Near-term Economics and Equity of Balancing Area Consolidation to Support Wind Integration

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ABSTRACT

Balancing area consolidation could have economic benefits and improve the reliability of the U.S. electricity network, especially when transitioning to a future with significantly increased levels of renewable generation. Yet there has been little consolidation since the Midwest Independent System Operator was created in 1998. This research addresses this disparity by measuring the size and equity of the near-term economic gains associated with balancing area consolidation in nine scenarios of different wind penetrations, natural gas prices, and efficiency gains associated with the frequency regulation market. This study finds that sharing of economic resources through balancing area consolidation is a policy that leads to economic gains that are Kaldor-Hicks efficient. These gains are equivalent to a total cost reduction of \$0.02-\$0.2/MWh but could be as high as \$1.7/MWh. Additionally, the data show little economic motivation for consolidation given the near-term expectation of wind penetration (0%- 20% by energy). These results help to explain why BA consolidation is not more wide-spread: there are few benefits to consolidating today and those benefits are inequitably distributed among those consolidating.

Keywords: Balancing area; Frequency Regulation; Consolidation; Wind power integration; Electricity market design; social welfare.

LIST OF SYMBOLS

Symbol	Description	Units
Sets		
T	Time, index t, each one hour in duration	Hour
I	Generators, index i, includes wind generators	-
J	Balancing Areas, index j	-
Abbreviations and Sub / Super Scripts		
ΔCS	Change in consumer surplus	USD 2009
ΔPS	Change in producer surplus	USD 2009
ΔSS	Change in social surplus	USD 2009
CBA	Acronym for the consolidated balancing area (CBA)	-
E	Subscript referring to the energy market	-
FR	Subscript referring to the frequency regulation market	-
Decision Variables		
e	Dispatch power by a generator for energy	MW*
fr	Assigned frequency regulation (decision variable)	MW
c	Wind curtailment (decision variable)	MW
Variables		
P_E	Energy Price	$/MWh
P_{FR}	Frequency Regulation Price	$/MW-Hr
Q_E	Total market quantity for energy	MW*
Q_{FR}	Total market quantity for frequency regulation	MW
C_E	Cost of providing energy	$/MWh
C_{FR}	Cost of providing frequency regulation	$/MW-Hr
L	Hourly load for a BA	MW*
$\hat{L}$	Peak Daily Load for a BA	MW*
$\bar{\bar{e}}$	Maximum power limit	MW*
$\underline{e}$	Minimum power limit	MW*
w	Wind generation	MW
$\overline{\overline{fr}}$	Maximum frequency regulation quantity	MW
$ramp_i$	Ramp limits	MW/Hr
$\overline{\overline{MW}}_i$	Generator physical capacity limit (upper bound)	MW

* The units on these variables represent values of power for one hour, which inherently are units of energy (MW-Hour, or MWh). So either MW or MWh could be used.

1 INTRODUCTION

1.1 GENERAL BACKGROUND

Wind generation in America has grown over four-fold in recent years [1] and this rapid increase in wind power will need to continue in order for the U.S. to meet its renewable energy goals. Wind power's inherent variability occurs on all time scales [2] and can have significant effects on the electricity grid's stability and reliability, as discussed in many integration studies, *e.g.*, the Eastern Wind Integration and Transmission Study [3]. Overcoming the limitations of renewable generation will be integral in maintaining a reliable grid today as well as enabling a more sustainable future.

A common method for counter-acting the variability of wind is to use flexible generation to negate the fluctuations in renewable generation. This adds an additional balancing cost to the consumer and diminishes the environmental and economic benefit of integrating renewable resources [4]. The ideal solution for managing the variability of wind power would be one that does not add costs, reduces the use of fossil-based generation, and builds upon current common operating procedures to allow the grid to be more flexible in the face of uncertainty. Balancing area consolidation could be the ideal option for exactly these reasons. It builds off of current industry standards [5], requires no additional generation resources (other than those already in operation), and may allow the power system to counteract variability in a more economical way while meeting reliability standards.

A balancing area (BA) is defined by the North American Electric Reliability Corporation (NERC) as: "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load resource balance within this area" [5]. It is a geographic area that needs to balance the demand and supply of electricity by buying (or providing) a type of reserve called frequency regulation. Flexible resources are paid to provide frequency regulation by changing their output up or down in response to a signal sent to them by the balancing area operators. More information on balancing areas can be found in the appendix.

BA consolidation covers a wide range of options that can be as simple as coordinating reserves with a neighbor, such as ACE Diversity Interchange; or it could be as comprehensive as full integration into a regional transmission organization and restructuring [6,7]. BA consolidation may provide benefits in two ways: i) consolidating multiple regions into a single BA would result in a new larger area with larger portfolio of generating assets, ensuring that the absolute cheapest set of resources are used to provide electricity; and ii) coordinating the unit commitment process with neighboring regions could help reduce the costs associated with physical limitations of the system such as minimum generation events. This paper focuses on the first effect of BA consolidation – the sharing of economic resources for energy and frequency regulation.

BA consolidation could be necessary in order to achieve aggressive penetrations of renewable generation [8-10] by capturing a more geographically diverse resource and potentially reducing the variability of net load (defined as load minus wind output). The effect of geographic diversity has been well analyzed in the literature *e.g.*, [11], and the resulting reduction in variability is a powerful argument for balancing area consolidation. This work does not focus on this effect but does innately capture it through the geographically coherent wind data used (see section 2.3.3). This paper focuses the economic benefits associated the increase in assets available for providing energy and frequency regulation that result when balancing areas consolidate. In addition, this paper evaluates these benefits in systems with increased wind power production.

1.2 Previous Research

There have been a number of papers that look at the economic benefits of balancing area consolidation today [12,13], but lack prospective insight into how wind may contribute to these benefits. Other papers include aggressive wind penetrations (~30% or higher) but only focus on the exchange of energy across borders, and do not consider the ability to coordinate frequency regulation or other reserves [14,15].

Other studies have reported the reliability benefits of BA consolidation through metrics such as the "ramping requirement", defined as the need for conventional power plants to quickly change their power output to follow changes in wind power output [16,17,10]. These studies assume that reducing ramping requirements *should* reduce the cost of energy and frequency regulation needed to maintain reliability. However, they do not model the frequency regulation market explicitly and, therefore, make no assessment of the reduction in cost. This study addresses this gap in the literature by explicitly modeling the frequency regulation market and calculating the cost of balancing before and after consolidation. This allows us to quantify the near-term economic benefits that occur in both the energy and the frequency regulation markets.

2 Methods

2.1 Metrics of Economic Gains

The goal of this research is to estimate the size and distribution of the economic benefit associated with balancing area consolidation as a mechanism to support the large scale integration of wind power. Balancing area consolidation can be thought of as a way of loosening a constraint on the electricity markets that requires the real-time balancing of energy to be done on individual geographic regions. After BA consolidation, energy is balanced over the aggregated region through inter-BA trades of energy and frequency regulation. The new, less constrained, markets will be able to find a solution that is at least as good as the original problem. Any benefits to society by loosening this constraint are gains in economic efficiency and are usually measured using economic surplus.

Social surplus is a measure of how much benefit (value or utility) society gains from consuming a good. It is equal to the sum of benefits to the consumers and producers of the good, called the consumer and producer surplus, respectively. This paper uses these three measures (consumer, producer, and social surplus) to estimate the benefits of consolidation. Each of these measures is found for each individual balancing area, and for the consolidated area. The effect of BA consolidation is found by comparing the measure of economic surplus for the consolidated area against the sum of all the unconsolidated regions' surplus.

The unique properties of the electricity markets make it easy to estimate the changes in consumer, producer, and social surplus. The change in consumer surplus is equivalent to the negative of the change in consumer expenditures and the change in producer surplus is equivalent to the change in producer profits. The change in total surplus is equal to the sum of the changes in consumer and producer surpluses. More information about the theory of economic efficiency is available in the appendix.

The consumers' expenditures in a market are equal to the product of the price and the market quantity – ($P_E * Q_E$ for energy, $P_{FR} * Q_{FR}$ for frequency regulation). The total consumer cost is the sum of the expenditures in these two markets. The change in consumer surplus (ΔCS_t, Equation 1) is equal to the negative of the difference between the total cost for the consolidated BA (denoted by the superscript *CBA*) and the sum of all the individual BAs (indexed by a superscript *j*).

Equation 1

$$\Delta CS_t = -\left[\left(P_{E,t}^{CBA} * Q_{E,t}^{CBA} + P_{FR,t}^{CBA} * Q_{FR,t}^{CBA}\right) - \left(\sum_j \left(P_{E,t}^j * Q_{E,t}^j\right) + \sum_j \left(P_{FR,t}^j * Q_{FR,t}^j\right)\right)\right]$$

The producer surplus for a market is equal to the sum of each generators' profit; this is equal to the quantity (*e* for energy, *fr* for frequency regulation) it provides multiplied by its profit margin – the difference between the market price (*P*) and the generators cost (C). The change in producer surplus is equal to the profit of all generators in the CBA (first bracket of Equation 2) minus the profit for all the generators in all the individual BAs (second bracket of Equation 2). The resulting difference is a measure of how much economic benefit goes to the producers.

Equation 2

$$\Delta PS_t = \left[\sum_i \left(P_{E,t}^{CBA} - C_{E,i}^{CBA}\right) * e_{E,i,t}^{CBA} + \sum_i \left(P_{FR,t}^{CBA} - C_{FR,i}^{CBA}\right) * q_{FR,i,t}^{CBA}\right]$$
$$- \left[\sum_i \sum_j \left(P_{E,t}^j - C_{E,i}^j\right) * e_{i,t}^j + \sum_i \sum_j \left(P_{FR,t}^j - C_{E,i}^j\right) * fr_{i,t}^j\right]$$

Equation 3 shows change in social surplus (ΔSS_t), equal to the sum of the change in producer (ΔPS_t) and consumer surplus (ΔCS_t).

Equation 3

$$\Delta SS_t = \Delta CS_t + \Delta PS_t$$

2.2 MIDWEST CASE-STUDY

MISO was founded in 1998; became a regional transmission operator in 2001; launched its energy market and started centralized dispatch of resources in 2005; and opened its ancillary services market and became a balancing authority on January 6th, 2009 when it consolidated 26 balancing areas at one time. Since then, MISO has grown and shrunk and it currently encompasses what used to be 28 different balancing areas before 2006 (details in the Appendix).

This study uses the MISO consolidation as a basis for analyzing the effect of balancing area consolidation on the economic dispatch of generating units. It does not include every potential costs or benefit such as those associated with administrative efficiency. The model used here is a short-run economic model and does not include the dynamics of how participants might change their behavior. As a result, the values presented in this paper will not match the actual net-benefits obtained through the consolidation of MISO. However, this analysis is representative of how economic resources are shared among consolidating BAs and therefore can provide general insights into the magnitude and equity of the near-term economic benefits of balancing area consolidation.

2.3 ECONOMIC DISPATCH MODEL

The goal of the economic dispatch model is to minimize the total cost of providing energy and frequency regulation for a specific BA, subject to the system constraints. These constraints include meeting system demands for energy and frequency regulation, and adhering to generator limits for energy, regulation, and hourly ramping. This optimization is done for each of the consolidating BAs individually and then again for all the regions as one consolidated balancing area (CBA). For each hour, the model produces dispatch instructions for energy and frequency regulation for each generator, and curtailment instructions for each wind farm. The economic dispatch model used in this paper is an inter-temporal, co-optimized economic dispatch model with the following formulation:

$$\min_{e,fr,c} Energy\ Costs + Regulation\ Costs$$

Energy Constraints

$\sum_{i=1}^{n} e_{i,t} + \sum w_{i,t} - c_t = L_{j,t}$	Generation + wind - curtailment = load
$\sum_{i=1}^{n} fr_{i,t} = FR\_Req$	Sum of freq. reg. = Freq. reg. requirement
$e_{i,t} \leq \overline{\overline{e_i}}$	Can't over schedule a resource for energy
$-e_{i,t} \leq 0$	Only positive energy production
$e_{i,t} \leq e_{i,t-1} + ramp_i$	Ramp-up limitation
$-e_{i,t} \leq -e_{i,t-1} + ramp_i$	Ramp-down limitation
$-e_{i,t} \leq -\underline{e_i}\ \forall i \in [nuclear]$	Must produce a minimum amount of energy*

Frequency Regulation Constraints

$fr_{i,t} \leq \overline{\overline{r_i}}$	Can't over schedule a resource for regulation
$-fr_{i,t} \leq 0$	Only positive regulation production

Coupling Constraints

$e_{i,t} + fr_{i,t} \leq \overline{\overline{MW_i}}$	Can't over schedule for energy + regulation
$-e_{i,t} + fr_{i,t} \leq 0$	Must produce energy to provide regulation

*This constraint is only for nuclear generation

More details about the optimization model can be found in the Appendix.

2.4 Input Data

Five data sets are used in this model: load, generation fleet, wind data, energy costs, frequency regulation bids, and estimates for frequency regulation requirements (outlined in sections 2.4.1-2.4.6). This model, and the data that goes into it, approximates the MISO consolidation but is not an exact copy of the MISO system. This allows for some flexibility in the input data, such as leaving out any BA for which some or all of the data is not available. In total, 24 historic balancing areas are modeled as 16 regions for every hour in of the year (see the appendix for more details).

In order to maintain the high correlation between wind and load data, it is critical that these data match temporally and geographically. For most BAs, load data are only available from 2006-2008 (section 2.4.1) while simulated wind data are only available for 2004-2006 (section 2.4.1). For this reason, we only model one year (2006) in this study.

2.4.1 Load

Hourly load data for each balancing area can be found in the planning reports submitted annually to the Federal Energy Regulatory Commission (FERC). Balancing areas that have been consolidated into MISO no longer need to submit these reports. However, reports for all the pre-consolidation balancing areas exist for 2006 through FERC Form 714[1]. Load data for two balancing areas (Michigan Electric Coordinated Systems and Muscatine Power and Water) were missing from the reports so these areas were not modeled in this analysis. The model assumes that the load of any consolidating BA does not change post-consolidation, so that the post-consolidation load is the sum of the pre-consolidation load of all BAs.

2.4.2 Generation fleet

Generators are modeled based on plant data from the eGrid database [18], which provides information on every generating unit in the U.S. including unit size, heat rate, fuel type, emissions data, and to which power control area each unit belongs.. To populate the individual

[1] An overview of the FERC Form 714 can be found here: http://www.ferc.gov/docs-filing/forms/form-714/overview.asp. Individual forms for a specific BA, in a specific year can be downloaded through FERC's eLibrary: http://www.ferc.gov/docs-filing/elibrary.asp.

balancing areas, the eGrid power control areas are matched to NERC balancing areas using the NERC CPS Bounds reports [19].

2.4.3 Wind data

Modeling a system at higher wind penetration level requires that time-series of wind production data are estimated for wind farms that do not currently exist. The Eastern Wind Dataset (EWD) does exactly that, providing three years' worth of simulated ten-minute average wind power output from 1,300 hypothetical wind sites in the Eastern Interconnect [3]. In order to model high wind penetration scenarios, we match EWD sites with the historic balancing areas and their respective data from 2006. Wind sites are geographically matched to historic BAs using the Ventyx Velocity Suites, first by estimating the footprint of the different balancing areas considered, then mapping the EWD sites. Sites that fall within the footprint of a BA are included in that BAs generation fleet. We note that while there may be some benefits to optimizing the location of the wind farms, wind farm development decisions are not currently done to optimize system operations. A study of the benefits of such optimization and the mechanisms to encourage optimal development of wind energy projects was beyond the scope of this study.

This geographic allocation method leads to some BAs having an incredibly high penetration of wind and others that had little to none. This disparity is addressed by pre-consolidating balancing areas that have different wind penetration levels and that are geographically contiguous. For example, the city of Columbia, Missouri does not have any EWD wind sites in its footprint and is almost entirely surrounded by Amren, where the total wind capacity would make up 26% of its total generation capacity (8,900 MW wind, 25,600 MW thermal, 34,500 MW total). These two BAs are assumed to be one in our pre-consolidation analysis. In total eight historic BAs are pre-consolidated with other historic balancing areas in order to more evenly distribute the wind resources. More details about this allocation procedure is available in the Appendix.

Two different wind penetration levels are modeled for this paper (0%, and ~20% by energy). The model can choose to curtail wind when it is economic to do so, or if it is required in order to meet physical constraints. The ~20% wind case is selected to align with the near-term renewable portfolio standards that exist in the United States.

2.4.4 Energy Costs

In a competitive market, economic theory suggests that the profit-maximizing bidding strategy for producers is to bid their short-run marginal cost [20]. For resources that use fossil fuels (*e.g., natural gas, oil and*, *coal*), the short-run marginal cost is estimated by the product of the unit's heat-rate (*mmBTU/MWh*) and the fuel price (*$/mmBTU*). For units that do not use fossil fuels (*nuclear, solar, wind, etc)*, data from previous literature is used as a proxy for the short-run marginal costs [21]. Table 1 summarizes the assumed fuel prices or assumed short-run marginal costs for each fuel type.

Table 1 Assumed fuel prices and short-run marginal cost of energy by fuel type (USD 2009). Fuel prices are average values. Short-run marginal costs are taken from Newcomer *et al* [21]

Fuel Type	Fuel Price ($/mmBTU)	Short-Run Marginal Cost ($/MWh)
Biomass		$50.00
Bituminous Coal	$2.72	
Distillate Fuel Oils	$13.14	
Hydro		$10.00
Lignite Coal	$1.59	
Natural Gas	$4.90	
Nuclear	Considered *must-run*, *i.e.*, $0 / MWh	
Petroleum Coke	$1.50	
Subbituminous Coal	$1.64	
Wind	Considered *must-run*, *i.e.*, $0 / MWh	

Some power plants listed in the eGrid database use more than one fuel. For these plants, a weighted average of the short-run marginal cost for the primary and secondary fuels is used. The weighing is based on the unit's historic fuel consumption.

2.4.5 Frequency Regulation Bids

The eGrid data does not provide information that can be used to directly estimate the marginal cost of providing frequency regulation, while MISO data was unavailable for 2006. Given this lack of information, historic bids for frequency regulation from the New York Independent System Operator (NYISO) are used to develop a simple heuristic to predict a unit's bid for frequency regulation. The NYISO is used as the basis for this heuristic, as this system is the most alike to MISO: they are both bi-directional frequency regulation markets, with similar compensation mechanisms that have single clearing prices and include the marginal unit's opportunity cost. These bids help to characterize the current behavior of suppliers and allow us to model the near-term economic effects of BA consolidation. More details about the bidding data are available in the appendix.

All generators, other than nuclear and wind generators, bid into the frequency regulation market and are assigned a frequency regulation bid quantity and price that are based on its size. Equation 4 and Table 2 describe the bid quantity and bid price for a generator as a function of its size.

Equation 4

$$Q_{FR-Bid,i} = \begin{cases} 0.06 * \overline{\overline{MW}}_i & for \quad \overline{\overline{MW}}_i < 200, 300 < \overline{\overline{MW}}_i < 1{,}000 \\ 0.14 * \overline{\overline{MW}}_i & for \quad 200 < \overline{\overline{MW}}_i < 300 \end{cases}$$

Table 2 Frequency Regulation bid prices (USD 2009) by generator size based on regressions of historic frequency regulation bids

Generator Size (MW)	Bid Price ($/MW-Hr)
< 100	$20.60
100-200	$7.40
200-300	$23.23
300-400	$34.62
400-500	$101.67
500-600	$60.40
600-700	$8.05
700-800	$200.00
800-900	-
900-1,000	$200.00

2.4.6 Frequency Regulation Requirement

The quantity of frequency regulation required by a balancing area has historically been primarily a function of the amount of load, but there is no absolute rule for calculating frequency regulation requirement; each balancing area can make its own rules as the quantity of frequency regulation that they use as long as they meet the reliability standards [22]. In order to calculate the frequency regulation requirement for each of the original MISO BAs (without wind capacity), this paper assumes a consistent procurement rule that is proportional to the daily peak load. This is consistent with documented industry practices [22].

For high wind scenarios, the reserve requirement needs to be larger to account for the additional variability wind adds to the system. The Western Wind and Solar Integration Study (WWSIS) [8] suggests that the amount of required "*variability reserves*" in every hour is 3% of load plus 5% of forecasted wind. Variability reserves is the WWSIS catchall phrase for load-following, contingency reserves ('spin' and 'non-spin'), and frequency regulation reserves. It is unclear how each of these reserve type contributes to the total amount of "variability reserves." As a starting point, we assume that frequency reserves account for half of the five percent in the heuristic and the other half is for operating reserves (spin and non-spin). Equation 5 shows the final heuristic for the frequency regulation reserve requirement used in this paper.

Equation 5

$$FR\ Req_{\,t,j} = \left(0.01 * \widehat{L_j}\right) + (0.5 * 0.05 * \sum_{i \in j} w_{t,j})$$

Balancing area consolidation can reduce the need for frequency regulation, when comparing the sum of all the pre-consolidated requirements against the post-consolidated requirement. Some of this reduction is due to the loads of the consolidating BAs not being coincidental, which results in the peak load of the CBA being lower than the sum of all individual BAs' peak load. This reduction in peak load would in turn reduce the amount of required frequency regulation as seen in Equation 5. This effect is inherently captured in our method.

Makarov *et al* [17] also suggest that frequency regulation energy, the integrated value of the frequency regulation control signal[2], could decrease by 30% (additional details in the appendix).

[2] This is known as the Automatic Generation Control (AGC) signal, which is an instruction by the balancing authority to all the units providing frequency regulation. This signal can be unique for all providers or one signal that is scaled to the amount of frequency regulation that a unit is providing.

To account for this effect, a frequency regulation efficiency parameter is used to reduce the post-consolidated requirement by 30% in some scenarios.

2.5 Sensitivity and Scenarios

Sensitivity analysis through parameterization is used to understand how the results might change with our assumptions. In order to evaluate the effect of natural gas prices on our analysis, we use a range of gas prices from $3-$10 per mmBTU, which represents the full range of EIA prediction for the next few decades [23]. Further, the first two scenarios (1-2) assume that the heuristic for the frequency regulation is unchanged after consolidation (Equation 5). The final scenario (3) assumes that the frequency regulation requirement for the CBA is 30% less than the original heuristic. This estimates the reliability improvements suggested by Makarov *et al* [17]. Table 3 summarizes the details of the sensitivity scenarios.

Table 3 Scenarios and the parameters varied. This parameterization of the model tests the sensitivity of the results. Natural gas prices are in USD 2009.

Scenario	Wind (%)	Frequency Regulation Requirement	Natural Gas Price ($/mmBTU)
1	0%	$0.010 * \widehat{L_j} + 0.0250 * \sum_{i \in j} w_{t,j}$	$4.90
1L	0%		$3.00
1H	0%		$10.00
2	20%	$0.010 * \widehat{L_j} + 0.0250 * \sum_{i \in j} w_{t,j}$	$4.90
2L	20%		$3.00
2H	20%		$10.00
3	20%	$0.007 * \widehat{L_j} + 0.0175 * \sum_{i \in j} w_{t,j}$	$4.90
3L	20%		$3.00
3H	20%		$10.00

L refers to model runs where the low gas price of $3/mmBTU is used
H refers to model runs where the high gas price of $10/mmBTU is used

3 Results

As previously noted, twenty-four of the twenty-eight current balancing areas that are in the Midwest ISO are modeled as sixteen pre-consolidation BAs and then again as the CBA. Table 4 summarizes the characteristics of these sixteen BAs including their average and peak load; thermal and wind generation capacity; and the wind penetration and curtailments.

Balancing area consolidation and the addition of wind cause shifts in the dispatch of units, and therefore the fuel mix that is used to produce electricity. As the change in fuel mix is not the primary focus of this paper, these results can be found in the appendix.

Previous research also shows that balancing area consolidation leads to reduction in a balancing area's ramping requirements [10,16,17]. The average daily maximum ramp rate for each balancing area, before and after consolidation, is used as a metric for how difficult it is to balance the system. This metric includes wind curtailments as a form of ramping as it is a form of dispatch instruction used to meet ramping needs. Figure 1 shows the change in the generation ramping (including curtailments) due to balancing area consolidation for two cases: without wind

Table 4 Wind penetration and curtailment by regions (~20% wind)

Region	Load (MW)		Capacity (MW)		Wind (GWh)			
	Avg.	Peak	Thermal	Wind	Delivered	% Energy	Curtailed	% Curtailed
1	2,100	3,700	5,000	1,400	3,200	17%	1	0.0%
2	2,300	3,500	5,000	1,200	3,000	15%	2	0.1%
3	9,900	17,600	26,300	7,600	19,200	22%	165	0.8%
4	4,500	8,700	12,200	1,700	3,600	9%	0	0.0%
5	6,000	9,900	12,800	4,300	10,000	19%	156	1.5%
6	3,100	4,600	5,000	2,500	6,800	25%	2	0.0%
7	380	680	2,000	0	0	0%	0	-
8	1,800	3,100	3,800	720	1,600	10%	0	0.0%
9	2,900	4,900	7,500	2,200	6,000	24%	0	0.0%
10	2,300	3,600	4,700	1,700	3,700	18%	0	0.0%
11	470	680	2,000	320	880	21%	0	0.0%
12	960	1,700	2,500	370	820	10%	0	0.0%
13	110	150	310	0	0	0%	0	-
14	280	490	3,000	0	0	0%	0	-
15	3,500	6,200	9,600	1,900	4,100	13%	2	0.0%
16	1,600	2,400	3,000	470	910	6%	0	0.0%
Sum*	42,200	71,900	104,700	26,400	63,800	17%	327	0.5%
Consolidated	42,200	71,000	104,700	26,400	64,000	17%	0	0.0%

* Values may not add up due to rounding

(load only), and with wind (Net-Load). The average daily maximum ramp rate requirment decresed by 19% for the load-only case, from 4,300 MW/hour for the non-consolidated BAs to 3,600 MW/hour for the CBA. These results are consistent with the previous research [10,16,17]. For net load, the average daily maximum ramp rate decreased by 34%, from 6,300 MW/hour for non-consolidated BA to, 4,700 MW/hour for the CBA. This reduction is to be expected given the previously shown effect of geographic diversity when integrating renewables [11].

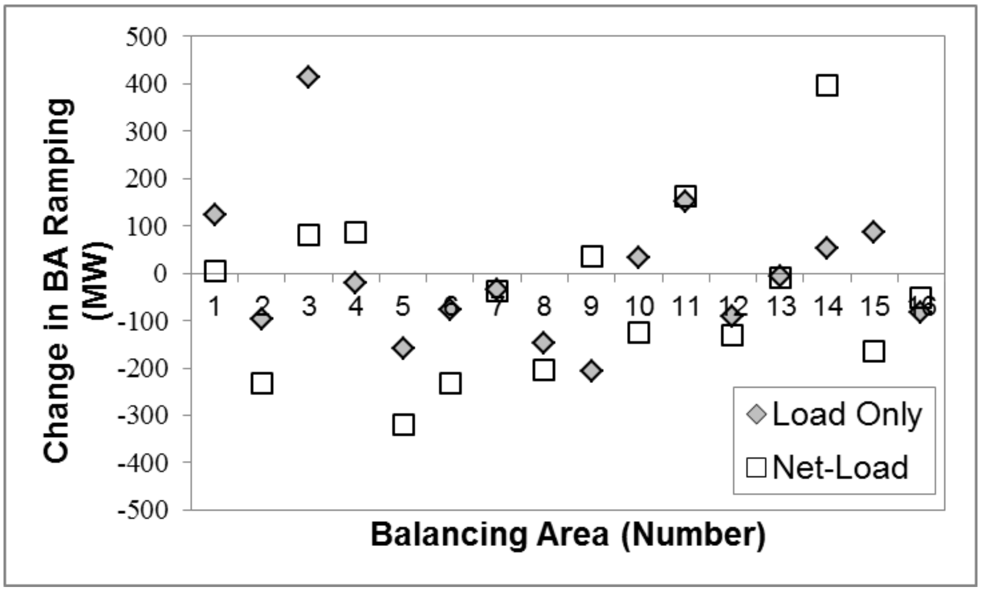

Fig. 1 The change in ramping due to balancing area consolidation, by balancing area, for the no wind (load only) and with wind (net-load) case. Note that all BAs do not experience a decreased amount of ramping; some are ramped more than they would have been otherwise

For every hour interval the model calculates the change in consumer, producer, and social surplus due to consolidation. For all scenarios, consumers benefit, through a $0.5-$2.7 billion per year reduction in expenditures. Producers, however, lose $0.16-$2.2 billion per year in profit. The total change in social surplus, due to gains in both the energy and frequency regulation markets, ranges from aproximatley $370 to $530 million dollars per year as shown in Table 5. When normalized by the total quantity of electricity sold, the change in social surplus is equivalent to $1.2-$1.7/MWh. This would be the expected average reduction in wholesale electricity prices caused by large-scale aggregation, assuming the consumers make the producers whole and there exists a perfectly competitive market.

The results of our load only (*i.e.*, no wind) case (scenario 1), show a change in social surplus equal to $530 million per year. This is remarkably similar to the ICF find of a hypothetical maximum savings of $552 million per year [13]. The fact that change in social surplus always increases means that there is always some benefit to consolidation, even without the presence of wind. The trends in these numbers also agree with the operational savings presented in Corcoran *et al* [12].

Table 5 Yearly totals for the key economic metrics of balancing area consolidation: change in producer profit, change in consumer expenditures, and change in social surplus (USD 2009). A negative change in producer profit signifies a reduction in producer surplus, while a negative change in consumer expenditures signifies an increase in consumer surplus

	ΔProducer Profit $ Mill / Year	ΔConsumer Expenditures $ Mill / Year	ΔSocial Surplus $ Mill / Year
1*	-$670	-$1,200	$530
1L	-$340	-$850	$510
1H	-$2,200	-$2,700	$500
2*	-$320	-$690	$370
2L	-$160	-$540	$380
2H	-$1,000	-$1,400	$400
3*	-$350	-$760	$410
3L	-$180	-$600	$420
3H	-$1,100	-$1,500	$400

Table 6 shows the economic gains and losses associated with the frequency regulation market (these values are a subset of the values shown in Table 5). Consumers benefit through a reduction in expenditures, approximately $7-$130 million per year depending on the scenario. Producers lose approximately $3-$80 million per year in profit. The economic gains associated with the frequency regulation market range between $7 to $50 million per year. Put another way, the economic gains in the frequency regulation market of $7-$50 million per year would be equivalent to a 0.002-0.02 cents per kWh reduction in the total cost of electricity. The social surplus gains associated with frequency regulation account for roughly 10% of the total social surplus benefits of balancing area consolidation. These changes in economic surplus are statistically significant as further detailed in the Appendix

Table 6 Yearly totals associated with the frequency regulation market for the key economic metrics of balancing area consolidation: change in producer profit, change in consumer expenditures, and change in social surplus (USD 2009). A negative change in producer profit signifies a reduction in producer surplus, while a negative change in consumer expenditures signifies an increase in consumer surplus

	Frequency Regulation ΔProfit $ Mill / Year	Frequency Regulation ΔExpenditures $ Mill / Year	Frequency Regulation ΔSocial Surplus $ Mill / Year
1	$3	-$7	$10
1L	-$3	-$10	$7
1H	$0	-$20	$20
2	-$3	-$10	$10
2L	-$1	-$10	$10
2H	-$40	-$60	$20
3	-$40	-$70	$30
3L	-$30	-$60	$30
3H	-$80	-$130	$50

To understand the effects of wind integration and the natural gas price in more depth, Figure 2 and Figure 3 show the distribution[3] of weekly[4] economic metrics.The median change in social

[3] These are boxplots. Each datum that goes into these plots represents one weeks' worth of simulation results. The red line in the center is the median of the data; area of the box represents the middle two quartiles of the data; the whiskers represent the full range of the data that are not considered outliers, with the outliers marked by red crosses.

[4] Results were aggregated by week in order to reduce the variance in the results. The one-hour data included large variance from interval to interval. This variance is not significant when utility

surplus for the nine scenarios shown ranged between $1.50 to $1.80 per MWh, (Figure 2). The effect of wind on the economics of balancing area consolidation can be seen in the difference between scenario 1 (no wind) and scenarios 2 and 3 (with wind). While wind increases the variation in the change in social surplus, it does not dramatically increase the economic motivation for balancing area consolidtion.

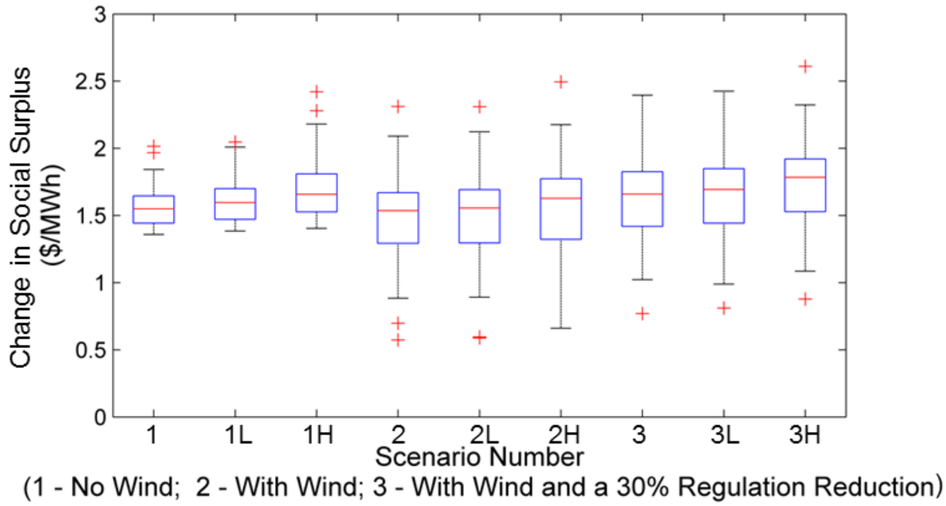

Fig. 2 The total change in social surplus (USD 2009) is represented by the box plots above for an assumed frequency regulation reduction and wind penetration. This incorporates the economic gains from both the energy and frequency regulation markets. Note that the median change in social surplus, represented by the red line in the center of each boxplot, does not dramatically change with wind penetration or with wind and assumed 30% frequency regulation reduction (3, 3L, and 3H)

Figure 2 also does not show any real effect of the natural gas price on the total social surplus gains. This result may be specific to this case-study, as natural gas constitutes a low percentage of power generation in MISO, less than 2% by energy in our model. The influence of natural gas prices may be different in a region such as New England, where natural gas is more heavily used.

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settlements are done on a weekly to a monthly basis. Weekly data provides statistical power and an understanding of the distribution on variance without being overwhelmed.

The median change in social surplus due to the frequency regulation market ranged between $0.02 to $0.20 per MWh[5] (Figure 3) – an order of magnitude smaller than the total surplus gains (Figure 2). The median change in social surplus in scenarios 1 & 2, which does not include improvements in frequency regulation efficiency, are significantly lower than those in scenario 3 (that includes a 30% frequency regulation requirement reduction for the consolidated BA). This suggests that the true gains in the frequency regulation market are highly sensitive to how much the consolidated BA can reduce its frequency regulation requirment. Since the benefits in the frequency regulation market are a small percentage of the total benefits of BA consolidation found in this study, the economic gains associated with reduced demand for frequency regulation would still be small.

[5] This is *not* the reduction in the price in frequency regulation. It is the expected reduction in the cost of frequency regulation, divided by the number of megawatt-hours of load. For example, if the price of frequency regulation were to be reduced by \$0.50 / MW_{FR}-Hr during an hour where there is 100 MWh of load and 2 MW of frequency regulation. The reduction in cost is equal to \$0.50/MW_{FR}-Hr x 2 MW_{FR} x 1 Hour = \$1. The normalized reduction in cost is equal to \$1 / 100 MWh = \$0.01 / MWh. This provides a level comparison to any reduction in energy costs.

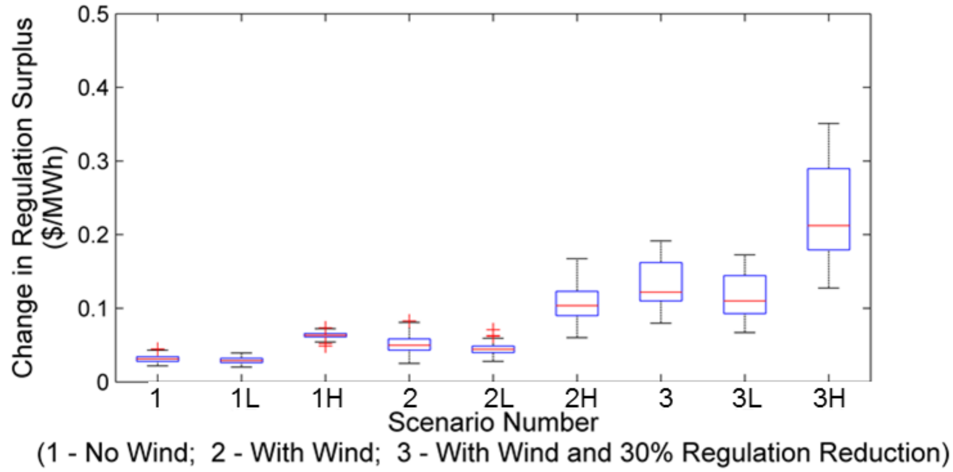

Fig. 3 Change in social surplus (USD 2009) in the frequency regulation market is represented by the box plots above for an assumed frequency regulation reduction and wind penetration. Note that the surplus gains shown above are approximately 1/20th the amount of the surplus gains shown in **Fig. 2**

The results presented in this paper include a wind penetration level of 20%. A higher wind penetration level (~30%) was also considered for this analysis. We found, however, the optimization model was unable to find a feasible solution due to the frequency regulation requirement constraint. For this model, we base the supply of frequency regulation on current bidding behavior and develope a heuristic to allocate the units' capacity between the energy and frequency regulation markets. Using this allocation, which is based on historical bidding data, there would not be enough supply for frequency regulation needed to support 30% wind. In order to meet this penetration level, generators would have to change their bidding behavior. Modeling such changes in market behavior was beyond the scope of this paper so a 30% scenario was not included in the analysis and is left for future work.

This analysis does not include transmission constraints, unit commitment, or intra-hour generator dispatch. A detailed discussion of these limitations and the resulting biases is included in the Appendix. We suggest, however, that eliminating these limitations would not alter the general conclusion of our analysis, though we encourage further research in this area.

4 DISCUSSION

Balancing area consolidation creates economic gains for society but these benefits are not equally distributed across all stakeholders. The results presented in the previous section suggest that BA consolidation benefits customers while the producers lose surplus. These results are a Kaldor-Hicks improvement - where social surplus increases but not everyone is better off. In order to achieve a scenario where both parties in the market are better off, known as a Pareto[6] improvement, mechanisms may need to be available so that consumers compensate the producers for their losses. This is likely to occur naturally in markets as producers change their bidding behavior in response to the loss in profit. Those BAs that are regulated would have to address this in rate cases with their public utility commission. Regardless of the state of restructuring, those considering consolidation should be careful to look at the changes in social surplus, not changes in consumer expenditures, as this is the appropriate metric of economic gains in Kaldor-Hicks efficient scenarios.

As previously noted, the majority (over 90%) of surplus gains come from the energy market. It is possible that some of these gains are already being accessed through other mechanism of cooperation, *e.g.*, imports, exports, power purchase agreements, etc. This analysis has a strict assumption built into the disaggregated counterfactual: that the balancing areas meet their energy

[6] A Pareto improvement should not to be confused with Pareto efficiency. Both concepts are based on the same principals but apply to different scenarios. Pareto efficient refers to the efficient allocation of goods given market constraints. Pareto improvements refer to a set of new possible Pareto efficient allocations based on a set of new possible market constraints. Often these constraints are set through policy.

needs only through resources that are located physically in their area. This is far from true in the real world. Data show that these balancing areas are already exchanging power and most likely accessing the low-hanging fruit of the gains seen in our results. This suggests that the actual amount of near-term social surplus gains associated with balancing area consolidation are somewhere between the total social surplus gains (~$1.7/MWh) and those only associated with the frequency regulation market, $0.02-$0.20 per MWh (see Figure 3). Therefore, those considering consolidation should look at methods of coordinating their economic dispatch of energy with their neighbors, where much of the economic benefit lie, without the additional costs of a full consolidation.

The results further suggest that, given the near-term expectation of wind (0-20%), there may not be a significant driver for BA consolidation. The addition of wind increased the variance of the economic gains but it did not change the size of these gains. Given current market behavior, the data help to explain why BA consolidation is not more wide-spread: there are few benefits to consolidate today and those benefits are inequitable among participants.

ACKNOWLEDGEMENTS

This work was funded by the Doris Duke Charitable Foundation, the RK Mellon Foundation, the Heinz Endowments, and the Electric Power Research Institute through their support to the RenewElec project at Carnegie Mellon University. The results and conclusion of this paper are the sole responsibility of the authors and do not represent the views of the funding source.

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Appendix - Near-term Economics and Equity of Balancing Area Consolidation to Support Wind Integration

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BALANCING AREAS

Balancing areas (BAs) are responsible for instantaneously matching supply and demand for electricity within their geographic boundaries. There are currently 103 BAs in the U.S. with sizes ranging between 70 MW and 153, GW as shown in Fig. 4 [24, 25]. The large number of BAs and wide size range suggest that there are significant opportunities for further consolidation.

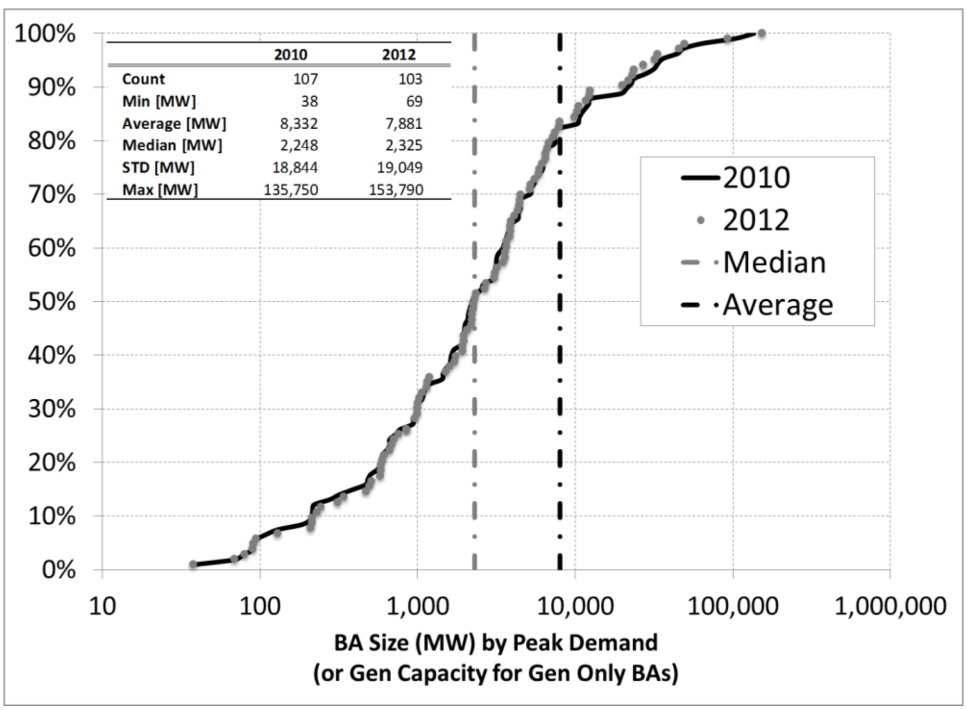

Fig. 4 Cumulative distribution function of balancing area sizes. There are 103 in North America ranging in size from 70 MW to 153 GW (median equal to 2,300 MW; mean size is 8,000 MW).

Assumed Frequency Regulation Reduction

Makarov *et al* [26] show a reduction in frequency regulation energy between 0-30% associated with balancing area consolidation. However, a 30% reduction in frequency regulation energy is difficult to enforce, as this energy quantity is driven by the imbalances and therefore is determined by the input data. To overcome this limitation, our model assumes a 30% reduction in frequency regulation capacity (scenario 3) to simulate the added efficiency associated with BA consolidation. This is essentially assuming that frequency regulation energy and frequency regulation capacity are equivalent (A review of the difference between frequency regulation capacity and frequency regulation energy is given below). While this may not be accurate, it demonstrates the results' sensitivity to the frequency regulation efficiency gains. Any bias resulting from this assumption is likely to be positive so that the mean savings seen in the results section are larger than they would be when enforcing a 30% reduction in regulation energy.

Frequency Regulation Capacity

Frequency regulation capacity is an amount of capacity, measured in megawatts (MW), that is held back from providing energy in order to counteract imbalances in the system that result from unexpected changes in imports, exports, generation, and load. Therefore frequency regulation capacity requirements are set ahead of time (*ex ante*[7]) in order to reserve capacity for this balancing service. The amount of capacity is based on the historic distribution of imbalances, historic performance on NERC balancing standards (CPS1 & CPS2), and common heuristics (*i.e.*, 1% of peak load).

Frequency Regulation Energy

Frequency regulation energy is an additional amount of energy produced or curtailed while providing frequency regulation and is equal to the integral of the absolute value of frequency regulation signal over time. This is a metric of how much movement is needed to counteract imbalances and is a function of the real-time imbalances. It does not, however, directly determine the required amount of frequency regulation capacity that must be scheduled ahead of time. For example one megawatt-hour of frequency regulation energy could be one megawatt of additional output for one hour and require one megawatt of frequency regulation capacity. Or the same one megawatt-hour of frequency regulation energy could be two megawatts of additional output for a half hour and require two megawatts of frequency regulation capacity.

[7] *Ex Ante* is Latin meaning "*before the event*" and is commonly used in describing how markets are cleared relative to the actual transaction. *Ex post*, meaning after the event, is the complement to *ex ante*.

SURPLUS

Under some simple assumptions, consumer expenditures and producer profit are appropriate proxies for consumer surplus and producer surplus, respectively. These assumptions include:

1. Each balancing area has a weakly monotonically increasing marginal supply curve. Under this assumption, a market's willingness to supply goods can be quantified as a function of price; and as price increases, so does the quantity of goods that the market is willing to supply.

2. Demand for any one market clearing interval is inelastic up to a critical price, after-which the demand for electricity is zero. Under this assumption, at any one point in time, demand is set by the consumers and is not a function of the market price up until a critical point, after which demand is zero. Inelastic demand is typical of power systems today, where demand response participation and consumer real-time pricing is very low. For example, MISO incorporated demand response in 2005 [see section 1.66 of 27] but in 2010 had only 270 MW of responsive load [28] compared to its total generation capacity of nearly 160 GW [29] – a participation rate of only 0.17% by capacity. For all intents and purposes, the Midwest ISO had inelastic demand from 2005 to 2010.

   Further, assumption 2 suggests that when price hits a certain dollar amount, consumers will not purchase electricity. For example, MISO has a maximum day-ahead offer cap, originally set to $1,000/MWh [see section 39.2.5.f of 30]. The consumer's maximum willingness to pay for load could be based off of the value of lost load (VOLL), a metric used by MISO to set operating reserve demand curves [see schedule 28 of 31]. The exact value of this dollar amount is not required; all that is necessary is that this value is the same before and after consolidation.

3. All participants have quasi-linear preferences. This is commonly known as the “money is money” assumption, which implies that the first dollar earned/saved brings exactly the same amount of utility as the tenth dollar earned/saved. This assumption implies that the supply curve and the demand curves are equivalent to utility functions for the producers and consumers.

All these assumptions result in an idealized market that can be represented as the illustration below (Fig. 5).

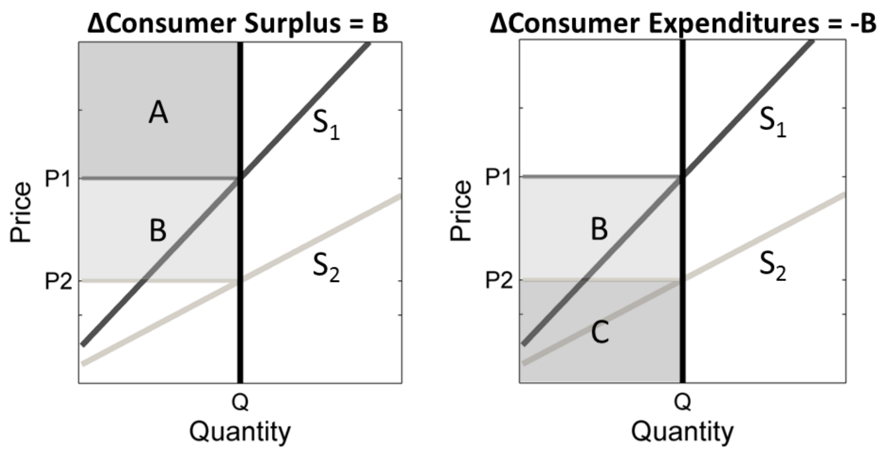

Fig. 5 An illustration of an idealized electricity market that meet some basic assumptions including inelastic demand (the dark vertical line). Also represented here are two supply curves and their respective clearing prices: S_1 & P_1 – the pre-consolidated supply curve and market price for a balancing area; and S_2 & P_2 – the post-consolidated supply curve and market price. The shaded regions represent different measures of surplus and changes in surplus

Fig. 5 shows the inelastic demand (the dark vertical line of assumption 2) and two supply curves, one pre-consolidated (S_1) and one post-consolidation (S_2). Also depicted are the respective clearing prices (P_1& P_2). The consumer surplus for this balancing area in the pre-consolidated state is the shaded area **A**; for the post-consolidated state, it is **A** and **B**. The change in consumer surplus from consolidation for this balancing area is the shaded region **B** (left side of the illustration). The consumer expenditures using the pre-consolidated supply curve (S_1) is equal to the amount represented in the shaded areas **B** and **C**; for the post-consolidated state, the expenditures are represented by the area **C**. The change in expenditures for consolidating for this balancing area is a reduction by the amount represented in the shaded area **B**.

Note that an increase in consumer surplus, under these assumptions, is equal to a reduction in consumer expenditures of the same magnitude. In this example, the change in consumer surplus is equal to **B** and the change in consumer expenditures is equal to -**B**.

On the producer side, Fig. 6 is an illustration of the described idealized market, similar to Fig. 5. The producer surplus for this balancing area in the pre-consolidated state is the shaded area **A**; for the post-consolidated state, it is **B**. The change in producer surplus from consolidation for this balancing area is the difference between shaded region **B** and **A**. The producer profit for this balancing area in the pre-consolidated state is the shaded region **A**; for the post-consolidated state it is region **B**. The change in producer profit is equal to the change in producer surplus: it is the difference between area **B** and area **A**.

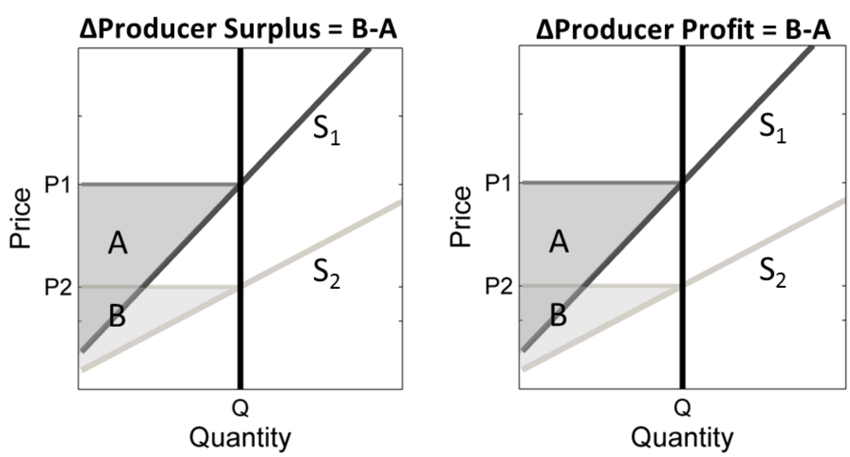

Fig. 6 An illustration of an idealized market that meet some basic assumptions including inelastic demand (the dark vertical line). Also represented here are two supply curves and their respective clearing prices: S_1 & P_1 – the pre-consolidated supply curve and market price for a balancing area; and S_2 & P_2 – the post-consolidated supply curve and market price. The shaded areas represent different measure of surplus and changes in surplus

Modeling MISO BAs

Thirty balancing areas have been a part of MISO at one point or another. Two BAs left MISO for PJM; two do not have sufficient wind resources in the Eastern Wind data set (EWD); and two do not have valid load data for 2006. This leaves twenty-four historic balancing areas for this analysis. Eight of these historic balancing areas are pre-consolidated with other areas in order to even out the penetration of wind, resulting in 16 modeled balancing areas (Table 7).

Table 7 MISO Balancing Areas
All of the balancing areas that have been consolidated into MISO and data relevant to our modeling effort: the year the BA entered and left MISO, the data set that is missing in order to model that BA, whether the BA is modeled in this study, whether the BA is pre-consolidated, and with whom it is pre-consolidated

Power control area name	Year Consolidated (Year Left)	Missing Data	Modeled	Pre-consolidated with another BA
Alliant - East	**2009**		**X**	
Alliant - West	**2009**		**X**	
Ameren -Illinois	**2009**		**X**	
Ameren - Missouri	**2009**		**X**	**Amren - Illinois**
Big Rivers Electric Corp.	**2010**	**EWD**		
Columbia MO City of	**2009**		**X**	**Amren – Illinois**
Consumers Energy Co.	**2009**		**X**	
Dairyland Power Coop.	**2010**		**X**	
Detroit Edison Co.	**2009**	**EWD**		
Great River Energy	**2009**		**X**	
Hoosier Energy REC	**2009**		**X**	
Indianapolis Power & Light Co.	**2009**		**X**	
Madison Gas and Electric Co.	**2009**		**X**	**Alliant - East**
Michigan Electric Coordinated Systems	**2009**	**Load**		
MidAmerican Energy Co.	**2009**		**X**	
Minnesota Power	**2009**		**X**	**Great River Energy**
Muscatine Power and Water	**2009**	**Load**		
Northern Indiana Public Service Co.	**2009**		**X**	
Northern States Power	**2009**		**X**	**Dairyland Power Coop.**
Otter Tail Power Company	**2009**		**X**	
Southern Illinois Power Cooperative	**2009**		**X**	
Southern Indiana Gas & Electric Co.	**2009**		**X**	**S. Illinois Power Coop.**
Southern Minnesota Mun. Power Agcy.	**2009**		**X**	**Great River Energy**
Springfield IL - CWLP City of	**2009**		**X**	**Amren – Ill.**
Upper Peninsula Power Co.	**2009**		**X**	

Power control area name	Year Consolidated (Year Left)	Missing Data	Modeled	Pre-consolidated with another BA
Wisconsin Energy Corp.	**2009**		**X**	
Wisconsin Public Service Corp.	**2009**		**X**	
WAPA - Upper Great Plains East	**2009**		**X**	
American Trans. / First Energy	**2009 (2009)**			
Duke Energy Corp.	**2009 (2010)**			
	26 Original +4 – 2 = 28 Current MISO BAs		**24 Actual BAs**	**16 Modeled BAs**

Errors in eGrid

There appears to be a few errors in the eGrid database. Primarily, not all heat rates that are reported appear valid – some are negative and others imply a unit efficiency of less than 1%. For units that have invalid heat rates, heat rates from previous versions of eGrid are used. If no other valid heat rate is available, the unit is not used in the model. In addition, some units appear to be incorrectly categorized by fuel type. For example, there are two plants labeled as nuclear but have a primary fuel of distillate fuel oil. Errors like these are corrected when the solution is obvious; otherwise the plants are excluded from the analysis.

EWD Wind Farms

Fig. 7 shows our graphical method of matching EWD wind farms with historic balancing areas. Wind farms that are not within one of the 24 modeled BAs are not used. Some discretion was used when wind farms were just outside the geographic border of a region, as the accuracy of the BA service territories is not known.

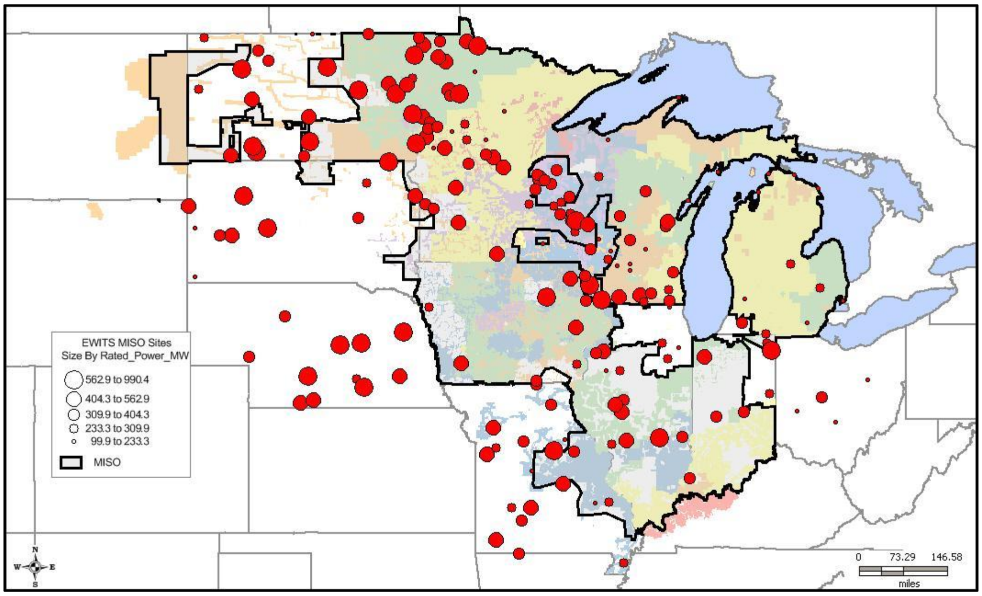

Fig. 7 Geographic representation of MISO today (dark black outline), the service territory of the historic BAs that integrated into MISO (colored regions), and the EWD wind farms (in red and sized based on name-plate capacity in megawatts)

The EWD data was developed to hit a target of 30% wind by energy for the entire Eastern Interconnection. Given the wind resources in the Midwest, using the full EWD dataset leads to an immense amount of wind for this region. It also leads to infeasible solutions for the economic dispatch model. A more moderate wind scenario is needed to model the near-term conditions of BAs today. For these reasons, only a subset of the EWD wind farms is used. Simulated wind farms from EWD are removed from the model in order of increasing capacity factor until an approximate wind penetration of 20% is achieved.

The ten-minute average wind production data provided by EWD are converted to hourly data so that they match sampling rate of the hourly load data.

FREQUENCY REGULATION BID ANALYSIS

As mentioned in the paper, the eGrid data do not include any information regarding the ability or cost of providing frequency regulation. So a heuristic on which generators should participate and how they should bid is explained in detail here.

It is often said that single cycle natural gas turbines *'should'*, or *'are better equipped'*, or *'are likely to provide'* frequency regulation. However, no reliable source could be found to limit the set of generators providing frequency regulation to a specific type. Some limited evidence exists that coal units do provide frequency regulation, although Kirby [32] criticizes one plant for doing so poorly. Additionally Kirby *et al* [33] provide evidence that nuclear plants tend not to provide frequency regulation. As they put it, "*Nuclear power plants choose not to participate in AGC because of the philosophy that reactor power is to be controlled only by the nuclear plant operator, and not by outside variables*." This model assumes that all generators, other than nuclear plants and wind farms, bid into the frequency regulation market, though at different quantities and different prices.

Historic frequency regulation bids from MISO do not exist for the timeframe of the analysis (2006) and current bid data from the MISO ancillary services market does not provide the unit's capacity, which is the explanatory variable for this analysis. Of all the other deregulated markets, the New York Independent System Operator is the most alike to MISO: they are both bi-directional frequency regulation markets and the two markets have similar compensation mechanisms with a single clearing price that includes the marginal unit's opportunity cost. For these reasons, the model uses historic bid data from the New York Independent System Operator (NYISO) to estimate frequency regulation costs based on unit size [34].

Using a regression analysis for a year's worth of bids from the NYISO, we develop a deterministic model based on generator size to estimate the average bid quantity (MW_{FR}) and the bid price ($\$/MW_{FR}$-Hr). The average bid quantity and price are calculated for each size bin. The size of the frequency regulation bid is linear, as shown in Fig. 8 and Fig. 9. However, generators that are between 200 and 300 MW in size bid a higher percentages of their capacity as frequency regulation (14%). In addition, the results show that only one unit larger than 1,000 MW bid into the frequency regulation market. This unit is the same size (2,700 MW) as the Robert Moses Niagra Falls hydro generation station, which has unique characteristics that allow it to provide frequency regulation. In our model, frequency regulation is not assigned to units over 1,000 MW in size.

As a result of this analysis we use a heuristic in which units that are between 200-300 MW bid 14% of their capacity in the frequency regulation market. We further assume that all other units under 1,000 MW bid 6% of their capacity for frequency regulation. The results of this deterministic model, plotted with the actual bids can be seen in Fig. 9.

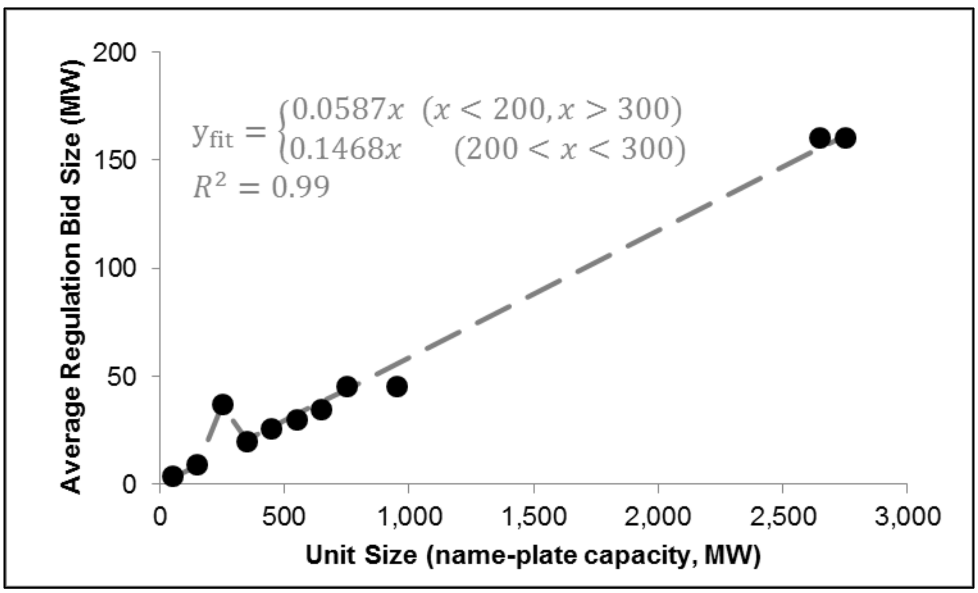

Fig. 8 The average bid quantity (MW) into the frequency regulation market, by generator size. Based on 2009 NYISO bid data

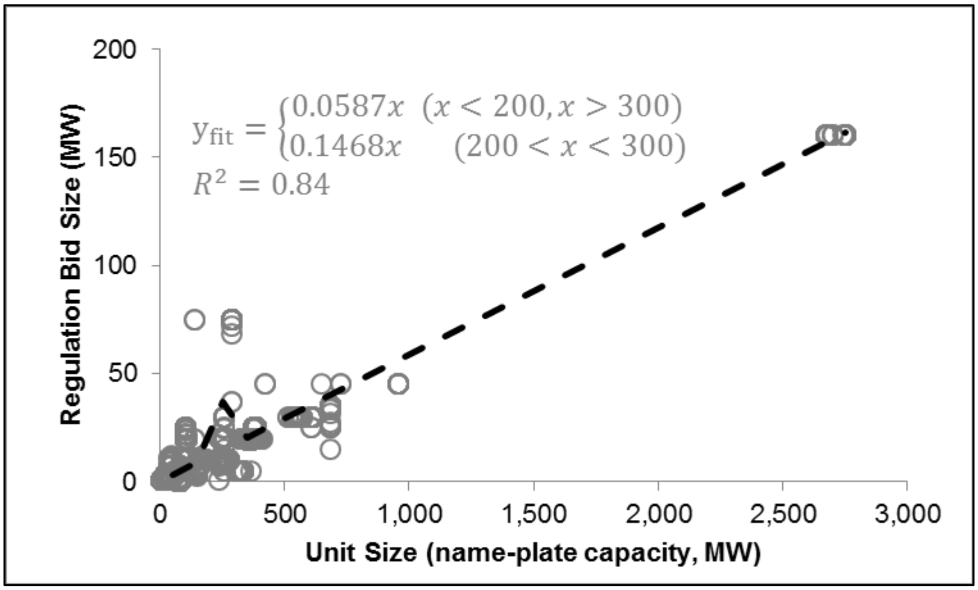

Fig. 9 The bid quantity (MW) into the frequency regulation market plotted with our fitted model using the unit's capacity as the explanatory variable

Historic bid data from the NYISO are again used to estimate a bid price ($/MW$_{FR}$-Hr) to units that are bidding into the frequency regulation market. The average price for each bin is used to assign a bid price to each selected generator (Fig. 10). Units that are nuclear, wind, or that are greater than 1,000 MW do not bid in a quantity for frequency regulation and are not assigned a bid price.

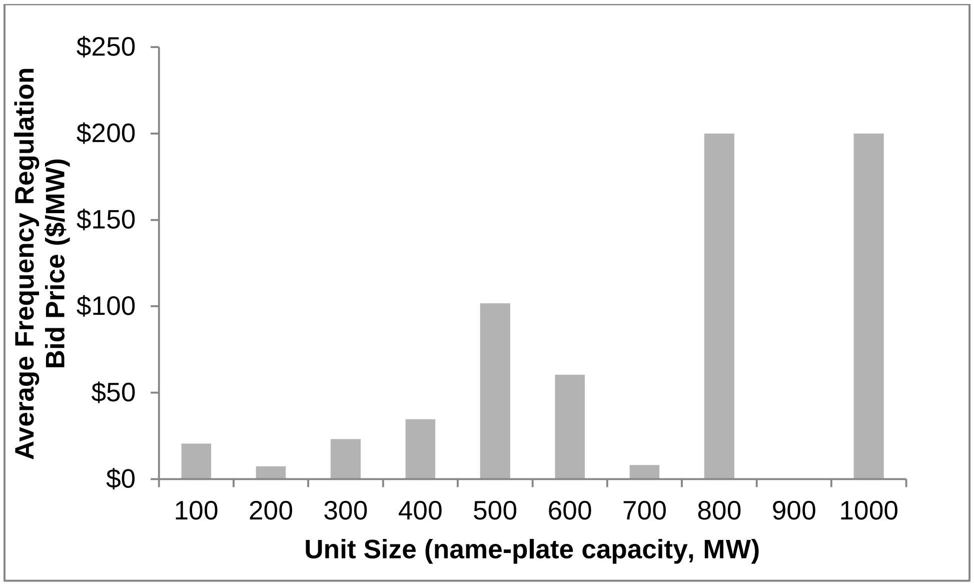

Fig. 10 The average Bid Price ($/MW) into the frequency regulation Market, by generator size. Based on 2009 NYISO bid data

ECONOMIC DISPATCH - ADDITIONAL DETAILS

The objective of the economic dispatch model is to minimize the costs of producing energy and providing frequency regulation to instantaneously match load. The body of the paper shows the most important details of the model. Below are additional details that may help the reader further understand the optimization problem.

Ramp Constraints

Hourly ramp constraints are imposed only on coal and nuclear units. No hourly ramp constraint is placed on single cycle or combined cycle units as these generators can ramp over their entire capacity within one hour [35]. For nuclear units, the hourly ramp limit is 1% of the unit's capacity per hour. This limit allows for some minimal amount of movement but encourages constant production. For coal units, the hourly ramp limit is 20% of its capacity per hour, which is consistent with the ramp limits used in previous literature [36].

Minimum Generation Limits for Nuclear Plants

Nuclear units are considered “must-run” in MISO and have a minimum generation limit. However, there is little reliable data on what this limit should be. Fig. 11 shows the cumulative distribution of the annual capacity factors for nuclear plants [37]. The data show that the majority of the nuclear plants (~80%) have annual capacity factors over 80%., which we choose as the minimum generation limit for the nuclear power plants in this model.

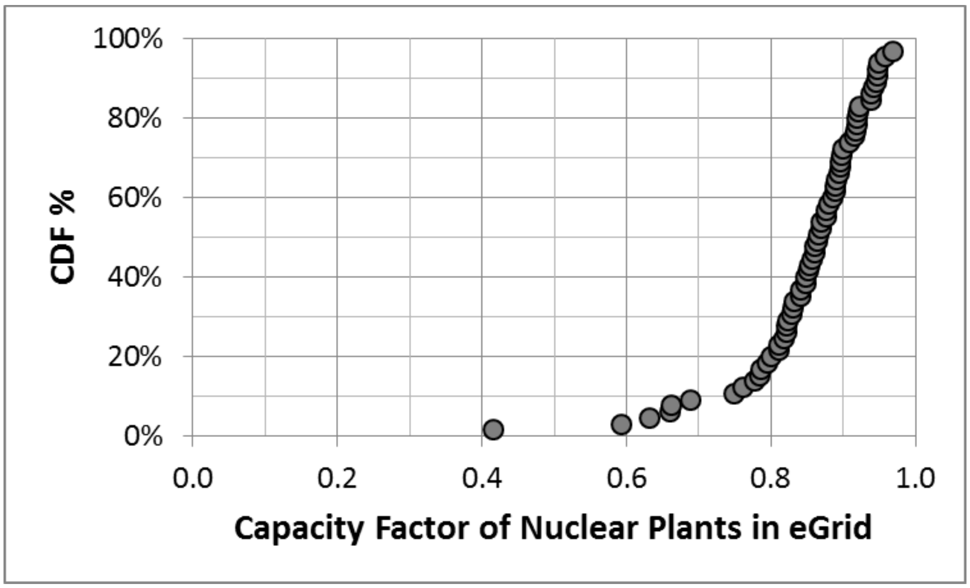

Fig. 11 Approximate cumulative distribution function of nuclear capacity factors in the eGrid data set (2009)

ADDITIONAL RESULTS

Fuel Mix

The model consistantly results in a fuel mix consisting of approximately 80% coal (by energy), 17% nuclear, and the balance provided by gas, oil, and biomass in the base-case (scenarios 1, 1L, and 1H), which agrees well with other data for MISO. The 2006 state-of-the-markets report says that coal provided 78% of the energy produced in MISO (Patton 2007). Compared to output data from MISO, our model results show a slightly higher contribution (17%) by nuclear resources that what was reported by an ICF study (14%). This difference is a result of forced/unforced outages for nuclear plants, which were not included in our model.

Our results also underestimate the amount of natural gas used in MISO. While ICF and market reports show that natural gas accounted for 6% of energy in market, our model results in natural gas providing only 2% of the energy in the system. We suggest that our model understimates the contribution of natural gas for a couple of reasons, including: 1) we do not include transmission constraints in our model, which limited the exchange of coal power between balancing areas. Having less interchanges of coal power requires some BA to go further up the dispatch curve and use natural gas units; and 2) the additional reserve requirements (*e.g.*, contingenceny reserves) that are not being captured in our model might be producing out-of-merit generation or opportunity cost payments, increasing cost.

Table 8, Table 9, and Table 10 show the dispatch by fuel for the base-case, low, and high natural gas price cases, respectively. Specifically, Table 8 compares scenarios 1 and 2; Table 9 compares scenarios 1L to 2L – low gas price without and with wind; and Table 10 compares scenarios 1H to 2H – high gas price without and with wind. As one might expect, with the availability of large amounts of wind energy (which have zero mariginal costs in our model), there is a drastic drop in thermal generation, compared to the zero wind case (Table 8).

The changes in fuel mix due to consolidation are explicately compared in Table 11. First, consolidation results in an increase in nuclear generation in all cases: approximately 1% increase in the case without wind, and 6% increase in the wind cases. In the pre-consolidation balancing areas, nuclear generators are primarily limited by daily minimum load limits and nuclear's own inability to ramp and provide load-following. Balancing area consolidation allows for "export" of nuclear energy to other areas and therefore increases nuclear's ability to provide energy. The same trend takes place in the scenarios that include wind.

Secondly, balancing area consolidation results in a decrease in natural gas consumptions in all scenarios - even when natural gas price is at $3/MMBtu. The reduction in natural gas production ranges from approximatly -50% to -100% depending on the case. Balancing area consolidation reduces the role of natural gas because it decreases the demand for ramping and frequency regulation (as shown in previous literature). In addition, balancing area consolidation also aggregates the supply from multiple areas allowing a shift to lower marginal cost resources such as nuclear and coal.

Coal production increases with balancing area consolidation without any wind in the system (by 1-2%, between 2,700-5,700 GWh depending on the gas price). As previously mentioned, BA consolidation allows areas with excesss cheap coal capacity to export their power and run at higher capacity factors. However, in the cases with wind, the effect of balancing area consolidation on coal power is less certain and ranges between no change to a 1% decrease. Note this is not the decrease in coal production due to the penetration of wind - the displacement of coal due to wind is closer to 55 TWh, over a 20% reduction. What is being described here is the change in coal production with the consolidation of balancing areas in a system that has approximately 20% wind energy.

Balancing area consolidation does not produce consistent results for oil and biomass esources. Oil and biomass are often co-fired with an additional fuel, with the primary fuel driving the change in generation from oil and biomass. If primary fuel is coal with a low cofiring capacity, then the unit might be low on the dispatch curve and exhibit the same trends as base-load coal. However if the unit is cofired with gas it, will exhibit trends similar to a natural gas unit.

Table 8 Base-case Scenarios

Energy production by fuel type and by region, before and after the addition of wind assuming $4.90/mmBTU natural gas (scenarios 1 and 2 compared)

Region	Energy Production by Fuel without Wind (GWh)				Energy Production by Fuel with Wind (GWh)			
	Coal	Nuclear	Gas	Oil / Biomass	Coal	Nuclear	Gas	Oil / Biomass
1	13,500	0	1,600	200	11,400	0	880	120
2	11,700	4,800	30	0	9,200	4,800	20	0
3	55,100	17,400	7	0	39,500	15,200	190	0
4	26,800	6,000	500	0	23,900	6,100	490	0
5	28,500	13,300	1,700	6	20,600	13,000	1,000	3
6	21,500	0	550	500	15,900	0	180	150
7	2,800	0	0	0	2,900	0	0	0
8	13,200	0	1	1	11,900	0	10	3
9	20,900	0	2	0	15,400	0	20	0
10	16,500	0	3	0	13,100	0	2	0
11	3,400	0	0	0	2,600	0	0	0
12	7,100	0	0	0	6,400	0	0	0
13	760	0	0	10	780	0	0	10
14	2,000	0	0	0	2,100	0	0	0
15	17,700	7,900	260	0	14,200	8,000	280	1
16	7,900	3,400	0	210	7,300	3,400	2	160
Sum*	249,000	52,800	4,700	930	197,000	50,500	3,100	450
Consolidated	253,200	53,100	320	960	195,800	53,600	660	870

*** Numbers may not add up due to rounding**

Table 9 Low gas price scenario
Energy production by fuel type and by region, before and after the addition of wind assuming $3/mmBTU natural gas (scenarios 1L and 2L compared)

Region	Energy Production by Fuel without Wind (GWh)				Energy Production by Fuel with Wind (GWh)			
	Coal	Nuclear	Gas	Oil / Biomass	Coal	Nuclear	Gas	Oil / Biomass
1	13,100	0	2,500	30	11,100	0	1,300	20
2	12,000	4,900	90	0	9,200	4,800	50	0
3	56,300	17,700	170	0	39,300	15,200	480	0
4	27,300	6,100	640	0	23,800	6,100	590	0
5	27,800	13,500	3,200	1	19,800	13,000	1,800	0
6	21,800	0	1,100	120	15,900	0	350	30
7	2,900	0	10	0	2,900	0	9	0
8	13,500	0	1	1	11,900	0	10	3
9	21,400	0	5	0	15,400	0	30	0
10	16,800	0	50	0	13,100	0	20	0
11	3,500	0	0	0	2,600	0	0	0
12	7,200	0	30	0	6,400	0	30	0
13	780	0	0	10	780	0	0	10
14	2,100	0	0	0	2,100	0	0	0
15	17,900	8,000	600	0	13,900	8,000	520	0
16	8,100	3,400	8	220	7,300	3,400	30	160
Sum*	252,000	53,600	8,400	380	195,000	50,500	5,200	220
Consolidated	257,700	54,200	2,100	980	194,300	53,600	2,200	870

*** Numbers may not add up due to rounding**

Table 10 High gas price scenario
Energy production by fuel type and by region, before and after the addition of wind assuming $10/mmBTU natural gas (scenarios 1H and 2H compared)

Region	Energy Production by Fuel without Wind (GWh)				Energy Production by Fuel with Wind (GWh)			
	Coal	Nuclear	Gas	Oil / Biomass	Coal	Nuclear	Gas	Oil / Biomass
1	14,700	0	750	240	11,700	0	310	130
2	12,000	4,900	30	1	9,000	4,700	9	1
3	56,500	17,700	0	0	38,700	14,900	2	20
4	27,700	6,100	230	90	23,700	6,000	150	90
5	29,400	13,500	1,100	440	20,300	12,700	530	200
6	22,000	0	180	810	15,600	0	50	230
7	2,900	0	0	0	2,800	0	0	0
8	13,500	0	0	1	11,600	0	8	5
9	21,400	0	0	0	15,100	0	0	1
10	16,900	0	1	0	12,900	0	0	0
11	3,500	0	0	0	2,600	0	0	0
12	7,200	0	0	0	6,300	0	0	0
13	780	0	0	10	760	0	0	10
14	2,100	0	0	0	2,000	0	0	0
15	18,500	8,000	7	9	14,100	7,800	1	40
16	8,100	3,400	0	230	7,200	3,300	0	160
Sum*	257,000	53,600	2,300	1,800	194,000	49,400	1,100	890
Consolidated	259,700	54,200	10	1,000	192,100	52,600	0	870

*** Numbers may not add up due to rounding**

Table 11 Change in thermal dispatch with balancing area consolidation
The change in thermal dispatch with balancing area consolidation over the nine scenarios and four main fuel categories. The change in dispatch values are represented in both gigawatt-hours and in percent change. Note that positive values represent an increased production in the consolidated state as compared to the unconsolidated state

	ΔCoal (GWh)			ΔNuclear (GWh)			ΔGas (GWh)			ΔOil/Biomass (GWh)		
Scenario / Gas Price	1	2	3	1	2	3	1	2	3	1	2	3
Base Case	4,200	-1,200	-1,000	300	3,100	3,200	-4,400	-2,400	-2,900	30	420	410
Low Gas (L)	5,700	-700	200	600	3,100	3,100	-6,300	-3,000	-3,900	600	650	650
High Gas (H)	2,700	-1,900	-2,600	600	3,200	3,100	-2,300	-1,100	-1,100	-800	-20	-30

	ΔCoal (%)			ΔNuclear (%)			ΔGas (%)			ΔOil / Biomass (%)		
Scenario / Gas Price	1	2	3	1	2	3	1	2	3	1	2	3
Base Case	2%	-1%	0%	1%	6%	6%	-90%	-80%	-90%	3%	90%	90%
Low Gas (L)	2%	-1%	0%	1%	6%	6%	-80%	-60%	-70%	100%	300%	300%
High Gas (H)	1%	-1%	-1%	1%	6%	6%	-100%	-100%	-100%	-40%	-2%	-5%

Additional Discussion

Significance Tests

The changes in consumer expenditures, producer profits, and total surplus are tested for statistically significance using a one-tail student's t-test. All of the samples tested have 51 degrees of freedom (52 data per sample - 1 = 51). The t-distribution for 50 degrees of freedom and a significance level (α) equal to 0.05 is 1.676. Table 12 and Table 13 show the mean changes in each economic metric and the p-value of the t-tests for scenarios 1, 2, and 3. Table 12 encompasses both the energy and frequency regulation market, and Table 13 only shows the economic changes associated with the frequency regulation market. Note that the key point here is that any mean change, shown in these tables, that has an associated p-value less than 10^{-3} is considered to be significantly different than zero. All of the changes shown are thus statistically significant.

Table 12 Statistical Significance Testing for the Energy and Frequency Regulation Marktes
The mean value for the change in key economic metrics associated with the energy and frequency regulation markets due to balancing area consolidation, in $/MWh (USD 2009). Note that all values shown are significant.

Energy & Frequency Regulation Markets $/MWh (p-value)			
Scenario	1	2	4
ΔProducer Profit	-$2.00 (1E-26)	-$1.10 (1E-15)	-$1.20 (1E-18)
ΔConsumer Expenditures	-$3.60 (1E-35)	-$2.50 (1E-32)	-$2.80 (1E-35)
ΔSocial Surplus	$1.60 (1E-36)	$1.50 (1E-34)	$1.60 (1E-36)

Table 13 Statistical Significance Testing for the Frequency Regulation Market
The mean value for the change in key economic metrics associated with the frequency regulation market due to balancing area consolidation, in $/MWh (USD 2009). Note that all values shown are significant

	Frequency Regulation $/MWh (p-value)		
Scenario	1	2	3
ΔProducer Profit	$0.01 (1E-6)	-$0.03 (1E-5)	-$0.19 (1E-23)
ΔConsumer Expenditures	-$0.02 (1E-24)	-$0.08 (1E-16)	-$0.32 (1E-27)
ΔSocial Surplus	$0.03 (1E-34)	$0.05 (1E-31)	$0.13 (1E-34)

Model Limitations and Biases

A major limitation of this model is the lack of transmission constraints. Most of the transmission data for North America has been classified since 2001 and was unavailable for this study. The lack of transmission constraints most likely introduces a positive bias to the results. Transmission constraints would limit how much power and frequency regulation each BA could export/import. This would produce higher prices for energy and frequency regulation in the consolidated balancing area, which in turn would reduce the economic gains associated with consolidating. Consequently, the results in this paper are likely to be an overestimate due to the lack of transmission constraints. This again strengthens our argument that the near-term gains associated with balancing area consolidation are likely to be low.

COUNTER-FACTUAL ASSUMPTION

The model results, as presented here, have a strict assumption built into the disaggregated counterfactual: that the balancing areas meet their energy needs only through resources that are located physically in their area. This is far from true as there currently are significant levels of imports/exports across balancing areas. This disaggregated counterfactual likely introduces an additional positive bias to the results. Table 14 (below) shows the net imports of energy for all the balancing areas modeled. These data suggest that these balancing areas are already exchanging power and most likely accessing the low-hanging fruit of economic gains seen in this model, reducing the near-term benefits of consolidation.

Table 14 Net-Imports
Actual data on the net-import of electricity for each of the 16 modeled regions

Region	Net-Import (% of Native Load)*		
	2006	2007	2008
1	23%	25%	24%
2	10%	7%	10%
3	-9%	-9%	-8%
4			
5	-2%	-2%	-2%
6	5%		-96%
7	-140%	-143%	-136%
8	-6%	-6%	-6%
9	6%	-3%	-17%
10	20%	20%	-107%
11	87%	102%	-145%
12	2%	0%	6%
13	83%		98%
14			
15	4%	12%	14%
16	5%		-9%

*Net-Import calculated by summing the area's yearly received (imports) and delivered (exports) exchanges with their neighboring areas.

UNIT COMMITMENT

This model does not account for unit commitment and focuses on the hourly dispatch of resources. Normally, adding minimum generation limits would require a unit commitment model. However, implementing a unit commitment model for over 1,200 decision variables (*611 generators x 2 decision variables per generator*) per time-step would exceed our computational limits. To overcome this limitation, we approximate the unit commitment process by optimizing the linear program over a twelve-hour period and then only stepping forward by six hours. In addition, our model assumes that the nuclear plants are price takers – *i.e.*, their bids are zero ($0/MWh). This means the solver is always going to have the nuclear plants online, eliminating the need for an integral constraint, returning the problem to a linear program, and eliminating the need for unit commitment.

The lack of unit commitment in the model could produce a negative bias to the results. A unit commitment model can incorporate additional constraints that an economic dispatch model cannot. Mainly these are a minimum generation limit for each unit and start-up constraints. There would be a significant bias to the BA consolidation results only when these constraints bind in the individual BA solutions but are resolved in the CBA's solution. This is most likely to occur when large amounts of wind push thermal units off-line or to their minimum generation limits. Given the amount of wind integrated in this study, it is likely that this bias is not large. At a higher penetration of wind, this bias would be significant and a unit commitment model would be required.

Hourly Time Interval

Some grid operators are moving towards intra-hourly dispatch to support wind integration, such as MISO. While modeling intra-hourly dispatch could provide further insights about the benefits of balancing area consolidation, we are limited by data availability, as most BAs do not report load at higher sample rates. In addition, MISO and other markets currently require that bids for energy or frequency regulation be valid for the entire hour. As a result modeling intra-hourly dispatch would not result in sub-hourly economic effects in an average hour.

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