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Integration of Stochastic Power Generation, Geographical Averaging and Load Response

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INTEGRATION OF STOCHASTIC POWER GENERATION, GEOGRAPHICAL AVERAGING AND LOAD RESPONSE

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Abstract - The objective of this paper is to analyze how the variability of wind affects optimal dispatches and reserves in a daily optimization cycle. The Cornell SuperOPF¹ is used to illustrate how the system costs can be determined for a reliable network (the amount of conventional generating capacity needed to maintain System Adequacy is determined endogenously). Eight cases are studied to illustrate the effects of geographical distribution, ramping costs and load response to customers payment in the wholesale market, and the amount of potential wind generation that is dispatched. 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 proposed regulatory changes for electricity markets are 1) to establish a new market for ramping services, 2) to aggregate the loads of customers on a distribution network so that they can be represented as a single wholesale customer on the bulk-power transmission network and 3) to make use of controllable load and geographical distribution of wind to mitigate the variability of wind generation as an alternative to upgrading the capacity of the transmission network.

Keywords - SuperOPF, Ramping Product, Load Response, Geographical Averaging

1 Introduction

THE current political environment² and concerns about global warming have favored the increase in generation from renewable resources, such as wind and solar, with renewable portfolio standards (RPS) in place for many states in the US [2].

The inherent variability of generation from renewable sources may lead to increases in the operating costs of the conventional generators used to follow the net load not supplied from renewable sources³, as well as increase the amount of installed dispatchable generation capacity needed to maintain System Adequacy. Both of the aforementioned characteristics impose additional costs on the system that should be properly included by regulators. The higher operating costs for conventional generators are partly offset by lower wholesale prices, due to reduced total annual generation from fossil fuels, replaced by zero marginal cost power. Nevertheless, the lower wholesale

prices imply lower annual earnings for conventional generators that lead to higher amounts of “missing money” needed to maintain the Financial Adequacy of these generators [3]. The objective of this paper is to study 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 3 and 4 discuss the specification of the different scenarios, and Sections 5 and 6 present the results. The final section summarizes the conclusions.

2 The Super OPF for Reliability Standards

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 [4]: 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. In a standard Security Constrained Optimal Power Flow (SCOPF), the objective is to minimize the cost of meeting load, while being able to respond to the $(n - 1)$ contingencies. The covering of the contingencies is treated as a set of physical constraints on the optimization. An alternative way to determine the optimal dispatch and nodal prices in an energy-reserve market using co-optimization (CO-OPT) was proposed by Chen et al. [5]. 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 (e.g. line-outages, unit-lost, and high load levels) with their corresponding probabilities of occurring. Using CO-OPT, the optimal pattern of reserves is determined endogenously and it adjusts to changes in the phys-

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

²e.g. the *American Recovery and Reinvestment Act of 2009*.

³I.e. due to additional ramping costs

ical and market conditions of the network. The SuperOPF [1] extends the CO-OPT criterion 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 SuperOPF⁴. From an economic planners perspective, the standard of one day in ten years for the LOLE⁵ 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. A simplified formulation of the SuperOPF is shown in (1).

$$\begin{aligned} & \min_{G_{ik}, R_{ik}, \text{LNS}_{jk}} \sum_{k=0}^K p_k \left\{ \sum_{i=1}^I \left[C_{G_i}(G_{ik}) + R_i^+(G_{ik} - G_{i0}^{t-1})^+ \right. \right. \\ & \left. \left. + R_i^-(G_{i0}^{t-1} - G_{ik})^+ \right] + \sum_{j=1}^J \text{VOLL}_j \text{LNS}(G_k, R_k)_{jk} \right\} \\ & + \sum_{i=1}^I [C_{R_i}(R_i^+) + C_{R_i}(R_i^-)] \end{aligned} \quad (1)$$

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

$k = 0, 1, \dots, K$	Contingencies in the system
$i = 0, 1, \dots, I$	Generators
$j = 0, 1, \dots, J$	Loads
p_k	Probability of contingency k occurring
G_i	Quantity of active power generated (MWh)
$C_G(G_i)$	Cost of generating G_i MWh
$R_i^+(G_{ik} - G_{i0}^{t-1})^+$	Cost of increasing gen. from previous hour
$R_i^-(G_{i0}^{t-1} - G_{ik})^+$	Cost of decreasing gen. from previous hour
VOLL_j	Value of Lost Load, (\$)
$\text{LNS}(G, R)_{jk}$	Load Not Served (MWh)
$R_i^+ < \text{Ramp}_i$	$(\max(G_{ik}) - G_{i0})^+$, Up res. quant. (MW)
$C_R(R_i^+)$	Cost of providing R_i^+ MW of up Reserves
$R_i^- < \text{Ramp}_i$	$(G_{i0} - \min(G_{ik}))^+$, Down res. quant. (MW)
$C_R(R_i^-)$	Cost of providing R_i^- MW of down Reserves

3 Calculation of ramping costs and limits imposed

This study analyzes the consequences of ramping for load following performed by conventional generators. Henceforth, the simulation is done in hourly steps. Ramping in shorter time scales (e.g. 15 minutes) is assumed to be more associated to the provision of ancillary services different to load following, a different product with a corresponding price. For every hour, a two-stage optimization problem is solved. In the first stage (hour-ahead), the dispatches for the next time period ($t + 1$) are determined

⁴A hard constraint is equivalent to specifying the VOLL as plus infinity.

⁵Loss Of Load Expectation.

⁶Therefore, a high ramping cost is set for generating units that have technical or operational constraints that make it expensive for them to adjust their power output (e.g. certain Nuclear units with limited ramping capabilities). Correspondingly, for combustion turbines with lower adjustment costs, a price close to 0 is set.

⁷To set these limits, the SuperOPF with endogenous reserves is 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 is used. This scenario requires other generators to ramp up to compensate for the low output from the wind farms. 2) For the minimum power output, the minimum load of the day with a high wind forecast is 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 (the cutoff speed is around 25 m/s), leading to either very high generation outputs or none at all.

by solving the SuperOPF with endogenous reserves, given the best available wind and load forecast. In the second stage (real-time), the wind realization is known. Then, the dispatches for the present time period ($t + 1$) are determined by solving a SuperOPF with reserves determined from the results of the first stage, updating the wind and load information. The outputs of each hour are interlinked, by setting the second-stage dispatches for hour t as the initial conditions for the dispatch in hour $t + 1$. Deviations above or below the previous hour dispatch are priced according to the ability of generators to move from their current operating point.⁶ In addition, limits on the maximum and minimum power output at any hour of the day are imposed per generator unit.⁷ The steady state conditions are obtained by running the test system simulation over three identical days. The test system stabilized fast, and after running the simulations, the differences in the dispatches, voltages, etc. between the corresponding hours in days two and three are close to 1×10^{-4} .

4 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. 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 mostly needed to provide reserve capacity.

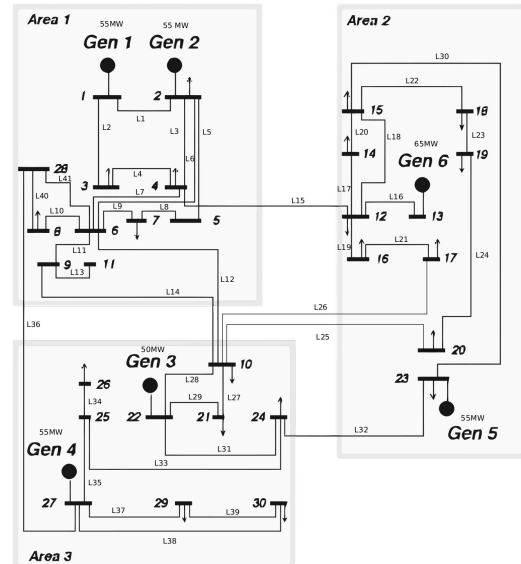


Figure 1: A One-Line-Diagram of the 30-Bus Test Network.

4.1 Characterization of Wind Generation and Load

The load profile chosen pertains to a day in April 2005, 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 is 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 model⁸ are 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 provides the realizations of wind speed observed and the power available from the wind farm. The observed wind speeds exhibit a substantial amount of variability on a relatively windy day.

4.2 Cases studied

The following cases are 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 ratings⁹. 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 generator¹⁰. 5) Distributed Wind: Geographically distributed wind in two areas of the system (bus 13 and bus 27); the wind forecast corresponds to historical data from New England, as in case 2. The capacity of each wind generator is 25MW, to maintain a comparable total wind capacity. This is equivalent to the effect of geographical averaging [8]. 6) Distributed Wind, Load Response: similar to case 5, with load compensating for periods in which no wind power is available in a single location. 7) Distributed Wind, Load Response: similar to case 6, with several loads in area 1 being responsive to the available wind in the system. 8) Distributed Wind, Load Response: similar to case 7, with loads in areas 1 and 2 being responsive to the available wind in the system. Cases 1-4 are 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[9]. Cases 5-7 are ran including ramping costs. Table 1 contains a summary of the generation characteristics used.

Table 1: Ramping and reserve costs

		Fuel Cost(\$/MW)	Gen. Avail (MW)	Res. Cost (\$/MW)	Ramp Cost (\$/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

Each unit is classified according to the generator’s capability to move from their current operating point, with corresponding ramping costs (peak (p), shoulder (s) or baseload (b))¹¹. The contingencies considered include 1) Line outages in the urban area. 2) Line outages between the urban area and the rural areas. 3) Full generation outages at a given bus. and 4) Observed realizations of wind speed conditional on a given forecast. Analyzing the impact of ramping costs requires looking at three main components: 1) The cost of covering the contingencies to maintain Operating Reliability, 2) hour-to-hour changes in the system load and 3) Accommodating the wind variability in the system. These three factors are considered in the evaluation of the different cases.¹² 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.

4.3 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 higher than the most expensive generation cost including ramping costs, but one hundredth of the VOLL for normal demand. 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.

5 Results for the Wholesale Market

For the results in this section, 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 geographical averaging, load response and ramp-

⁸The ARMA model is developed with hourly wind speed data from New England, the methodology for this modeling is described in [6]

⁹Long term, short term and emergency ratings.

¹⁰The 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 [7]. However, there may be dispatches below the potential wind output because the available wind energy is not forced into the system.

¹¹In addition to 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. Therefore, units with higher potential for pollution when changing their power output are priced with ramping costs. Ideally, this would optimally discourage them from moving from their current operation point.

¹²It should be noted that the variability of wind generation is not the only factor that affects ramping costs.

Table 2: Summary of Key Results

	Case 1	Case 1n	Case 2	Case 2n	Case 3	Case 3n	Case 4	Case 4n	Case 5	Case 6	Case 7	Case 8
L.Paid ^a	268	213	175	150	79	86	196	134	183	141	150	151
G.Cap ^b	190	191	237	241	230	242	190	192	233	211	195	199
G.En ^{*,c}	4,011	4,026	4,031	4,015	3,965	3,978	4,018	4,026	4,045	3,943	3,876	3,882
M.WE ^{*,d}	0	0	518	827	319	745	714	883	530	524	559	559
C.Gn ^e	100	100	87	79	92	81	82	78	87	87	86	86
LNS	5	7	6	6	8	11	7	7	6	16	16	13
W.disp(%a)	NA	NA	53	84	32	76	73	90	54	53	57	57

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

^a \$1,000/day

^b Generation Capacity Needed (MW)

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

^d Wind Energy Dispatched (MWh)

^e Conventional Generation (%)

^f Load Not Served (Hours/day)

^g Wind used as % of available wind Energy

ing costs affect operations and costs?. The reported daily costs correspond to sums over 24 hours of the expected costs from the second stage optimization of the Super-OPF (i.e. expected costs over 18 contingencies for a given wind realization). The key results for the twelve scenarios are presented in Table 2. The payments from load (row 1) show substantially lower payments for all wind cases compared to the no wind scenarios. The lower payments come from displacement of carbon fuels by wind, whenever it is available. While payments from loads are reduced, the generation capacity needed to maintain operational reliability is increased as wind is introduced (move from case 1 to cases 2, 3 and 5). This is due to the possibility of a wind cutoff. Introducing load response for wind outages (Cases 6, 7 8) alleviates this pressure and allows for lower generation capacity needed. The expected amounts of LNS are small and occur only in certain contingencies. The amount of wind dispatched is expectedly higher in cases in which no ramping costs are included [9]. The maximum amount of wind dispatched occurs in Case 4, with coupling of an ESS to the wind generator.¹³ The distribution of the wind capacity (Case 2 to Case 5) keeps the payments from loads and the amount of wind used almost identical. However, the generation capacity needed to maintain reliability marginally decreases (2%). Load response further reinforces this effect, with modest increases in wind dispatched, but significantly lower generation capacity needed (18% less Case 2 to Case 7). As a side effect, load response decreases the amount of wind generation used. This is a consequence of the increased LNS in non-peak hours, coming from changes in the load pattern of the day.

6 Wholesale Market Payments and the Daily Cycle

The analysis will initially focus on the impact of ramping costs, and then explore the effects of geographical distribution and load response in a daily cycle. Figure 2 has the composition of payments by customers for cases 1 - 3.

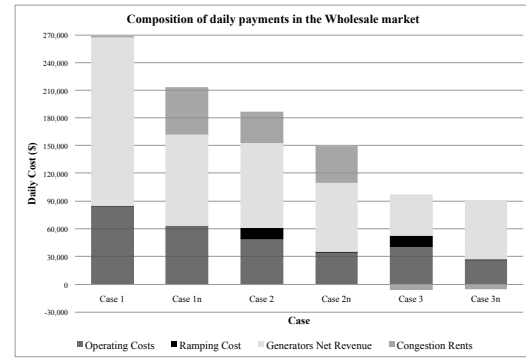


Figure 2: Payments in the Wholesale Market, Ramping

From left to right, the operating costs are progressively reduced by adoption of zero-cost wind. Cases with no congestion (Cases 3 and 3n) contribute the most to system benefits, extending to the payments made from loads. This is not always the case, as the fact that there is no congestion in the system leads to homogeneous Locational Marginal Prices (LMP), which can revert as higher payments from customers to cheap generation sources.¹⁴ Ramping costs on the other hand do not reflect big changes among cases, and are comparable in the 2 wind cases shown. The net revenues for generators follow a change similar to the operating costs, decreasing as the amount of wind dispatched increases. With the exception of the no congestion cases, the inclusion of ramping costs leads to cases in which generators revenues are lower. The difference between what customers pay and what generators receive are assumed to be transferred to transmission owners. In all cases there is a positive amount paid to transmission, with the exception of the no-congestion cases (Cases 3 and 3n). This is due to uniform LMP's in the system. Focusing on the effects of geographical distribution and load response with ramping costs, Figure 3 has the composition of customer payments for the remaining cases, revealing the lowest operating costs for Case 4, constant potential output, due to highest wind usage. The load response cases (Cases 6 to 8) show similarly low operating costs, explained by lower demand in high demand hours

¹³and even higher when ramping costs are not included in the optimization.

¹⁴For example higher LMPs in rural areas (2 and 3 in the test system, Figure 1). See e.g. [9].

that make use of expensive generation sources.

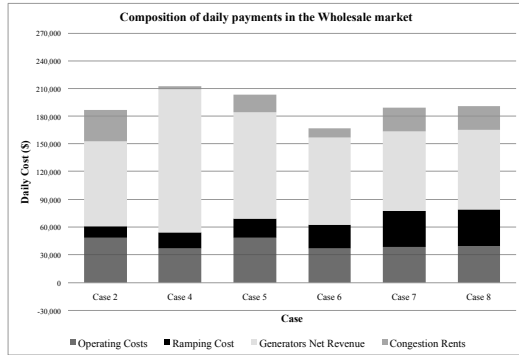


Figure 3: Wholesale Market Payments, Distribution and Load Response

While ramping costs are generally low in all cases, the demand response cases command the highest payments, due to moves in the contracted amounts.¹⁵ In all cases, congestion rents are positive, with the largest amount in the baseline wind case (Case 2), due to separation of LMP's between demand centers and generation buses. Case 4 on the other hand, with low congestion in the system, leads to the lowest payments to transmission owners. In terms of system benefits, Case 6 (Load Response and Wind distribution) leads to the lowest overall payments for consumers. Interestingly, distributing the amount of load response among many loads - each one with lower capacity response - leads to cases in which the ramping costs are high, while the benefits to customers are not too high, a byproduct of the test network used.

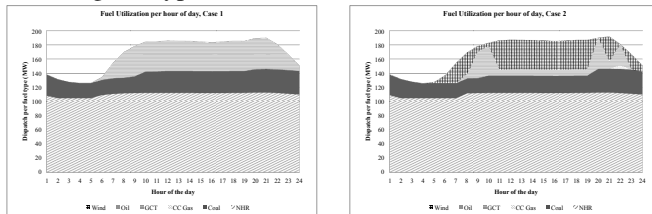


Figure 4: Daily Cycle, Effects of Adding Wind

Figure 4 shows the effect of adding wind in the system, while including ramping costs for the historical daily pattern of wind and load (forecasts for hour-ahead and realizations for real time). While baseload units (NHR, Coal) usage remains relatively unchanged, the introduction of wind mainly affects the amount contracted and dispatched of Gas Combustion Turbines (GCT). Due to the excess capacity installed, not all fuel types are dispatched, e.g. Oil and Combined Cycle Gas (CC gas).

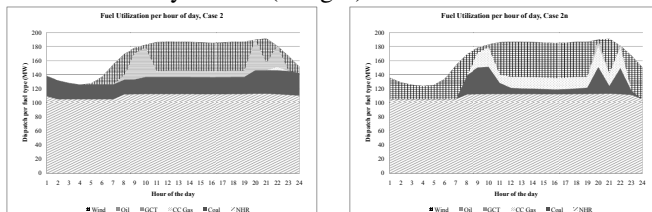


Figure 5: Daily Cycle, Effects of Ramping Costs

The inclusion of ramping costs affects the amount of wind dispatched as well as the units used to cover demand and wind shortages. Figure 5 compares the baseline Wind

with and without ramping costs (Cases 2 and 2n). The removal of ramping costs (Case 2n) substantially increases the amount of zero marginal cost wind (59% increase) but also leads to no utilization of coal units in low demand periods. In cases in which wind is curtailed for equipment protection, the ramping is done by GCT when including ramping costs (Case 2, left pane), while when the ramping costs are not included (Case 2n), the ramping is done by Coal, and it is optimal to use CC Gas in peak demand times. This result is consistent with a least-cost merit order dispatch in each case, taking into account the costs included in the optimization.

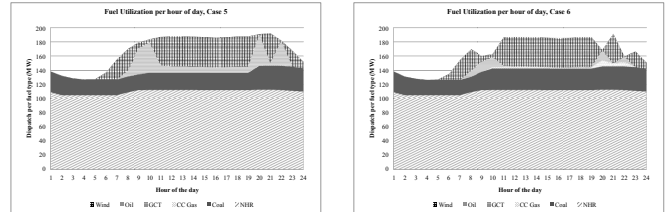


Figure 6: Effects of Geo-Distribution and Load Response

The following cases will all have ramping costs included, to analyze the patterns of generation with further changes aimed at better use of both the stochastic and the conventional generation capacity. The distribution of Wind Capacity (Case 5, left pane Figure 6) leads to a similar dispatch pattern to that observed in the base case wind (Case 2), with more pronounced replacement of conventional capacity by wind. If load response is joined with geographic distribution of wind, coal baseload units are dispatched in an almost-constant fashion, and some CC gas is required to cover wind shortages, due to the location of these units in the test network used. The combination of Load Response in several locations and wind capacity distribution leads to a case in which all dispatchable generation is used with little changes from hour to hour, therefore avoiding sudden increases in usage of the ramping units (Figure 7). This regimen allows for less stress in the network, and therefore helps to reduce the needs for transmission upgrades. Given the technical and political hurdles to transmission expansion, establishing mechanisms by which Loads can respond and be compensated¹⁶ can help to meet the RPS and goals that policy makers have regarding Wind and other Stochastic generation sources, while improving the situation for all market participants.

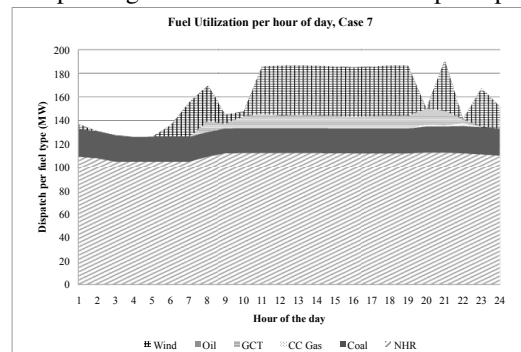


Figure 7: Load Response, Ramping Costs and Wind Distribution

¹⁵The wind shortages simulated are unexpected, for equipment protection. As such, the first stage contracted large amounts of wind power, due to the expected high wind outputs that realized, but could not be used.

¹⁶As in this case, above the marginal cost of the most expensive generation unit.

7 Conclusions

This paper proposes a basic ramping product for load following, analyzing the hourly effects it has on generation dispatches, operating costs and welfare for the wholesale electricity market participants. Policies like distribution of the wind capacity and aggregation of customers at the distribution level, with capacity to respond to changes in the availability of stochastic generation sources, are analyzed. A representative day is used, with high potential levels of wind generation and substantial hour to hour variability in the amount of wind power available. There are three main results obtained: 1) Ramping Costs have substantial effects on the amount of wind dispatched, as well as the generation mix dispatched to cover load. 2) Geographical distribution of the wind capacity helps to alleviate the problems derived from wind variability, as long as the wind characteristics of the locations are complementary. 3) Load Response provides support for the network in the instances in which wind generation capacity is not available. The analysis was performed using the SuperOPF, in the Co-Optimization framework of minimizing the expected cost of serving load for a set of credible contingencies in the system, linking period-to-period outcomes of the optimization. Since both up and down reserves are determined endogenously, it internalizes the variability of stochastic resources. The assignment of ramping costs to generating units establishes the economic problem of determining what kind of generation is needed to sustain the stochastic nature of wind: low fuel cost, high ramping cost units, akin to peaking capacity, or low fuel cost, high ramping cost units, akin to baseload capacity. Geographic distribution of the stochastic capacity leads to marginally higher usage of the resource, even if the wind characteristics of the sites are identical. Higher negative correlation between wind sites helps to further use the installed capacity[11]. This is a key factor when determining the location of future wind capacity installation. The usage of load response to support stochastic resources provides a decreased variability in the use of dispatchable resources necessary. These three factors are an important consideration to inform further policy for renewables adoption.

Acknowledgments

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