Geographical Averaging and Ancillary Services for Stochastic Power Generation

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Abstract*—The distribution of stochastic generation from renewables across different geographical locations can, in certain cases, help to mitigate the inherent variability in output. This variability of generation from renewables may 1) increase the operating costs of the conventional generators used to follow the net load not supplied by stochastic capacity and 2) increase the amount of reserve conventional generating capacity needed to maintain Operating Reliability. In this scenario, customers have lower wholesale prices, due to reductions in the total annual generation from fossil fuels, while generators face higher operating costs for conventional generators caused by additional ramping that partly offset the customer benefits. However, the lower wholesale prices ($/MWh) imply lower annual earnings for conventional generators that lead to higher amounts of missing money ($/MW) needed to maintain the financial adequacy of installed generating units. The objective of this paper is to determine how variability from a stochastic generation resource affects the optimal hour-to-hour dispatch of generating units and the corresponding operating costs and wholesale prices. The results show that the inclusion of ramping costs for conventional generation affect the amount of energy dispatched from the stochastic generator, and the total costs composition observed in the system. The Cornell SuperOPF[1] is used to illustrate how the operating costs and wholesale prices can be determined for a reliable network (the amount of conventional generating capacity needed to maintain Operating Reliability is determined endogenously). The results in this paper use a typical daily pattern of load and capture the cost of ramping by including additions to the operating costs of the generating units associated with the hour-to-hour changes in their optimal dispatch. The calculations for determining endogenous up and down reserves are included, and the wind generation cost is assumed to be zero. Additionally, the maximum and minimum available capacities for all hours in the day are constrained to the optimal capacities for the hours with the highest and the lowest loads. Different scenarios are evaluated for a given hourly realization of wind speeds using specified amounts of installed wind capacity with and without ramping costs. The analysis also evaluates the effects of eliminating network constraints, as well as the elimination of wind variability by accounting for the effects of spatial aggregation of different wind locations.

I. Introduction

The main objective of this paper is to evaluate how the ramping costs incurred when levels of wind generation change from hour to hour affect the optimum dispatch of generators, the total operating costs (i.e. fuel and Operation and Maintenance -O&M) and the average nodal prices paid by customers. The analysis uses the SuperOPF to solve for the optimum dispatch for each hour in a representative day to minimize expected costs (operating plus ramping costs) for different scenarios. An important feature of the SuperOPF is that the optimum levels of reserves are determined endogenously and respond to changes in the system such as the additional variability of wind generation. This paper is structured as follows. The next section discusses a brief overview of Reliability Standards, the structure of the SuperOPF and how it differs from a conventional optimization that minimizes costs subject to maintaining reliability standards. Sections III and IV discuss the modeling of the problem and the specification of the different scenarios, and Sections V-VII present the results. The final section summarizes the conclusions.

II. NERC Reliability Standards and the SuperOPF

The North-American Electric Reliability Corporation, NERC, has been given the responsibility to set the standards for reliability for the North American Bulk Power Network. NERC uses the following two concepts to evaluate the reliability of the bulk electric supply system [1]:

1) *Adequacy - The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.*
2) *Operating Reliability - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.*

The traditional NERC standard of one day in ten years for the Loss of Load Expectation (LOLE) is still treated by many regulators as the appropriate measure for the reliability of the bulk transmission system. While the time horizon for Resource Adequacy involves long term planning, with many sources of stochastic uncertainty (e.g. equipment servicing, demand growth, emergency operating procedures), and special emphasis on generation expansion, for Operating Reliability the time horizon is much shorter. This shorter horizon allows

[1]A stochastic contingency-based security constrained AC OPF with endogenous reserves, co-optimizing dispatch with a set of credible contingencies.

to have better observability of factors that affect operation, and hence less inherent uncertainty. The $n-1$ standard is a commonly accepted measure for Operating Reliability.

In a standard Security Constrained Optimal Power Flow (SCOPF), the objective is to minimize the cost of meeting load, and at the same time, be able to respond to the $(n-1)$ contingencies. Covering the contingencies is treated as a set of physical constraints on the optimization. Chen et al. [2] have proposed an alternative way to determine the optimal dispatch and nodal prices in an energy-reserve market using co-optimization (CO-OPT). The proposed objective function minimizes the total expected cost (the combined production costs of energy and reserves) for a base case (intact system) and a specified set of credible contingencies (line-out, unit-lost, and high load) with their corresponding probabilities of occurring. Using CO-OPT, the optimal pattern of reserves is determined endogenously and it adjusts to changes in the physical and market conditions of the network. For example, the amount of reserves needed typically increases after the addition of an intermittent source of generation from a wind farm. This framework corresponds to using a conventional $n-1$ contingency criterion to maintain Operating Reliability. In practice, the number of contingencies that affect the optimal dispatch is much smaller than the total number of contingencies. In other words, by covering a relatively small subset of critical contingencies, all of the remaining contingencies in the set can be covered without shedding load.

III. General Problem Formulation

The problem considered extends the CO-OPT framework to include the cost of Load-Not-Served (LNS), and also distinguishes between positive and negative reserves for both real and reactive power. In this SuperOPF framework ([3]-[5]), a high Value Of Lost Load (VOLL) is specified as the price of LNS. In a conventional SCOPF used by most System Operators, the $n-1$ contingencies are treated as hard constraints rather than as economic constraints as they are in the SuperOPF.[2] From an economic planners perspective, the standard of one day in ten years for the LOLE should correspond to equating a reduction in the expected annual cost of operating the system, including changes in the expected cost of LNS, with the annual cost of making an investment in additional capacity.

The formulation of the problem looks at a two settlement market, with a period ahead contracting and a redispatching in real time. In the first stage (e.g. hour-ahead), the dispatches for the next time period $(t+1)$ were determined by solving the SuperOPF with endogenous reserves and the best available wind forecast. In the second stage (real-time), the wind realization is known and, using this new information, the dispatches for the present time period $(t+1)$ were determined by solving a SuperOPF with reserves determined from the results of the first stage. The outputs of each hour were interlinked, by setting the second-stage dispatches for hour t as the initial conditions for the dispatch in hour $t+1$. The process is then repeated for the next period of time. A simplified formulation of the problem is shown in (1).

$$\min_{G_{ik},R_{ik},\mathrm{LNS}_{jk}} \sum_{k=0}^{n_c} p_k \Bigg\{ \sum_{i=1}^{I} \Bigg[C_{G_i}(G_{ik}) + \mathrm{R}_i^{+}(G_{ik}-G_{t-1,i0})^{+} + \mathrm{R}_i^{-}(G_{t-1,i0}-G_{ik})^{+} \Bigg] + \sum_{j=1}^{J} \mathrm{VOLL}_j \mathrm{LNS}(G_k,R_k)_{jk} \Bigg\} + \sum_{i=1}^{I} [C_{R_i}(R_i^{+}) + C_{R_i}(R_i^{-})] \tag{1}$$

Subject to meeting Load and all of the nonlinear AC constraints of the network.

TABLE I
Definition of Variables, simplified Formulation

$k=0,1,\ldots,n_c$	Contingencies in the system
$i=0,1,\ldots,I$	Generators
$j=0,1,\ldots,J$	Loads
p_k	Probability of contingency k occurring
G_i	Quantity of apparent power generated (MVA)
$C_G(G_i)$	Cost of generating G_i MVA of apparent power
$\mathrm{R}_i^{+}(G_{ik}-G_{t-1,i0})^{+}$	Cost of increasing generation from previous hour
$\mathrm{R}_i^{-}(G_{i0}-G_{t-1,ik})^{+}$	Cost of decreasing generation from previous hour
VOLL_j	Value of Lost Load, ($)
$\mathrm{LNS}(G,R)_{jk}$	Load Not Served (MWh)
$R_i^{+} < \mathrm{Ramp}_i$	$(max(G_{ik})-G_{i0}))^{+}$, up reserves quantity (MW)
$C_R(R_i^{+})$	Cost of providing R_i^{+} MW of upward reserves
$R_i^{-} < \mathrm{Ramp}_i$	$(G_{i0}-min(G_{ik})^{+}$, down reserves quantity (MW)
$C_R(R_i^{-})$	Cost of providing R_i^{-} MW of downward reserves

Focusing on the active power procurement problem, the AC constraints of the system include:

1) Equality constraints, consisting of the set of non linear power balance equations for real and reactive power for each generator.

$$g_P^k(\theta^k, V^k, P^k, Q^k) = 0, \quad k = 0 \ldots n_c \tag{2}$$
$$g_Q^k(\theta^k, V^k, P^k, Q^k) = 0, \quad k = 0 \ldots n_c \tag{3}$$

2) Standard Inequality constraints, consisting of the set of branch flow limits as non-linear functions of the bus voltage angles and magnitudes.

$$h_f^k(\theta^k, V^k, P^k, Q^k) \le 0, \quad k = 0 \ldots n_c \tag{4}$$
$$h_t^k(\theta^k, V^k, P^k, Q^k) \le 0, \quad k = 0 \ldots n_c \tag{5}$$

3) Additional Inequality constraints, consisting of:
   a) Upward and downward deviations from the contracted power in the previous period and the power dispatches in each contingency according to ramping capability of the unit:

$$p_{ik} - \hat{p}_{t-1,i} \le p_{ik}^{+}, \forall i,k \tag{6}$$
$$\hat{p}_{t-1,i} - p_{ik} \le p_{ik}^{-}, \forall i,k \tag{7}$$

[2] A hard constraint is equivalent to specifying the VOLL as plus infinity.

b) Upward and downward ramping capability according to reserves contracted:

$$p^{+}_{ik} \leq \hat{r}^{+}_{Pi} \quad \forall i, k \tag{8}$$

$$p^{-}_{ik} \leq \hat{r}^{-}_{Pi}, \quad \forall i, k \tag{9}$$

c) Upward and downward deviations from the base case in the current period and the power dispatches in each contingency according to ramping capability of the unit

$$\begin{array}{l} -\Delta^{-}_{Pi} \leq p_{ik} - p_{i0} \leq \Delta^{+}_{Pi} \\ -\Delta^{-}_{Qi} \leq q_{ik} - q_{i0} \leq \Delta^{+}_{Qi} \end{array} \quad \forall i, \quad k = 1 \dots n_c, \tag{10}$$

Any deviations above or below the previous hour dispatch were priced according to the ability of generators to move from their current operating point. This information is exogenous. Generators are compensated in the real time settlement for deviations on their contracts, once the uncertainty from the stochastic resources has been cleared. Operating reserves on the other hand are contracted in the day-ahead market.

In addition, limits on the maximum and minimum power output at any hour of the day were imposed per generator unit. To set these limits, the SuperOPF with endogenous reserves was solved for the following two cases: 1) For estimating the maximum power available at any hour, the power output observed at the maximum load of the day with a low wind forecast, was used.[3] 2) For the minimum power output, the minimum load of the day with a high wind forecast was used. The high wind forecast scenario is very challenging for System Operators, given the high probability of cutoff to protect the integrity of the equipment at high wind speeds,[4] leading to either very high generation outputs or none at all.

The steady state conditions were obtained by running the test system simulation over three identical days. After running the simulations, the differences in the dispatches, voltages, etc. between the corresponding hours in days two and three were close to 1×10^{-4}.

The basic objective of this analysis is to determine how ramping costs affect the optimum daily pattern of dispatch and the corresponding nodal prices. This includes analyzing the effects of conventional generators ramping for load following. Therefore the time steps used were hourly. While there is ramping done in shorter time steps, these are more associated to provision of services different to load following, and as such are a different product with an associated price (e.g. frequency regulation). Since wind generation is inherently variable, different network and wind specifications are considered.

IV. The Case Study Setup and Scenarios

This case study is based on a 30-bus test network that has been used extensively in our research to test the performance of different market designs using the MATPOWER platform. The one-line-diagram of this network is shown in Fig. 1. The 30 nodes and the 39 available lines are numbered in Fig 1 and this numbering scheme provides the key to identifying the locations of the specific contingencies described in the discussion to follow; the six generators are identified with their respective capacities. The network is divided into three regions, (Areas 1 - 3); Area 1 represents an urban load center with a large load, a high VOLL and expensive sources of local generation from Generators 1 and 2. The other two areas are rural with relatively small loads, low VOLLs and relatively inexpensive sources of generation from Generators 3 - 6. Consequently, an economically efficient dispatch uses the inexpensive generation in Areas 2 and 3 to cover the local loads and as much of the loads in Area 1 as possible.

A. The Test Network

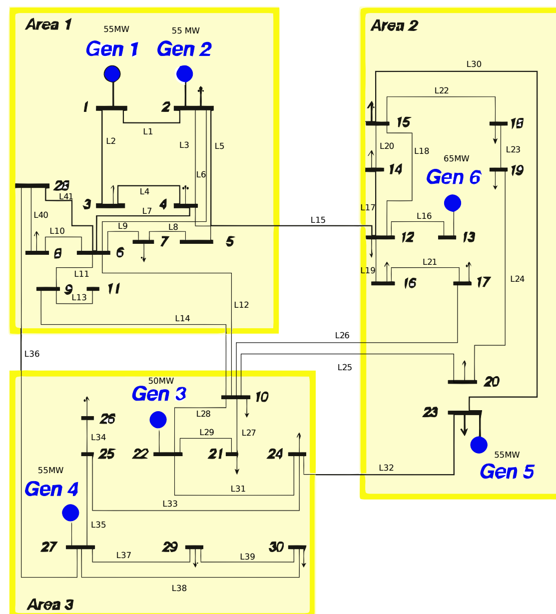

Fig. 1. A One-Line-Diagram of the 30-Bus Test Network.

The capacities of the transmission tie lines linking Areas 2 and 3 with Area 1 (Lines 12, 14, 15 and 36) are the limiting factors. Since lines and generators may fail in contingencies, the generators in Area 1 are primarily needed to provide reserve capacity. The general structure of the network poses a problem which can be likened to the situation faced by the system operators and planners in areas with high urban concentration and remote cheap sources of generation. In this case, most of the load is in the Urban center (Area 1) and the inexpensive sources of baseload capacity (hydro, coal and nuclear) are located in rural areas (Areas 2 and 3)[6].

B. Characterization of Wind Generation and Load

The load profile chosen corresponds to a day in April 2005 (Fig. 2), where no large changes in the loads observed hour to hour occur, and the average load level of the day is relatively low. The main criterion for selecting a day was to have an example in which the system is not under stress because of

[3] This scenario requires other generators to ramp up to compensate for the low output from the wind farms.

[4] The cutoff speed is around 25 m/s.

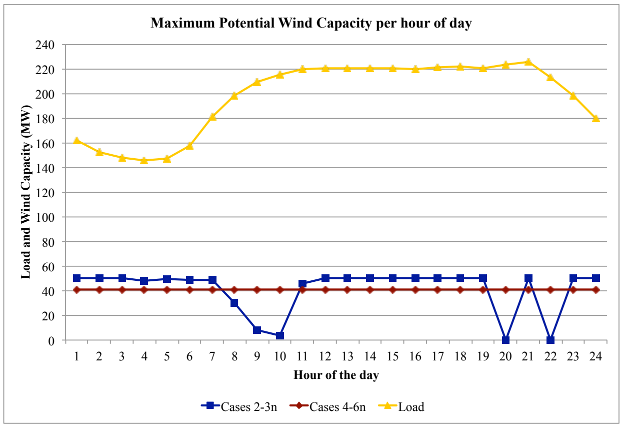

Fig. 2. Potential Usable Wind Capacity over a day for all cases.

lack of conventional generation capacity. The corresponding hourly predictions of wind speed from an ARMA model[5] were used to establish the forecasts that planners would have had hour-to-hour given the available information at the time. Finally, the historical data for that day provided the realizations of wind speed observed and the power available from the wind farm.

C. Cases studied

The following six cases were considered.

1) No wind; with a 35 MW coal unit installed at bus 13.
2) Baseline: A wind farm with a capacity of 50 MW is added at bus 13, with zero offer price in the wholesale market. The wind farm installed capacity is around 12% of the installed generation capacity in the system. The coal capacity installed at bus 13 remains unmodified.
3) No Network: Similar to case 2, eliminating the resistance for all lines, as well as setting all transmission line ratings[6] to zero.
4) Constant wind: Similar to case 2, with a constant potential power output. This represents the net effect of coupling storage or batteries to the wind generator.[7]
5) Distributed Wind: Geographically distributed wind in two areas of the system (bus 13 and bus 27), with output in one location compensated by output in the other location, achieving a constant potential power output. The capacity of each wind generator is 25MW, to maintain a comparable total wind capacity. This is equivalent to the effect of geographical averaging [9].
6) Distributed Constant Wind: Similar to case 5, with both locations having a constant power output. As with case four, this case represents the effect of coupling storage to both of the wind generators. The six cases are run with and without the cost of ramping for different types of units.

Table II contains a summary of the generation characteristics used. The classification of the ramping over a daily cycle

TABLE II
RAMPING AND RESERVE COSTS

		Fuel Cost ($/MW)	Gen. Avail (MW)	Res. Cost ($/MW)	Ramp Cost ($ $\cdot t$/MW)
Oil	(p)	95	65	10	0
GCT	(p)	80	45	10	0
CC Gas	(s)	55	40	20	30
NHR	(s)	5	65	20	30
Coal	(b)	25	70	30	60
NHR	(b)	5	50	30	60

is indicated in parenthesis next to each fuel type (peak (p), shoulder (s) or baseload (b)). The ramping costs assigned match the aforementioned classification (p, s, b), reflecting the generators' capability to move from their current operating point.[8] The contingencies considered include line outages in the urban area, line outages between the urban area and the rural areas, full outage of generation at a given bus and different realizations of wind speed conditional on a given forecast. Analyzing the impact of ramping costs requires looking at three main components: 1) The hour-to-hour changes in the system load. 2) The cost of covering the contingencies to maintain Operating Reliability, and 3) The accommodation of wind variability in the system. All three of these factors are considered in the evaluation of the different cases.[9]

V. RESULTS FOR THE WHOLESALE MARKET

The results presented in this section summarize the economic costs of covering the same daily pattern of load in the twelve different scenarios discussed in the previous section for the network shown in Fig. 1. For this analysis, it is assumed that the wholesale market is deregulated. The main questions of interest in this section are: 1) how much generating capacity is needed for Operating Reliability. 2) what happens to the wholesale prices and operating costs, and 3) how ramping costs affect operations and costs.

The reported daily costs for each scenario are the sums over 24 hours of the expected costs using the second-stage optimization of the SuperOPF.[10] The key results for the twelve scenarios are presented in Table III. The Load Paid shows that the total daily payments made by customers in the wholesale market in all wind scenarios are substantially lower than the NO Wind scenario (Case 1). These cost reductions represent the displacement of fossil fuels by wind generation whenever

[5]The ARMA model was developed with hourly wind speed data from New England, the methodology for this modeling is described in [7]

[6]Long term, short term and emergency ratings.

[7]The constant potential output means that available power at any point of time is the same. This type of smoothing also occurs with spatial aggregation of the total generation from wind farms at different locations [8]. However, there may be dispatches below the potential wind output because the available wind energy is not forced into the system.

[8]Besides the operating constraints, environmental concerns also play a role in the optimal price to be set for each unit. The ramping costs used in the case study take into account the considerations from [10] regarding the consequences of ramping for CO_2 and NO_x emissions.

[9]It should be noted that the variability of wind generation is not the only factor that affects ramping costs.

[10]In other words, the expected costs are computed for the 18 different contingencies for a given wind realization.

the wind blows. The generally lower wholesale payments with wind generation in Table III contrast with the amounts of conventional generating capacity needed to maintain Operating Reliability (Gen.Cap). The underlying reason for the contrast between Case 4 and the other two wind cases is that the variability of wind generation in Cases 2 and 3 increases the size of the cutout contingency at high wind speeds. The total amount of energy dispatched over the day is roughly the same in Cases 1, 2 and 4 to 6, and the 2% reduction observed with wind and no network (Case 3) reflects the lower network losses when transmission is unconstrained. The expected amounts of Load Not Served (LNS) are very small all four cases, and if LNS is greater than zero, the load shedding only occurs when some contingencies are realized. One would expect that eliminating ramping costs would reduce wholesale payments and increase the use of available wind generation. Although wholesale payments are substantially lower in Cases 1n and 3n compared to Cases 1 and 3, there is essentially no reduction in Cases 2n and 4n compared to Cases 2 and 4, and mild reductions in Cases 5n and 6n compared to Cases 5 and 6.[11] This apparent paradox will be explained later in the discussion of Fig. 5 but it should be noted that the objective criterion for the SuperOPF is to minimize the total operating costs. This criterion does not imply that wholesale payments are minimized.

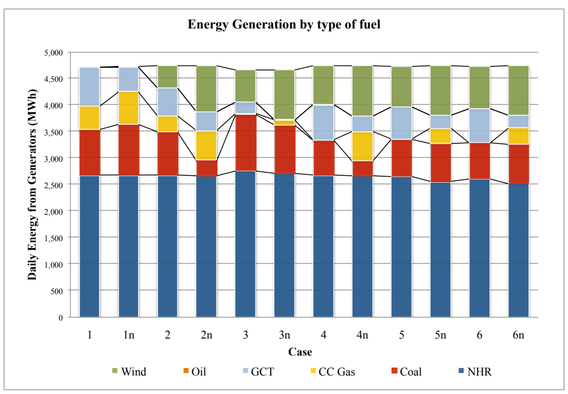

Fig. 3. The Composition of Generation by Fuel Type.

The amounts of wind generation dispatched are more consistent with expectations and in all cases they increase when ramping costs are eliminated. The distribution of capacity in different locations of the system allows for higher amounts of wind dispatched, reaching levels up to 88% higher (Case 6) than those observed in the base wind case (Case 2) with the same capacity, and providing positive evidence to the hypothesis that geographical distribution of stochastic resources allows for better use of these resources in terms of capacity. The differences in the optimum daily patterns of dispatch by type of generator are shown in Fig. 3. The total generation from baseload units (Nuclear, Hydroelectric, Refuse -NHR) is essentially the same in all cases[12] but there are major differences in the other sources.

Adding wind in Case 2 reduces the generation by Combined Cycle Gas (CC Gas) compared to Case 1. With wind and no network (Case 3), more wind and increased coal displace CC Gas and Gas Combustion Turbines (GCT).[13] With constant wind (Case 4), Distributed negatively correlated wind (Case 5) and Distributed constant wind (Case 6), compared to Case 2, more wind displaces CC Gas and coal. By removing the ramping costs with NO Wind (Case 1 to Case 1n), CC Gas displaces GCT. Eliminating ramping costs with wind (Case 2 to 2n) increases the dispatch from wind and CC Gas and reduces the dispatch from GCT and coal. The same type of comparison with wind and no network (Case 3 to 3n) shows that additional wind displaces mainly coal, and with constant wind (Case 4 to 4n), additional wind and CC Gas displaces GCT and coal. In the cases with distribution of the wind capacity installed, removing the ramping costs leads to fuel compositions favoring marginal use of wind and adoption of CC Gas as well as the lowest usage of NHR capacity across the board. The underlying reason is that the location of wind and subsequent higher usage requires support from the coal generators, that therefore replace away NHR.

Utilization of Wind Capacity

Accommodating wind generation in a network depends on the prevalent conditions and constraints imposed from other generators, as well as flows within the system. The amount of wind dispatched as a percentage of the maximum available,

[11] Around 15%, supported by the location of wind in different areas of the system.

[12] With the exception of the distributed wind cases, in which NHR is replaced away by wind, though in a small scale

[13] Removing transmission constraints makes it possible to move closer to a merit order dispatch by importing more inexpensive generation into Area 1.

TABLE III
SUMMARY OF KEY RESULTS

	1	1n	2	2n	3	3n	4	4n	5	5n	6	6n
Load Paid ($1,000/day)	336	289	242	242	251	128	231	228	268	228	269	227
Generation Capacity Needed (MW)	224	224	255	273	271	271	225	225	230	230	224	225
Energy Needed to cover load of day (MWh)	4,713	4,718	4,741	4,738	4,666	4,671	4,734	4,746	4,728	4,744	4,730	4,745
Wind Energy Dispatched (MWh)	0	0	428	870	612	953	734	966	773	934	807	946
Conventional Generation (%)	100	100	91	82	87	80	84	80	84	80	83	80
Load Not Served	7	7	0	7	7	0	7	7	7	7	7	7
Wind used as % of available wind Energy	NA	NA	43	88	62	96	74	98	79	95	82	96

* 50MW of Wind capacity installed, calculations over 24 hours.

can vary greatly depending on wind penetration and costs in the system. This is a challenging task given the uncertainties in wind speed realizations. The data used for this case study corresponds to a period in April when the wind speeds were very high,[14] and this makes the effects of wind variability larger than they would be under average wind conditions.

The third part of the analysis considers the wind usage in the system for cases with ramping costs. In determining the optimum amount of wind dispatched, it is important to determine the potential amount of wind generation that is available. Fig. 4 illustrates the observed results. The elimination of network constraints (Cases 3 and 3n) increases the average amounts of wind dispatched compared to the corresponding baseline cases (Cases 2 and 2n, Fig. 4) because it allows for a merit order dispatch of the units according to marginal costs, as most economic literature model. This allows all dispatchable generation to adjust in order to accommodate the variability of wind. In the simulations done, the coupling of an energy storage system (ESS) to wind generation (Cases 4, 4n, 6 and 6n) exhibit higher average dispatch at three quarters of the available wind capacity, and potential generation in excess of 80% of the installed capacity. Use of negatively correlated wind in different locations (Cases 5 and 5n) yields results intermediate between those aforementioned, consistent with the findings shown in Table III.

As expected, ESS coupling and geographical distribution of wind allow for ever higher average wind utilization (moving from Case 4 to Case 5 to Case 6). But additionally, including ramping costs in the minimization problem directly affects the Maximum Actual dispatches of wind observed. In Case 2 (baseline Wind), the maximum dispatch observed is 62% of the maximum potential wind, while in Case 4 (Constant Potential Wind) this ratio is 95%. The reason for this apparent waste of zero-cost wind is due to the penalization imposed in the event that a wind cutout occurs. In such a case, the other generating units have to quickly adjust their dispatches, therefore incurring the cost of ramping up or down. The probability of the low wind realization contingency ranges between 14% and 24%, which understandably reduces the maximum wind committed at any hour of the day. In Case 3 (No Network), though the ramping cost is included, the elimination of network constraints allows for better accommodation of the stochastic resource.

VI. Payments in the Wholesale Market

The overall composition of costs in the wholesale market for the different scenarios are summarized in Fig. 5. For NO Wind in Case 1, the total cost to customers is relatively high and most of this total is Net Revenue for the conventional generators above their true operating costs. The Operating Costs make up about 35% of the total payments. A small share of the payments in Case 1 goes to Congestion Rents.[15]

[14]Here we have the benefit of hindsight to observe the realizations of wind output.

[15]The difference between the payments by customers and the payments to generators.

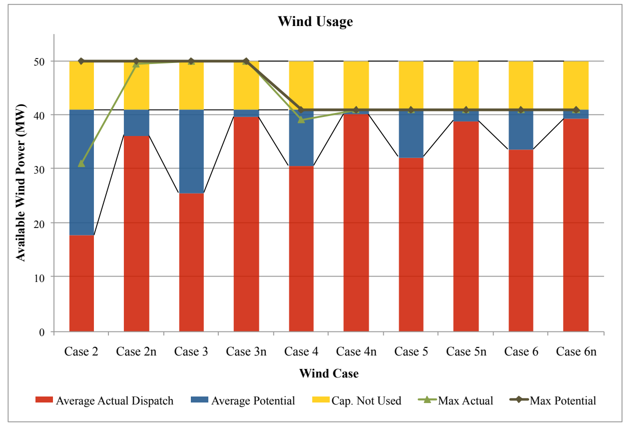

Fig. 4. The Wind Utilizations Observed.

Removing ramping costs in Case 1n decreases the Generators Net Revenue and increases the size of the Congestion Rents.

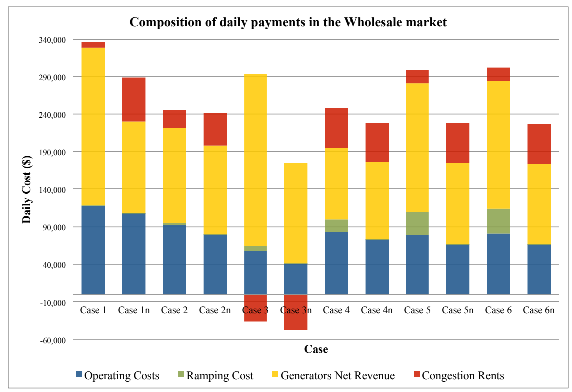

Fig. 5. The Composition of Payments by Customers in the Wholesale Market.

By adding wind, the Operating Costs are reduced slightly due to dispatching more of the zero-cost resource. In Case 3, the Operating Costs are even lower due to dispatching more wind generation and removal of the network constraints. With constant wind, the Operating Costs are lower than Cases 2 and 2n but higher than they are in Cases 3 and 3n. In terms of measuring the system benefits, the cases with wind and no network (Cases 3 and 3n) contribute the most to system benefits even though the total costs to customers do not reflect this. For most of the wind scenarios, the total payments drop substantially compared to NO Wind, and most of the reductions come from much lower Net Revenues for the conventional generators. However, Cases 3 (No Network), 5 and 6 have higher Net Revenue for generators. In Case 3, this is driven by homogeneous prices in the system due to the lack of network, therefore driving up the locational marginal prices (LMP) in cheap generation locations. In cases 5 and 6, the distribution of wind generations resources allows for higher wind usages and achieves lower operating costs than those observed in a single wind location with ESS (Case 4). However, it requires more backup generators ready to support the contingency of an outage, which drives up the LMP and therefore the generators Net Revenue for the cases in which ramping costs are considered. As expected, removing ramping costs (Cases 5n and 6n) leads to lower operating costs than those observed in a single location with ESS (Case 4).

The Congestion Rents and the Net Generators Revenue are the pool of financial resources available to cover the capital costs incurred by the transmission owners and generators, respectively. In cases where the Congestion Rents are negative, corresponding to instances when the Independent System Operator (ISO) pays more to generators than the amount they receive from customers, the amount of missing money for transmission owners is larger.

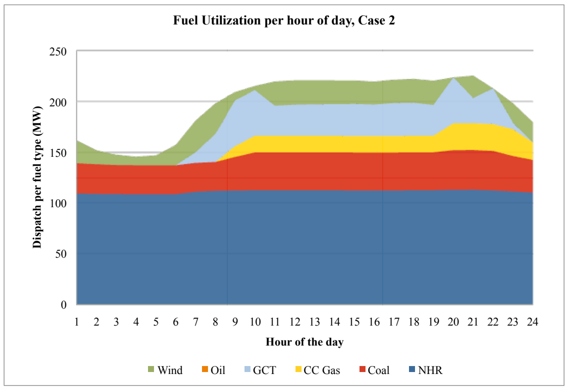

Fig. 6. The Composition of Generation observed in Case 2, baseline Wind.

VII. Wind and Ramping costs in a daily cycle

Given the daily pattern of load and the variability of wind, changes in the composition of fuel types used for generation to meet load are needed; Fig. 6 shows the implications for Case 2. With the exception of two hours in which the output from the wind farm is zero due to very high wind speeds, the wind resource is highly utilized, displacing generation from the conventional generators. This happens at all hours of the day and is consistent with a least-cost merit order dispatch. The variability of wind dispatch is mitigated by GCT.

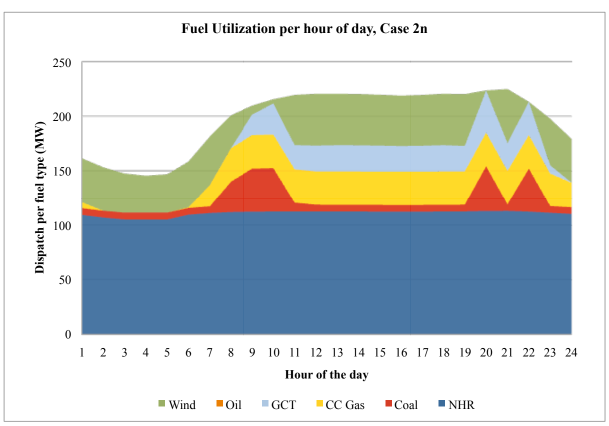

Fig. 7. The Composition of Generation overs a day in Case 2n, Wind without ramping costs.

By eliminating the ramping costs (Case 2n, Fig. 7), the wind utilization at all hours of the day increases, mostly at the expense of load following units with penalties for ramping. This is a direct consequence of ignoring the high ramping cost of coal because it is now less expensive to use coal instead of GCT to mitigate wind variability. In addition, wind generation displaces coal at times of the day when the system loads are low (1AM to 5AM approximately). In Case 2, the ramping is done by GCT (0$/MW cost of ramping + 80$/MW cost of generation), while in Case 2n the ramping is done by coal (25$/MW cost of generation and the 60$/MW cost of ramping is ignored).

The corresponding average nodal prices in Areas 1, 2 and 3 are shown in Fig. 8 for Case 2 together with the amount of wind dispatched (measured on the right hand axis). When the system load is high during the day, the hourly prices in the urban center (Area 1) are the highest and the the prices in Area 2, where the wind farm is located, are the lowest. At night when the system load is low, wind generation can set the price in all three areas because network constraints are minimal. When wind generation drops to zero, the average prices in the three areas are all high and the price differences are small.

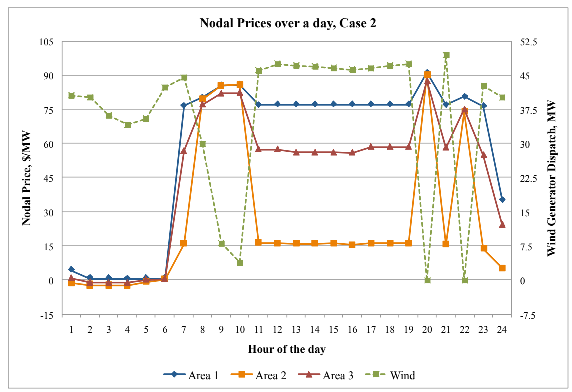

Fig. 8. Nodal Prices and Wind Dispatches in Case 2, Wind with ramping costs.

The availability of wind generation is one of the drivers for the costs observed and the generation mixes obtained. Accommodating wind generation in a network depends on the flows in the system, and the location of the wind generators, among other factors. In the study cases, the maximum real available capacity[16] can be categorized in two main groups: capacity from a single wind location with uncertain realizations and capacity from coupling with ESS systems/geographical averaging. These groups are identified in Fig. 2, showing how the the second group has a very different - and straightforward characterization. It changes the stochastic nature of wind to a constant availability, and allows for higher wind usage (Fig. 4).

However, higher wind usage does not necessarily mean

[16]Once uncertainty is removed, for the second stage of the optimization, real-time run.

higher benefits for consumers. As indicated by Fig. 5, the most effective mechanism to lower wholesale costs is by distributing wind generation. Recall, the objective criterion for the SuperOPF is to minimize the total operating costs. The real benefit to customers is to lower the total system cost, that includes the expected cost of operations, including ramping costs, Load Not Served and capital. Some of these costs are covered in other markets such as a capacity market.[17]

Therefore, although there are clear benefits in the increase of transmission capacity in the system, other consequences arise with the relief of congestion, like higher payments made by consumers. Policy makers should have these factors in mind for proposed planning and investment of transmission, especially given the intricacies of expanding the electric network.

VIII. Conclusions

This paper evaluates how ramping costs affect the optimum daily dispatch of the generating units used to meet a specified pattern of hourly loads and the corresponding effects on operating costs and nodal prices, focusing on the effects of introducing a variable source of wind generation to the generating mix. A representative day is specified with relatively high levels of potential wind generation and substantial variability from hour to hour caused in part by cutouts at high wind speeds. The results show that ramping costs have substantial effects on the amount of wind dispatched and the types of generator used to mitigate the variability of wind. In spite of this the total ramping costs are always relatively small compared to the other operating costs. The analysis uses the SuperOPF to minimize the expected cost of meeting load for a set of different states of the system that include generator and line outages as well as the uncertainty of the amount of wind generation.[18]

The underlying economic problem is to determine whether it is less expensive to mitigate wind variability using units that have high fuel costs and low ramping costs (e.g. combustion turbines) or units with low fuel costs and high ramping costs (e.g. baseload capacity).[19] The main results show that adding wind capacity to a network lowers the operating costs, as expected, because wind generation displaces generation from fossil fuels. If ramping costs are ignored, even more wind is dispatched and coal units rather than combustion turbines are the generators used to mitigate wind variability. However, the lower operating costs do not lead to an equivalent reduction of the nodal prices because the System Operator retains more of the payments made by customers (i.e. the congestion rents increase). From the perspective of determining the economic benefits for the system, reducing the sum of operating costs and ramping costs is the important criterion because the net earnings and the congestion rents are really transfers from customers to generators and transmission owners. These transfers are payments that partially cover the capital costs of installed capacity. Increases in these transfers are usually offset by reductions in the missing money needed to maintain financial adequacy.[20] Reducing the amount of conventional generating capacity needed to maintain System Adequacy is the other major way to increase system benefits. The lowest operating and ramping costs occur when the network constraints are removed. When the variability of wind is removed, the operating costs are higher because it is difficult to accommodate high levels of wind generation and meet all of the network constraints. The message for regulators is that ramping costs make a substantial difference in how the system operates, and the provision of ramping services should be rewarded in the same way that regulation is rewarded. For example, the owners of utility scale storage should expect to receive income for providing ramping services and for reducing the capacity contribution to meeting the peak system load. In addition, storage can be used to charge at night when prices are low and to discharge at higher prices during the day. It is likely that all three sources of income will be needed to make storage capacity financially viable for services other than regulation.

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[17] See [11] for a discussion of this issue

[18] The realized wind speed determines the maximum amount of generation from the wind turbines but some of this potential generation may be spilled in the optimum dispatch. In addition, cutouts occur to protect the turbines when the wind speed is above 25m/sec.

[19] Since the results are based on static hour-by-hour optimizations rather than a multi-period optimization for different hours, the specifications do not use tight physical constraints on the ramping of baseload units to limit their generation. Current research is developing a multi-period version of the SuperOPF that can solve a standard unit commitment problem.

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