**UNITING THE NATION'S POWER GRIDS:
OPENING MARKETS TO INTEGRATE LARGE SCALE RENEWABLE POWER**

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by
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TITLE: UNITING THE NATION'S POWER GRIDS:
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LARGE SCALE RENEWABLE POWER

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ABSTRACT

Uniting the Nation' Power Grids:

Opening Markets to Integrate Large Scale Renewable Power

Jeffrey Kenneth Wilkinson

As renewable energy becomes increasingly cost competitive and Renewable Portfolio Standards (RPS) push states to produce more and more of their steadily growing power demands from renewable sources, the need to solve the problems associated with renewable penetration becomes a priority. The intermittent nature of solar and wind power generation require additional cost that inhibit their implementation as penetration levels grow. Reliability remains power utilities' top priority while they struggle to upgrade their systems. Old generation facilities will be decommissioned, renewable energy projects will come on line and transmission upgrades become inevitable. Variability on the grid is currently mitigated through the use of Operational Reserves. These units are costly and utilities are currently looking for ways to reduce the amount of reserves required. Balancing Area cooperation is currently being considered by many as the most economical and environmentally conscience method to mitigate variability. Many aspects of Balancing Area cooperation will be discussed along with the motivations for their implementation.

A 22.5 square mile area of land in Clovis, NM will be the home of the Tres Amigas project designed to unite the three asynchronous grids of our Nation with the purpose of improving reliability and reducing cost through the exchange of

power and ancillary services such as VAR support and Operating Reserves. This paper will investigate the implications of this project on the Operational Reserves required to mitigate variability due to increasing renewable energy penetration by enabling Balancing Areas to cooperate across regions that are currently not assessable.

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INTRODUCTION

Our world currently faces a challenge never seen before. Reduce our consumption of carbon based fuels or suffer the consequences of global warming. Although renewable energy technologies are becoming increasingly affordable, the utilities, also known as Balancing Authorities (BAs), are reluctant to incorporate them into their planning despite the Renewable Portfolio Standards (RPS) mandates. [1] BAs are the responsible entities that integrate resource plans ahead of time, maintain load-interchange-generation balance within their area, and support Interconnection frequency in real time. [2] BA resistance to renewable energy integration is primarily due to their variable nature. A solar farm can drastically reduce its output power in a matter of minutes due to overhead clouds. Wind farms have similar patterns of variability although less drastic in nature. Variability is nothing new to power systems. Loads have gone up and down from the very beginning. Loads however are much more predictable and we have developed methods to deal with this variability.

In the March/April 2012 edition of IEEE power & energy magazine, the article “The Golden Spike” detailed the plans of the Tres Amigas project. This ambitious project aims to unite the Nation’s grids by allowing bi-directional flow of power. Figure 1 shows that both wind and solar resources exist in close proximity to the project site. Excitement for the prospect of channeling these rich sources of renewable energy in either direction to the major load sources of our Nation is only curtailed by the realization that these sources are inherently

undesirable to utilities. The effects of the variable nature on the Operational Reserves required to maintain a reliable power system will be detailed in chapter II. These effects initially show up as changes in system frequency and chapter III will discuss the performance metrics enforced by the North American Reliability Corporation (NERC) to force Balancing Areas (BAs) to contribute a fair portion of

Figure 1: Wind Energy Existing Along the Divides between Asynchronous Regions

their Operational Reserves to maintain a reliable grid within their respective region.

The Operating Cost of these Operation Reserves is the primary motivation behind BAs searching for methods to mitigate variability. The idea of sharing load and variable generation profiles along with the reserves required to account for them is being investigated by industry in greater frequency and chapter IV provides an overview of some of these strategies. Full BA consolidation has occurred recently and will be the focus of the analysis of this paper. The method used to determine the benefits of BA consolidation is detailed in chapter V and

follows the methods used by the National Renewable Energy Laboratories (NREL) Eastern Wind Integration and Transmission Study (EWITS) [3].

The large quantities of data required the use of Matlab and a reusable tool for performing these analyses has been developed. It is the desire of this author to encourage further studies in the area of BA cooperation and renewable energy integration in general.

I. Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) are policies signed into law by many states that mandate a certain percentage of their electrical production come from renewable sources within a finite timeframe. Many states also specify provisions indicating minimum values for specific technologies. Figure 2 shows the participating states along with their respective goals and provisions. [4] Additionally, states also define which technologies are eligible under their RPS requirements. Figure 3 shows the eligible technologies by state.

State	Target (% of electricity sales)	Specific Provisions (% of electric sales)
AZ	15% by 2025	4.5% by 2012 from distributed energy resources
CA	20% by 2010	
CO	IOUs 20% by 2020; electric cooperatives and municipal utilities 10% by 2020	IOUs: 0.4% solar by 2020
CT	27% by 2020	4% Energy Efficiency and CHP by 2010
DC	20% by 2020	0.4% solar by 2022
DE	20% by 2019	2.005% solar by 2019
HI	20% by 2020	
IA	105 MW by 2025	
IL	25% by 2025	18.75% wind by 2013
MA	Class I: 4% by 2009 (+1%/year after); Class II: 3.6% renewable, 3.5% waste energy by 2009; APS: 5% by 2020 increasing by 0.25% each year after.	Class II: 3.6% renewable, 3.5% waste energy by 2009
MD	20% by 2022	2% solar by 2022
ME	30% by 2000; 10% new by 2017	
MI	10% by 2015	
MN	Xcel Energy (utility) 30% by 2020; other utilities 25% by 2025	Xcel Energy: 25% wind
MO	15% by 2021	0.3% solar retail sales by 2021
MT	15% by 2015	
ND*	10% by 2015	
NH	23.8% by 2025 - 16.3% new	0.3% solar by 2025
NI	22.5% by 2021	2.12% from solar by 2021
NM	IOUs: 20% by 2020; rural electric cooperatives 10% by 2020	Wind: 4%; solar: 4%; biomass and geothermal: 2%; distributed renewables: 3% by 2020 (IOU only)
NV	20% by 2015	1% solar by 2015
NY	24% by 2013	0.154% customer-sited by 2013
OH	25% by 2025 (12.5% renewable energy)	1% solar by 2025
OR	Large utilities (>3% state's total electricity sales) 25% by 2025	Smaller utilities 5-10% by 2025 (depending on size)
PA	18% by May 31, 2021 (8% renewable energy)	0.5% solar by 2025
RI	16% by 2020	
SD*	10% by 2015	
TX	5,880 MW by 2015	At least 500 MW from renewables other than wind
UT*	20% by 2025	
VA*	12% of 2007 sales by 2022	
VT*	20% by 2017; Total incremental energy growth between 2005-2012 to be met with new renewables (10% cap)	
WA	15% by 2020	
WI	10% by December 31, 2015	

Figure 2: States RPS and Specific Provisions

The process of accounting for RPS compliance is somewhat complicated and inconsistent from state to state. In general a Renewable Energy Credit (REC) is considered to be 1 MWh of Renewable Energy generation. [5] A REC is considered to be used or have expired once it is linked to an equivalent quantity of consumed electricity. This enables REC producers to bank or sell their credits as needed. Different states have different rules on how these RECs can be bought, sold or banked, thus

adding to the complexity of the system. Tracking systems have been installed to ensure double counting does not occur.

Energy Source	AZ	CA	CO	CT	DE	DC	HI	IA	IL	MA	MD	ME	MI	MN	MO	MT	NC	ND	NH	NJ	NM	NV	NY	OH	OR	PA	RI	SD	TX	UT	VA	VT	WA	WI
Biofuels	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Biomass	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
CHP/Waste Heat	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Energy Efficiency	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Fuel Cells	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Geothermal	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Hydro	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Landfill Gas	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Municipal Waste	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Ocean Thermal	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Photovoltaics	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Solar Thermal Electric	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Tidal	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Waste Tire	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Wave	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Wind	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*

Figure 3: Eligible Technologies under States RPS Requirements

Additionally, each state has different rules on whether or not the REC must be generated within the state or region as shown in Figure 4.

State	Geographic Eligibility
Arizona	State generation or interconnection
California	State generation or delivery (CAISO) ^a
Colorado	No restrictions
Connecticut	Regional generation or delivery (ISO-NE) ^a
Delaware	Regional generation or delivery (PJM) ^a
District of Columbia	Regional generation or delivery (PJM) or from states adjacent to PJM
Hawaii	In-state projects only
Illinois	In-state projects only, unless cost-effective alternative available from adjacent state
Iowa	In-state projects only
Maine	Regional generation or delivery (ISO-NE)
Maryland	Regional generation or delivery (PJM) or from states adjacent to PJM
Massachusetts	Regional generation or delivery (ISO-NE)
Minnesota	State generation or delivery
Montana	State generation or delivery
Nevada	State generation or delivery
New Hampshire	Regional generation or delivery (ISO-NE)
New Jersey	Regional generation or delivery (PJM)
New Mexico	State generation or delivery
New York	State generation or delivery (NYISO) ^a
North Carolina	State generation or delivery
Oregon	Regional generation or delivery
Pennsylvania	Regional generation or delivery (PJM)
Rhode Island	Regional generation or delivery (ISO-NE)
Texas	State generation or interconnection
Washington	Regional location or state delivery
Wisconsin	State generation or delivery

Figure 4: RPS Rules on Geographic Eligibility

Of course an RPS is only successful if the BAs realize the goals as written into law. Without consequences, BAs lack the motivation to incorporate renewable generation into their systems. Each state is different in their approach to forcing compliance. Fines or penalties in the form of Alternative Compliance Payments (ACP) are common, although some BAs will claim meeting compliance due to the fact that the funds given in ACPs go toward supporting new renewable energy projects. Figure 5 displays the states RPS policies and noncompliance penalties. It should be noted that some states have vague policies. New Mexico's noncompliance penalty reads "State regulators may impose but amount(s) not specified". In addition, RPS cap cost exists that allow for noncompliance on the basis that a "Reasonable Cost Threshold" has been reached by the ratepayers due to the increased cost of implementing renewables.

Politics play a huge role in every aspect of RPS development and implementation. The basis of the final analysis of this paper rest on the RPS of each state where the seven BAs under consideration reside. Most of us understand the importance of these goals and many of us believe that they are not aggressive enough to curtail the potentially disastrous consequences of continuing to fill our atmosphere with greenhouse gases. However, we must be able to implement these goals and still maintain a reliable electrical infrastructure. Until renewable energy production becomes cost competitive with conventional carbon based generation, RPS will be the driving force by which renewable energy production will increase.

State	Noncompliance Penalty/Alternative Compliance Payment (ACP)
Arizona	State regulators may impose but amount(s) not specified
California	5.0¢/kWh noncompliance penalty
Colorado	State regulators may impose but amount(s) not specified
Connecticut	5.5¢/kWh noncompliance penalty
Delaware	<u>ACP system</u> <ul style="list-style-type: none"> • 2.5¢/kWh (first year of noncompliance) • 5.0¢/kWh (second year of noncompliance) • 8.0¢/kWh (third year of noncompliance and subsequent years) <u>ACP for solar:</u> <ul style="list-style-type: none"> • 25¢/kWh (first year of noncompliance) • 30¢/kWh (second year of noncompliance) • 35¢/kWh (third year of noncompliance and subsequent years)
District of Columbia	<u>ACP system</u> <ul style="list-style-type: none"> • 2.5¢/kWh for Tier 1 resources • 1.0¢/kWh for Tier 2 resources • 30.0¢/kWh for solar
Hawaii	State regulators may impose but amount(s) not specified
Illinois	State regulators may impose but amount(s) not specified
Iowa	None
Maine	ACP for new capacity requirement start at 5.712¢/kWh, adjusted for inflation.
Maryland	<u>ACP system</u> <ul style="list-style-type: none"> • 2.0¢/kWh for Tier 1 resources • 1.5¢/kWh for Tier 2 resources <u>ACP for solar:</u> <ul style="list-style-type: none"> • 45¢/kWh for solar in 2008 • 40¢/kWh in 2009, decreasing by 5¢ bi-annually until it reaches 5¢/kWh in 2023 and beyond.
Massachusetts	<u>ACP system:</u> <ul style="list-style-type: none"> • 5.0¢/kWh • In 2003, adjusted annually for inflation, so was set at \$57.12 in 2007
Minnesota	State regulators may impose but amount(s) not specified
Montana	1.0¢/kWh noncompliance penalty
Nevada	State regulators may impose but amount(s) not specified
New Hampshire	<u>ACP varies according to the four classes of eligible resources:</u> <ul style="list-style-type: none"> • 5.712¢/kWh for Class I (new renewables); • 15¢/kWh for Class II (solar); and • 2.8¢/kWh for Class III and IV (existing biomass, methane and hydroelectric). • Starting in 2008, ACP will be adjusted annually using the Consumer Price Index.
New Jersey	<u>ACP system</u> <ul style="list-style-type: none"> • 5.0¢/kWh for Class I and II resources • 30.0¢/kWh for solar
New Mexico	State regulators may impose but amount(s) not specified
New York	None (RPS is state-administered)
North Carolina	State regulators may impose but amount(s) not specified
Oregon	PUC establishes ACP for each compliance year for each electricity supplier
Pennsylvania	<u>ACP system (not recoverable in rates)</u> <ul style="list-style-type: none"> • 4.5¢/kWh for Tier 1 and Tier 2 resources • For solar, 200% of average market value of solar credits
Rhode Island	<u>ACP system:</u> 5.0¢/kWh (2003\$, adjusted annually by the Consumer Price Index)
Texas	Noncompliance penalty is the lesser of 5¢/kWh or 200% of the average cost of credits traded during the year
Washington	5.5¢/kWh noncompliance penalty
Wisconsin	Noncompliance penalty of up to \$500,000

Sources: UCS, 2007; Database of State Incentives for Renewables and Efficiency (www.dsireusa.org); and individual state RPS laws and rules.

Figure 5: States RPS Policies and Noncompliance Policies

II. Effects of Variable Generation on Operational Reserves

Power systems are currently designed to mitigate variability. The goal is of course to match generation output to load. Historically this has been done with Operating Reserves. While some generation sites such as coal and nuclear keep constant outputs, others such as gas turbine or combined cycle have the ability to ramp up or down their output drastically and quickly. Figure 6 below provides typical data on the ramp rates of various generation types.

	Ramp Rate (% of Nameplate/Minute)
Combined-Cycle	3.8
Combustion Turbine	13.5
Hydroelectric	22.3
Steam	3.1

Figure 6: Generic Ramp Rates for Specific Generation Type

Intermittent sources such as solar and wind have variable outputs that require other generation sites be “on call” to ramp down their output when the sun shines or the wind blows and ramp up their output when the clouds appear or the wind dies down. Solar and wind forecasting can help operators plan accordingly, but accuracy is crucial to avoid load shedding and harm to grid infrastructure.

Variability is not a new issue. Loads have varied since the beginning of power generation. Consumers of every type contribute to this variability.

Industry runs their motors and lighting differently depending on the time of day. Residential customers use their electricity in a varying yet somewhat predictable pattern. Demand Side Management (DSM) gives incentives to encourage users to modify their consumption to off peak hours thus controlling variability to some extent. Now renewables place the variability on the supply side as well as the load side. For the purpose of this study, variability will be defined as the load minus renewable variability.³

The National Renewable Energy Lab (NREL) conducted the Western Wind and Solar Integration Study (WWSIS), a three year study detailing how variability of load and renewable energy could be managed through scheduling and Operating Reserves. The study included several states and numerous BAs. Of these BAs, El Paso Electric (EPE) and Public Service Company of New Mexico (PNM) on the western side of Tres Amigas both participated in this study. Southwest Public Service Company (SPS) on the eastern side of Tres Amigas along with the Electric Reliability Council of Texas (ERCOT) to the south of Tres Amigas, participated in the Eastern Wind Integration and Transmission Study (EWITS) conducted a few years earlier. Methods of the EWITS study will be used to analyze the effects of the Tres Amigas connection. EPE and PNM in the west, SPS in the east and ERCOT to the south each operate in separate asynchronous grids. As it stands without Tres Amigas, the transmission of power from region to region is not possible. Chapter VI will detail the analysis of opening each regions access to the neighboring regions Operating Reserves. Sharing the technological and geographic diversity of renewable energy sources

will decrease operating cost as well as curtailment of wind generation. Curtailment of wind generation is a last resort when all dispatchable resources are operating at their minimum levels. Obviously, wind itself is free and renewable after the station has been built. Not using the available wind is analogous to wasting fuel.

Figure 7 shows the various generation outputs matching load in the WWSIS study during the month of July when the variability of renewables is low. The right figure is without renewables and the left is with 30% of the generation output coming from wind and solar.

Comparing the right figure to the left figure, the brown shaded area corresponding to gas turbine generation, which is the most expensive but also the most dispatchable, has been almost completely eliminated. Next the light blue area corresponding to Combined Cycle generation is the majority of the sources displaced.

Figure 7: Generation Outputs with no renewables (left) and 30% renewables (right) in Mid-July

A more drastic case is presented in Figure 8. Renewable sources produce more power and more variability during mid-April and require a greater degree of Operating Reserve and scheduling flexibility to accommodate these conditions.

Figure 8: Generation Outputs with no renewables (left) and 30% renewables (right) in Mid-April

As can be seen from the left plot in Figure 7, renewables primarily offset gas turbine and combined cycle in Mid-July when variability is less drastic, but offsets more steam coal and less gas turbine when variability is at its worst as seen in Figure 8. The balance between reliability and cost are at play here. The preference is to use less gas. The cost of gas generation is approximately \$9.50/MBTU while the cost of coal is only \$2.00/MBTU. Furthermore, combined cycle plants have efficiencies reaching nearly 60 percent while gas turbine plant efficiencies are between 35 to 42 percent depending on the age of the technology.⁵

The scheduling of Operating Reserves to deal with the net load variability is done on the day ahead, hour ahead, real time dispatch and Automatic

Generation Control (AGC) regulation. Although there are some inconsistencies in how Regulation and Load Following are defined, in general Load Following is adjusted every 5 minutes and looks ahead 65 minutes. Regulation is online and waiting to adjust on a second by second basis. Additionally, Operating Reserves are categorized as either spinning or non-spinning. As changes in load occur, so will a corresponding change in system frequency. Details of these responses will be explored in Chapter III. Spinning reserves must be on-line, unloaded and ready to correct these changes automatically using governor response. Additionally, errors in load forecasting will be compensated for by operator dispatch of spinning reserves. Non-spinning reserve units are capable of coming on line within a particular time frame. Additionally, loads designated for adjustment or shedding are considered non-spinning reserves. As such, both spinning and non-spinning reserves are used for Load Following reserves, but only spinning reserves are used for Regulation. Contingency reserves are held for instances when a generating unit inadvertently goes off-line. Contingency reserves must be greater than the largest possible single loss of generation or 5% of BAs load requirement, whichever is greater. Half of the contingency reserve must be spinning. Figure 9 shows the graphical representation of the Operating Reserve allocation.

Figure 9: Operating Reserve Allocation

Figure 10 shows how Load Following and Regulation combine to match the variability in load. The red plot in Figure 10 corresponds to the left axis and identifies regulation that would require units with higher ramp rates. The load following in blue would utilize more economical units with lower ramp rates. The two operational reserves shown in red and blue combine to follow the load shown in green. Since the effective load is considered to be the conventional load minus variable generation, increasing variability due to renewables will directly affect regulation when changes occur in 10 minute or less time frames and affect load following when the hour ahead forecasting of renewable output is inaccurate.

The amount and type of Operational Reserves required to mitigate variability is dependent upon many factors. Type and quality of regulating units

along with the economic aspects of dispatch are worthy of many Theses concentrating specifically on this topic.

Figure 10: Regulation (red) and Load Following (blue) Combine to Match Load (green)

An example illustrating the degree to which renewable penetration can affect the amount of regulation requirement can be illustrated in the EWITS study that simulated four different scenarios as listed below in Table 1:

Table 1: Description of Four Separate EWITS Study Scenarios

Scenario 1: 20% Wind Penetration	Scenario 2: 20% Wind Penetration	Scenario 3: 20% Wind Penetration	Scenario 4: 30% Wind Penetration
Onshore: Utilizes high-quality wind resources in the Great Plains, with other development in the eastern United States where good wind resources exist.	Hybrid with Offshore: Some wind generation in the Great Plains is moved east. Some East Coast offshore development is included.	Local with Aggressive Offshore: More wind generation is moved east toward load centers, necessitating broader use of offshore resources.	Aggressive On- and Offshore: Meeting the 30% energy penetration level uses a substantial amount of the higher quality wind resource in the NREL database.

Although three of the four studies are identical in their amounts of wind penetration, the resulting regulation requirements are quite different as can be seen in Figure 11.

Figure 11: Regulating and Load Following Reserve Requirements for Four different EWITS Study Scenarios

This trend will be repeated in Chapter VI when the results of this Thesis show that factors such as increasing the geographic area over which wind power is aggregated play a huge role in motivating Balancing Areas to cooperate with adjacent Balancing Areas. Aggregating wind resources from remote locations will reduce the overall variability of their renewable generation and thereby reduce regulation requirements and the associated operating cost.

III. North American Electric Reliability Corporation Metrics

There are over 100 Balancing Authorities (BAs) in North America with the adjacent BAs connected through tie-lines as shown below in Figure 12. In the United States there are three separate regions, each operating asynchronously from one another. Only a hand full of low power AC-DC-AC connection points exist from region to region and for the most part these separate regions experience the boundary to an adjacent region as the end of the world. Within each region, BAs operate in phase with one another and buy and sell power to one another as needed. Since they are connected, the performance or balance of generation and load of one BA affects the adjacent BAs with which they are connected. The North American Electric Reliability Corporation (NERC) was first established in response to the 1965 blackout with the mission of ensuring the reliability of the North American power system.

Figure 12: Regions and Balancing Authorities of North America

In order to execute their mission NERC has developed many metrics by which BAs must comply. Loads vary across the day (inter-hour) and within minutes (intra-hour) as can be shown to the right in Figure 13.

Figure 13: Typical load variation

Operating Reserves can be categorized into two types, Load Following or Regulation. Both address the time varying characteristic of balancing generation and load under normal operations. [6] However, Regulation is determined by intra-hour (1-10 minute changes) and Load Following is determined by inter-hour (40 minute to 1 hour changes). Figure 14 below describes the differences and displays a graphic of the relative variations.

Figure 14: Comparison of Load Following and Regulation Reserves

Load Following is typically scheduled and may utilize both Automatic Generation Control (AGC) and non-AGC units, while Regulation requires faster response and typically uses AGC units exclusively.

Figure 15: Graphical Display of Supply and Demand Balance

Load Following and Regulation

Reserves ensure that load demand and generation output are balanced. This balance is determined by BA sales, purchases, loads, losses and generation as shown in Figure 15. The consequences of an imbalance begin to show in system frequency. Operating generators are subjected to overheating and mechanical stress when large frequency deviations are present. Although we may intuitively understand that as loads become greater than generation, frequency must decrease, there exist fundamental relationships between frequency and power. Generators change frequency in response to load according to their innate Speed Droop (SD) characteristics. This can be

Figure 16: Speed Droop Characteristics of Synchronous Generators (left) and Simple Two Generator Single Load System (right)

determined by plotting the frequency measured at no load up to full load. [7] This relationship can be seen to the left in Figure 16 along with a relationship for output power in terms of system frequency.

Using the simplified system seen to the right in Figure 16 consisting of two generators and one load, we can build House Diagrams that graphically show how frequency will respond to either an increase in load or a reduction in power output from one of the generators. From the standpoint of mitigating variability we are primarily interested in two cases. Case 1 represents a typical change in load and is illustrated on the left in Figure 17 below as a change in the width of the lines labeled Load 1 and Load 2. Case 2 depicted on the right, represents a change in power from the variable renewable source P_{G1} while the load remains constant.

Figure 17: Response of Simple Two Gen System to Increased Load (left) and Decreased Generation (right)

On the left, the increased load shown as the wider bar requires more power from both of the generators but at a lower frequency. On the right, the decrease in power at P_{G1} from P_1 to P_2 at a constant load requires more power

from P_{G2} also at a lower frequency. The development of equations 1 through 5 on the following pages will illustrate mathematically how system frequency changes with changes in load and changes in generations. Equation 3-1 gives the relationship between load and generation. Equations 3-2 and 3-3 provide the innate speed droop characteristic as given in Figure 16. Substituting 3-2 and 3-3 into 3-1 and solving for f_{sys} we obtain equation 3-4 which shows how f_{sys} changes opposite to load since all other variables are constants. Similarly, substituting 3-3 into 3-1 and solving for f_{sys} we obtain equation 3-5. Although 3-4 and 3-5 both show relationships for f_{sys} , 3-5 contains the variable P_{G1} and shows that system frequency increases as power generation is increased if the load is held constant.

$$P_{Load} = P_{G1} + P_{G2} \quad 3-1$$

$$P_{G1} = SP1(f_{NL1} - f_{sys}) \quad 3-2$$

$$P_{G2} = SP2(f_{NL2} - f_{sys}) \quad 3-3$$

$$f_{sys} = \frac{SP1 * f_{NL1} + SP2 * f_{NL2} - P_{Load}}{SP1 + SP2} \quad 3-4$$

$$f_{sys} = \frac{P_{G1} + SP2 * f_{NL2} - P_{Load}}{SP2} \quad 3-5$$

System Frequency is of great importance to system stability. It is Operating Reserves that must control frequency stability. Many metrics including Area Control Error (ACE), Control Performance Standards (CPS1 and CPS2), Disturbance Control Standard (DCS), Frequency Response Standard (FRS), Balancing Authority ACE Limit (BAAL) and Frequency Deviation Limits (FDL)

were introduced by The North American Electric Reliability Corporation (NERC) as standards used to monitor how well a BA balances generation against load, wind generation, solar generation and interchange.¹⁴

The BA's Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance. ACE is used to determine a BA's control performance with respect to the BA's impact on system frequency and has been used for many years.

There are two inputs into a BA control process. The net interchange error is the difference between what was scheduled to be purchased or sold to an adjacent BA through a tie-line and what was actually exchanged. The frequency Bias is the contribution in generation required from a particular BA to maintain the desired system frequency of 60 Hz. Shared meters exist between BAs connected through tie-lines to track these variables for control and accounting.

Equation 3-6 gives the relationship of these inputs to the ACE calculation and Figure 18 displays the block diagram of the control system.¹⁴

$$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} \quad 3-6$$

Where:

NI_A = Net Interchange, Actual in [MW]

NI_S = Net Interchange, Scheduled in [MW]

B = Balancing Authority Bias in [MW/.1Hz] and is a negative number

F_A = Frequency, Actual in [Hz]

F_S = Frequency, Scheduled in [Hz]

I_{ME} = Interchange (tie line) Metering Error in [MW]

The calculated ACE is the metric by which the Automatic Controlled Generation (ACG) units adjust their power output to maintain system balance. The $(NI_A - NI_S)$ term represents interchange error and the $10B(F_A - F_S)$ term represents the BAs required contribution to maintain the scheduled frequency. The B (BA

Figure 18: ACE Metric Used to Control ACG Units

frequency Bias) is proportional to the size of the BA. The smaller BAs will have a lower B and thus a smaller impact on their ACE score when frequency deviations occur. Conversely, larger BAs will have a larger B and therefore a larger impact on their ACE score when frequency deviations occur. This ensures fairness in assigning responsibility to maintain system frequency. It should be noted that B is a negative number. Therefore if system frequency is lower than scheduled the ACE score reduces. The net interchange can increase or decrease the ACE score. If the BA takes in more power than scheduled the ACE score will decrease and if the BA provides more power than scheduled the ACE score will increase. The sign of ACE score along with the relative movement of the first term with the second are the primary considerations. ACE values closest to zero are desired. Positive values indicate a surplus of power and negative values indicate a deficiency of power. If the system frequency is lower than scheduled the second term is pushing the ACE lower, but this is only desirable if the ACE

term is currently positive due to more outgoing power than scheduled within a BA, which would therefore push the system frequency back up to desired levels. The two terms interplay with one another to ensure that each BA assumes fair responsibility for its share of providing Operating Reserves to maintain a stable grid.

For years ACE was used exclusively to control performance, but on February 1, 1998 new standards were introduced to ensure system reliability in a more effective and efficient manner using statistical frequency theory. Two Control Performance Standards (CPS1/CPS2) were developed. Both CPS1 and CPS2 ensure that BAs do not contribute to frequency deviation. CPS1 assigns each BA with a share of control responsibility for maintaining the scheduled interconnection frequency. On a minute by minute basis, the BAs ACE score is divided by its Bias (B) and then multiplied by its frequency error ($F_A - F_S$). This value must not exceed the square of a targeted frequency bound ε_1 common to every BA within its interconnecting region.

$$\left(\frac{ACE}{-10B} \right)_1 (F_A - F_S)_1 \leq \varepsilon_1^2 \quad 3-7$$

The subscript 1 denotes a one minute average and ε_1 is the RMS value of the one minute average frequency errors as recorded by selected sites within the region over a one year period as selected by a NERC Resources Subcommittee whose purpose is to determine a desired frequency profile.⁹

Dividing both sides of 3-7 by ε_1^2 normalizes the left hand side, which is then defined as the Control Factor (CF).

$$CF = \left(\frac{ACE}{-10B} \right)_1 \left(\frac{F_A - F_S}{\varepsilon_1^2} \right)_1 \quad 3-8$$

Finally the CPS1 score can be calculated using the 12 month average of the Control Factor. A minimum score of 100 must be maintained and a score of 200 occurs when ever ACE is zero or the actual frequency F_A and the scheduled frequency F_S are equal.

$$CPS1 = 100 * (2 - CF_{12-month\ average}) \quad 3-9$$

CPS1 assesses how a particular BAs one minute ACE averages affects frequencies deviations over the year. The second measure, CPS2 is designed to bound Area Control Error (ACE) ten-minute averages and in doing so provides a means to limit excessive unscheduled power flows that could result from large ACEs. At least 90% of the ACE ten minute averages must be below a selected limit L_{10} .

$$ACE_{10-minute\ average} \leq L_{10} \quad 3-10$$

$$L_{10} = 1.65 * \varepsilon_{10} \sqrt{-10B * B_T} \quad 3-11$$

$$CPS2 = 100 * \left[1 - \frac{Violations_{1-month}}{Total\ Periods - Unavailable\ Periods} \right] \quad 3-12$$

Where B_T is the sum of every BA's Bias within the interconnection and B is the BA's particular frequency bias. The CPS2 score can then be calculated and must be below 90. A violation occurs every time equation 10 is not met.

There are consequences to not complying with the control performance standards as taken from NERCs Performance Standard Reference Document⁹.

Compliance for BAs. *A BA that does not comply with CPS is not providing its required regulation services.*

1. If a BA does not comply with the CPS, the BA is not permitted to provide regulation or other services related to control performance for any other BA(s) or other entities. Those services are to be determined by the NERC RS.

2. A BA failing to comply is directed by the standard to take immediate corrective action and achieve compliance within three months. If necessary, a BA is directed by the standard to buy sufficient supplemental regulation to achieve compliance

The Disturbance Control Standard (DCS) is used to ensure that a BA returns to its scheduled frequency within defined limits after a disturbance between 80-100% of its most severe single contingency in less than 10 minutes. These disturbances are confined to loss of generation, as loss of load is far less common. This standard also uses ACE as a metric. If the ACE is initially negative the BA must return to its pre-disturbance value. If the ACE is positive it needs only return to zero. Compliance with the DCS is mandatory 100% of the time. Any violation requires that the BA carry additional contingency reserves in the quarter following the violation.

A new standard, Balancing Authority ACE Limit (BAAL) is under development to replace CPS2 and DCS. They are designed to prevent unwarranted load shedding and to prevent frequency-related cascading collapse of the interconnected grid. The standard has been designed so that the BA ACE

Limits (BAALs) become frequency sensitive and can be used by the system operators as performance indicators in real-time. [8]

Efforts to control frequency are not perfect and deviations in frequency are common. Time control efforts must be made for clocks driven of sources with frequencies not at exactly 60Hz. For example if an average frequency of 60.001 Hz was maintained over 10 hours, clocks would be 0.6 seconds too fast. For this reason Time Error Correction (TEC) must compare system clocks with official time provided by the National Institute of Standards and Technology (NIST).

RPS legislation along NERC metrics and the associated penalties for non-compliance provide motivations for BAs to ensure that the Operating Reserves are sufficient to fulfill their obligations. Again, the cost of these services are quite substantial and minimizing the amount of reserves necessary is of growing concern as renewable penetration increases in order to meet each states RPS and as regulating agencies such as NERC continue to impose compliance with the aforementioned metrics as well as the new metrics that may be implemented in the near future.

IV. Balancing Area Cooperation

Balancing Area cooperation will become the single most important tool to mitigate problems with reliability and control performance. [8] Although large scale battery storage and Demand Side Management (DSM) including the use of Vehicle to Grid (V2G) battery storage to provide regulation services are currently being studied, little has been done to incorporate these technologies and ideas into the operational planning of our Nation's grids. On the other hand, some BAs have already combined to form Consolidated Balancing Authorities (CBA). For example 26 BAs in the Midwest Independent System Operators (MISO) formed a single BA in 2005 and 8 BAs in the Western Electrical Coordinating Council (WECC) merged in 2006.

The following discussions on Balancing Area Cooperation are intended to introduce some of the organizational structures that could be implemented to allow for sharing of resources between BAs. Subsequent Theses could choose any one of these organization structures as a complete topic. The Tres Amigas interconnection could enable cooperation between BAs that are currently isolated from one another. The last considered organizational cooperation, full BA consolidation, will be the focus of Chapter VI.

Consolidations form in different structures most of which are summarized on pages 28 through 30 in Table 2. All of the variations of a complete merger are an attempt to achieve better control performance and reliability while reducing the associated cost. All of this relates back to the Area Control Error (ACE)

calculations. Variability of net load, that is actual load minus variable generation, directly determines the amount of required operational reserves. As we have seen in Chapter III, the ACE calculation is a function of the difference in actual and scheduled interchange as well as the difference in actual and scheduled frequency. If BAs are meeting their load requirements then their ACE scores and associated Control Performance Standard (CPS1 and CPS2) scores are better met and less operating reserves are required. Since ACE scores of adjacent BAs are poorly correlated, the standard deviation of the sum of cooperating BA ACE scores is always less than the sum of the standard deviations of cooperating BA ACE, as seen below in the development for Equation 4-1. By definition:

$$\begin{aligned}\sigma(ACE_A + ACE_B) &= \sqrt{\sigma^2(ACE_A) + \sigma^2(ACE_B) + 2\rho_{AB}\sigma(ACE_A)\sigma(ACE_B)} \\ &= \sqrt{(\sigma(ACE_A) + \sigma(ACE_B))^2 + 2(\rho_{AB} - 1)\sigma(ACE_A)\sigma(ACE_B)}\end{aligned}$$

Since $-1 \leq \rho_{AB} \leq 1$

$$\sigma(ACE_A + ACE_B) \leq \sigma(ACE_A) + \sigma(ACE_B) \quad 4-1$$

Where σ is the standard deviation and ρ is the auto correlation.

There are several approaches to consolidating BAs. Consolidating the ACE metric between BAs is known as ACE Diversity Exchange (ADI). ADI takes advantage of the sign changes among ACE values. These sign changes cancel each other out as BAs combine their ACE controls. This rule based method has been implemented in the WECC and has shown to benefit every participating BA.

A 25 MW cap based on operational experience was placed to limit the possibility of transmission line overloading.¹⁴ Caps such as these may be too conservative and limit efficiency or not conservative enough and allow transmission line congestion. The BAs share a common ACE which is then distributed to ensure that each receives

Figure 19: ACE Diversity Exchange Modified Controls

their appropriate share of the metric. The use of this approach ensures that the ACE scores of each BA control their operating reserves in the most efficient manner. As such, the ACE scores always move towards zero and never change signs nor do other BA functions change. Figure 19 displays the modified controls using the ADI rule based method.

As listed in Table 2, Dynamic Scheduling (DS) is a widely used BA cooperation option. This method brings ancillary services to a control area where resources are limited. Additionally, RPS goals not easily met in one area can be transferred to another in a more expeditious and economical manner. DS moves the energy services of a

Figure 20: Dynamic Scheduling Configuration

load or generation into a different unconnected area. Figure 20 graphically depicts this configuration.

While Dynamic Scheduling uses real time metering to transfer control of the energy services to another location not physically connected, a variation of DS called pseudo tie electronically shifts the ACE score by changing the actual interchange instead of the scheduled interchange. Both methods are beneficial regarding BAs ability to meet RPS, serve remote loads and provide/received ancillary services. However, large scale use of DS has not been implemented and new studies are underway to determine impacts.

Table 2: Balancing Authority Consolidation Options

Category	Explanation	Options	Explanation	Comments
Actual BA consolidation in a single Balancing Authority in WECC	Participating BAs form a single Balancing Authority	Full actual consolidation	BAs merge and all balancing functions are centralized	Example: Actual consolidation of 26 BAs in the MISO area into a single BA on January 6, 2009
		Virtual or partial consolidation	Participating BAs or utilities perform some or all balancing functions individually based on certain sharing agreements	
Wind only BA	Wind power producers form their own BA			Example : Glacier Wind
Sharing or globalization of some of the balancing functions	Participating BA share some of the balancing functions, but do not form a single Balancing Authority	Primary reserve (frequency response) sharing and coordination	BAs determine and provide frequency response based on the system wide standard and share the amount of response provided by each BA based on certain sharing agreement	European transmission system operators use this option for primary reserves (frequency response)
		ACE sharing (or ADI)	Participating BAs calculate a common ACE in real time and share the ACE diversity based on certain sharing principles	Examples: (1) Simple ADI (like in WECC) (4) ADI with globalized use of regulation resources
				Some possible variants: (1) Bilateral market or agreements (e.g., using dynamic schedules) (2) Spot market

Table 2 cont.: Balancing Authority Consolidation Options

Category	Explanation	Options	Explanation	Comments
Sharing balancing services and resources	The balancing services can be provided by resources outside of the BA that needs these services. Also, the same resource could provide services to multiple BAs.	Flexibility market or other similar globalization options for load following services (intra-hour balancing)	Participating BA use market or other mechanisms to provide wide area intra-hour balancing service	Some possible variants: (1) Bilateral market or agreements (e.g., using dynamic schedules) (2) Spot market
		Coordinated scheduling process	Participating BAs build and optimize their generation and interchange schedules in a coordinated fashion based on their load, wind and solar generation forecasts	
		Dynamic schedules	A balancing resource is scheduled and/or controlled from an outside BA. Its output is telemetered to the BA where this resource is accounted for.	Currently, this is a widely used option.
		Globalization of balancing services in a wide area	BAs have access and can use balancing resources outside their Balancing Authority	Example: regulation (secondary reserve) market and globalization in Germany
Globalization and sharing of unscheduled deviations	Participating BAs agree to globalize unscheduled deviations and balance only against some share of these deviations	Regulation resource sharing	A regulation resource provide regulation services for 2 or more BAs	PNNL project funded by BPA and CEC
		Globalization and sharing of unscheduled deviations of wind and solar resources	The arrangement covers only wind and solar station errors	Example: Germany

Table 2 cont.: Balancing Authority Consolidation Options

Category	Explanation	Options	Explanation	Comments
		Globalization includes all deviations including load deviations		Note differences with sharing the balancing functions
		The sharing goes below the BAs' level to the level of specific resources	The resources get only a fraction of their own balancing responsibility	Resources have a choice between self-provided regulation, buying regulation service from some other resources or using services provided by BAs. The option is currently under discussion at BPA
Sub-hour scheduling within each participating BA	Participating BAs' scheduling process is conducted for sub-hour time intervals for all resources within the BA	The arrangement is done for participating BAs only, with the external BAs, the one hour schedules are used		Used in MISO, ERCOT, PJM, ISO-NE, NYISO, IESO, NYISO, CAISO, ...
Sub-hour scheduling within and among participating BAs	Participating BAs' scheduling process is conducted for sub-hour time intervals among BAs	The arrangement is done for participating BAs only, with the external BAs, the one hour schedules are used All interconnection is using sub-hour schedules		Used in Germany, Being implemented between NYISO, ISO-NE, IESO

In order to study the effects of Dynamic Scheduling, two performance envelopes have been developed. The first performance envelope used includes

Figure 20: Capacity, Ramp Rate, Ramp Duration and Energy

four different metrics. The capacity (curve) is the amount of generation available in MW. The ramp rate (slope) is a measure of how quickly a generating unit can increase or decrease its output in MW/min. The ramp duration is the amount of time the unit can maintain the max ramp rate and the energy is the integral (area under curve) of capacity with respect to time. Figure 21 depicts these metrics. [8]

If the ramp rate is insufficient then additional generating units must be online to compensate for the inability to appropriately match the load. Cost increases with extra generation but units capable of higher ramp rates are typically more expensive to operate.

The second performance envelope introduces the concept of ramping cycles. While ramping continues in the same direction, all data points belong to the same half-cycle. Once the system changes from ramping up or down to ramping down or up, a new half-cycle begins. Figure 22 below depicts such a cycle.¹⁴

Figure 21: Second Performance Envelope for Dynamic Scheduling

Using net load, scheduling, load following, and regulation data, impact reports can be used to develop necessary capacity and ramp rates. The following pages are examples of scheduling, load following and regulation requirements that can be created using the two aforementioned performance envelopes. Exploring the methods used to create these predictions could provide for additional Theses. Pacific Northwest Laboratories create a document

“Analysis Methodology for Balancing Authority Cooperation in High Penetration of Variable Generation”¹⁴ for the U.S. Department of Energy detailing DS and many other forms of BA cooperation that extend beyond the scope of this Thesis and are introduced only to recognize the need for further study.

Below are examples of ahead scheduling, load following and regulation.

Figure 23: Scheduling Capacity Example over One Month Period

Figure 22: Load Following Capacity Example over One Month Period

Figure 24: Regulation Example over One Month Period

Figures 26 through 28 show an example of the requirements of scheduling, load following and regulation using the performance envelopes described above.

Figure 25: Scheduling Requirements as Determined by DS Performance Envelopes

Figure 26 Load Following Requirement as Determined by DS Performance Envelopes

Figure 27: Regulation Requirements as Determined by DS Performance Envelopes

Wind only Balancing Authorities remain an option for wind farm providers to become a unified BA. Taking advantage of the geographic diversity would serve to mitigate the variability of generation. The wind only BA would be

responsible to provide or purchase the operational reserves necessary to comply with the ACE based control performance standards just as any other BA. This is an advantage to traditional BA as they would not have to deal with the variable nature of wind generation. The Wind BAs could utilize the expertise developed in forecasting wind to deal with variability in perhaps a more efficient manner. A big disadvantage for Wind only BAs would be the lack of interaction with loads that have an uncorrelated variability which would normally help smooth out net load in a traditional BA.

A Consolidated Balancing Authority (CBA) exists when 2 or more BAs merge to form a single BA. The hour ahead scheduling, load following and regulation services formerly controlled by each individual BA, now become controlled by the CBA. Transmission limits are followed as to not jeopardize system security. The sharing of a wider range of geographic diversity benefits the CBA by smoothing out the variability of load and wind generation. Less operating reserves are then required yet more are available. This surplus will be necessary to realize the ambitious RPS goals of many states. The reduced need for operating reserves can be seen directly from the ACE equation. The first term is the difference in actual interchange minus the scheduled interchange. What would normally be an inadvertent interchange between BA is no longer the case in the CBA. This sharing of resources as a larger entity reduces this term. The ACE driven control performance standards CPS1 and CPS2 used to penalize BA out of compliance provides further motivation to consolidation. The cost of dealing with boundary issues regarding metering would also be

eliminated. Furthermore, independent decisions in one BA without knowledge of adjacent BA states can adversely affect both. It is this form of BA cooperation that will be explored in Chapter VI of this paper.

V. Standard Deviation as a Method for Determining Operational Reserves

Since renewable penetration is relatively low, on the order of 3%, empirical methods to predict Operational Reserves do not yet exist. Using Standard Deviation provides a theoretical method to estimate Operational Reserves. It is this method that was used by NREL during the EWITS study and will be used in the next chapter to explore the effects of connecting BAs in the three asynchronous regions of the United States via the Tres Amigas interconnection. It should be noted that fluctuations in wind power do not need to be matched one for one with reserve generation. Rather it is the aggregation of all generations and loads that must be balanced. [9] The impact of wind variability can be divided into two categories, variations due to inter-hour changes as a result of the nature of wind and variations due to inaccurate forecasting. Historically Operational Reserves have only had to deal with changes in load or disturbances. Now that renewable generation also changes, it makes sense to change the definition of load. If we define the net load NL to be the load minus the power produced by wind, we can define the change in net load (ΔNL) according to equation 5-1 below. With load and wind being uncorrelated and using equation 5-2 we can develop equation 5-3. Finally using the fact that standard deviation is the square of the variance we can develop equation 5-4.

$$\Delta NL = NL_i - NL_{i-1} = (L_i - W_i) - (L_{i-1} - W_{i-1}) = \Delta L_i - \Delta W_i \quad 5-1$$

$$\text{Var}[aX + bY + c] = a^2 * \text{Var}[X] + b^2 * \text{Var}[Y] + c * 2 * \text{Cov}[X, Y] \quad 5-2$$

$$VAR(\Delta NL) = VAR(\Delta L - \Delta W) = VAR(\Delta L) + VAR(\Delta W) \quad 5-3$$

$$\sigma_{NL} = \sqrt{\sigma_L^2 + \sigma_W^2} \quad 5-4$$

Where NL, L and W denote net load, load and power from wind respectively at time i . The operation and planning of a power system are about mitigating risk. Figure 29 shows that in a normally distributed ΔNL , $\pm 3\sigma$ must be accounted for in order to cover 99.7% of the variation. Where σ is the standard deviation as given in equation 5-5.

$$\sigma = \sqrt{\frac{1}{N} \sum_{i=1}^N (x_i - \mu)^2}, \text{ where } \mu = \frac{1}{N} \sum_{i=1}^N x_i \text{ over } N \text{ samples} \quad 5-5$$

Figure 28: Normally Distributed Data Showing $\pm 3\sigma$ Covers 99.7% of Data.

A study was conducted by Ener Nex Corp as directed by the Minnesota legislature for 2005, to determine if the 3σ method did in fact cover the 99% required exceedance level. Figure 30 shows that the sigma method more than covers the 99% exceedance level.

Figure 29: Exceedance Level Comparison of Load and Net Load (Load and Wind)

Observations from grid operators have led to the widely used assumption that 1% of the hourly load forecast represents 3 times the standard deviation of load fluctuations. [9] Using this factor of 3 to cover the regulation requirements and the industry standard of 1% of load value for regulation, equation 5-7 can be developed by substituting equation 5-6 into equation 5-5.

$$R_L = 3 * \sigma_{load\ fluctuation} \approx .01\ Hourly\ Load\ Forecast \quad 5-6$$

$$R_{L,w} = 3 * \sqrt{\left(\frac{R_L}{3}\right)^2 + \sigma_{wind\ fluctuation,h}^2} \quad 5-7$$

Where R_L is the Regulation required due to load only and $R_{L,w}$ is the regulation required due to load and wind combined. It is important to remember that Equation 5-7 returns the regulation required for a particular hour. A particular Hourly Load Forecast R_L and the standard deviation of the wind fluctuations within the same hour $\sigma_{wind\ fluctuation,h}$ are used for this calculation. As seen in equation 5-6, calculating R_L is a straight forward process and obtained using 1 percent of past hourly load data just as operators do in industry. Calculating $\sigma_{wind\ fluctuation,h}$ is not as straight forward and becomes the most tedious calculation when determining regulation requirements. The subscript h in $\sigma_{wind\ fluctuation,h}$ denotes the standard deviation that can be expected from the average wind output of the particular hour for which regulation is being determined. Once the average wind output for the hour is determined only then can the $\sigma_{wind\ fluctuation,h}$ be determined. The $\sigma_{wind\ fluctuation,h}$ is different depending on the current output of the wind turbines. Changes in wind speed cause greater changes in the standard deviation of wind output when the turbines are operating within the midrange of the maximum output. In fact, as we will see shortly, this relationship becomes quadratic. We must first determine standard deviation of wind over a particular range of turbine nameplate capacity which we will denote $\sigma_{wind\ fluctuation\ decile}$. The process entails aggregating the time series wind output across every location within a particular BA. That is, for every 10 minute time point, all of the turbine output data values in MW are added together. Then taking the difference between the next time series turbine wind

output and the current time series output, the change in 10 minute wind output can be calculated as shown below in equation 5-8.

$$DW_{10min} = Aggregated\ Wind_{(t+10min)} - Aggregated\ Wind_{(t)} \quad 5-8$$

The DW_{10min} and aggregated wind values are then sorted by aggregated wind and grouped into deciles. The standard deviation of DW_{10min} ($\sigma_{wind\ fluctuation\ decile}$) within each decile grouping can be calculated according to equation 5-9.

$$\sigma_{wind\ fluctuation\ decile} = \sqrt{\frac{1}{N} \sum_{i=1}^N (DW_i - \mu)^2} \quad 5-9$$

$$where\ \mu = \frac{1}{N} \sum_{i=1}^N DW_i\ over\ N\ samples\ within\ each\ decile$$

Once all ten of the $\sigma_{wind\ fluctuation\ decile}$ values are determined a plot can be developed as shown on the following page in Figure 31. This plot is important because it gives us the behavior of $\sigma_{wind\ fluctuation,h}$ as the percentage of output capacity of the wind turbine changes. Greater changes in $\sigma_{wind\ fluctuation,h}$ can be expected when the turbine is operating in the midrange of the nameplate capacity. The maximum expected error occurs in the midrange of the aggregate production because it would be where the largest number of turbines are operating on the steep part of their power curves. For low levels of production, the error is small because the output is small; at higher production levels, the error also declines, because in this region, many turbines are operating above

rated wind speed, where fluctuating wind speed does not translate into varying energy production.²³

The second order polynomial developed from the trendline is then used to determine each hours $\sigma_{wind\ fluctuation,h}$. Using an example where the current hours average aggregated wind output is 660 MW and inserting this value into the example polynomial from the trendline plot in Figure 31 below we obtain the following value:

$$\sigma_{wind\ fluctuation,h} = -2 \times 10^{-4} * (660)^2 + .2137 * (660) + 3.0639 = 57\ MW$$

This value of 57 MW is the standard deviation that can be expected from the changes in wind output for the hour when the average aggregated wind turbine output is at 660 MW. Finally the regulation requirement for the hour could be calculated by inserting this value along with the regulation requirements due to the load R_L into equation 5-7.

Figure 30: Sigma as a Function of Average hourly Production

For example if the forecasted load for this hour was 2970 MW the regulation required due to wind and load together would be as follows:

$$R_L = 3 * \sigma_{load\ fluctuation} \approx .01\ Hourly\ Load\ Forecast = .01 * 2970 = 297\ MW$$

$$R_{L,w} = 3 * \sqrt{\left(\frac{R_L}{3}\right)^2 + \sigma_{wind\ fluctuation,h}^2} = 3 * \sqrt{\left(\frac{297}{3}\right)^2 + 57^2} = 342\ MW$$

Therefore 342 MW of available power must be online and waiting to either ramp up or ramp down within 10 minutes in order to properly balance generation and load.

A sigma normalized to the current capacity of the wind generator $\sigma_{wind\ fluctuation,h(pu)}$ can be obtained by dividing by $\sigma_{wind\ fluctuation,h}$ by the average of the aggregated wind output for each hour and plotted against

the per unit nameplate capacity of the wind turbines. This is valuable when comparing the effects of aggregating more wind over a greater geographic area.

The Eastern Wind Integration and Transmission study (EWITS) compiled data from wind production alone starting at 500 MW up to 85 GW. As seen in Figure 22 below, the Normalized Sigma($\sigma_{wind\ fluctuation,h(pu)}$) decreases with larger systems which shows that as larger geographic footprints are covered, the variations in output become less. As before, in all cases the normalized sigma varies along with the percentage of name plate capacity of the wind generating units. At lower out power wind speeds are less power and changes are therefore smaller. Similarly, when units are operating closer to or at full capacity changes in wind speed change output power less or not at all.

Figure 31: $\sigma_{wind\ fluctuation}$ Varies by Size and Percent of Capacity

The significance of Figure 32 can be shown by comparing the 500 MW and 5,000 MW curves. If for example 10 identical BAs each capable of producing a maximum of 500 MW of wind power during an hour where the wind

turbines were operating at 50 percent capacity, using Figure 32, the standard deviation of wind fluctuations on the hour would be as follows:

$$\sigma_{wind\ fluctuation,h} = \sigma_{wind\ fluctuation,h(pu)} * Max\ output = .065 * 500 = 32.5\ MW$$

If the regulation due to load during this hour was 75 MW, the total regulation for all 10 BAs would be as follows:

$$\begin{aligned} 10 * R_{L,w} &= 10 * 3 * \sqrt{\left(\frac{R_L}{3}\right)^2 + \sigma_{wind\ fluctuation,h}^2} = 10 * 3 * \sqrt{\left(\frac{75}{3}\right)^2 + 32.5^2} \\ &= 1230\ MW \end{aligned}$$

However if these same 10 BAs were to merge as a consolidated BA the standard deviation of wind fluctuations on the hour would calculate as:

$$\sigma_{wind\ fluctuation,h} = \sigma_{wind\ fluctuation,h(pu)} * Max\ output = .027 * 5000 = 135\ MW$$

The regulation due to load would be 10 fold at 750 MW and the regulation for the consolidated BA calculates as:

$$R_{L,w} = 3 * \sqrt{\left(\frac{R_L}{3}\right)^2 + \sigma_{wind\ fluctuation,h}^2} = 3 * \sqrt{\left(\frac{750}{3}\right)^2 + 135^2} = 852\ MW$$

A savings of 380 MW of regulation for that hour could be achieved by consolidating the 10 smaller BAs into a single larger BA. In chapter VI this trend will prove savings for every BA consolidation considered.

Additional reserves equal to one standard deviation must be set aside for hourly wind forecast errors ($\sigma_{forecast\ error}$). This error is due to inter-hour wind

variability. The forecast error is calculated by subtracting the wind output data from one hour prior. This persistence method is commonly used to determine forecast error.²³ A similar method as was used to determine $\sigma_{wind\ fluctuation,h}$ is used to determine $\sigma_{forecast\ error}$. One standard deviation of $\sigma_{forecast\ error}$ is added to the reserve requirements calculated for load and 10 minute wind variations. The total reserve requirement is displayed in equation 5-10 on the following page.

$$R_{L,w\ total} = 3 * \sqrt{\left(\frac{R_L}{3}\right)^2 + \sigma_{wind\ fluctuation,h}^2 + \sigma_{forecast\ error}^2} \quad 5-10$$

However, the total spinning reserve contains a component that is allocated specifically to be used if wind generation is less than the forecast in the previous hour. To avoid double counting of these reserves, the profile is adjusted. [3] This is accomplished by subtracting the $\sigma_{forecast\ error}$ component if the previous hours average hourly aggregated wind is greater than the current hour. An example taken from the EWITS shows all of the calculations and adjustment performed to complete the regulation requirements needed and can be seen in figure 33. Taking row 3 as an example we can see how each column value was populated. Columns 1 and 2 are recorded data and require no calculations. Column 3 (R_L) was calculated using the value from column 1 and equation 5-6.

$$R_L = 3 * \sigma_{load\ fluctuation} \approx .01\ Hourly\ Load\ Forecast = .01 * 53993 = 540\ MW$$

Column 4 ($\sigma_{wind\ fluctuation,h}$) uses the polynomial taken from Figure 34 as they are developed by taking the standard deviation of the changes in 10 minute wind output within each decile sorted by aggregated wind.

$$\sigma_{wind\ fluctuation,h} = -3 \times 10^{-6} * (14261)^2 + .0532 * (14261) + 70.876 = 219\ MW$$

Column 5 ($R_{L,w}$) was calculated by taking column 4 ($\sigma_{wind\ fluctuation,h}$) and column 3 (R_L) and inserting then in equation 5-7.

$$R_{L,w} = 3 * \sqrt{\left(\frac{R_L}{3}\right)^2 + \sigma_{wind\ fluctuation,h}^2} = 3 * \sqrt{\left(\frac{540}{3}\right)^2 + 219^2} = 851\ MW$$

Column 6 is the regulation required for the single largest contingency and is not considered in this paper during the analysis in Chapter VI. The value used is typically 50% of 1.5 time the single largest hazard or a specially designated value. [3] Column 7 ($\sigma_{forecast\ error}$) uses the polynomial taken from Figure 35 as they developed by taking the standard deviation of the changes in hour ahead forecast error within each decile sorted by aggregated wind. Using the previous hours wind the following calculation results.

$$\sigma_{forecast\ error} = -8 \times 10^{-6} * (15174)^2 + .1357 * (15174) + 512.1 = 729\ MW$$

Column 8 is the sum of columns 5, 6 and 7. This represents $R_{L,w\ total}$ as given in equation 5-10 minus the contingency reserves. Again, the contingency reserves will not be considered in the analyses of this paper. Column 9 is the change in

wind output which is calculated by taking Column 2 row_i – column 2 row_{i-1}. The adjustment in column 10 only occurs if the value in column 9 is negative. Finally column 11 gives the adjusted reserve requirements. [3] Notice that for the hour 3 the change in wind generation from the previous hour was negative as seen by the value in parenthesis in column 9 (2335). As stated before, to avoid double counting, the $\sigma_{forecast\ error}$ value in column 10 was subtracted out of the total reserve requirements of column 8. The new adjusted value is shown in column 11.

COLUMN NUMBER	1	2	3	4	5	6	7	8	9	10	11
HOUR	ACTUAL LOAD (MW)	ACTUAL WIND (MW)	REGULATION FOR LOAD (MW)	σ_{ST} (MW)	TOTAL REGULATION (MW)	CONTINGENCY RESERVE-SPINNING (MW)	$\sigma_{Next\ Hour\ Error}$ (MW)	TOTAL SPINNING RESERVE (MW)	CHANGE IN WIND GENERATION (MW)	ADJUSTMENT (MW)	ADJUSTED SPINNING RESERVE (MW)
1	56,341	11,860	563	280	1,011	2,271	1,037	4,319	50	0	4,319
2	54,788	15,174	548	187	785	2,271	996	4,052	3,314	0	4,052
3	53,993	14,261	540	219	851	2,271	729	3,851	(913)	729	3,122
4	53,786	11,926	538	279	994	2,271	820	4,085	(2,335)	820	3,265
5	54,922	10,843	549	295	1,042	2,271	993	4,337	(1,084)	993	3,344
6	58,120	10,283	581	301	1,073	2,271	1,043	4,387	(559)	1,043	3,444

Figure 32: Example of Calculations and Adjustments to Reserve Requirement due to Reduction in Hourly Wind

Figure 33: $\sigma_{wind\ fluctuation,h}$ as a Function of Average Hourly Production

Figure 34: $\sigma_{forecast\ error}$ as a Function of Average Hourly Production

Repeating this procedure for every hour of every day, it is possible to determine the average regulation requirements across an entire year. Different scenarios can be analyzed by choosing wind locations from a broader geographic area. NRELs Western Wind interactive map provides the means to

select wind sites by state and longitude and latitude position. [10] In the following chapter, methods are developed to quickly and easily download large quantities of data. Matlab code was written to almost instantly process the 46.2 million data points required for this paper's analysis, through every process mentioned in this chapter. Comparisons are then made to determine the value of interconnecting the three asynchronous regions of the United States through the Tres Amigas project in Clovis, NM.

VI. Impacts of Using the Tres Amigas Interconnection

Currently Balancing Area cooperation between the 3 asynchronous regions is not an option. The following chapter will analyze the impacts of consolidating BAs. The objective is to take advantage of the diversity of wind output across regions. Seven BAs are considered for this analysis. Five of these BAs are within the Western Region, one is in the East and ERCOT stands alone in Texas. Figure 36 and Table 3 below show these BAs and provide a full name corresponding to each acronym along with each BA's peak demand and RPS. The focus of this analysis primarily considers the impacts as seen by the Public Service Company of New Mexico (PNM). Although PNM is connected to six other BAs in the Western Region, only four of these BAs are considered due to a lack of available data for WALC and WACM.

Figure 35: Region near Tres Amigas under Investigation

Table 3: Balancing Area Considered in Analysis

Balancing Area	Acronym	2020 Peak Demand (MW)	2020 RPS
Public Service Company of New Mexico	PNM	2289	20%
El Paso Electric	EPE	2094	20%
ERCOT ISO	ERCO	32484	15%
Southwest Public Service Company	SPS	5493	15%
Tucson Electric Power Company	TEPC	2800	15%
Salt River Project	SRP	9500	15%
Arizona Public Service Company	AZPS	11400	15%

The analysis uses methodology similar to that used in the NREL Eastern Wind Integration and Transmission Study (EWITS), as described in the previous chapter. Fifteen cases were considered as given in Table 4. An X in the row of each case indicates the BAs that have consolidated to form a single combined BA. Cases 1 through 7 consider each BA functioning independently. Then cases considering combined BAs can be compared by adding the regulation requirement in (MW) of the BA alone and then subtracting the regulation requirements in (MW) of the consolidated BAs. Multiplying this difference by 8760 hours in one year represents the regulation requirement savings in MWh. Cases 8 and 9 explore the effects of utilizing the Tres Amigas interconnection to consolidate PNM with SPS in the east and then consolidate PNM with SPS and ERCO in Texas. Immediately following, case 10 looks at PNM consolidating with every other BA in the West. It makes sense to compare these two cases directly and this will be looked at in the analysis following the results. Cases 11 through 15 continue to add BAs one at a time until all have consolidated. Certainly many other permutations could have easily been considered. Once the data has been loaded into variables in this Thesis's Matlab workspace, running additional cases can be repeated as fast as it takes to change the variable names in the function

call entry. The fifteen cases explored are sufficient to show the trend of continuing to aggregate more wind over a broader geographic area.

Table 4: Cases Considered During Analysis

	PNM	SPS	ERCO	EPE	TEPC	SRP	AZPS
Case 1	X						
Case 2		X					
Case 3			X				
Case 4				X			
Case 5					X		
Case 6						X	
Case 7							X
Case 8	X	X					
Case 9	X	X	X				
Case 10	X			X	X	X	X
Case 11	X	X		X			
Case 12	X	X	X	X			
Case 13	X	X	X	X	X		
Case 14	X	X	X	X	X	X	
Case 15	X	X	X	X	X	X	X

The Matlab workspace and functions were created to facilitate rapid analysis and provide a tool for future investigations. Therefore methodology is first described and results are then presented. It should be noted that first a case involving consolidation between two regions was executed in excel. The results were used to check that the Matlab code provided identical results. After this was ensured, the cases described above in Table 4 were executed and results were tabulated. Analysis that takes days to complete manually combining the excel wind data files found on NRELs Western Wind Data interactive map can be completed in seconds with the Matlab tool developed in the study. It should be noted that hourly load data for each BA was not available. Minor modification of code could enable the integration of this data into future studies. It was recently discovered that hourly load data for the years corresponding to the wind data (2004, 2005 and 2006) is available from FERC. FERC form 714 is a lengthy

process that could not be completed in time to incorporate the data into this study. Nevertheless, for the purpose of this study, sample load data taken from a similar analysis was used. [11] The data was scaled to each BAs capacity and used for everyday of the year. While this provides inaccurate reserve requirements for the load portion of the calculation, the impacts of combining wind power is unaffected and the relative changes from acting alone to functioning together in a consolidated BA is valid. It is these changes that this study wishes to investigate. The use of a common scaled load profile is sufficient to show these changes while still providing accurate enough regulation requirements from the load contribution.

It was first necessary to import the wind data sets from the NREL Western Wind Data interactive map. [10] Selecting sites with high capacity values, obtains data from sites with high amounts of output power most likely to be selected by potential wind power companies. Next it was necessary to choose sites that fall within a particular BAs region. There are various opinions of what locations fall into a particular BAs region. Proximity to high power transmission lines could be the most effective method, however the longitude and latitude of each BAs transmission system is not readily available. Due to this constraint, a generalized longitude and latitude selection was used to determine when sites fall into a particular BA. Red windmill icons represent sites with average output capacities over 40% of maximum and were selected first. Next orange windmill icons representing sites with average output capacities between 35 and 45% were selected. The site numbers were written down along with their average

capacities until enough sites were selected to meet the RPS requirements of the year 2020. This was calculated by multiplying each sites average capacity factor by 30 MW to obtain the average yearly output. Adding each site together until the average output power met the RPS as given in the Integrated Resource Planning (IRP) documents. Often the RPS is given in units of energy (MWh) and dividing this value by 8760 hours for the year yielded the average MW output needed from renewable sources. For example Public Service Company of New Mexico (PNM) has a projected midrange RPS of 1750 GWh needed by 2020. Dividing this by 8760 hours in the year gives a needed average output power from renewables of 200 MW. If the sites selected average 40% capacity factor each at 30 MW then $200 / (30 * 0.4) = 17$ locations needed for PNM. Table 5 below provides the 2020 projected loads for the BAs considered in this study and gives the number of 30 MW data sets needed to estimate meeting their perspective RPS goals. The Load Forecast data was obtain from various IRPs as displayed in Appendix A.

Table 5: Load Forecast and Number of 30 MW sites needed to meet RPS for each BA

Balancing Area	Acronym	2020 Load Forecast (GWh)	Average MW needed	RPS	30 MW wind sites needed to meet RPS
Public Service Company of New Mexico	PNM	16000	200	1750 GWh	17
El Paso Electric	EPE	10600	245	20%	20
ERCOT ISO	ERCO	400,000	5880	5880 MW	490
Southwest Public Service Company	SPS	27000	462	15%	38
Tucson Electric Power Company	TEPC	35000	600	15%	50
Salt River Project	SRP	35000	600	15%	50
Arizona Public Service Company	AZPS	150000	2568	15%	214

In order to expedite the process of loading the wind data into the Matlab directory to execute the analysis, a file reading program was loaded into the command prompt window. These directions are located in Appendix B and were obtained from George Scott at NREL. [12] All of the Matlab functions mentioned in this paper are listed in Appendix C. The site numbers were loaded into a variable in Matlab and the buildTextFile function was used to generate a text file for the Wget program to automatically download the files. It was necessary to place this text file in the same directory as the Wget file. For me this was C:\Users\Jeff Wilkinson. This method was absolutely necessary when downloading the 879 files needed for this study.

Using PopMatrix function in Matlab, matrices containing the wind data for every location within each BA were created. Each column of the matrix contains the wind output data of a particular site. This output data, as developed by NREL for the Western Wind and Solar Integration Study (WWSIS), corresponds to the output as would be provided by ten Vestas V-90 3 MW turbines for a total of 30 MW per location. Each of these matrices contains 52560 rows of data. This provides a wind data point every 10 minutes for an entire year.

Within the aveRegulationRequirementsFinalRev function, wind data is then aggregated across all locations within a particular BA or consolidated BA to create a column vector labeled aggWind of 52560 rows. Then the change in wind output (DW) was calculated, as described in Chapter V using equation 5-9, to create a column vector of 52559 rows.

The last row of the `aggWind` vector is truncated. The vectors `aggWind` and `DW`, now of equal size, are concatenated and sorted according to the aggregated wind output column. Next the `groupDeltaWindByaggWindandCalcSigma` function is called where the delta wind output is grouped into deciles. The standard deviation of each of these groups $\sigma_{\text{wind fluctuation decile}}$ is calculated and the function then returns these values. These values are plotted against output to form plots similar to those found in the EWITS study as shown in the previous chapter in figure 31. The polynomial expression estimating this distribution along with the decile bins are obtained using the `buildPolynomial` function. The average hourly production of wind power is then calculated using the `hourlyWindAveParticularDay` function.

Now the standard deviation of each of the 8760 hours within a year can be calculated. As discussed in the previous chapter, equations 5-6 and 5-7 can be used to determine the operational reserves required due to fluctuations in wind.

Additional reserves to account for errors in forecasting must also be calculated. The forecast error is calculated by subtracting the wind output data from one hour prior. This persistence method is commonly used to determine forecast error. [3] A similar method, as was used to determine $\sigma_{\text{wind fluctuation,h}}$, is used to determine $\sigma_{\text{forecast error}}$. One standard deviation of $\sigma_{\text{forecast error}}$ is added to the reserve requirements calculated for load and 10 minute wind variations. The total reserve requirement is displayed in equation 5-10 as seen in the previous chapter and again the adjustments were made to avoid double counting due to reduction of wind in the Matlab function “`regulationAve`”.

Once the regulation requirements for all 365 days of the year were calculated, they were averaged. Additionally, the plots of $\sigma_{\text{wind fluctuation},h}$ and $\sigma_{\text{forecast error}}$ were normalized for the purpose of displaying the different cases collectively in per unit. The behavior expected is that as the number of locations increases over larger geographic distances, the change in aggregated wind output will decrease. In every case where BAs consolidated, the behavior was similar to the plots given in Figure 32 in the previous chapter.

Each of the following pages includes the cases as listed in Table 4 of this chapter. The hourly regulation requirements averaged for the year are displayed along with the per unit $\sigma_{\text{wind fluctuation}}$ and $\sigma_{\text{forecast error}}$ as a function of nameplate capacity plots. In the cases where two or more BAs have consolidated, comparisons between the participating BAs functioning alone and together are given. A factor of \$9.72 US dollars per MWh of regulation was used to provide a monetary value of the regulation requirement savings. [13] The per unit plots provide a visual performance index for the wind it represents. The y-axis gives the per unit standard deviation in MW for the wind at each particular percentage of nameplate capacity. In general these plots are lower for larger BAs since the wind is spread out over larger distances. However, it should be noted that these plots change according to the selection of wind sites. Wind power providers wish to place as many wind turbines as possible in closer proximity to transmission lines with terrain that is easier to manage yet still provides the highest concentration of persistent wind. This however is not desirable to the BA. The BA would prefer that each wind turbine is spread out as far as possible to provide

less overall variability. Wind sites in close proximity go up and down in their outputs together. While turbines located 50 to 100 miles apart are more likely to balance each other's outputs to a smoother total output. This can explain some of the differences in the per unit plots from BA to BA. Pay specific attention to the plots and the number of 30 MW sites within each BA when looking at the first 7 cases. Also note how adding additional BAs reduces the per unit plots in every case. Although as more BAs are added, the differences become less. Pay particular attention to the contribution of each BA and to the per unit plots relative to the number of 30 MW sites added as given in Table 5 of this chapter.

Case 1: Public Service Company of New Mexico (PNM) Functioning Independently

Table 6: Hourly Regulation Requirements Averaged through the Year for PNM

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	44.10	45.55	89.65
2	44.21	45.87	66.27
3	44.87	46.67	68.31
4	44.87	46.72	69.44
5	45.61	47.26	69.35
6	45.66	47.08	69.54
7	45.71	46.71	68.15
8	46.39	46.83	71.01
9	46.99	46.99	70.20
10	47.76	47.23	69.66
11	48.38	47.44	72.21
12	48.75	47.36	72.08
13	49.20	47.44	72.20
14	49.08	46.92	70.72
15	48.48	45.96	68.23
16	47.99	45.39	69.26
17	47.28	44.83	68.96
18	46.53	44.65	71.77
19	46.53	45.13	73.44
20	46.71	45.31	71.44
21	46.91	45.78	70.11
22	46.05	45.77	66.06
23	45.10	45.57	68.75
24	44.57	45.68	69.15
Total	1117.73	1110.14	1695.97
Average	46.57	46.26	70.67

Figure 36: Normalized $\sigma_{\text{wind fluctuation}}$ as a of Function Per Unit NamePlate Capacity for PNM (17 sites)

Figure 37: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for PNM (17 sites)

Case 2: Southwest Public Service Company (SPS) Functioning Independently

Table 7: Hourly Regulation Requirements Averaged through the Year for SPS

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	113.76	129.75	243.51
2	119.65	135.41	206.83
3	123.73	139.44	213.09
4	128.15	143.24	218.12
5	130.01	144.82	215.15
6	128.13	143.72	204.79
7	128.64	143.57	200.66
8	128.91	142.74	199.12
9	129.85	142.22	194.42
10	131.61	142.22	188.03
11	132.44	142.02	195.01
12	132.42	140.88	194.23
13	133.98	140.89	194.60
14	131.32	137.34	181.07
15	127.09	132.37	170.45
16	124.58	129.91	174.97
17	117.81	124.93	174.56
18	113.34	122.29	175.10
19	112.87	122.52	176.37
20	111.87	121.72	169.81
21	109.88	120.78	172.96
22	108.80	121.66	167.64
23	113.40	126.68	183.14
24	117.29	130.96	191.30
Total	2949.55	3222.09	4604.95
Average	122.90	134.25	191.87

Figure 38: Normalized $\sigma_{\text{wind fluctuation}}$ as a of Function Per Unit NamePlate Capacity for SPS (38 sites)

Figure 39: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for SPS (38 sites)

Case 3: ERCOT ISO (ERCO) Functioning Independently

Table 8: Hourly Regulation Requirements Averaged through the Year for ERCO

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	763.98	955.16	1719.14
2	774.26	991.93	1450.39
3	783.30	1016.22	1502.87
4	789.08	1028.79	1485.52
5	798.49	1029.49	1424.09
6	804.11	1026.37	1398.98
7	811.38	1013.47	1361.87
8	825.85	998.54	1338.93
9	841.89	990.58	1316.27
10	863.82	985.42	1308.88
11	879.55	978.73	1322.71
12	897.63	976.94	1288.75
13	910.01	968.64	1278.01
14	918.22	953.20	1165.74
15	910.49	919.02	1175.22
16	896.85	891.06	1163.14
17	874.81	862.90	1151.85
18	842.17	837.49	1149.26
19	825.20	829.24	1184.33
20	830.33	833.14	1244.99
21	822.56	837.64	1244.42
22	787.83	846.54	1212.11
23	772.10	884.69	1299.06
24	766.68	927.57	1372.99
Total	19990.58	22582.77	31559.52
Average	832.94	940.95	1314.98

Figure 40: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function of Per Unit NamePlate Capacity for ERCO (490 sites)

Figure 41: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for ERCO (490 sites)

Case 4: El Paso Electric (EPE) Functioning Independently

Table 9: Hourly Regulation Requirements Averaged through the Year for EPE

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	67.27	70.28	137.55
2	66.59	69.79	96.64
3	66.63	69.86	98.90
4	66.22	69.54	103.34
5	67.45	70.42	102.53
6	67.27	70.01	100.26
7	66.97	69.35	100.50
8	67.72	69.52	103.70
9	68.13	69.47	102.98
10	68.94	69.68	103.88
11	69.82	70.10	107.09
12	70.46	70.28	105.39
13	71.43	70.81	108.57
14	71.24	70.31	103.94
15	70.24	69.17	102.33
16	69.81	68.77	104.98
17	68.72	68.00	105.78
18	68.30	68.25	108.14
19	68.93	69.31	113.00
20	69.12	69.52	108.30
21	69.83	70.36	108.02
22	69.08	70.42	101.26
23	68.00	70.12	105.46
24	67.42	70.15	104.96
Total	1645.58	1673.46	2537.50
Average	68.57	69.73	105.73

Figure 42: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function of Per Unit NamePlate Capacity for EPE (20 sites)

Figure 43: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for EPE (20 sites)

Case 5: Tucson Electric Power Company (TEPC) Functioning Independently

Table 10: Hourly Regulation Requirements Averaged through the Year for TEPC

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	81.07	84.75	165.81
2	80.55	85.43	120.25
3	80.97	86.83	129.66
4	81.78	88.39	136.23
5	83.36	89.37	132.69
6	84.11	89.06	126.05
7	85.38	88.36	124.03
8	87.33	87.35	125.05
9	88.53	85.47	120.87
10	89.83	83.03	124.26
11	90.53	80.42	125.64
12	91.37	78.13	124.78
13	92.19	76.13	123.14
14	93.01	74.94	126.21
15	92.90	72.90	123.50
16	92.08	71.45	121.72
17	90.33	69.95	124.98
18	87.83	69.60	128.27
19	86.75	70.72	136.05
20	87.83	72.87	140.23
21	87.93	75.43	138.71
22	84.60	76.66	132.89
23	82.05	78.69	126.30
24	81.15	82.20	126.31
Total	2083.45	1918.13	3103.65
Average	86.81	79.92	129.32

Figure 44: Normalized σ_{wind} fluctuation as a Function of Per Unit NamePlate Capacity for TEPC (50 sites)

Figure 45: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for TEPC (50 sites)

Case 6: Salt River Project (SRP) Functioning Independently

Table 11: Hourly Regulation Requirements Averaged through the Year for SRP

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	93.00	101.52	194.52
2	92.24	101.62	144.00
3	92.16	102.17	149.75
4	92.66	103.03	159.70
5	94.38	103.97	149.46
6	96.23	105.22	146.77
7	97.55	104.81	148.29
8	99.18	103.70	143.39
9	99.85	101.64	141.68
10	101.19	99.98	146.18
11	101.31	97.03	139.70
12	101.30	94.13	142.55
13	101.51	91.69	140.78
14	101.71	89.69	141.95
15	101.75	88.31	146.64
16	101.11	87.52	144.95
17	99.76	87.08	144.29
18	98.15	88.13	148.88
19	97.95	90.35	156.96
20	99.31	92.76	162.21
21	98.57	93.53	162.63
22	95.36	94.33	151.29
23	92.83	95.61	148.26
24	93.14	99.76	151.64
Total	2342.19	2317.59	3606.49
Average	97.59	96.57	150.27

Figure 46: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function of Per Unit NamePlate Capacity for SRP (50 sites)

Figure 47: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for SRP (50 sites)

Case 7: Arizona Public Service Company (AZPS) Functioning Independently

Table 12: Hourly Regulation Requirements Averaged through the Year for AZPS

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	309.84	344.03	653.87
2	307.44	348.10	473.63
3	308.42	354.02	514.38
4	311.66	360.60	535.22
5	319.23	365.44	520.34
6	323.55	365.03	481.41
7	330.12	362.12	481.16
8	339.70	357.69	488.69
9	345.65	348.74	477.69
10	353.39	339.51	496.49
11	357.94	328.31	495.69
12	362.49	318.28	495.92
13	366.95	309.68	494.17
14	370.01	301.51	493.40
15	370.34	292.52	495.35
16	367.47	286.97	486.48
17	360.43	281.60	499.47
18	349.58	281.48	511.57
19	345.49	289.28	543.77
20	349.81	299.36	580.26
21	348.26	308.23	564.54
22	332.49	313.84	532.20
23	318.97	321.15	501.46
24	312.52	334.76	497.31
Total	8161.74	7812.22	12314.45
Average	340.07	325.51	513.10

Figure 48: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function of Per Unit NamePlate Capacity for AZPS (214 sites)

Figure 49: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for AZPS (214 sites)

Case 8: PNM and SPS Consolidation

Table 13: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM and SPS

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	135.94	144.39	280.33
2	138.61	148.05	231.76
3	142.30	152.11	237.67
4	144.51	154.51	237.32
5	145.44	154.98	234.64
6	145.58	154.63	230.33
7	146.02	153.89	221.76
8	147.03	153.00	221.08
9	148.34	152.50	219.19
10	150.80	152.83	213.25
11	152.00	152.51	218.77
12	152.87	151.80	217.54
13	153.94	151.43	217.47
14	152.51	148.33	205.98
15	149.78	144.03	196.89
16	148.23	142.29	203.70
17	144.30	139.00	202.03
18	141.59	138.08	215.04
19	141.10	138.94	217.12
20	141.37	139.12	213.17
21	139.61	138.27	203.33
22	136.16	137.91	197.90
23	135.49	140.16	210.73
24	137.42	144.24	215.55
Total	3470.93	3527.02	5262.58
Average	144.62	146.96	219.27

Table 14: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
262.54	219.27	378,993	\$3,683,820

Figure 50: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM and SPS

Figure 51: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM and SPS

Case 9: PNM, SPS and EPE Consolidation

Table 15: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM,SPS and EPE

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	176.58	184.39	360.97
2	177.38	186.42	287.46
3	180.09	189.79	292.10
4	181.44	191.39	292.48
5	183.11	192.17	288.44
6	184.30	192.47	283.39
7	185.25	191.64	276.37
8	187.04	190.78	283.54
9	188.62	190.06	280.06
10	191.37	190.15	271.30
11	193.19	189.89	280.18
12	194.52	189.14	276.12
13	195.76	188.50	277.28
14	195.10	185.85	269.10
15	193.05	182.20	256.29
16	191.77	180.89	269.00
17	188.49	178.32	270.90
18	185.86	178.14	287.53
19	185.55	179.66	292.97
20	186.44	180.40	291.85
21	185.22	180.21	269.08
22	180.56	179.51	262.78
23	177.45	180.27	275.45
24	177.44	183.46	274.24
Total	4465.56	4455.70	6768.87
Average	186.07	185.65	282.04

Table 16: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
368.27	282.04	755,383.76	\$7,342,330

Figure 52: Normalized σ_{wind} fluctuation as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS and EPE

Figure 53: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS and EPE

Case 10: PNM, SPS and ERCO Consolidation

Table 17: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM,SPS and ERCO

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	817.94	1007.45	1825.39
2	827.05	1045.60	1544.62
3	837.06	1072.93	1604.56
4	843.56	1087.19	1581.39
5	854.77	1088.62	1502.33
6	862.00	1086.02	1495.57
7	872.38	1074.17	1454.69
8	891.18	1060.22	1427.02
9	910.63	1053.04	1403.10
10	935.64	1047.64	1399.09
11	954.10	1041.01	1383.34
12	974.53	1039.12	1381.07
13	989.25	1030.96	1382.26
14	998.01	1012.52	1268.46
15	990.29	975.16	1269.98
16	976.44	946.67	1256.19
17	953.12	917.72	1253.03
18	917.97	892.69	1264.33
19	899.46	885.33	1305.07
20	904.50	888.62	1340.30
21	894.76	891.65	1309.63
22	853.94	898.71	1333.59
23	832.38	935.85	1363.26
24	823.23	979.82	1450.91
Total	21614.19	23958.72	33799.19
Average	900.59	998.28	1408.30

Table 18: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Total Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
1577.52	1408.30	1,482,352.81	\$14,408,469

Figure 54: Normalized σ_{wind} fluctuation as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS and ERCO

Figure 55: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS and ERCO

Case 11: PNM, EPE, TEPC, SRP, and AZPS Consolidation

Table 19: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM, EPE, TEPC, SRP, AZPS

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	480.78	530.30	1011.08
2	474.82	534.00	729.58
3	475.61	542.89	791.80
4	479.68	552.22	819.38
5	491.36	558.18	791.06
6	498.79	557.45	739.56
7	510.79	553.54	757.70
8	528.40	548.14	761.72
9	540.67	537.01	751.47
10	555.13	524.42	775.59
11	565.53	511.58	766.34
12	575.39	499.86	789.09
13	584.39	489.10	783.33
14	591.06	478.56	784.67
15	593.06	467.03	796.72
16	588.80	458.69	792.47
17	578.06	451.62	798.26
18	560.23	451.90	814.82
19	552.05	461.97	864.41
20	557.72	475.10	901.79
21	553.55	485.98	879.87
22	525.54	491.24	829.74
23	500.59	498.34	783.97
24	486.63	516.56	774.00
Total	12848.63	12175.70	19288.42
Average	535.36	507.32	803.68

Table 20: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Total Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
969.09	803.68	1,448,918.08	\$14,083,484

Figure 56: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM, EPE, TEPC, SRP, AZPS

Figure 57: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM, EPE, TEPC, SRP, AZPS

Case 12: PNM, SPS, ERCO and EPE Consolidation

Table 21: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM, SPS, ERCO and EPE

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	835.21	1019.05	1854.25
2	842.34	1054.94	1562.82
3	852.07	1082.27	1623.35
4	858.24	1096.28	1606.18
5	870.21	1098.05	1513.58
6	878.37	1096.05	1516.96
7	890.20	1084.91	1473.96
8	910.74	1071.51	1450.20
9	931.34	1064.32	1431.03
10	957.84	1059.23	1411.82
11	977.75	1053.26	1431.67
12	999.10	1051.39	1410.10
13	1014.63	1043.16	1414.04
14	1023.99	1024.53	1299.24
15	1017.17	987.96	1295.18
16	1003.50	960.11	1287.73
17	979.97	931.64	1293.04
18	944.49	908.08	1309.33
19	926.01	902.35	1353.05
20	931.48	906.37	1385.60
21	921.62	909.75	1335.12
22	878.61	915.81	1361.35
23	853.74	949.90	1397.49
24	841.70	991.84	1475.83
Total	22140.31	24262.73	34492.94
Average	922.51	1010.95	1437.21

Table 22: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Total Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
1683.25	1437.21	2,155,321.09	\$20,949,721

Figure 58: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO and EPE

Figure 59: Normalized $\sigma_{\text{forecast error}}$ as a Function Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO and EPE

Case 13: PNM, SPS, ERCO, EPE and TEPC Consolidation

Table 23: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM, SPS, ERCO, EPE and TEPC

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	865.04	1031.24	1896.27
2	868.52	1063.58	1586.71
3	877.14	1090.24	1643.81
4	883.03	1104.24	1623.64
5	896.88	1106.47	1543.99
6	907.09	1105.25	1546.69
7	923.02	1095.95	1524.25
8	949.25	1085.08	1490.28
9	973.97	1079.00	1473.74
10	1004.44	1074.44	1471.67
11	1027.54	1069.20	1502.05
12	1051.13	1066.74	1454.02
13	1068.95	1058.20	1480.03
14	1079.47	1038.13	1354.12
15	1074.56	1002.73	1354.06
16	1061.21	975.96	1350.87
17	1037.31	949.22	1355.26
18	1000.25	928.15	1380.07
19	980.73	923.96	1435.37
20	986.71	928.45	1451.82
21	975.90	932.59	1428.13
22	927.48	938.43	1437.43
23	893.69	966.35	1446.01
24	874.27	1004.45	1515.39
Total	23187.61	24618.06	35745.70
Average	966.15	1025.75	1489.40

Table 24: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Total Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
1812.57	1489.40	2,830,894.77	\$27,516,297

Figure 60: Normalized σ_{wind} fluctuation as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO, EPE and TEPC

Figure 61: Normalized $\sigma_{\text{forecast error}}$ as a of Function Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO, EPE and TEPC

Case 14: PNM, SPS, ERCO, EPE, TEPC and SRP Consolidation

Table 25: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM, SPS, ERCO, EPE, TEPC and SRP

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	899.33	1050.73	1950.06
2	899.27	1079.67	1628.17
3	906.27	1104.76	1672.44
4	911.63	1118.29	1682.23
5	927.38	1120.68	1602.63
6	940.11	1120.76	1570.79
7	960.16	1113.36	1568.90
8	991.81	1104.69	1529.83
9	1020.30	1099.17	1506.54
10	1054.45	1094.62	1533.17
11	1080.61	1089.73	1553.75
12	1106.33	1086.54	1522.59
13	1126.34	1077.53	1523.80
14	1138.01	1056.28	1397.41
15	1134.68	1022.04	1414.09
16	1121.82	997.07	1419.82
17	1097.71	972.56	1421.47
18	1058.99	953.98	1450.72
19	1038.22	951.19	1504.42
20	1044.63	956.24	1543.57
21	1032.68	960.67	1512.48
22	978.75	965.96	1514.48
23	936.95	989.12	1517.10
24	911.15	1024.32	1557.96
Total	24317.60	25109.94	37098.40
Average	1013.23	1046.25	1545.77

Table 26: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Total Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
1962.84	1545.77	3,653,528.35	\$35,512,296

Figure 62: Normalized σ_{wind} fluctuation as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO, EPE, and TEPC

Figure 63: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO, EPE and TEPC

Case 15: PNM, SPS, ERCO, EPE, TEPC, SRP and AZPS Consolidation

Table 27: Hourly Regulation Requirements Averaged through the Year for Consolidated PNM, SPS, ERCO, EPE, TEPC, SRP and AZPS

Hour	Load and Wind Regulation (MW)	Forecast Error Regulation (MW)	Total Regulation (MW)
1	1084.66	1189.97	2274.63
2	1074.15	1213.68	1867.56
3	1077.23	1238.75	1898.11
4	1082.52	1254.36	1958.16
5	1106.32	1258.50	1848.55
6	1126.10	1259.31	1825.83
7	1159.12	1253.26	1806.69
8	1208.75	1246.49	1805.36
9	1250.37	1239.70	1764.50
10	1298.83	1233.42	1830.50
11	1336.06	1227.00	1855.51
12	1370.73	1220.35	1821.06
13	1399.90	1209.15	1851.18
14	1418.20	1184.39	1724.21
15	1420.41	1150.07	1729.10
16	1407.63	1125.60	1726.15
17	1380.22	1103.36	1754.95
18	1332.22	1089.20	1788.75
19	1305.36	1090.60	1877.54
20	1313.88	1098.94	1925.39
21	1297.19	1106.07	1892.09
22	1221.47	1112.39	1859.84
23	1153.78	1129.37	1832.48
24	1107.15	1162.78	1844.10
Total	29932.24	28396.71	44362.24
Average	1247.18	1183.20	1848.43

Table 28: Comparison between BAs Functioning Separately and Functioning as Consolidated BA

Total Regulation with BAs Separate (MW)	Total Regulation with BAs as Combined (MW)	Average Total Regulation Savings (MWh)	Amount Saved in Operating Cost over 1 Year Period
2475.94	1848.43	5,497,003.02	\$53,430,869

Figure 64: Normalized $\sigma_{\text{wind fluctuation}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO, EPE, TEPC, AZPS

Figure 65: Normalized $\sigma_{\text{forecast error}}$ as a Function of Per Unit NamePlate Capacity for Consolidated PNM, SPS, ERCO, EPE, TEPC, AZPS

Some of the first observations should include the number of 30 MW wind sites of each BA in general provides for lower valued per unit plots and thus less operating reserves due to their wind. However, this trend has exceptions. Table 25 provides the peak per unit $\sigma_{\text{wind fluctuation,h}}$ values ordered by the number of wind site and SPS with 38 wind sites has a higher peak per unit sigma value than both PNM and EPE with 17 and 20 sites respectively. Also, EPE with 20 sites has a higher peak value than PNM with 17 sites.

Table 29: Sigma Wind Per Unit Peak Values Sorted by Quantity of Wind

BA	PNM	EPE	SPS	TEPC	SRP	AZPS	ERCO
Number of Wind Sites	17	20	38	50	50	214	490
Normalized $\sigma_{\text{wind fluctuation}}$	0.041	.052	0.060	0.023	0.031	0.020	0.020

An explanation for these exceptions can easily be found. To illustrate this point comparison of three additional per unit plots are created in Matlab. The three plots can be seen below in Figure 67. Plots “SPS15”, “SPS30” and “SPS15,EPE15” represent the following cases. First SPS15 depicts 15 closely packed sites within SPS. Next SPS30 depicts 15 additional sites also closely packed near the first 15 and only a small difference is noted in the corresponding plots. Finally the first SPS15 sites are combined with 15 additional sites over 300 miles away in EPE. This fictional aggregation of more spread out wind sites, “SPS15,EPE15”, provides a significant change in the per unit plot.

Clearly how closely packed the sites are is a key factor. It is obvious that some BA sites are more closely packed than others. If this were a single BA making the decision to obtain wind from the SPS15,EPE15 locations instead of

the SPS30 locations, a staggering \$2,644,204 would be saved in regulation operating cost per year.

Figure 66: Illustration of Impact due to Site Proximity

This leads us into the next relevant topic. In each of the cases that consolidate two or more balancing areas, substantial savings in operating cost occur. Table 30 below list these savings by consolidation.

**Table 30: Yearly Reserve Requirement Operating Cost Savings due to Consolidations
(Millions of US dollars)**

PNM, SPS	3.68
PNM, SPS, EPE	7.34
PNM, SPS, ERCO	14.41
PNM, EPE,TEPC,SRP,AZPS	14.08
PNM, SPS, ERCO, EPE	20.95
PNM, SPS, ERCO, EPE, TEPC	27.52
PNM, SPS, ERCO, EPE, TEPC,SRP	35.51
PNM, SPS, ERCO, EPE, TEPC,SRP,AZPS	53.43

These savings of course would be divided up among the participating entities.

The question of how to divide these savings is not a clear matter. Methods to

fairly divide these savings will be left for further studies. However, it will be mentioned that the savings does not always correspond equally with the amount of wind. For example 14.41 million US dollars saved from the 545 site PNM-SPS-ERCO consolidation is very close to the 14.08 million in savings from the 351 site PNM-EPE-TEPC-SRP-AZPS consolidation. This is another example of the importance of diversifying geography. The 3 BA consolidation may aggregate more MW of wind but the 5 BA consolidation is spread out over a similar area. Perhaps the relative area of particular BA would be an equally weighted metric compared with amount of wind for allocating percentages of savings. Figure 68 shows that in general regulation savings increases with increasing quantity of wind. As shown early this is primarily due to increasing geographic area and a plot of regulation savings as a function of geographic area would most likely show a stronger correlation.

Figure 67: Savings in Operating Cost of Reserves Increases as more Wind is Aggregated

VII Conclusion and Future Work

The analysis performed clearly shows that BA cooperation is advantageous at every level. The benefits seen in reduction of cost of Operating Reserves continue even after many BAs have consolidated into one. The use of reusable tools, such as the one developed for this paper, are crucial when analyzing large volumes of data. Improvements are required before applying the Matlab functions provided in Appendix C to real life analysis. Acquiring real load data from FERC should be the first step. Integrating this into the code should be a simple matter. Expanding the data sets to include the years 2004 and 2005 should be another simple matter that could improve the accuracy. It should be noted that using the load data and wind data from the years 2004 through 2006 will only represent what would have happened during these years if the given amount of wind had been incorporated into the net load profile. However, one could easily argue that these representations could provide a fairly accurate view of conditions in the future. Studies involving changes of wind patterns over many years are needed to ensure that this is the case.

Working directly with BAs considering consolidation would be an ideal case. Many assumptions were made about the location of wind sites and the placement of these sites within a particular BA. As was explained by Jack King of NREL, there exist many opinions regarding what regions belong to a particular BA verses another. Working with actual BAs considering cooperation might provide for agreement. The sites were selected for this study were based on an assumption that wind farm locations would be concentrated in particular areas

and the size of these farms were not consistently chosen. Again working with actual BAs that might provide current locations of wind farms and a more realistic projection of future wind farms could provide for much more accurate and rewarding studies.

The Full BA consolidation is only one of many options. The details of other options were briefly mentioned in Chapter IV and work regarding these variations along with the implications of the NERC metrics on choosing particular cooperation methods over another will be a vast area of study in the future. It is the hope of this author that students will continue this important and relatively new area of study. I believe that these methods will be key in the integration of large scale renewable penetration.

Furthermore, the emphasis of this study was on wind power integration. Solar power will continue to become increasingly cost competitive and its impact on meeting the growing RPS goals of many states will be pronounced. Solar power marries well with wind power as they seem to complement each other. Solar power is often more prevalent and constant when wind power is not present. The inclusion of solar power variability into further studies is imperative as this will be the future of renewable power to some still to be determined quantity.

As mentioned in the Acknowledgements section of this paper, relationships were crucial to the success of this study. Expanding these relationships and building new ones while continuing to pass down the

knowledge gained during this investigation will be crucial during the process of discovering solutions geared specifically towards increasing the amount of renewable energy produced in the United States. Other countries are far ahead of us in this pursuit. Denmark has the goal of 50% of its energy from wind by 2020 and 100% of its energy from wind by 2050, which is indeed ambitious. We can stand to learn much from other countries and it has been the experience of this author that when reaching out for help, often help is given. Truly, asking for help from those who have gone before you will prove useful as well as extending help to those behind us.

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Appendix A – 2020 Load Forecast

Figure 69: PNM Minimum RPS Requirements [17]

Year	Customers	% Chg.	Native System Energy (GWH)	% Chg.	Native System Peak Demand (MW)	% Chg.
2010	373,155		8,046		1,616	
2011	378,288	1.38%	8,247	2.50%	1,660	2.72%
2012	389,223	2.89%	8,513	3.23%	1,715	3.31%
2013	398,107	2.28%	8,840	3.84%	1,782	3.91%
2014	406,823	2.19%	9,085	2.77%	1,832	2.81%
2015	415,087	2.03%	9,385	3.30%	1,895	3.44%
2020	459,638	2.15%	10,637	2.23%	2,153	2.28%

Figure 68: EPE Load Forecast [21]

Figure 71: SPS Load Forecast [20]

Figure 70: ERCOT Load Forecast [19]

Figure 72: SRP Load Forecast [22]

Figure 73 TEPC Load Forecast

Appendix B – NREL Wind Data Sets Downloading Directions

The following text was provided by George Scott from the National Renewable Energy Laboratories. Used in conjunction with the provided Matlab function buildTextFile, mass quantities of wind site data can be downloaded automatically without supervising the process. This is absolutely necessary when obtain the thousands of files needed to perform large scale analysis.

So your file might look like this:

```
http://wind.nrel.gov/Web_nrel/data/2004/160.csvhttp://wind.nrel.gov/Web_nrel/data/2005/160.csv
http://wind.nrel.gov/Web_nrel/data/2006/160.csv
http://wind.nrel.gov/Web_nrel/data/2004/2.csv
http://wind.nrel.gov/Web_nrel/data/2004/21345.csv
```

This file asks for 3 years from site 160, and 1 year from 2 and 21345.

If you have obtained one of the yearly file lists (e.g., wwsis_files_2004.txt), you can use it to retrieve a year of data. You can then copy it to a new file (e.g., wwsis_files_2005.txt) and use a text editor to change every occurrence of '2004' to '2005'. Then use this new file to obtain the next year of data, and so on.

Finally you need a program to read that file and retrieve the data. I use

'wget', a free program that runs on most operating systems:

<http://en.wikipedia.org/wiki/Wget>

<http://wget.addictivecode.org/FrequentlyAskedQuestions#download>

(If you're using Windows, get one of the Windows binaries)

To run wget, just open a command prompt window and say 'wget -i flist.txt'

(assuming that the file you made is called 'flist.txt').

There are probably other ways to do it, but I find that wget works quickly and it's easy to set up the input file, so I haven't looked into any other programs.

(If you are unfamiliar or uncomfortable with the command line interface on your machine, please contact your local computer geek. NREL cannot provide assistance on anything not directly related to our database and server.)

Downloading the data, by following these instructions, by using the map interface or by any other means, implies that you agree to the following disclaimer:

This data and software ("Data") is provided by the National Renewable Energy Laboratory ("NREL"), which is operated by the Alliance for Sustainable Energy, LLC ("ALLIANCE") for the U.S. Department Of Energy ("DOE").

Access to and use of these Data shall impose the following obligations on the user, as set forth in this Agreement. The user is granted the right, without any fee or cost, to use, copy, modify, alter, enhance and distribute these Data for any purpose whatsoever, provided that this entire notice appears in all copies of the Data. Further, the user agrees to credit DOE/NREL/ALLIANCE in any publication that results from the use of these Data. The names DOE/NREL/ALLIANCE, however, may not be used in any advertising or publicity to endorse or promote any products or commercial entities unless specific written permission is obtained from DOE/NREL/ ALLIANCE. The user also understands that DOE/NREL/Alliance is not obligated to provide the user with any support, consulting, training or assistance of any kind with regard to the use of these Data or to provide the user with any updates, revisions or new versions of these Data.

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Appendix C – Matlab Code used for Analysis

```
function [ textFile ] = buildTextFile( fileNumbers,numFileNumbers )
%Returns text into a variable that may be then pasted into a text file
and
%saved into the same directory as the Wget file.(See Appendix B)
textFile='';

for site = 1:1:numFileNumbers

textFile=strcat(textFile,sprintf('http://wind.nrel.gov/Web_nrel/data/20
06/%d.csv\r\r',fileNumbers(site)));

end


%Set numFiles equal number of Wind Data Sets importing and fileName
equal
%to Balancing Area acronymn
function [ powerMatrix ] = PopMatrix( BA_abrv,numFiles )

%sets filename Balancing Area abbreviation to first site ex: PNM(1)
fileName=sprintf('%s (%d).csv',BA_abrv,1);
%reads first excel file
tempName = xlsread(fileName,'E2:E52561');

%builds columns 2 through numFiles of data set matrix
for fileNum = 2:numFiles
%sets filename to next site ex: PNM(2)
    fileName=sprintf('%s (%d).csv',BA_abrv,fileNum);
%reads next excel file
    nextColumn = xlsread(fileName,'E2:E52561');
%concatenates next excel file with previous
    powerMatrix=cat(2,tempName,nextColumn);
%resets tempName to contain column vectors of total files ex : PNM1
    PNM2...PNMlast
    tempName = powerMatrix;
end
```

```

function [resultsReg,resultsPlotsPU ] =
aveRegulationRequirementsFinalRev( BA,loadProfile,numColumns)
%Calculates the regulation requirements needed for BA
count=0;

%Aggregates the wind output of all locations within the BA
aggWind=sum(BA,2);

DW=deltaWind(aggWind);

aggWindTruncatedForDW=aggWind(1:52559,:);

aggWindCatdeltaWind=cat(2,aggWindTruncatedForDW,DW);

sortedDWbyaggWind=sortrows(aggWindCatdeltaWind,1);

bundledSigmasDW = groupDeltaWindByaggWindandCalcSigma(
sortedDWbyaggWind,numColumns);
bundledSigmasDWpu=bundledSigmasDW/(30*numColumns);

FE=forecastError(aggWind);

aggWindTruncatedForFE=aggWind(7:52560,:);

aggWindCatforecastError=cat(2,aggWindTruncatedForFE,FE);

sortedFEbyaggWind=sortrows(aggWindCatforecastError,1);

bundledSigmasFE = groupForecastErrorByaggWindandCalcSigma(
sortedFEbyaggWind,numColumns);
bundledSigmasFEpu=bundledSigmasFE/(30*numColumns);

[sigmaWindpoly,sigmaFEpoly]=buildPolynomial(bundledSigmasDW,bundledSigmasFE,numColumns);

for day =1:1:365
    ActualWind = hourlyWindAveParticularDay( aggWind,day );
    [ aveTotalRegulation,aveRegulationWithWind,aveRegulationForecastError ]
= regulationAve( loadProfile,ActualWind,sigmaWindpoly,sigmaFEpoly );
    if count ==0
        TotalReg=aveTotalRegulation;
        RegWithWind=aveRegulationWithWind;
        RegForecastError=aveRegulationForecastError;
        count=1;
    else
        TotalReg=cat(2,TotalReg,aveTotalRegulation);
        RegWithWind=cat(2,RegWithWind,aveRegulationWithWind);
        RegForecastError=cat(2,RegForecastError,aveRegulationForecastError);
    end
end

```

```
hourlyAveTotalReg=sum(TotalReg,2)/365;  
hourlyAveRegWithWind=sum(RegWithWind,2)/365;  
hourlyAveRegForecastError=sum(RegForecastError,2)/365;  
  
resultsReg =  
cat(2, hourlyAveRegWithWind, hourlyAveRegForecastError, hourlyAveTotalReg)  
;  
resultsPlotsPU = cat(2, bundledSigmasDWpu, bundledSigmasFEpu);  
end
```

```

function [ sigmaDW,count,endGroup] =
groupDeltaWindByaggWindandCalcSigma( sortedDWbyaggWind,numColumns)
%Bundles sortedDWbyaggWind into deciles and takes the standard
deviation
%within each decile

decileIncrement = 30*numColumns/10;

done=zeros(10,1);
sigmaDW=zeros(10,1);
count=zeros(10,1);
endGroup=zeros(10,1);

for time = 1:1:52559;
    if sortedDWbyaggWind(time,1) > decileIncrement*1 && done(1) == 0
        done(1)=1;
        count(1)=count(1)+1;
        endGroup(1)=time-1;
        sigmaDW(1)=std(sortedDWbyaggWind(1:endGroup(1),2:2),1);

    end
    if sortedDWbyaggWind(time,1) > decileIncrement*2 && done(2) == 0
        done(2)=1;
        count(2)=count(2)+1;
        endGroup(2)=time-1;

sigmaDW(2)=std(sortedDWbyaggWind(endGroup(1)+1:endGroup(2),2:2),1);

    end
    if sortedDWbyaggWind(time,1) > decileIncrement*3 && done(3) == 0
        done(3)=1;
        count(3)=count(3)+1;
        endGroup(3)=time-1;

sigmaDW(3)=std(sortedDWbyaggWind(endGroup(2)+1:endGroup(3),2:2),1);

    end
    if sortedDWbyaggWind(time,1) > decileIncrement*4 && done(4) == 0
        done(4)=1;
        count(4)=count(4)+1;
        endGroup(4)=time-1;

sigmaDW(4)=std(sortedDWbyaggWind(endGroup(3)+1:endGroup(4),2:2),1);

    end
    if sortedDWbyaggWind(time,1) > decileIncrement*5 && done(5) == 0
        done(5)=1;
        count(5)=count(5)+1;
        endGroup(5)=time-1;

sigmaDW(5)=std(sortedDWbyaggWind(endGroup(4)+1:endGroup(5),2:2),1);

    end
    if sortedDWbyaggWind(time,1) > decileIncrement*6 && done(6) == 0

```



```

done(6)=1;
count(6)=count(6)+1;
endGroup(6)=time-1;

sigmaDW(6)=std(sortedDWbyaggWind(endGroup(5)+1:endGroup(6),2:2),1);

end
if sortedDWbyaggWind(time,1) > decileIncrement*7 && done(7) == 0
done(7)=1;
count(7)=count(7)+1;
endGroup(7)=time-1;

sigmaDW(7)=std(sortedDWbyaggWind(endGroup(6)+1:endGroup(7),2:2),1);

end
if sortedDWbyaggWind(time,1) > decileIncrement*8 && done(8) == 0
done(8)=1;
count(8)=count(8)+1;
endGroup(8)=time-1;

sigmaDW(8)=std(sortedDWbyaggWind(endGroup(7)+1:endGroup(8),2:2),1);

end
if sortedDWbyaggWind(time,1) > decileIncrement*9 && done(9) == 0
done(9)=1;
count(9)=count(9)+1;
endGroup(9)=time-1;

sigmaDW(9)=std(sortedDWbyaggWind(endGroup(8)+1:endGroup(9),2:2),1);

end
if time==52559
done(10)=1;
count(10)=count(10)+1;
sigmaDW(10)=std(sortedDWbyaggWind(endGroup(9)+1:52559,2:2),1);
end
end
end

```

```

function [ bundledSigmasFE,count,endGroup] =
groupForecastErrorByaggWindandCalcSigma( sortedFEbyaggWind,numColumns)
%Bundles sortedDWbyaggWind into deciles and takes the standard
deviation
%within each decile

decileIncrement = 30*numColumns/10;

done=zeros(10,1);
bundledSigmasFE=zeros(10,1);
count=zeros(10,1);
endGroup=zeros(10,1);

for time = 1:1:52554;
    if sortedFEbyaggWind(time,1) > decileIncrement*1 && done(1) == 0
        done(1)=1;
        count(1)=count(1)+1;
        endGroup(1)=time-1;
        bundledSigmasFE(1)=std(sortedFEbyaggWind(1:endGroup(1),2:2),1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*2 && done(2) == 0
        done(2)=1;
        count(2)=count(2)+1;
        endGroup(2)=time-1;

bundledSigmasFE(2)=std(sortedFEbyaggWind(endGroup(1)+1:endGroup(2),2:2)
,1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*3 && done(3) == 0
        done(3)=1;
        count(3)=count(3)+1;
        endGroup(3)=time-1;

bundledSigmasFE(3)=std(sortedFEbyaggWind(endGroup(2)+1:endGroup(3),2:2)
,1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*4 && done(4) == 0
        done(4)=1;
        count(4)=count(4)+1;
        endGroup(4)=time-1;

bundledSigmasFE(4)=std(sortedFEbyaggWind(endGroup(3)+1:endGroup(4),2:2)
,1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*5 && done(5) == 0
        done(5)=1;
        count(5)=count(5)+1;
        endGroup(5)=time-1;

```

```

bundledSigmasFE(5)=std(sortedFEbyaggWind(endGroup(4)+1:endGroup(5),2:2)
,1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*6 && done(6) == 0
        done(6)=1;
        count(6)=count(6)+1;
        endGroup(6)=time-1;

bundledSigmasFE(6)=std(sortedFEbyaggWind(endGroup(5)+1:endGroup(6),2:2)
,1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*7 && done(7) == 0
        done(7)=1;
        count(7)=count(7)+1;
        endGroup(7)=time-1;

bundledSigmasFE(7)=std(sortedFEbyaggWind(endGroup(6)+1:endGroup(7),2:2)
,1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*8 && done(8) == 0
        done(8)=1;
        count(8)=count(8)+1;
        endGroup(8)=time-1;

bundledSigmasFE(8)=std(sortedFEbyaggWind(endGroup(7)+1:endGroup(8),2:2)
,1);

    end
    if sortedFEbyaggWind(time,1) > decileIncrement*9 && done(9) == 0
        done(9)=1;
        count(9)=count(9)+1;
        endGroup(9)=time-1;

bundledSigmasFE(9)=std(sortedFEbyaggWind(endGroup(8)+1:endGroup(9),2:2)
,1);

    end
    if time==52554
        done(10)=1;
        count(10)=count(10)+1;

bundledSigmasFE(10)=std(sortedFEbyaggWind(endGroup(9)+1:52554,2:2),1);
    end
end
end

```

```

function [ sigmaWindpoly,sigmaFEpoly ] = buildPolynomial(
bundledSigmasDW,bundledSigmasFE,numColumns )
%Builds the string to be used for the Sigma Wind polynomial
bins=zeros(10,1);

for bin =1:1:10
    bins(bin)=30*numColumns/10*(2*bin-1)*.5;
end
sigmaWindpoly=polyfit(bins,bundledSigmasDW,2);
sigmaFEpoly=polyfit(bins,bundledSigmasFE,2);
end

```

```

function [ ActualHourlyWindParticularDay ] =
hourlyWindAveParticularDay( aggWind,day )
%UNTITLED2 Summary of this function goes here
% Detailed explanation goes here
count2=0;
ActualHourlyWindParticularDay=zeros(24,1);
for hourIncrement=1:6:139;
    count2=count2+1;
    hour=144*(day-1)+hourIncrement;
    ActualHourlyWindParticularDay(count2)=sum(aggWind(hour:hour+5))/6;
end

```

```

function [ totalRegulation,regulationWithWind,regulationForecastError ]
= regulationAve(
loadProfile,ActualHourlyWindParticularDay,sigmaWindpoly,sigmaFEpoly )
%Returns the regulation requirements for all 24 hours with a particular
day
totalRegulation=zeros(24,1);
regulationWithWind=zeros(24,1);
regulationForecastError=zeros(24,1);
%Calculate regulation for first hour as no adjustments are needed
regulationWithWind(1)=3*sqrt((.01*loadProfile(1)/(3))^2+((sigmaWindpoly
(1)*(ActualHourlyWindParticularDay(1))^2+sigmaWindpoly(2)*(ActualHourly
WindParticularDay(1))+sigmaWindpoly(3))^2);
regulationForecastError(1)=(sigmaFEpoly(1)*(ActualHourlyWindParticularD
ay(1))^2+sigmaFEpoly(2)*(ActualHourlyWindParticularDay(1))+sigmaFEpoly(
3));
totalRegulation(1)=regulationWithWind(1)+regulationForecastError(1);
for hour = 2:1:24
regulationWithWind(hour)=3*sqrt((.01*loadProfile(hour)/(3))^2+((sigmaWi
ndpoly(1)*(ActualHourlyWindParticularDay(hour))^2+sigmaWindpoly(2)*(Act
ualHourlyWindParticularDay(hour))+sigmaWindpoly(3))^2);
regulationForecastError(hour)=(sigmaFEpoly(1)*(ActualHourlyWindParticul
arDay(hour))^2+sigmaFEpoly(2)*(ActualHourlyWindParticularDay(hour))+sig
maFEpoly(3));

    %check to see if forecast of the previous hour was less than
actual,
    %if so then must subtract the regulatonForecastError from
    %regulationWithWind to prevent double counting. See pg 149 of
EWITS.
    if ActualHourlyWindParticularDay(hour-1) >
ActualHourlyWindParticularDay(hour)
        totalRegulation(hour)=regulationWithWind(hour);
    else

totalRegulation(hour)=regulationWithWind(hour)+regulationForecastError(
hour);
    end
end
end
end

```