurate transmission assumptions. In addition, a detailed loads and resources study would be able to refine the generator resource definitions. With improved transmission and generation assumptions, analyses for the High VG Penetration Scenario could be more robust.

There are current efforts underway in the Northwest Power Pool Market Assessment and Coordination Committee and the Southwest Variable Energy Resource Initiative group seeking to further analyze some of these areas. Within these groups, additional subject matter experts will refine assumptions and simulation methodologies to improve the estimates of benefits.

Appendix A – Present Operation in the Western Interconnection

Present Operation in Western Interconnection

Each BA in the WI is independently responsible for meeting its own demand via Unit Commitment and interchange. The operation of a BA can be generally described as follows:

- **Hourly Day-ahead Unit Commitment (UC) and scheduling**. Each BA performs a DA Unit Commitment and generation scheduling to meet its DA forecasted demand. The DA forecasted renewable generation profiles, load forecasts, and interchange obligations are used in the Unit Commitment. The BA on-line capacity, net of scheduled interchange, will meet or exceed the BA hourly demands and reliability requirements. Each BA holds a certain amount of on-line capacity or off-line quick-start capacity to meet the contingency reserves requirements; i.e., spinning and non-spinning reserves. Also, the Unit Commitment for each BA will honor the regulation up and down reserves. Recently, many BAs introduced flexibility up and down reserves to augment traditional load following reserve requirements to accommodate the renewable generation variable and uncertainty. The DA unit comment and economic dispatch determine the power exchange between BAs to minimize the system cost.

- **Hourly Hour-ahead UC and scheduling**. Hour ahead operation in the present systems reflect trading, bi-lateral agreements, tagging, markets, decisions about short time startup of fast responding units, and use of hydro resources to augment DA decisions on Unit Commitment. DA Unit Commitment decisions for the long start-up generators are locked in during the DA commitment. In some BAs (such as CAISO) with an hour-ahead (HA) market, HA Unit Commitment is performed at 75 minutes ahead of each trading hour. In other BAs, the Unit Commitment will be performed on an ongoing basis when there is latest load and renewable generation forecasts, or based on the generation and transmission facility availability changes. In this report, this kind of Unit Commitment in general is called the hour-ahead Unit Commitment. The exchange schedules between BAs determined in the DA are revised in the HA scheduling of committed generation. In the HA Unit Commitment and scheduling, the hour-ahead renewable generation forecast is used. The reserve requirements in the DA unit commitment are verified or modified in the HA Unit Commitment and dispatch as well.

- **Intra-hourly Real-time economic dispatch**. The real-time (RT) dispatch is performed at an intra-hourly interval to accommodate the actual intra-hourly load and renewable generation variability and uncertainty. Only the contingency reserve requirements and the regulation up / down requirements are honored in the real time dispatch. In contrast, the flexibility reserve requirements are relaxed in the real-time economic dispatch.

In the current operation practice in the WI, BA interchange is generally scheduled on an hourly basis from a process including the DA Unit Commitment, HA Unit Commitment, and dispatch process. In real-time, BAs must manage actual interchange to schedules to meet frequency and reliability requirements defined by control performance standards (CPS). While practicality allows actual interchange to deviate slightly from scheduled interchange, CPS2 requires that 90 percent of the 10-minute average Area Control Error (ACE)[7] values over the course of a month are within a tolerance band based on the size of the BA; i.e., L_{10}.

[7] ACE is a measure of the difference between actual and scheduled interchange, adjusted for system frequency and meter error.

Appendix B – Generator Capacity Values for the Three Scenarios

Table 28: Generator Capacity - PNNL Scenario					
BA	Generator Type				
	biomass	CC	Coal	CT	DR
AESO	337	4,520	5,881	4,477	11
APS	35	4,226	3,101	1,127	105
AVA	165	528	-	244	-
BANC	18	1,456	-	416	51
BCTC	542	240	-	66	-
BPA	136	3,286	1,456	102	-
CAISO	884	18,283	232	9,016	4,300
CFE	-	1,896	-	805	-
CHPD	-	-	-	-	40
DOPD	-	-	-	-	-
EPE	-	510	-	69	101
GCPD	-	-	-	-	-
IID	55	117	-	375	-
IPC	-	300	15	531	367
LDWP	7	1,779	1,847	955	-
NEVP	16	4,654	275	1,160	316
NWMT	-	120	2,511	-	-
PACE	-	2,418	7,578	405	848
PACW	57	1,010	-	100	45
PGN	64	1,169	510	-	-
PNM	68	810	1,892	636	45
PSC	-	2,381	3,259	2,648	349
PSE	31	711	-	606	-
SCL	-	-	-	-	-
SPP	23	688	768	400	121
SRP	-	5,154	3,075	944	490
TEP	-	-	1,705	203	173
TIDC	-	319	-	-	-
TPWR	-	-	-	-	-
WACM	-	597	3,846	1,071	-
WALC	-	1,853	350	159	-
WAUW	-	-	-	-	-

Table 29: Generator Capacity - PNNL Scenario					
BA	Generator Type				
	Geothermal	Hydro	Nuclear	Other	Pumped Storage
AESO	-	520	-	12	-
APS	-	0	4,035	-	-
AVA	-	715	-	24	-
BANC	-	1,359	-	-	-
BCTC	-	10,107	-	-	-
BPA	136	18,342	1,160	-	-
CAISO	2,499	4,927	4,486	401	1,809
CFE	806	-	-	-	-
CHPD	-	1,551	-	-	-
DOPD	-	-	-	-	-
EPE	-	-	-	193	-
GCPD	-	1,923	-	-	-
IID	732	-	-	61	-
IPC	63	1,658	-	36	-
LDWP	-	159	-	-	1,272
NEVP	-	-	-	177	-
NWMT	-	440	-	119	-
PACE	202	77	-	-	-
PACW	-	1,044	-	-	-
PGN	58	584	-	-	-
PNM	15	35	-	50	-
PSC	-	20	-	148	324
PSE	-	171	-	8	-
SCL	-	1,377	-	-	-
SPP	614	5	-	121	-
SRP	-	29	-	-	146
TEP	-	-	-	-	-
TIDC	-	145	-	-	-
TPWR	-	728	-	-	-
WACM	-	1,200	-	20	236
WALC	-	2,266	-	-	-
WAUW	-	75	-	140	-

Table 30: Generator Capacity - PNNL Scenario					
BA	Generator Type				
	Pumping Load	Small Hydro	Solar	Steam	Wind
AESO	-	30	-	78	3,969
APS	-	-	470	514	204
AVA	-	36	-	-	246
BANC	254	67	-	-	-
BCTC	-	90	-	904	1,105
BPA	-	174	32	131	6,694
CAISO	2,260	960	9,498	1,120	6,693
CFE	-	-	-	304	10
CHPD	-	-	-	-	-
DOPD	-	-	-	-	-
EPE	-	-	70	490	-
GCPD	-	-	-	-	-
IID	-	74	925	159	289
IPC	-	197	11	7	334
LDWP	-	-	1,083	1,451	623
NEVP	-	-	707	-	-
NWMT	-	-	-	-	842
PACE	-	61	-	238	1,713
PACW	-	80	-	64	1,142
PGN	-	88	-	15	1,214
PNM	-	-	331	100	901
PSC	-	-	1,738	50	2,398
PSE	-	10	-	-	153
SCL	-	9	-	-	-
SPP	-	3	110	225	150
SRP	-	30	796	513	-
TEP	-	-	305	248	-
TIDC	-	15	-	-	-
TPWR	-	-	-	-	-
WACM	-	28	-	57	1,220
WALC	-	-	337	20	-
WAUW	-	-	-	-	-

Table 31: Generator Capacity – PUC EIM Scenario					
BA	**Generator Type**				
	biomass	**CC**	**Coal**	**CT**	**DR**
AESO	337	4,520	5,881	4,477	11
APS	35	4,226	3,101	1,127	105
AVA	165	528	-	244	-
BANC	18	1,456	-	416	51
BCTC	542	240	-	66	-
BPA	136	3,286	1,456	102	-
CAISO	884	18,283	232	9,016	4,300
CFE	-	1,896	-	805	-
CHPD	-	-	-	-	40
DOPD	-	-	-	-	-
EPE	-	510	-	69	101
GCPD	-	-	-	-	-
IID	55	117	-	375	-
IPC	-	300	15	531	367
LDWP	7	1,779	1,847	955	-
NEVP	16	4,654	275	1,160	316
NWMT	-	120	2,511	-	-
PACE	-	2,418	7,578	405	848
PACW	57	1,010	-	100	45
PGN	64	1,169	510	-	-
PNM	68	810	1,892	636	45
PSC	-	2,381	3,259	2,648	349
PSE	31	711	-	606	-
SCL	-	-	-	-	-
SPP	23	688	768	400	121
SRP	-	5,154	3,075	944	490
TEP	-	-	1,705	203	173
TIDC	-	319	-	-	-
TPWR	-	-	-	-	-
WACM	-	597	3,846	1,071	-
WALC	-	1,853	350	159	-
WAUW	-	-	-	-	-

Table 32: Generator Capacity – PUC EIM Scenario					
BA	Generator Type				
	Geothermal	Hydro	Nuclear	Other	Pumped Storage
AESO	-	520	-	12	-
APS	-	0	4,035	-	-
AVA	-	715	-	24	-
BANC	-	1,359	-	-	-
BCTC	-	10,107	-	-	-
BPA	136	18,342	1,160	-	-
CAISO	2,499	4,927	4,486	401	1,809
CFE	806	-	-	-	-
CHPD	-	1,551	-	-	-
DOPD	-	-	-	-	-
EPE	-	-	-	193	-
GCPD	-	1,923	-	-	-
IID	732	-	-	61	-
IPC	63	1,658	-	36	-
LDWP	-	159	-	-	1,272
NEVP	-	-	-	177	-
NWMT	-	440	-	119	-
PACE	202	77	-	-	-
PACW	-	1,044	-	-	-
PGN	58	584	-	-	-
PNM	15	35	-	50	-
PSC	-	20	-	148	324
PSE	-	171	-	8	-
SCL	-	1,377	-	-	-
SPP	614	5	-	121	-
SRP	-	29	-	-	146
TEP	-	-	-	-	-
TIDC	-	145	-	-	-
TPWR	-	728	-	-	-
WACM	-	1,200	-	20	236
WALC	-	2,266	-	-	-
WAUW	-	75	-	140	-

Table 33: Generator Capacity – PUC EIM Scenario					
BA	Generator Type				
	Pumping Load	Small Hydro	Solar	Steam	Wind
AESO	-	30	-	78	2,969
APS	-	-	470	514	201
AVA	-	36	-	-	535
BANC	254	67	-	-	-
BCTC	-	90	-	904	1,105
BPA	-	174	20	131	7,026
CAISO	2,260	960	9,161	1,161	6,684
CFE	-	-	-	304	10
CHPD	-	-	-	-	-
DOPD	-	-	-	-	-
EPE	-	-	70	490	-
GCPD	-	-	-	-	-
IID	-	74	925	159	286
IPC	-	197	1	7	334
LDWP	-	-	617	1,451	623
NEVP	-	-	707	-	-
NWMT	-	-	-	-	838
PACE	-	61	-	238	1,713
PACW	-	80	-	64	1,141
PGN	-	88	-	15	810
PNM	-	-	331	100	901
PSC	-	-	1,038	50	2,390
PSE	-	10	-	-	153
SCL	-	9	-	-	-
SPP	-	3	110	225	150
SRP	-	30	796	513	-
TEP	-	-	305	248	-
TIDC	-	15	-	-	-
TPWR	-	-	-	-	-
WACM	-	28	-	57	1,216
WALC	-	-	337	20	-
WAUW	-	13	-	-	-

Table 34: Generator Capacity – High VG Penetration Scenario					
BA	**Generator Type**				
	biomass	**CC**	**Coal**	**CT**	**DR**
AESO	337	4,520	5,881	4,477	11
APS	35	4,226	3,101	1,127	105
AVA	165	528	-	244	-
BANC	18	1,456	-	416	51
BCTC	542	240	-	66	-
BPA	136	3,286	1,456	102	-
CAISO	884	18,283	232	9,016	4,300
CFE	-	1,896	-	805	-
CHPD	-	-	-	-	40
DOPD	-	-	-	-	-
EPE	-	510	-	69	101
GCPD	-	-	-	-	-
IID	55	117	-	375	-
IPC	-	300	15	531	367
LDWP	7	1,779	1,847	955	-
NEVP	16	4,654	275	1,160	316
NWMT	-	120	2,511	-	-
PACE	-	2,418	7,578	405	848
PACW	57	1,010	-	100	45
PGN	64	1,169	510	-	-
PNM	68	810	1,892	636	45
PSC	-	2,381	3,259	2,648	349
PSE	31	711	-	606	-
SCL	-	-	-	-	-
SPP	23	688	768	400	121
SRP	-	5,154	3,075	944	490
TEP	-	-	1,705	203	173
TIDC	-	319	-	-	-
TPWR	-	-	-	-	-
WACM	-	597	3,846	1,071	-
WALC	-	1,853	350	159	-
WAUW	-	-	-	-	-

Table 35: Generator Capacity – High VG Penetration Scenario					
BA	Generator Type				
	Geothermal	Hydro	Nuclear	Other	Pumped Storage
AESO	-	520	-	12	-
APS	-	0	4,035	-	-
AVA	-	715	-	24	-
BANC	-	1,359	-	-	-
BCTC	-	10,107	-	-	-
BPA	136	18,342	1,160	-	-
CAISO	2,499	4,927	4,486	401	1,809
CFE	806	-	-	-	-
CHPD	-	1,551	-	-	-
DOPD	-	-	-	-	-
EPE	-	-	-	193	-
GCPD	-	1,923	-	-	-
IID	732	-	-	61	-
IPC	63	1,658	-	36	-
LDWP	-	159	-	-	1,272
NEVP	-	-	-	177	-
NWMT	-	440	-	119	-
PACE	202	77	-	-	-
PACW	-	1,044	-	-	-
PGN	58	584	-	-	-
PNM	15	35	-	50	-
PSC	-	20	-	148	324
PSE	-	171	-	8	-
SCL	-	1,377	-	-	-
SPP	614	5	-	121	-
SRP	-	29	-	-	146
TEP	-	-	-	-	-
TIDC	-	145	-	-	-
TPWR	-	728	-	-	-
WACM	-	1,200	-	20	236
WALC	-	2,266	-	-	-
WAUW	-	75	-	140	-

Table 36: Generator Capacity – High VG Penetration Scenario					
BA	Generator Type				
	Pumping Load	Small Hydro	Solar	Steam	Wind
AESO	-	30	-	78	7,938
APS	-	-	2,670	514	1,820
AVA	-	36	136	-	2,030
SMUD	254	67	374	-	1,738
BCTC	-	90	-	904	2,210
BPA	-	174	386	131	5,927
CAISO	2,260	960	10,324	1,161	7,631
CFE	-	-	14	304	294
CHPD	-	-	-	-	-
DOPD	-	-	-	-	-
EPE	-	-	216	490	50
GCPD	-	-	272	-	180
IID	-	74	463	159	1,602
IPC	-	197	1	7	809
LDWP	-	-	2,648	1,451	-
NEVP	-	-	1,114	-	1,406
NWMT	-	-	34	-	5,771
PACE	-	61	655	238	6,664
PACW	-	80	64	64	3,586
PGN	-	88	41	15	-
PNM	-	-	562	100	4,733
PSC	-	-	1,307	50	2,727
PSE	-	10	107	-	963
SCL	-	9	88	-	-
SPP	-	3	361	225	2,721
SRP	-	30	2,857	513	180
TEP	-	-	892	248	540
TIDC	-	15	9	-	-
TPWR	-	-	20	-	-
WACM	-	28	1,073	57	11,902
WALC	-	-	1,199	20	2,399
WAUW	-	-	12	-	360

Appendix C – Operating Reserve Assumptions

Data on operating reserve is posted on the WECC VGS website. Because of the large amounts of data, links are provided below instead of including the data in this report.

PNNL Scenario

Regulation:
http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/Shared%20Documents/BA%20Cooperation%20Study/Reserves%20Assumptions/PNNL%20Scenario%20regulation%20requirements.xlsx

Load Following:
http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/Shared%20Documents/BA%20Cooperation%20Study/Reserves%20Assumptions/PNNL%20Scenario%20load%20following%20requirements.xlsx

PUC EIM Scenario

Day-Ahead:
http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/Shared%20Documents/BA%20Cooperation%20Study/Reserves%20Assumptions/PUC%20EIM%20Scenario_DA_2020_TOTALFLEXSPIN.csv

Real-Time:
http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/Shared%20Documents/BA%20Cooperation%20Study/Reserves%20Assumptions/PUC%20EIM%20Scenario_RT_2020_TOTALFLEXSPIN.csv

High VG Penetration Scenario

Regulation:
http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/Shared%20Documents/BA%20Cooperation%20Study/Reserves%20Assumptions/High%20VG%20Penetration%20regulation%20requirements.xlsx

Load Following:

http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/Shared%20Documents/BA%20Cooperation%20Study/Reserves%20Assumptions/High%20VG%20Penetration%20load%20following%20requirements.xlsx

Appendix D – Hurdle Rates for PUC EIM Scenario

Table 37: PUC EIM Scenario Hurdle Rates		
Interface	Backward Hurdle Rate ($/MWh)	Forward Hurdle Rate ($/MWh)
AB_BC	3.63	4.72
AB_NWE	3.63	4.72
AVA_BC	3.63	4.07
AVA_BPA	3.26	4.07
AVA_PACW	5.06	4.07
AVA_PGN	1.62	4.07
AZPS_CA	3.88	9.62
AZPS_IID	4.13	2.12
AZPS_LADWP	9.68	9.62
AZPS_NM	5.43	2.12
AZPS_SRP	2.98	2.12
AZPS_TEP	4.88	2.12
AZPS_WALC	3.64	2.12
BPA_BANC	5.99	8.94
BPA_BC	3.63	3.26
BPA_CA	7.29	11.44
BPA_LADWP	9.68	8.94
BPA_NNV	6.04	6.44
BPA_PACW	5.06	3.26
BPA_PGN	1.62	3.26
BPA_PSE	0.96	3.26
CA_BANC	5.99	3.88
EPE_CA	10.88	20.13
IID_CA	3.88	4.13
IPC_AVA	4.07	11.36
IPC_BPA	3.26	11.36
IPC_NNV	6.04	11.36
IPC_PACW	5.06	11.36
IPC_PGN	1.62	11.36
LADWP_CA	3.88	9.68
NEVP_CA	3.88	8.03
NEVP_LADWP	9.68	8.03
NEVP_WALC	3.64	3.03
NM_EPE	5.63	5.43
NM_WALC	3.64	5.43
NNV_CA	3.88	6.04

Table 37: PUC EIM Scenario Hurdle Rates		
Interface	Backward Hurdle Rate ($/MWh)	Forward Hurdle Rate ($/MWh)
NNV_LADWP	9.68	40
NNV_NEVP	3.03	6.04
NWE_AVA	4.07	14.72
NWE_BPA	3.26	14.72
NWE_PACE	5.06	14.72
NWE_WACM	7.27	12.22
PACE_AZPS	3.62	12.56
PACE_CA	9.68	40
PACE_IPC	3.86	5.06
PACE_LADWP	9.68	40
PACE_NEVP	2.03	12.56
PACE_NNV	6.04	5.06
PACE_WACM	7.27	10.06
PACE_WALC	2.64	12.56
PACW_CA	3.88	10.06
PACW_PGN	1.62	5.06
PSCO_NM	5.43	9.22
PSCO_WALC	3.64	11.72
SRP_CA	3.88	7.98
SRP_TEP	4.88	2.98
SRP_WALC	3.64	2.98
TEP_EPE	5.63	4.88
TEP_NM	5.43	2.38
WACM_NM	5.43	14.77
WACM_PSCO	4.22	14.77
WACM_WALC	3.64	14.77
WALC_CA	3.88	8.64
WALC_IID	4.13	3.64
WALC_LADWP	9.68	8.64
WALC_TEP	4.88	3.64

Appendix E – Transmission Expansion Assumptions

Table 38: Transmission Assumptions for High VG Penetration Scenario

New Transmission Line Name	From Bus	From Region	To Bus	To Region	Capacity (MW)
AEOANT&1_67797 to ANTICLIN_67826 1 1	67797_AEOANT&1	PACE_UT	67826_ANTICLIN	PACE_UT	2000
ARR___PS_11014 to ARROYO_11017 1 1	11014_ARR___PS	EPEC	11017_ARROYO	EPEC	275
ARR___PS_11014 to ARROYO_11017 1 2	11014_ARR___PS	EPEC	11017_ARROYO	EPEC	275
BELL BPA_40091 to BELL SC_40096 1 2	40091_BELL BPA	AVA	40096_BELL SC	AVA	1905.3
BENALTO4_54155 to SARCEE 4_54161 06 1	54155_BENALTO4	AESO	54161_SARCEE 4	AESO	449
BILINGS_62082 to BLGS PHA_62045 1 1	62082_BILINGS	NWMT	62045_BLGS PHA	NWMT	300
BILINGS_62082 to BLGS PHA_62045 1 2	62082_BILINGS	NWMT	62045_BLGS PHA	NWMT	300
BURNS_45029 to SUMMER L_41043 1 2	45029_BURNS	PACW	41043_SUMMER L	BPA	1500
CAL SUB_64025 to CAL S PS_64023 1 1	64025_CAL SUB	SPPC	64023_CAL S PS	SPPC	150
CAL SUB_64025 to CAL S PS_64023 1 2	64025_CAL SUB	SPPC	64023_CAL S PS	SPPC	150
CARIBOU_30250 to BELDENTP_30261 1 1	30250_CARIBOU	PG&E_VLY	30261_BELDENTP	PG&E_VLY	212
CARIBOU_30250 to BELDENTP_30261 1 2	30250_CARIBOU	PG&E_VLY	30261_BELDENTP	PG&E_VLY	212
CBK 500_50791 to CR_NEST1_54458 1 2	50791_CBK 500	BCTC	54458_CR_NEST1	AESO	940
CBK 500_50791 to SEL500_50792 1 1	50791_CBK 500	BCTC	50792_SEL500	BCTC	2485.5
DELTA_45087 to CASCADE_31468 1 1	45087_DELTA	PACW	31468_CASCADE	PG&E_VLY	83
DELTA_45087 to CASCADE_31468 1 2	45087_DELTA	PACW	31468_CASCADE	PG&E_VLY	83
DELTA_45087 to CASCADE_31468 1 3	45087_DELTA	PACW	31468_CASCADE	PG&E_VLY	83
DEVERS_24804 to MIRAGE_24806 1 1	24804_DEVERS	SCE	24806_MIRAGE	SCE	494
DEVERS_24804 to MIRAGE_24806 1 2	24804_DEVERS	SCE	24806_MIRAGE	SCE	494
FOURCORN_14001 to MOENKOPI_14002 1 1	14001_FOURCORN	APS	14002_MOENKOPI	APS	1567.5
GARRISON_40459 to TAFT_41057 1 1	40459_GARRISON	BPA	41057_TAFT	BPA	1732.1
GENESEE4_54525 to HVDC_GN1_54624 DC 1	54525_GENESEE4	AESO	54624_HVDC_GN1	AESO	1200
GLEN PS_79028 to GLENCANY_79031 1 1	79028_GLEN PS	WALC	79031_GLENCANY	WALC	350
GLEN PS_79028 to GLENCANY_79031 1 2	79028_GLEN PS	WALC	79031_GLENCANY	WALC	350

Table 38: Transmission Assumptions for High VG Penetration Scenario					
New Transmission Line Name	From Bus	From Region	To Bus	To Region	Capacity (MW)
GLEN PS_79028 to GLENCANY_79031 1 3	79028_GLEN PS	WALC	79031_GLENCANY	WALC	350
GN1_LN1_90001 to LN1_GN1_90002 1 2	90001_GN1_LN1	AESO	90002_LN1_GN1	AESO	1600
HA PS_18002 to H ALLEN_18001 2 1	18002_HA PS	NEVP	18001_H ALLEN	NEVP	300
HENTAP2_30880 to GATES_30900 1 1	30880_HENTAP2	PG&E_VLY	30900_GATES	PG&E_VLY	478
HENTAP2_30880 to GATES_30900 1 2	30880_HENTAP2	PG&E_VLY	30900_GATES	PG&E_VLY	478
HN1_SN1_90005 to SN1_HN1_ 90006 1 1	90005_HN1_SN1	AESO	90006_SN1_HN1	AESO	1000
HP1_SP1_90007 to SP1_HP1_90008 1 1	90007_HP1_SP1	AESO	90008_SP1_HP1	AESO	1000
HVDC_GP1_54623 to GP1_LP1_90003 1 2	54623_HVDC_GP1	AESO	90003_GP1_LP1	AESO	150
HVDC_HN1_55614 to HN1_SN1_90005 1 1	55614_HVDC_HN1	AESO	90005_HN1_SN1	AESO	250
HVDC_HN1_55614 to HN1_SN1_90005 1 2	55614_HVDC_HN1	AESO	90005_HN1_SN1	AESO	250
HVDC_HN1_55614 to HN1_SN1_90005 1 3	55614_HVDC_HN1	AESO	90005_HN1_SN1	AESO	250
HVDC_HN1_55614 to HN1_SN1_90005 1 4	55614_HVDC_HN1	AESO	90005_HN1_SN1	AESO	250
HVDC_HP1_55615 to HP1_SP1_90007 1 1	55615_HVDC_HP1	AESO	90007_HP1_SP1	AESO	250
HVDC_HP1_55615 to HP1_SP1_90007 1 2	55615_HVDC_HP1	AESO	90007_HP1_SP1	AESO	250
HVDC_HP1_55615 to HP1_SP1_90007 1 3	55615_HVDC_HP1	AESO	90007_HP1_SP1	AESO	250
HVDC_HP1_55615 to HP1_SP1_90007 1 4	55615_HVDC_HP1	AESO	90007_HP1_SP1	AESO	250
IMPRLVLY_22356 to ROA-230_20118 1 1	22356_IMPRLVLY	SDGE	20118_ROA-230	CFE	796.7
INTERMT_26043 to MONA_65995 2 2	26043_INTERMT	LADWP	65995_MONA	PACE_UT	600
INYO_24728 to INYO PS_24730 1 1	24728_INYO	SCE	24730_INYO PS	SCE	56
INYO_24728 to INYO PS_24730 1 2	24728_INYO	SCE	24730_INYO PS	SCE	56
JANET 7_54207 to JANET 4_54160 T2 1	54207_JANET 7	AESO	54160_JANET 4	AESO	400
JFRSNPHA_65860 to JEFFERSN_65850 1 1	65860_JFRSNPHA	PACE_ID	65850_JEFFERSN	PACE_ID	112
JFRSNPHA_65860 to JEFFERSN_65850 1 2	65860_JFRSNPHA	PACE_ID	65850_JEFFERSN	PACE_ID	112
JFRSNPHA_65860 to JEFFERSN_65850 1 3	65860_JFRSNPHA	PACE_ID	65850_JEFFERSN	PACE_ID	112
JFRSNPHA_65860 to JEFFERSN_65850 1 4	65860_JFRSNPHA	PACE_ID	65850_JEFFERSN	PACE_ID	112
KEARNEY_30830 to HERNDON_30835 1 1	30830_KEARNEY	PG&E_VLY	30835_HERNDON	PG&E_VLY	328.7
KESWICK_37558 to J.F.CARR_37555 1 2	37558_KESWICK	BANC	37555_J.F.CARR	BANC	319

Table 38: Transmission Assumptions for High VG Penetration Scenario					
New Transmission Line Name	**From Bus**	**From Region**	**To Bus**	**To Region**	**Capacity (MW)**
KESWICK_37558 to J.F.CARR_37555 1 3	37558_KESWICK	BANC	37555_J.F.CARR	BANC	319
KESWICK_37558 to J.F.CARR_37555 1 4	37558_KESWICK	BANC	37555_J.F.CARR	BANC	319
KESWICK_37558 to J.F.CARR_37555 1 5	37558_KESWICK	BANC	37555_J.F.CARR	BANC	319
LANGDON2_54158 to CR_NEST1_54458 01 1	54158_LANGDON2	AESO	54458_CR_NEST1	AESO	940
LANGDON2_54158 to CR_NEST1_54458 01 2	54158_LANGDON2	AESO	54458_CR_NEST1	AESO	940
LANGDON2_54158 to CR_NEST1_54458 01 3	54158_LANGDON2	AESO	54458_CR_NEST1	AESO	940
LANGDON2_54158 to CR_NEST1_54458 01 4	54158_LANGDON2	AESO	54458_CR_NEST1	AESO	940
LUZ LSP_24736 to KRAMER_24701 1 1	24736_LUZ LSP	SCE	24701_KRAMER	SCE	478
LUZ LSP_24736 to KRAMER_24701 1 2	24736_LUZ LSP	SCE	24701_KRAMER	SCE	478
MALIN_40687 to ROUND MT_30005 2 1	40687_MALIN	BPA	30005_ROUND MT	PG&E_VLY	1558.8
MARBLE_64905 to MARBLE_38136 1 1	64905_MARBLE	SPPC	38136_MARBLE	PG&E_VLY	20
MARBLE_64905 to MARBLE_38136 1 2	64905_MARBLE	SPPC	38136_MARBLE	PG&E_VLY	20
MATL AB_56451 to MATL AB_62365 1 1	56451_MATL AB	AESO	62365_MATL AB	NWMT	541
MATL AB_56451 to MATL AB_62365 1 2	56451_MATL AB	AESO	62365_MATL AB	NWMT	541
MATL AB_56451 to MATL AB_62365 1 3	56451_MATL AB	AESO	62365_MATL AB	NWMT	541
MC CALL_30875 to HENTAP2_30880 1 1	30875_MC CALL	PG&E_VLY	30880_HENTAP2	PG&E_VLY	329
MC CALL_30875 to HENTAP2_30880 1 2	30875_MC CALL	PG&E_VLY	30880_HENTAP2	PG&E_VLY	329
MEAD_19038 to PERKINS_15034 1 2	19038_MEAD	WALC	15034_PERKINS	SRP	1905
NLY 230_50784 to NLY 2PS2_50822 2 1	50784_NLY 230	BCTC	50822_NLY 2PS2	BCTC	400
NLY 230_50784 to NLY 2PS2_50822 2 2	50784_NLY 230	BCTC	50822_NLY 2PS2	BCTC	400
NLY 230_50784 to NLY 2PS2_50822 2 3	50784_NLY 230	BCTC	50822_NLY 2PS2	BCTC	400
OLINDAW_37565 to KESWICK_37558 1 2	37565_OLINDAW	BANC	37558_KESWICK	BANC	458
OLYMPC_26087 to TARZANA_26093 1 1	26087_OLYMPC	LADWP	26093_TARZANA	LADWP	382
PAVANT_66210 to UTAH-NEV_64124 1 1	66210_PAVANT	PACE_UT	64124_UTAH-NEV	SPPC	358.5
PAVANT_66210 to UTAH-NEV_64124 1 2	66210_PAVANT	PACE_UT	64124_UTAH-NEV	SPPC	358.5
POPULUS_67794 to ANPOPC&1_67811 1 1	67794_POPULUS	PACE_UT	67811_ANPOPC&1	PACE_UT	2000
RBFLCPS_64883 to ROBINSON_64885 1 1	64883_RBFLCPS	SPPC	64885_ROBINSON	SPPC	600

Table 38: Transmission Assumptions for High VG Penetration Scenario					
New Transmission Line Name	**From Bus**	**From Region**	**To Bus**	**To Region**	**Capacity (MW)**
RBGONPS_64884 to ROBINSON_64885 2 1	64884_RBGONPS	SPPC	64885_ROBINSON	SPPC	600
RED DEE4_54152 to CROSSF T_54988 01 2	54152_RED DEE4	AESO	54988_CROSSF T	AESO	408
RIMROCK_62062 to RMRK PHA_62061 1 1	62062_RIMROCK	NWMT	62061_RMRK PHA	NWMT	100
RIMROCK_62062 to RMRK PHA_62061 1 2	62062_RIMROCK	NWMT	62061_RMRK PHA	NWMT	100
RINALDI_26061 to SYLMARLA_26094 1 1	26061_RINALDI	LADWP	26094_SYLMARLA	LADWP	708.3
ROUND MT_30005 to TABLE MT_30015 2 1	30005_ROUND MT	PG&E_VLY	30015_TABLE MT	PG&E_VLY	1905.2
SANJN PS_79060 to SAN_JUAN_10292 1 1	79060_SANJN PS	WACM	10292_SAN_JUAN	PNM	600
SANJN PS_79060 to SAN_JUAN_10292 1 2	79060_SANJN PS	WACM	10292_SAN_JUAN	PNM	600
SHIP PS_79061 to SHIPROCK_79063 1 1	79061_SHIP PS	WACM	79063_SHIPROCK	WALC	400
SHIP PS_79061 to SHIPROCK_79063 1 2	79061_SHIP PS	WACM	79063_SHIPROCK	WALC	400
SHIPROCK_79063 to BLKGLADE_72770 1 2	79063_SHIPROCK	WALC	72770_BLKGLADE	PSC	418
SIGURD_66345 to SIGURDPS_66355 1 1	66345_SIGURD	PACE_UT	66355_SIGURDPS	PACE_UT	303
SIGURD_66345 to SIGURDPS_66355 1 2	66345_SIGURD	PACE_UT	66355_SIGURDPS	PACE_UT	303
SLVR PK_64094 to SLVR PS_64096 1 1	64094_SLVR PK	SPPC	64096_SLVR PS	SPPC	17
SLVR PK_64094 to SLVR PS_64096 1 2	64094_SLVR PK	SPPC	64096_SLVR PS	SPPC	17
SLVR PK_64094 to SLVR PS_64096 1 3	64094_SLVR PK	SPPC	64096_SLVR PS	SPPC	17
SLVR PK_64094 to SLVR PS_64096 1 4	64094_SLVR PK	SPPC	64096_SLVR PS	SPPC	17
SLVR PKX_64095 to SLVR PK_64094 1 1	64095_SLVR PKX	SPPC	64094_SLVR PK	SPPC	17
SLVR PKX_64095 to SLVR PK_64094 1 2	64095_SLVR PKX	SPPC	64094_SLVR PK	SPPC	17
SLVR PKX_64095 to SLVR PK_64094 1 3	64095_SLVR PKX	SPPC	64094_SLVR PK	SPPC	17
SLVR PKX_64095 to SLVR PK_64094 1 4	64095_SLVR PKX	SPPC	64094_SLVR PK	SPPC	17
SN1_HN1_ 90006 to HVDC_SN1_54613 1 1	90006_SN1_HN1	AESO	54613_HVDC_SN1	AESO	250
SN1_HN1_ 90006 to HVDC_SN1_54613 1 2	90006_SN1_HN1	AESO	54613_HVDC_SN1	AESO	250
SN1_HN1_ 90006 to HVDC_SN1_54613 1 3	90006_SN1_HN1	AESO	54613_HVDC_SN1	AESO	250
SN1_HN1_ 90006 to HVDC_SN1_54613 1 4	90006_SN1_HN1	AESO	54613_HVDC_SN1	AESO	250
SP1_HP1_90008 to HVDC_SP1_54614 1 1	90008_SP1_HP1	AESO	54614_HVDC_SP1	AESO	250
SP1_HP1_90008 to HVDC_SP1_54614 1 2	90008_SP1_HP1	AESO	54614_HVDC_SP1	AESO	250

Table 38: Transmission Assumptions for High VG Penetration Scenario					
New Transmission Line Name	From Bus	From Region	To Bus	To Region	Capacity (MW)
SP1_HP1_90008 to HVDC_SP1_54614 1 3	90008_SP1_HP1	AESO	54614_HVDC_SP1	AESO	250
SP1_HP1_90008 to HVDC_SP1_54614 1 4	90008_SP1_HP1	AESO	54614_HVDC_SP1	AESO	250
TABLE MT_30015 to VACA-DIX_30030 1 1	30015_TABLE MT	PG&E_VLY	30030_VACA-DIX	PG&E_VLY	2145.9
TOLUCA_26079 to TOLUCA_26078 1 2	26079_TOLUCA	LADWP	26078_TOLUCA	LADWP	800
TRINITY_37640 to J.F.CARR_37555 2 1	37640_TRINITY	BANC	37555_J.F.CARR	BANC	319
TRINITY_37640 to J.F.CARR_37555 2 2	37640_TRINITY	BANC	37555_J.F.CARR	BANC	319
TRINITY_37640 to J.F.CARR_37555 2 3	37640_TRINITY	BANC	37555_J.F.CARR	BANC	319
TRINITY_37640 to J.F.CARR_37555 2 4	37640_TRINITY	BANC	37555_J.F.CARR	BANC	319
UTAH-NEV_67657 to HA PS_18002 1 1	67657_UTAH-NEV	PACE_UT	18002_HA PS	NEVP	300
UTAH-NEV_67657 to HA PS_18002 1 2	67657_UTAH-NEV	PACE_UT	18002_HA PS	NEVP	300
VINCENT_24155 to PEARBLSM_25616 1 2	24155_VINCENT	SCE	25616_PEARBLSM	SCE	357
WABAMUN9_54134 to CARVEL02_55364 96 1	54134_WABAMUN9	AESO	55364_CARVEL02	AESO	121
WABAMUN9_54134 to CARVEL02_55364 96 2	54134_WABAMUN9	AESO	55364_CARVEL02	AESO	121
WEBER_30505 to TESLA E_30624 1 1	30505_WEBER	PG&E_VLY	30624_TESLA E	PG&E_VLY	299.2
WEBER_30505 to TESLA E_30624 1 2	30505_WEBER	PG&E_VLY	30624_TESLA E	PG&E_VLY	299.2
WESTWING_14005 to PERKINS_15034 1 1	14005_WESTWING	APS	15034_PERKINS	SRP	1905.2
WILSON_30800 to STOREY 2_30795 1 1	30800_WILSON	PG&E_VLY	30795_STOREY 2	PG&E_VLY	269
ADELANTO_26003 to RINALDI2_26115 1 1	26003_ADELANTO	LADWP	26115_RINALDI2	LADWP	1593
BORDEN_30805 to GREGG_30810 1 1	30805_BORDEN	PG&E_VLY	30810_GREGG	PG&E_VLY	269
COACHELV_21007 to RAMON_21076 1 1	21007_COACHELV	IID	21076_RAMON	IID	392.8
FT CHUR_64053 to FT CH PS_64048 1 1	64053_FT CHUR	SPPC	64048_FT CH PS	SPPC	150
HA PS_18002 to H ALLEN_18001 1 1	18002_HA PS	NEVP	18001_H ALLEN	NEVP	300
HA PS_18002 to H ALLEN_18001 2 2	18002_HA PS	NEVP	18001_H ALLEN	NEVP	300
MILL CRK_62004 to MLCK PHA_62355 1 1	62004_MILL CRK	NWMT	62355_MLCK PHA	NWMT	350
STOREY 2_30795 to BORDEN_30805 1 1	30795_STOREY 2	PG&E_VLY	30805_BORDEN	PG&E_VLY	269

Table 39: Transmission Interface Expansion for the High VG Penetration Case				
Interface	Existing Rate (MW)		Expanded Rate (MW)	
	Max Flow	Min Flow	Max Flow	Min Flow
ALBERTA - BRITISH COLUMBIA	700	-720	2000	-2000
BONANZA WEST	785	-9999	1570	
BRIDGER WEST	3700	-9999	5700	
IDAHO - MONTANA	337	-256		-800
IDAHO - SIERRA	500	-360	1500	
IID - SCE	600	-99999	1800	
INTERMOUNTAIN - MONA 345 KV	1400	-1200		-2400
MONTANA - NORTHWEST	2200	-1350	4400	
MONTANA SOUTHEAST	600	-600	1800	-1800
NORTHWEST - CANADA	2000	-3150	4000	-6300
NW to Canada East BC	400	-400	2000	-1600
PACIFICORP_PG&E 115 KV INTERCON.	100	-45	300	-135
PATH C	1400	-1400		-2800
PAVANT INTRMTN - GONDER 230 KV	440	-235	880	
PG&E - SPP	160	-150		-450
TOT 1A	800	-800	2000	
TOT 2A	690	-690	1880	-1380
Tot 2a 2b 2c Nomogram	1570	-1600	3140	
TOT 2B1	560	-600	1120	
TOT 2B2	265	-300	530	
TOT 2C	600	-600	1200	-1200
TOT 3	1800	-1800	5000	
Z4-Perkins - Big Sandy	1238	-1238	2476	
Z7-Imperial Valley - La Rosita	797	-797	1297	
Z7-Path 45	408	-800		-1200
Z9-HA-Red Butte PS	300	-300	1200	
Z9-Shiprock - Lost Canyon PS	400	-400	1600	
Z9-Sigurd - Glen Canyon PS	300	-300	600	-600
CA INDEPENDENT - MEXICO (CFE)	408	-408		-816
Combined 4a 4b	1096	-9999	2192	
EAGLE MTN 230_161 KV - BLYTHE 16	72	-218	144	
FOUR CORNERS 345/500	1000	-1000	2000	-2000
INYO - CONTROL 115 KV TIE	56	-56	224	-224
Montana Alberta Tie Line	325	-300		-2000

Table 39: Transmission Interface Expansion for the High VG Penetration Case				
Interface	**Existing Rate (MW)**		**Expanded Rate (MW)**	
	Max Flow	**Min Flow**	**Max Flow**	**Min Flow**
NORTHERN - SOUTHERN CALIFORNIA	4000	-3000		-4000
PACIFIC DC INT SOUTH	2780	-3100	5560	
SDG&E - MEXICO (CFE)	408	-800	816	
SILVER PEAK - CONTROL 55 KV	17	-17	34	-34
SOUTHWEST OF FOUR CORNERS	2325	-9999	4650	
TOT 7	890	-9999	1780	
Z1- N. Gila - Imperial Valley	1905	-9999	3810	