

Integrating Wind Power: A Potential Role for Controllable Demand

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Abstract—With high penetrations of wind generation, it is likely that some potential power production from this source will be spilled unless the inherent variability of this source is mitigated in some way. Installing dedicated on-site storage or backup generators, for example, is one effective but expensive way to do this. Without some form of mitigation, some wind generation will be spilled even if its operating cost (i.e. the offer into the wholesale market) is zero. The two main reasons are 1) transmission congestion when demand is high limits the ability of the network to transfer available wind power to customers, and 2) limiting the size of wind contingencies (i.e. cutouts to protect turbines from damage at high wind speeds). Under these conditions, another way to reduce the amount of wind spilled is to use controllable demand to shift demand from peak to off-peak periods using thermal storage and electric vehicles, for example. Controllable demand can also be used to provide other ancillary services, like ramping services to offset fluctuations in wind generation. These demand technologies are likely to be more cost effective than dedicated equipment because a large part of their capital cost is already covered by their primary uses for space conditioning and transportation. Using the Cornell SuperOPF, operations on a test network are simulated for a typical day to compare the effects of 1) controllable load, 2) on-site storage, and 3) upgrading transmission capacity. The different scenarios are evaluated in terms of 1) the percentage of potential wind generation spilled, 2) the total operating cost of production, and 3) the amount of installed capacity needed to maintain operating reliability. The results show that controllable load improves (reduces) all three criteria by alleviating congestion and mitigating wind variability. In contrast, the beneficial effects are smaller for both on-site storage, because it does not shift load to off-peak periods, and for upgrading transmission, because it does not mitigate wind variability.

I. INTRODUCTION

Mitigating the variability of generation from renewable sources can be accomplished by installing storage capacity and/or controllable (dispatchable) loads. The objective of this paper is to evaluate how the ramping costs incurred in load following affect the optimal dispatches of a given generation fleet, and demonstrate how markets for electricity should be modified to provide the correct economic signals for compensating storage and controllable loads that reflect the true system costs/benefits of ramping services and reducing the capital cost of maintaining System Adequacy.

The next section discusses 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 specification of the different scenarios, and Sections V-VI present the results. The final section summarizes the conclusions.

II. THE SUPER OPF FOR RELIABILITY STANDARDS

To evaluate the reliability of the bulk electricity supply, The North-American Electric Reliability Corporation (NERC) uses the following two concepts[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 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.

In a standard Security Constrained Optimal Power Flow (SCOPF), the basic objective is to minimize the cost of meeting load, while being 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 the SuperOPF [3], the CO-OPT criterion is modified to include the cost of Load-Not-Served (LNS), also distinguishing between positive and negative reserves for both real and reactive power. 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. 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 objective of this study is to determine how a combination of geographical distribution of wind, load response, and ramping costs affect the patterns of dispatch and the payments in the wholesale market.

III. RAMPING COSTS AND LIMITS IMPOSED

To analyze the effects of conventional generators ramping for load following, the time steps used were hourly. While there is ramping done is 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).

For every hour, a two-stage optimization problem was solved. In the first stage (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 $t + 1$. Any deviations above or below the previous hour dispatch were priced according to the ability of generators to move from their current operating point. Therefore, a high ramping cost was set for generating units that have technical or operational constraints that make it expensive for them to adjust their power output¹. Correspondingly, for combustion turbines with lower adjustment costs, a price close to 0 was set.

In addition, limits on the maximum and minimum power output at any hour of the day were imposed per generator unit. The steady state conditions were obtained by running the test system simulation over three identical days. The test system stabilized very fast, and 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} .

IV. THE PROBLEM SETUP AND CASE STUDY SCENARIOS

This case study is based on a 30-bus test network (Figure 1) that has been used extensively in our research to test the performance of different market designs using the MATPOWER platform [6]. 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.

¹e.g. certain Nuclear units with limited ramping capabilities.

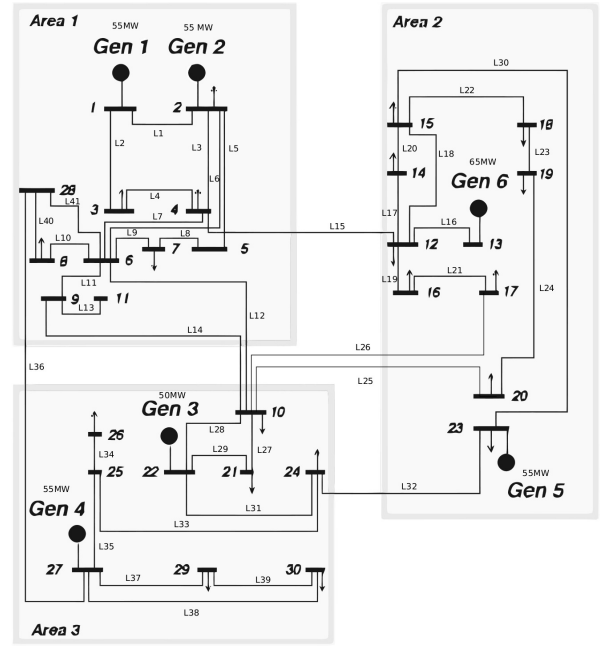


Fig. 1. A One-Line-Diagram of the 30-Bus Test Network.

A. Characterization of Wind Generation and Load

The load profile chosen corresponds to a day in April 2005 when there are no large changes in the loads observed hour to hour, and there is a relatively low average load level for the day. The main criterion for selecting a day was to have an example in which the system is not under stress because of lack of conventional generation capacity. Once this day was chosen, the corresponding hourly predictions of wind speed from an ARMA model were used to establish the forecasts that planners would have had hour-to-hour given the available information at the time. The ARMA model was developed with hourly wind speed data from New England. The methodology for this modeling is described in [7]. Finally, the historical data for that day provided the realizations of wind speed observed and the power available from the wind farm.

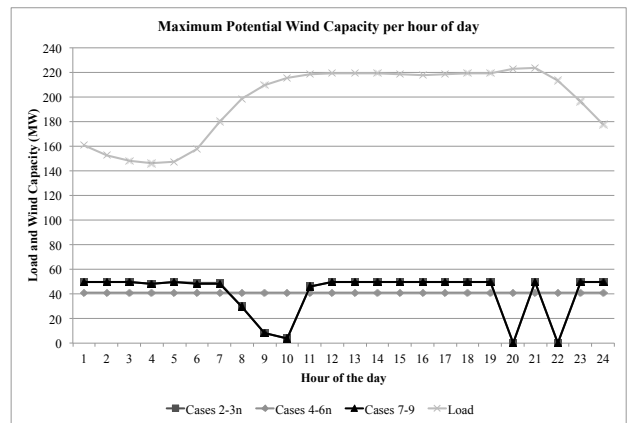


Fig. 2. Potential Usable Wind Capacity over a day for all cases.

B. Cases studied

The following cases were considered:

- 1) No wind; with a 35 MW coal unit installed at bus 13.
- 2) Baseline single location Wind: 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 Congestion: Similar to case 2, eliminating the resistance for all lines, as well as neglecting all transmission line ratings².
- 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 generator³.
- 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, but instead of negatively correlated wind, both locations have a constant power output. As with case 4 this case represents the effect of coupling storage to both of the wind generators.
- 7) Baseline Distributed Wind. Similar to case 5, but instead of negatively correlated wind, the wind forecast corresponds to historical data from New England, as in case 2.
- 8) Distributed Wind, Load Response: similar to case 7, with load compensating for periods in which no wind power is available.
- 9) Distributed Wind, Perfect Load Response: two sources of wind generation and a flat load over the day, corresponding to a case perfect of load response, eliminating arbitrage over the day.

All cases but Case 9 were run with and without the cost of ramping for different types of units. This allows one to compare the effect of ramping on wind adoption.

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. This implies that units with higher potential for pollution when changing their output are priced with ramping costs. Ideally, this would optimally discourage them from moving from their current operation point.

The contingencies considered include

- 1) Line outages in the urban area.

²Long term, short term and emergency ratings.

³The 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.

- 2) Line outages between the urban area and the rural areas.
- 3) Full outage of generation at a given bus.
- 4) 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.
- 3) The accommodation of wind variability in the system.

All three of these factors are considered in the evaluation of the different cases, and it should be noted that the variability of wind generation is not the only factor that affects ramping costs.

The set of contingencies considered both in the hour-ahead and in the real time stage was maintained constant for all hours of the simulated day.

C. Load Response and battery coupling

The characterization of Energy Storage Systems (ESS) for this study took into account charging and discharging over the horizon specified, which is reflected as a limited amount of wind capacity in the system. This allows for a basic modeling of storage in the system. Load response on the other hand was derived from the optimal results obtained from a case with and without ESS coupling in terms of wind usage. The differences found were then assigned as additional load in Area 1, with a VOLL just above the most expensive generation cost including ramping costs. This pricing reflects the “inconvenience cost” for customers at a higher price than fuel costs, in line with the compensation that is expected to make load response more widespread.

V. RESULTS FOR THE WHOLESALE MARKET

The results presented in this section summarize the economic costs of covering the same daily pattern of load for the scenarios above outlined, using a modified IEEE 30 bus case. 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 do ramping costs affect operations and costs?.

The first part of the analysis includes an overview of all the results obtained, contrasting the cases with and without ramping costs (the latter ones marked with ‘n’ at the end). The reported daily costs correspond to sums over 24 hours of the expected costs from the second stage optimization of the SuperOPF (i.e. expected costs over 18 contingencies for a given wind realization). The key results for the scenarios are presented in Table I.

The first row (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 the wind blows, and

at low loads, the expected generation from wind is the dominant source. Compared to NO Wind, the wholesale payments are 72% of this level with wind (Case 2), 75% with wind and no congestion (Case 3), 69% with constant wind (Case 4), 79% with distributed negatively correlated wind (Case 5), 80% with distributed constant wind (Case 6), 63% with distributed normal wind (Case 7) and 74% with distributed wind and load response (Case 8). Eliminating differences hour to hour in load (Case 9) allows for a better

The generally lower wholesale payments with wind generation in Table I contrast with the amounts of conventional generating capacity needed to maintain Operating Reliability (GCap). Compared to NO Wind, the capacity needed increases by 14% with wind (Case 2), by 21% with wind and no congestion (Case 3), 18% with distributed normal wind (Case 7) and 8% higher with distributed wind and load response (Case 8). The underlying reason for needing more capacity is that the wind speed for the particular day chosen drops to zero during a high load period.

For cases in which, either the wind resource is geographically distributed, or there is some mechanism to smooth out the wind output, the amount of conventional generation is close or identical to the no wind case (Cases 4, 5, and 6). The underlying reason for the contrast between Cases 4, 5 and 6 and the other two wind cases is that the variability of wind generation in Cases 2, 3 7 and 8 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 most Cases, and the reductions observed (1% for Case 3 and 2% for Case 8) reflect the lower network losses when transmission is unconstrained and the effect of load response respectively. The expected amounts of LNS are very small in all cases, and if $LNS > 0$, the load shedding occurs when some contingencies occur.

The amounts of wind generation dispatched are relatively consistent with expectations, and increases in wind usage are observed when 1) Wind is distributed in the system (Cases 5 and 7) or 2) the uncertainty of wind output is removed by use of an Energy Storage System (ESS) as modeled in the runs (Cases 4 and 6). Load response either in outages (Case 8) or

over the day (Case 9) decreases the overall amount of energy needed, and the amount of wind energy used in the system.

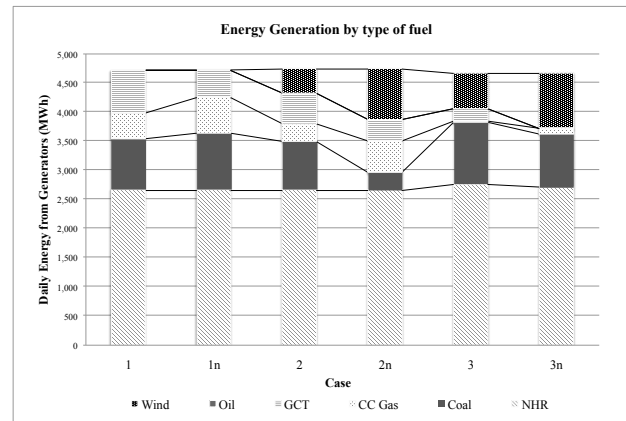


Fig. 3. Generation Composition by Fuel Type and Ramping Costs

The second part of this analysis compares the impact of adding ramping costs on amounts of wind dispatched (MWh) for three of the cases: No Wind, Normal Wind and No Congestion. The differences in the optimum daily patterns of dispatch by type of generator are shown in Figure 3. While the total generation from baseload units (Nuclear, Hydroelectric, Refuse -NHR-) is essentially the same in all cases, there are major differences in the other sources. Adding ramping costs with no wind (Case 1n) leaves the generation composition almost identical, with some increase in NHR and Coal at the expense of Combined Cycle Gas (CC Gas) and Gas Combustion Turbines (GCT), with lower costs. Adding wind in Case 2 reduces the generation by CCC Gas compared to Case 1. Removing ramping costs with wind (Case 2n) increases as expected the amount of Wind, at the expense of more expensive Coal Generation. With wind and no congestion (Case 3), more Wind and Coal displaces CC Gas and (GCT), and removing ramping costs leads to even higher usage of Wind and Coal⁴.

⁴Removing transmission constraints makes it possible to move closer to a merit order dispatch by importing more inexpensive generation into Area 1.

TABLE I
SUMMARY OF KEY RESULTS

	1	1n	2	2n	3	3n	4	4n	5	5n	6	6n	7	7n	8	8n	9
L.Paid ^a	336	289	242	242	251	128	231	228	268	228	269	227	214	232	248	223	188
GCap ^b	224	224	255	273	271	271	225	225	230	230	224	225	265	271	242	256	206
GEN ^c	4,713	4,718	4,741	4,738	4,666	4,671	4,734	4,746	4,728	4,744	4,730	4,745	4,738	4,739	4,631	4,658	4,528
M.WE ^d	0	0	428	870	612	953	734	966	773	934	807	946	586	865	641	865	754
C.Gn ^e	100	100	91	82	87	80	84	80	84	80	83	80	88	82	86	81	83
LNS	7	7	0	7	7	0	7	7	7	7	7	7	7	7	17	17	10
W.disp(%a)	NA	NA	43	88	62	96	74	98	79	95	82	96	60	90	65	88	77

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

^b \$1,000/day

^c Generation Capacity Needed (MW)

^d Energy Needed to cover load of day (MWh)

^e Wind Energy Dispatched (MWh)

^f Conventional Generation (%)

^g Load Not Served (Hours/day)

^h Wind used as % of available wind Energy

Figure 4 shows that the usage of load response, coupled with distributed wind resources allows for lower total energy usage (3% less energy required than in Case 1 (No Wind) and 4% than in the baseline wind (Case 2). The effect of placing wind

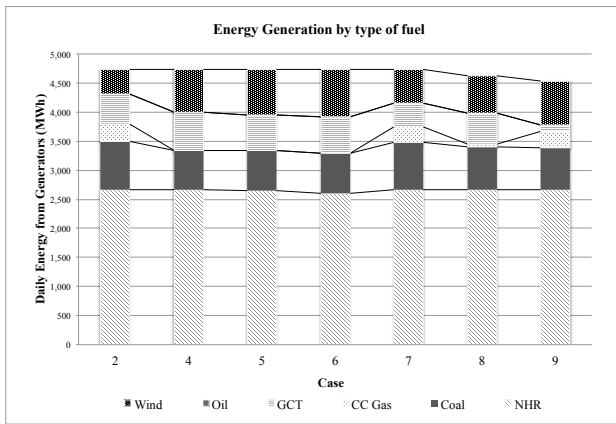


Fig. 4. The Composition of Generation by Fuel Type.

generation in locations with negatively correlated winds (Case 5) is similar to the modeling of ESS coupling in the system (Cases 4 and 6), not only in terms of the wind used, but also for the overall composition of generation for all fuels, with almost identical results. Furthermore, comparing Baseline Distributed Wind (Case 7) with the Baseline Wind (Case 2) isolates the effect of distributing wind with identical conditions. These two cases show the benefits in terms of increased wind usage, which in turn lead to monetary benefits for customers.

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. Figure 5 illustrates an expected result: ESS coupling and geographical distribution of wind allow for ever higher average wind utilization (moving from Case 4 to Case 5 to Case 6). Interestingly, load response decreases the average amount of wind generation used. This is due to load shedding observed when the load is increased to compensate for drops in the potential amount of wind generation. In the simulations, this drop in potential wind generation happens at peak load hours. This is, however, a characteristic of the specified simulation and is not typical. In many regions, high wind speeds tend to occur at night when loads are relatively low. In the case of a flat load over the day, the overall energy required is reduced thanks to congestion relief, but the amount of wind used also diminishes.

VI. WIND, RAMPING COSTS AND LOAD RESPONSE IN A DAILY CYCLE

The last part of the analysis examines the base case wind utilization over a full day for the base cases.

Figure 6 shows the generation mix in Case 2 (Baseline wind), for a historical daily pattern of load and wind variability. With the exception of two hours in which the output

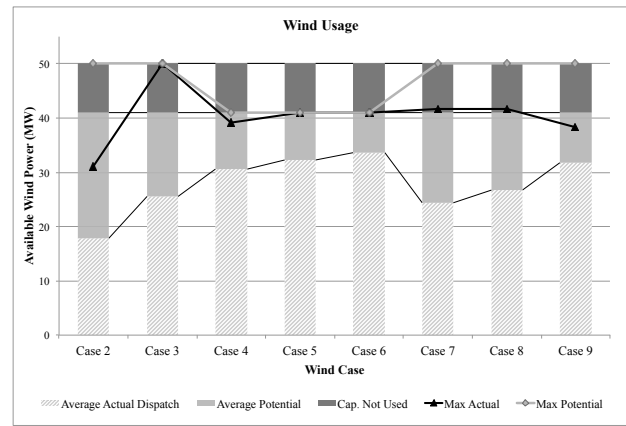


Fig. 5. The Wind Utilizations Observed.

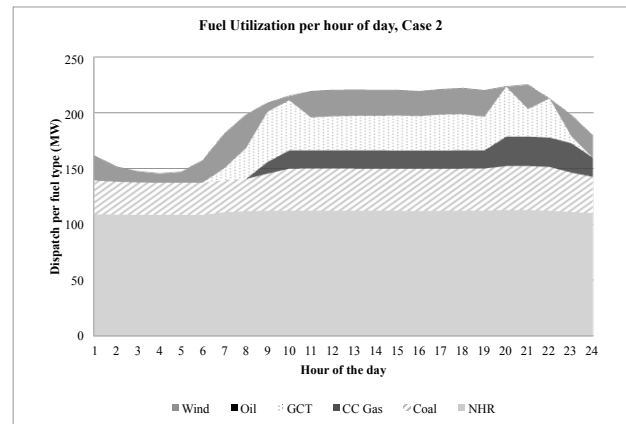


Fig. 6. The Composition of Generation overs a day in Case 2, baseline Wind.

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 ramping for load following and the variability of wind dispatch is mitigated by GCT and to a lesser degree CC Gas.

Figure 7 shows that geographical distribution and load response (Case 8) contribute to even higher wind penetrations⁵, with the patterns observed in Case 2 increased in terms of variability of wind and load following. Coal in both cases is almost constant, due to the high cost of moving it from the current operating point (Ramping Costs included in the simulation).

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, the location of the wind generators, and the ability of load to interact with load. In the study cases, the maximum real available capacity⁶ can be categorized in three main groups: capacity from a single wind location

⁵In the hours when available.

⁶Once uncertainty is removed, for the second stage of the optimization, real-time run.

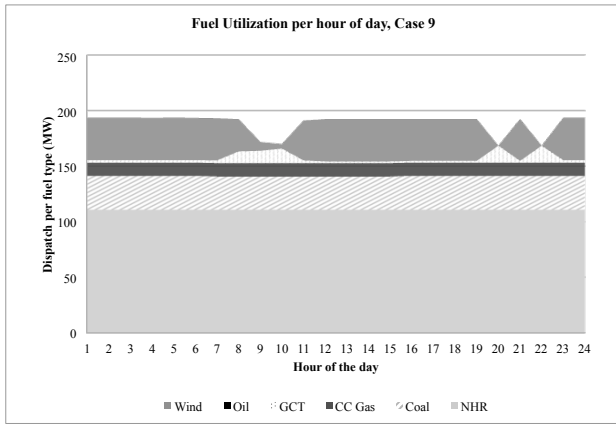


Fig. 7. The Composition of Generation overs a day in Case 9, Perfect Load Response

with uncertain realizations, capacity from coupling with ESS systems/geographical averaging, and capacity from multiple wind locations with uncertain realizations. While the first and third groups are similar enough to be undistinguishable in Figure 2, the group in the middle has a very different - and straightforward characterization. It changes the stochastic nature of wind to a constant availability, and allows for higher wind usage (Figure 5).

However, higher wind usage does not necessarily mean higher benefits for consumers. The real benefit to customers is to lower the total system cost, that includes the expected cost of operations, including ramping, Load Not Served and capital. Some of these costs are covered in other markets such as a capacity market.⁷

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.

⁷See [11] for a discussion of this issue.

VII. CONCLUSION

This paper evaluates different ways of mitigating the inherent variability of wind power by determining the optimum amount of conventional generating units committed to meet a specified pattern of hourly loads and the corresponding effects on the operating costs and capital costs. 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 and amounts of generating units used to mitigate the variability of wind generation. Consequently, there are also substantial effects on the total operating and capital costs. 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 actual amount of wind generation. The underlying economic problem is to determine whether it is less expensive to mitigate different levels of 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). 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 used to mitigate wind variability. However, the lower operating costs do not lead to an equivalent reduction of the total costs because lower operating costs may be associated with higher capital costs (i.e. more conventional generating capacity committed to meet reliability standards).

Table II shows a summary of the main characteristics of the key wind cases, summarizing the operating and capital costs for the important scenarios analyzed. The operating costs for a representative day are converted to the costs per MWh by dividing the cost shown in Table I by the number of MWh demanded in the day. The capital costs are computed by dividing the annual capital cost per MW using the costs for different types of capacity in [6] by 365 times the number of

TABLE II
SUMMARY OF KEY WIND CASES

	Case 1 <i>No Wind</i>	Case 2 <i>Normal W.</i>	Case 3 <i>Transm. W.</i>	Case 4 <i>ESS + Wind</i>	Case 9 <i>Load Resp. W.</i>
Conv. Capacity Committed <i>MW</i>	224	255	271	225	206
Wind Dispatched <i>% of Available Wind</i>	0	43	62	74	77
Operating Costs <i>\$/MWh</i>	23	19	12	17	12
Capital Cost <i>\$/MWh</i>	38	46	52	53	45
Total Operating+Capital Cost <i>\$/MWh</i>	61	65	64	70	57

MWh demanded in the day (this simplification is equivalent to assuming that the characteristics of the day analyzed are the same for every day during the year).

Using this procedure to evaluate the total cost/MWh, adding wind capacity (Case 2 compared to Case 1) increases the total cost/MWh because more conventional generating capacity is needed to deal with the variability of wind generation even though operating costs are lower. When the physical network constraints are removed (Case 3), the system is able to accommodate more wind generation but the lower operating costs lead to small reductions in total costs because even more conventional capacity is needed to guard against possible cutouts. When the amount of potential wind generation is held constant (Case 4), representing the effects of dedicated on-site storage capacity, more potential wind generation is dispatched but operating costs do not go decrease substantially from Case 2 because expensive conventional units are still dispatched when the system demand is high and the transmission network is congested. In contrast, controllable demand (Case 9) is able to mitigate the variability of wind generation like Case 4 but also to 1) reduce the total amount of conventional capacity committed because the daily load pattern is flattened, and 2) to reduce the dispatch of expensive conventional generating units by reducing the congestion on the network.

Although the implied superiority of controllable demand in this analysis is conditional on the specific empirical specification of the network and cannot be extrapolated to other specifications, it does indicate a potentially productive direction for future research. In many ways, the fundamental choice for mitigating the inherent variability of generation from renewable sources on the future electric grid is whether supply-side options like transmission upgrades and utility-scale storage are economically better than managing demand more effectively. It is likely that the optimum choice will be different in different situations. However, an important advantage of using controllable loads is that a large part of the capital cost of this option will be covered by other uses of the technology. For example, most of the cost of the batteries in electric vehicles is covered by providing transportation services and most of the cost of thermal storage is covered by providing space conditioning.

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