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The Hidden System Costs of Wind Generation in a Deregulated Electricity Market

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Abstract

Earlier research has shown that adding wind capacity to a network can lower the total annual operating cost of meeting a given pattern of loads by displacing conventional generation. At the same time, the variability of wind generation and the need for higher levels of reserve generating capacity to maintain reliability standards impose additional costs on the system that should not be ignored. The important implication for regulators is that the capacity payments [“missing money”] for each MW of peak system load is now much higher. Hence, the economic benefits to a network of using storage, controllable load and other mechanisms to reduce the peak system load will be higher with high penetrations of wind generation. These potential benefits are illustrated in a case study using a test network and a security constrained OPF with endogenous reserves (SuperOPF). The capabilities of the SuperOPF provide a consistent economic framework for evaluating Operating Reliability in real-time markets and System Adequacy for planning purposes. The scenarios considered make it possible to determine 1) the amount of conventional generating capacity needed to meet the peak system load and maintain System Adequacy, and the amount of wind dispatched, 2) total payments by customers in the Wholesale Market, and the amount of missing money paid to generators to maintain their Financial Adequacy, 3) changes in the congestion rents for transmission that are collected by the system operator, and finally, 4) the total annual system costs paid by customers directly in the Wholesale Market and, indirectly, as missing money. The results show that the benefits (i.e. the reduction in the total annual system costs) from making an investment in wind capacity and/of upgrading a tie line are very sensitive to 1) how much of the inherent variability of wind generation is mitigated, and 2) how the missing money paid to conventional generators is determined (e.g. comparing a regulated market with a deregulated market).

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In a recent study initiated by the US Department of Energy (DOE 2008), the effects of increasing dependence on wind energy to 20% of the total generation of electricity by 2030 are evaluated. The study is relatively positive about this scenario and states:

Until recently, concerns had been prevalent in the electric utility sector about the difficulty and costs of dealing with the variability and uncertainty of energy production from wind plants and other weather-driven renewable technologies. But utility engineers in some parts of the United States now have extensive experience with wind plant impacts, and their analyses of these impacts have helped to reduce these concerns [...] winds variability is being accommodated, and given optimistic assumptions, studies suggest the cost impact could be as little as the current level - 10% or less of the value of the wind energy generated.

The DOE study focuses on the initial capital cost of installing the wind capacity and upgrading the transmission network and compares these costs to the lower operating costs when wind energy displaces fossil fuels. The objective of this paper is to show that there are other, hidden costs of wind power associated with the need to maintain the “Financial Adequacy” of conventional generating capacity. Since wind capacity is essentially a non-dispatchable source of energy, it may contribute relatively little capacity for meeting the reliability standard of Generation Adequacy. Nevertheless, wind generation, when it is available, is essentially free and it displaces most conventional sources of generation. As a result, the capacity factors of conventional generators are typically reduced when wind capacity is added. This happens even though the total amount of conventional capacity needed to maintain reliability may actually increase. Consequently, these conditions lead to increasing amounts of “missing money” for generators that are generally paid through some form of Capacity Market in most deregulated markets in the US.¹ For example, generating units in New York City have typically been paid over \$100,000/MW/year.² This paper argues that Financial Adequacy should be treated as an additional criterion for planning purposes that would complement the standard engineering criterion of maintaining “System Adequacy”. The case study presented herein shows that the total system costs charged to customers increase if a new wind farm replaces an existing coal unit on a network. With the wind farm in place, the increase in missing money is larger than the decrease in total operating costs in the Wholesale Market. For an investment to be economically viable from an economic planning perspective, the total annual cost of maintaining the existing system must go down and this decrease in cost must be bigger than the annualized cost of financing the investment. If some form of storage capability such as a battery mitigates the variability of wind generation, the total annual cost of the existing system

¹Some energy only markets do not have a Capacity Market, and some other way of maintaining the financial viability of conventional generators, such as tolerating high, scarcity prices, is used.

²Figures 10 and 11 on p. 15 of (NYISO 2007).

does decrease. The battery charges when the wind speed is higher than the forecast and discharges when it is lower than the forecast, and in this way, the net wind generation is smoothed over time.³ As a result, there is an effective floor on the amount of generation from wind capacity when the indirect generation from discharging the battery is included. The presence of this floor reduces the total amount of conventional generating capacity that is needed to meet the peak system load and maintain System Adequacy, and as a result, the amount of missing money is also reduced. In addition, the total amount of wind that is spilled (i.e. wasted) is reduced when batteries are coupled with the wind farm.⁴ The overall objectives of the paper are to demonstrate through a case study 1) why Financial Adequacy is an important concept that should be considered by system planners, 2) why the social value of storage and controllable load increases when intermittent sources of generation are added to a network, and 3) how the cost of missing money to customers differs between a regulated and a deregulated market. The structure of the paper includes four additional sections. Section 2 describes the SuperOPF and shows how this analytical framework relates to the NERC standards for Operating Reliability and System Adequacy. Section 3 presents the specifications for a case study that considers the effects of replacing a coal unit by a large wind farm with three times the installed capacity of the coal unit. Since the wind farm causes more congestion on the network when the wind blows, a series of additional scenarios show the effects of upgrading the capacity of a tie line to reduce this congestion. Since congestion rents on the network are treated as one source of income for transmission owners, reducing these rents implies that there will be more missing money that must be paid by customers outside the Wholesale Market to ensure that the transmission owners are financially viable. The missing money for both generators and transmission owners contributes to the total annual system cost of maintaining System Adequacy and Financial Adequacy. The results for all of the scenarios are presented in Section 4 and the implications of these results for the cost of missing money in a regulated and a deregulated market are discussed in Section 5. The overall conclusions of the analysis and some suggestions for regulators are summarized in Section 6.

1. NERC Reliability Standards and the SuperOPF

Federal legislators have formally recognized the importance of maintaining Operating Reliability in the Energy Policy Act of 2005 (EPACT05), and the major effect of this legis-

³This type of smoothing also occurs with spatial aggregation of the total generation from wind farms at different locations. (Milligan, et al. 2009).

⁴In one of the scenarios, must-take contracts for wind generation are evaluated by making the cost of not using available wind generation expensive, and in this scenario, the total annual system cost of maintaining System Adequacy is substantially higher than the corresponding cost without the wind farm.

lation is to give the Federal Energy Regulatory Commission (FERC) the overall authority to enforce reliability standards throughout the Eastern and Western Inter-Connections (see FERC [5]). The North-American Electric Reliability Corporation (NERC) has been appointed by FERC as the new Electric Reliability Organization (ERO), and NERC has been given the responsibility to specify explicit standards for reliability. A draft set of reliability standards were released for public comment from April 23rd to May, 25th, 2009 (NERC 2009). This report contains over 1000 pages and covers a wide range of different topics. Although the important issue of System Adequacy is referenced many times, the report recognizes the important feature and the major complication of how the North American Bulk Power Network is governed. There are many layers of governance, and in general, State regulators determine the rules for maintaining System Adequacy. The NERC uses the following two concepts to evaluate the reliability of the bulk electric supply system (NERC 2007):

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.*

To simplify the concept of Adequacy, it is convenient to adopt a single measure, and 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 adequacy of the bulk transmission system (i.e., this does not include outages of the local distribution systems caused, for example, by falling tree limbs and ice storms). Adequacy implies that past investments in the capacity of the electric delivery system must be sufficient to make the real-time operations meet the reliability standards.⁵ As a result, the Adequacy standard has important economic and financial implications that should be addressed by regulators in a more systematic and transparent way. In this paper, it is argued that a new criterion of “Financial Adequacy” should be treated as one of the standard measures used by system planners to evaluate the desirability of proposed changes to system capacity.

Chen (Chen, et al. 2005) have proposed an alternative way to determine the optimal dispatch and nodal prices in an energy-reserve market using co-optimization (CO-OPT).

⁵Note that the time horizon for Resource Adequacy involves long term planning, with many sources of stochastic uncertainty (e.g. forecast of demand, equipment servicing, emergency operating procedures), and special emphasis on generation expansion. Operational reliability on the other hand has a much shorter time horizon, allowing for better observability of many factors and therefore less inherent uncertainty. The $n - 1$ standard is a commonly accepted measure for Operating Reliability.

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.

In the SuperOPF (Thomas, et al. 2008, Lopez-Lezama, et al. 2006, Murillo-Sanchez & Thomas 1998), the CO-OPT criterion is modified to include the cost of Load-Not-Served (LNS), and it also distinguishes 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 Security-Constrained OPF 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.⁶ Increasing the stress on a network by, for example, increasing the peak system load over a planning horizon eventually causes load shedding, and typically, load shedding occurs first in one or more of the contingencies. Since the expected cost of LNS in a contingency is determined by multiplying a large VOLL by a small probability, the overall effect on the total expected system cost may be modest. 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 following section describes the characteristics of the 30-bus test network used in the case study and the specifications for the simulations. The basic objective of this analysis is to evaluate the effects of replacing an existing coal unit by a large new wind farm. The initial amounts of installed capacity are sufficient to meet the standard for System Adequacy, and since wind generation is inherently intermittent, the installed capacity of the wind generators is substantially larger than the capacity of the coal unit. In addition, the analysis determines the economic benefit of upgrading a transmission tie line to transfer more wind generation from a remote location to an urban center.

⁶A hard constraint is equivalent to specifying the VOLL as plus infinity.

2. The Scenarios Evaluated in the Case Study

The 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 Figure 1. The 30 nodes and the 39 lines are numbered in Figure 1 and this numbering scheme provides the key to identifying the locations of the specific contingencies described in the following discussion. In addition, the six generators are also identified. 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 regions 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.

[Figure 1 about here]

2.1. The 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 the same type of problem faced by the system operators and planners in the New York Control Area. Most of the load is in New York City (i.e. Area 1) and the inexpensive sources of baseload capacity (hydro, coal and nuclear) are located upstate (i.e. Areas 2 and 3).⁷

2.2. The Realizations of Wind Generation

There are three different forecasts of the level of wind generation (high, medium and low), and each forecast has four possible outcomes,⁸ summarized for NORMAL Wind in Table 1. With no wind capacity installed, the contingency $k = 0$ corresponds to the intact system using the forecasted level of load (i.e. the network shown in Figure 1). The analysis that underlies the information presented in Table 1 has three components that are described in a paper by (Anderson & Cardell 2008). The first component is a set of time-series data for

⁷Additional information about the specifications of the case study are given in (Mount, et al. 2009)

⁸The realized levels of net wind generation in Column 4 are different from the levels for NORMAL (and NASTY Wind), and they represent the effect of coupling batteries with the wind farm to reduce the range of outcomes for a given forecast of wind speed and to provide a floor > 0 to the amount generated.

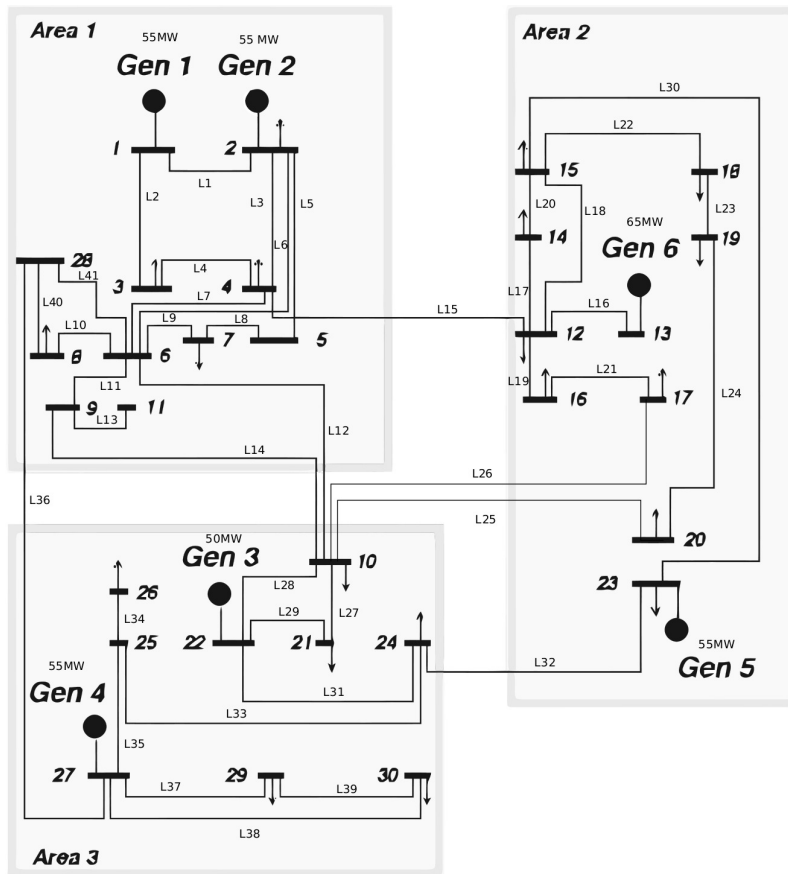


Figure 1: A One-Line-Diagram of the 30-Bus Test Network.

hourly wind speeds at a specific location (in New England for this case study). The second component is an ARMA model for predicting wind speed (one hour ahead for this case study), and finally, there is a power curve for a wind turbine that converts a given wind speed to the amount of energy generated (wind turbines are also specified as a potential source of positive reactive power in the SuperOPF). It should be noted that none of the scenarios presented include the effect of the spatial aggregation of wind generation from different sites.

[Table 1 about here]

An important point that underlies the levels of generation in Column 3 of Table 1 is that the ranges of observed wind speeds for each wind forecast (Low, Medium or High)

are much larger than the range of the forecasted wind speeds that define each bin. Consequently, the ranges of generation for a given wind forecast are also very large. The outcomes for a High wind forecast are the most challenging for System Operators because there is a substantial probability of 14% that the turbines will cut out at very high wind speeds (> 25 meters/second) to avoid damaging the equipment. Hence, the distribution of wind speeds is bimodal with modes at 0% and 100% of the maximum level of generation⁹

The following four different Cases for wind generation are considered:

1. NO Wind; with a 35 MW coal unit installed at Generator 6, at bus 13.
2. NORMAL Wind; with the coal unit replaced by 105MW of wind capacity, using the wind speed specifications in Table 1 and zero for the offer price in the wholesale auction.

⁹These extreme specifications are used on purpose in this case study to provide stress on the network when wind capacity is installed to show how the installed capacity needed to maintain Generation Adequacy is affected. In practice, there may be a substantial amount of smoothing of total wind generation from wind farms located in different regions of a network.(Milligan et al. 2009).

Table 1: Specifications of the Wind Contingencies for NORMAL and NICE Wind

Forecasted Wind Speed	Probability of Forecast	Wind Generation ^a		Output Probability ^b
		Normal	Nice	
LOW (0-5 m/s)	11	0	33	66
		7	33	26
		33	33	5
		73	38	3
MEDIUM (5-13 m/s)	46	6	41	24
		38	55	20
		62	55	18
		93	58	38
HIGH (13+ m/s)	43	0	35	14
		66	70	4
		94	70	3
		100	70	79

^a % of Installed Wind Capacity, 105MW of Wind capacity installed.

^b Conditional on Forecast.

3. NICE Wind; the same as Case 2 with a different set of specifications for the realizations of wind generation (see Table 1) that represent the net effect of coupling wind generation with storage batteries.¹⁰
4. NASTY Wind; the same as Case 2 with the offer price in the wholesale auction set to -\$1,500/MWh to force the acceptance of wind generation in the auction and represent a Must-Take form of contract between the wind farm and the System Operator.

In addition, the same four Cases are rerun after making an upgrade to Transmission Line L15 in Figure 1. This upgrade doubles the transfer capacity of the main tie line linking the wind farm in Area 2 to the urban center in Area 1. These Cases are referred to as Case 1UP, Case 2UP, etc.

3. Results for the Wholesale Market

The results presented in this section summarize the economic costs for the network shown in Figure 1 of meeting the same annual pattern of load for the eight different scenarios discussed in the previous section. 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 to maintain System Adequacy, and 2) what happens to the wholesale prices and operating costs.

The four different types of wind generation considered are NO Wind, NORMAL Wind, NICE Wind (i.e. wind generation coupled with storage) and NASTY Wind (i.e. must-take contracts for wind generation), and the order of the eight scenarios is:

1. Case 1; NO Wind
2. Case 1UP; NO Wind + Upgrade
3. Case 2; NORMAL Wind
4. Case 2UP; NORMAL Wind + Upgrade
5. Case 3; NICE Wind
6. Case 3UP; NICE Wind + Upgrade

¹⁰The rationale for Case 3 is that the batteries are charged when the realized wind speed is high and they are discharged when the wind speed is low, and most importantly, when the wind turbines cutout for safety reasons at very high wind speeds.

7. Case 4; NASTY Wind

8. Case 4UP; NASTY Wind + Upgrade

For each scenario, the reported annual costs are the sums over 100 load levels of the expectation of the costs for the three forecasts of wind speed shown in Table 1 using the second-stage optimization of the SuperOPF.¹¹ The key results for the eight scenarios are presented in Table 2. The first row (Load Paid) shows that the annual payments made by customers in the wholesale market are substantially lower than the NO Wind scenario (Cases 1 and 2) for all of the wind scenarios except Case 4 (NASTY Wind). 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. For NICE Wind with the upgraded tie line (Case 3UP), the customers only pay one sixth of the corresponding cost with NO wind (Case 1) in the wholesale market. Wind also displaces fossil fuels in the Case 4, and the high wholesale prices paid by customers are caused by the increased cost of dealing with congestion on the network.¹² The generally lower wholesale costs of purchases with wind generation in Table 2 contrast with the amounts of conventional generating capacity needed for System Adequacy (Gen. Capacity Needed). The capacity needed is roughly the same with NORMAL Wind (Cases 2 and 2UP) as it is with NO Wind (Cases 1 and 1UP), and it is even higher with NASTY Wind (Cases 4 and 4UP). It is only with NICE Wind that the capacity needed is substantially lower (Cases 3 and 3UP). The underlying reason is that the storage capacity coupled with wind generation in Cases 3 and 3UP provides a floor on the minimum generation of 35 MW from the wind farm, including the effect of the cutout contingency at very high wind speeds. In addition, less of the potential wind generation is spilled.

[Table 2 about here]

Even though the production cost and price offer of wind generation is set to zero for NORMAL Wind, the maximum amount of wind capacity dispatched (Max Wind Committed) is only 35MW compared to the true maximum of 105MW because of the high cost of covering the contingency when the wind turbines cutout. More wind generation can be used economically when the tie line is upgraded (Case 2UP) or if storage capacity

¹¹In other words, the expected costs are computed for the 18 different contingencies for each one of the three forecasts of wind speed.

¹²When wind generation is the dominant source at low loads, it is difficult to accommodate this generation on the network because so much of the total generation is produced at a single node. With a must-take contract in Case 4, there is an economic penalty for not using all of the available generation from wind even though this source increases the marginal production cost substantially and this marginal cost sets the market price in a uniform price auction.

Table 2: Summary of Key Results

	case1	case1UP	case2	case2UP	case3	case3UP	case4	case4UP
Load Paid ^a	68,915	66,171	22,373	14,705	23,560	11,934	78,570	36,650
GenCap ^{*, b}	283	288	288	286	242	259	295	292
MaxWC ^{*, c}	0	0	35	83	43	73	105	105
C.Gen ^d	100	100	88	86	78	75	56	55
LNS ^e	16	15	4	4	7	7	34	20

* 105MW of Wind capacity replaces 35MW of Coal capacity in Cases 2, 3 and 4

^a \$1000/Year.

^b Gen Capacity Needed (MW)

^c Max Wind Committed (MW)

^d Conventional Generation (%)

^e Load Not Served (Hours/Year)

is coupled with the wind generation (Cases 3 and 3UP). However, the amount of wind capacity that is dispatched is not really limited by the physical capacity of the network. In Cases 4 and 4UP with must-take contracts, all 105MW of wind capacity are dispatched but the consequence is that customers have to pay a lot more in the wholesale market for congestion and a lot more to maintain System Adequacy.

The overall cost of purchases in the wholesale market for the different scenarios is summarized in Figure 2. 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 one fifth of the total payments. A small payment in Case 1 goes to Congestion Rents (the difference between the payments by customers and the payments to generators) but with the tie line upgrade in Case 1UP, the Congestion Rents are negative. With NORMAL Wind and NICE Wind, the total payments drop substantially compared to NO Wind, and most of the reductions come from much lower Net Revenues for the conventional generators. The Net Revenue for the wind generators is relatively small. The results for NASTY Wind are very different. Operating Costs and the Net Revenue for the conventional generators are both higher than they are in Case 1 unless the tie line is upgraded in Case 4UP. Accommodating large quantities of unmitigated wind generation on the network is expensive and does not benefit customers. It is interesting to note that the Net Revenue for wind generators is still relatively small.

The sum of the Net Revenues earned by the conventional generators and the Congestion Rent is the Operating Surplus in the wholesale market, and this quantity represents the amount of money available to cover capital costs. In the same way, the Net Revenue for the wind generator can be used to cover the investment in the wind farm. Using NO Wind (Case 1) as the base for comparison, the Operating Surplus is much lower for NOR-

MAL and NICE Wind (Cases 2 and 3) and slightly higher for NASTY Wind (Case 4). The Operating Cost in Case 4 is high because the mix of generating capacity dispatched is very different from the least-cost merit order due to network constraints and congestion. In all four cases, upgrading the tie line reduces the Operating Cost and makes it possible to rely more on the inexpensive sources of generation.

[Figure 2 about here]

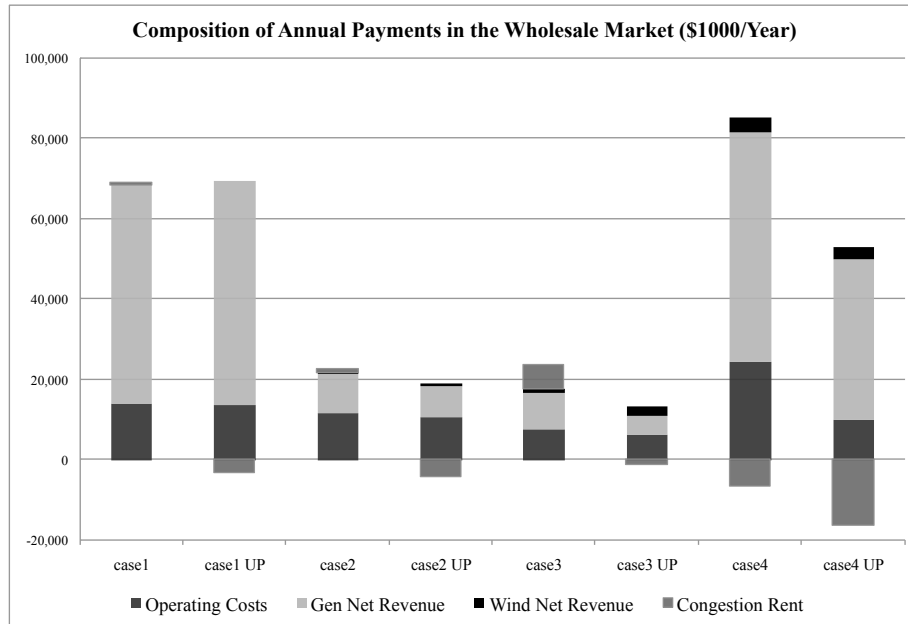


Figure 2: The Composition of Payments by Customers in the Wholesale Market.

4. Determining the Amount of Missing Money

The final component of the analytical framework is to describe how much missing money is required by generators above their annual earnings in the Wholesale Market to ensure that they are financially viable. This is the main implication of requiring that an electric delivery system should maintain Financial Adequacy as well as Physical Adequacy. In addition, changes in the amount of congestion rents collected by the System Operator in the Wholesale Market affect how much additional money is needed to pay transmission owners a regulated rate of return on their capital investment in transmission and distribution.

Even though the total payment made to transmission owners is the same in all scenarios, the proportion of this amount coming from congestion rents is determined in the analysis.

Under a regulated regime, the rates charged to customers are set so that utilities receive enough revenue to cover all operating costs and a fair rate of return of and on the depreciated book value of the capital assets that are considered by the regulators to be used and useful. This procedure is assumed to still be the appropriate method of paying for transmission and distribution assets in a deregulated market. For merchant generators, however, their revenue in a deregulated market comes from 1) being paid the nodal prices for their generation and ancillary services in the Wholesale Market,¹³ and 2) payments for capacity in a Capacity Market if such a market exists. These generators expect to earn a market rate of return on the market value of their generating assets. Given the physical durability of conventional generating units relative to the standard regulatory accounting rates of depreciation, the market value of conventional capacity is typically substantially higher than the book value would have been under continuous regulation.¹⁴ This is a major additional cost that should be compared with any gains in economic efficiency in the Wholesale Market that lower operating costs.

[Table 3 about here]

The amount of missing money for a conventional generator is determined by specifying the minimum annual earnings needed to maintain its Financial Adequacy. In a deregulated market, it is assumed that the minimum annual earnings above the annual operating costs correspond to the replacement value for each generating unit. The values used in the analysis are shown in Table 3. As long as the annual earnings in the Wholesale Market are bigger than the minimum earnings, the generating unit meets the standard of Financial Adequacy and there is no missing money. On the other hand, if the annual earnings in the Wholesale Market are less than the minimum earnings, the difference between the minimum earnings and the actual earnings measures the amount of missing money. Dividing the amount of missing money by the amount of generating capacity needed for System Adequacy gives the minimum price of capacity (\$/MW/Year) needed for Financial Adequacy. In other words, as long as the price paid in a Capacity Market is larger than the minimum price for every conventional generating unit, it is big enough to maintain Financial Adequacy.

¹³These payments may also be made through forward contracts, but the contract prices will still reflect the expectations of traders about future prices in the Wholesale Market. In addition, there may be bilateral contracts that include two-part payments for energy, or an ancillary service, and for capacity.

¹⁴The late Mike Rothkopf was one of the few economists to raise this issue as an important reason for being skeptical about the widely held belief among academics and regulators that deregulating electric utilities would benefit customers. See (Rothkopf 2007).

The final step in the calculation of the total amount of missing money for conventional generators is to specify a structure for the Capacity Market. It is assumed, following the structure of the market in New York, that the Capacity Market is divided into two regions; Area 1, the urban region, Areas 2 and 3, the rural region.

Each region sets its own capacity price and this price is equal to the highest of the minimum capacity prices needed for Financial Adequacy for all of the generating units in a region. The market price is paid for all of the generating capacity in a region that is needed to meet the peak system load and maintain System Adequacy. This procedure follows the standard practice used to make payments in a uniform price auction.

The simplest type of missing money is for transmission owners. It is assumed for all scenarios that transmission owners received \$30 million/Year to cover all of their costs for the existing network including the annualized capital costs. Part of this total is paid by the Congestion Surplus in the wholesale market (see Figure 2) and the remaining part corresponds to the missing money. For scenarios in which the ISO pays more to generators than the amount received from customers, the Congestion Surplus is negative and the corresponding missing money will be larger than \$30 million/Year. However, customers still pay the same total cost of transmission and the only feature that changes from scenario to scenario is the amount of money contributed in the wholesale market.

For generators, the situation is more complicated because the amount of conventional generating capacity needed for reliability purposes varies from scenario to scenario as well as the total annual operating costs. Nevertheless, the total annualized capital cost of the conventional generating units is paid in a similar way to the payments for transmission.

Table 3: The Missing Money for Conventional Generators with NO Wind (Case 1)

	1	2	3	4	5	6	7	8
	Minimum Earnings/MW \$1000/MW/year	Required Capacity MW	Minimum Earnings \$1000/year	Actual Earnings \$1000/year	Difference Actual - Min. \$1000/year	Missing Money Max(-Diff, 0) \$1000/year	Price of Capacity \$1000/MW/year	Capacity Payments \$1000/year
Gen 1	88.00	20.00	1,760.00	1,452.00	-308.00	308.00	15.00	1,623.00
	88.00	15.42	1,357.00	106.00	-1,252.00	1,252.00	81.00	1,252.00
Gen 2	88.00	25.00	2,200.00	2,204.00	4.00	0.00	0.00	2,029.00
	88.00	25.00	2,200.00	406.00	-1,794.00	1,794.00	72.00	2,029.00
Gen 3	460.00	30.00	13,800.00	12,784.00	-1,016.00	1,016.00	34.00	5,113.00
	131.00	20.00	2,620.00	845.00	-1,775.00	1,775.00	89.00	3,409.00
Gen 4	460.00	35.00	16,100.00	14,775.00	-1,325.00	1,325.00	38.00	5,965.00
	131.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gen 5	460.00	20.00	9,200.00	5,791.00	-3,409.00	3,409.00	170.00	3,409.00
	230.00	35.00	8,050.00	2,911.00	-5,139.00	5,139.00	147.00	5,965.00
Gen 6	460.00	30.00	13,800.00	9,255.00	-4,545.00	4,545.00	152.00	5,113.00
	230.00	27.76	6,385.00	3,796.00	-2,589.00	2,589.00	93.00	4,731.00
TOTAL		283.18	77,472.00	54,324.00	-23,148.00	23,153.00		40,639.00

Some of the money comes from the wholesale market (Gen Net Revenue in Figure 2) and the rest is paid as missing money through a Capacity Market. The calculations for determining the amount of missing money in a deregulated market are illustrated in Table 3 for the NO Wind scenario.

The steps used to calculate the payments for capacity outlined in Table 3 were completed for each scenario. These payments together with the payments to transmission owners are added to the Total Annual Operating Costs to give the Total Annual System Cost charged directly in the wholesale market and indirectly as missing money to customers.

In contrast, an ideal regulated market would have regulators set the rates paid by customers to cover all of the prudent operating costs and capital costs of the conventional generators. These rates typically would include fixed rates for energy and possibly for capacity for some customers, and real time rates and capacity rates for other customers. However, the effects of different rate structures on load are ignored for all scenarios in this paper and the focus is on the differences in Total Annual System Costs for the same annual pattern of load. The main differences in a regulated market from the procedures used for a deregulated market in Table 3 are 1) the Minimum Earnings/MW in Column 1 are determined by the book value of capital rather than the market value, and 2) the capacity payments cover the missing money for each unit in Column 6 and would also confiscate excess profits (i.e. positive differences in Column 5). In other words, even if the lower book values in Column 1 are ignored, the customers would only pay \$23 million/Year (Column 6) under regulation rather than \$40 million/Year (Column 8) in a Capacity Market.

In the next section, The Total Annual System Costs paid by customers are calculated for the eight wind scenarios for the following three types of market (note that the component costs for a given wind scenario in the wholesale market in Figure 2 are the same in all three markets)¹⁵:

1. Mkt1: Deregulated Market paying the missing money through a Capacity Market (i.e. like Table 3),
2. Mkt2: Pay the missing money only (i.e. pay Column 6 instead of Column 8 in Table 3),
3. Mkt3: Regulated Market paying legitimate capital costs using a book value equivalent to 50% of the market value (i.e. pay Column 5 using 50% of the values in Column 1 of Table 3).

¹⁵Customers may not actually pay the wholesale prices in a regulated market but the annual operating costs are still the same as they are in a deregulated market for each wind scenario.

5. Total Annual System Costs in Different Markets

Typically, generating units in an economically efficient market do not receive enough net revenue in the wholesale market to maintain Financial Adequacy. The mechanism for paying the cost of capital for generating units in the three different markets is similar to the way that transmission owners are paid.¹⁶ The income needed for Financial Adequacy comes from both the Net Revenue in the wholesale market and the missing money. In Mkt2, the missing money is paid directly to individual generators. In a deregulated market (Mkt1), the missing money is paid indirectly through a Capacity Market that results in higher payments than Mkt2. The main difference between Mkt2 and the Regulated Market (Mkt3) is that the Minimum Earnings/MW for the individual generating units is only half as big as it is in the other two markets.

In all three markets, if the levels of the different types of generating capacity needed for System Adequacy remain the same, the generators capital costs also stay the same. Lower earnings in the wholesale market are simply offset by higher payments for missing money.¹⁷ Hence, the only effective ways to reduce the total annual payments to generators for capital costs in a given market are 1) to reduce the amount of conventional capacity needed for System Adequacy, and, to a lesser extent, 2) to change the mix of generating units needed for System Adequacy.

Figure 3 summarizes the overall results of the analysis for the three different markets by showing the composition of the Total Annual Systems Costs for the four wind scenarios with no tie line upgrade. The first three components (the lowest three) are the Operating Costs, the Generator Net Revenue and the Wind Net Revenue. For each wind scenario, the operating costs are identical for the three different markets and the payments for missing money are highest in a deregulated market (Mkt1) and lowest in a regulated market (Mkt3). The payments made to generators in the wholesale market are substantially lower with NORMAL and NICE Wind (Cases 2 and 3) compared to NO Wind (Case 1), but this reduction for NORMAL Wind is effectively offset by the increase in the amount of missing money paid to the conventional generators. This missing money is lower for NICE Wind because less generating capacity is needed to maintain System Adequacy, and as a result, the Total Annual System Cost is also lower.¹⁸ For NASTY Wind (Case 4), both the

¹⁶The fact that most of the generating units do need additional earnings is consistent with a competitive wholesale market. If all offer prices in the wholesale auction equal the true marginal operating costs and the combination of different types of generation is economically efficient, all generating units would have the same amount of missing money/MW equal to the capital cost of the most expensive peaking unit.

¹⁷In a Regulated Market (Mkt3), the payments are not actually made in two parts but the rates paid by customers would be set high enough to cover all of the operating and capital costs.

¹⁸The total payments made to transmission owners are the same in all scenarios and the payments to wind generators and the costs of shedding load are always relatively small.

Operating Costs and the missing money for conventional generators are higher than the corresponding values for NO Wind. The main conclusion is that focusing on a reduction in the average wholesale price when wind capacity is introduced into a deregulated market in Figure 2 can be very misleading unless the effects on the missing money needed by the conventional generators and transmission owners is also considered.

[Figure 3 about here]

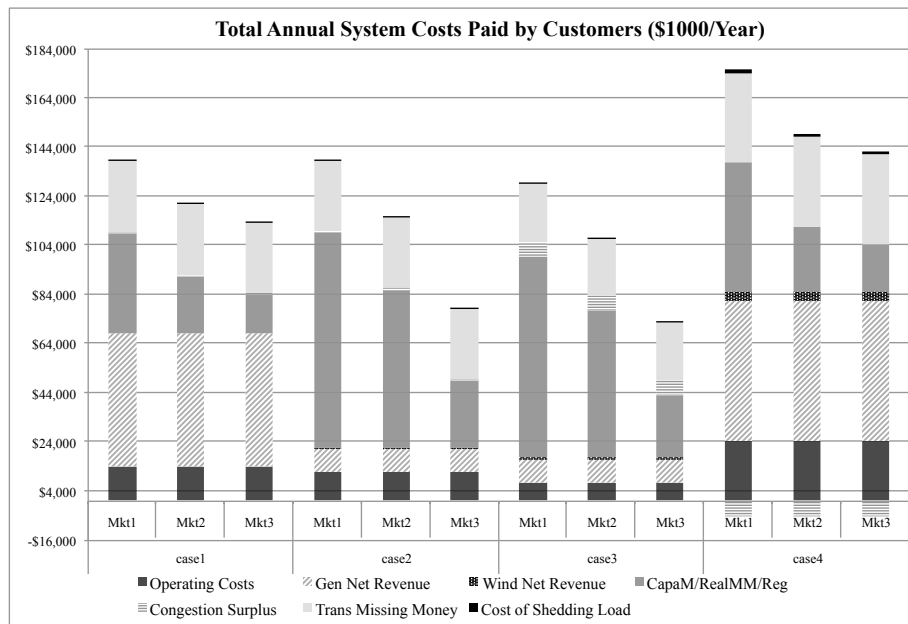


Figure 3: The Total Annual System Costs Paid by Customers.

The underlying reason for calculating the Total Annual System Costs is to determine the viability of making investments in wind capacity and in upgrading a tie line. The economic justification for making an investment corresponds to having a reduction in the Total Annual System Costs that is bigger than the annual capital cost of financing the investment. The Total Annual System Costs for NO Wind are \$139, \$122 and \$114million/Year for Mkt1, Mkt2 and Mkt3, respectively, and Table 4 summarizes the savings in the Total Annual System Costs for a given market from investing in the three different wind scenarios (Cases 2-4) compared to NO Wind (Case 1). For all three markets, the savings for NASTY Wind (Case 4) are negative and there is no economic justification for making this investment. For NORMAL Wind (Case 2) and NICE Wind (Case3), the

savings are highest and positive in a regulated market (Mkt1) and lowest, and slightly negative for NORMAL Wind, in a deregulated market (Mkt1). Finally, the additional savings comparing NICE Wind to NORMAL Wind measures the value of having storage capacity mitigate wind variability. This value is smallest in a regulated market because the price of conventional capacity (missing money/MW) is lower than it is in the other two markets.

[Table 4 about here]

Table 4: Savings in the Total Annual System Cost from investment in wind generation

($\$1000/\text{Year}$)	Case 1	Case 2	Case 3	Case 4
Case 1- Case s				
Mkt1	0.00	-218.00	9,310.00	-30,035.00
Mkt2	0.00	5,548.00	14,139.00	-21,340.00
Mkt3	0.00	35,152.00	40,938.00	-21,831.00

Table 5 summarizes the savings in the Total Annual System Costs from upgrading the tie line for Cases 1 - 4 in the three different markets. The savings from the upgrade are computed for each combination of wind scenario and market. In a deregulated market (Mkt1), the savings are positive in all four wind scenarios. The largest savings are for NASTY Wind (Case 4) because of the need to accommodate the maximum 105MW of wind generation under a must-take contract. The savings are smallest for NICE Wind (Case 3) because the storage capacity effectively reduces the maximum wind generation put on the network (i.e. at high wind speeds, some wind generation is used locally to charge the battery). In fact, the savings from upgrading the tie line are negative in Mkt2 and Mkt3 for NICE Wind. The savings from the upgrade are also negative in Mkt2 and Mkt3 for NO Wind (Case 1). Comparing the results for NICE Wind and NASTY Wind demonstrates that coupling storage capacity with wind generation is in effect a substitute for adding transmission capacity. Once again, using the changes in the Annual Operating Costs of the conventional generators as a guide for determining the benefit of additional transmission capacity may be highly misleading.

[Table 5 about here]

Table 5: Savings in the Total Annual System Cost Available from upgrading a tie line

(\\$1000/Year) Case sUP- Case s	Case 1	Case 2	Case 3	Case 4
Mkt1	7,177.00	6,930.00	1,872.00	25,593.00
Mkt2	-1,959.00	531.00	-2,765.00	24,256.00
Mkt3	-1,509.00	480.00	-1,321.00	49,637.00

6. Conclusions

This paper considers the practical need of determining which generating units will be needed on a network to maintain reliability and how to keep them financially viable. The overall recommendation of the paper is to propose that Financial Adequacy should be considered as an additional criterion for planning purposes in deregulated markets. The specific objectives of this paper are to demonstrate why it is important when evaluating different wind scenarios to 1) determine the amount of conventional generating capacity needed to maintain System Adequacy endogenously, and 2) evaluate the economic effects of wind generation on the financial viability of these conventional generators. The first objective addresses the physical nature of System Adequacy, and it is accomplished using the co-optimization capabilities of the SuperOPF. The endogenous amounts of generating capacity needed to meet the same peak system load in different scenarios can vary substantially, and these different amounts of capacity define the requirements for maintaining System Adequacy on a given network. In general, the total amount of conventional generating capacity needed (dispatched capacity plus upward reserve capacity) may increase when a variable source like wind generation replaces conventional generation. This can occur even when the generation from wind displaces a substantial portion of the conventional generation.

Meeting the second objective is accomplished by determining the total annual earnings above the operating costs for individual generating units in a wholesale market. These earnings are compared with specified minimum levels of earnings, and if the actual amount earned for any generating unit is less than the corresponding minimum level, there is missing money, implying that an additional source of income is needed to maintain the Financial Adequacy of that unit. Three different types of market are considered to calculate the payments made for the missing money. Mkt1 is a deregulated market that has the highest payments because 1) the missing money is determined using the market value of the generating units, and 2) the payments made in a capacity market set the capacity price at the highest amount of missing money/MW for any generating unit. Mkt2 is the same as Mkt1

except the payment corresponds to the actual missing money needed for each generating unit (i.e. there is no capacity market and the implicit price for capacity paid is not the same for every generating unit). Mkt3 is a regulated market that has the lowest payments because 1) the missing money is determined by the depreciated book value of the generating units rather than the market value, and 2) generators are paid only for legitimate capital costs (i.e. similar to Mkt2).

For each type of market, the overall implication of evaluating the Financial Adequacy for generators is that if a unit needs missing money, reducing the earnings of the unit in the wholesale market simply increases the amount of missing money needed. In terms of the annual earnings, it is a zero-sum game. Since adding wind capacity to a network will tend to lower the earnings of the conventional generators in the wholesale market, these lower earnings will be offset to a large extent by higher amounts of missing money.¹⁹

The real net benefits associated with adding wind capacity to and/or upgrading transmission for a network come from the following three sources:

1. Reducing the real operating costs (e.g. for fossil fuels) of the conventional generating units,
2. Reducing the total amount of conventional generating capacity needed to maintain System Adequacy,
3. Reducing the excess profits of the conventional generators.²⁰

The message for the State regulators who oversee deregulated markets is that it may be very misleading to interpret reductions in the average prices in a wholesale market due to adding wind generation as indicative of positive net benefits for the network. In some of the scenarios considered in this paper, the annual payment in the wholesale market decreases at the same time that the Total Annual System Cost increases. For planning purposes, it is essential to consider the Financial Adequacy of the conventional generators as well as the wholesale prices when evaluating the economic net benefits of adding wind capacity and/or upgrading transmission on a network. Even though the scenarios presented in this paper make the characteristics of wind generation difficult for the network to accommodate,²¹ the most important conclusion is unaffected. Adding wind generation to

¹⁹A similar zero-sum game exists for regulated transmission owners. Some earnings come from the congestion rents in the wholesale market and the rest is made up as additions to the retail rates charged to customers.

²⁰Excess profits imply that the actual earnings for a generating unit are larger than the minimum amount needed for Financial Adequacy. This amount depends on the type of market considered. For example, excess profits are highest in the deregulated market, Mkt1, and are zero in a regulated market, Mkt3.

²¹The beneficial effects of the spatial aggregation of different wind farms on reducing the amount of conventional generating capacity needed for reliability are not considered

a network will lower the annual earnings of the conventional generators in the wholesale market, and at the same time, increase the amount of missing money. The higher payments per MW needed to maintain the Financial Adequacy of the conventional generators imply that there should also be higher economic incentives for equipment like storage and controllable loads that can reduce the amount of installed generating capacity needed to maintain System Adequacy. The economic benefits of reducing the peak system load per MW will be higher when there is more wind generation on a network.

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