

Wind Integration Studies: Optimization vs. Simulation

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1. Introduction

A variety of circumstances have focused attention in the electricity industry on the large scale development of renewable energy generation. The motivations for this attention include concerns about the environmental effects of fossil fuel generation as well as the dependence of electricity production on fossil fuels. For all practical purposes these concerns mean the large scale deployment of wind energy. Wind energy is the most economic of the various renewable energy technologies.¹ Among the many challenges posed by adopting policies favoring renewable energy is adapting the existing power system to the substantially different technical characteristics of wind generation compared to the thermal generation technologies which dominate the existing power system. Wind generation exhibits substantial variation in availability. It typically is more available during off-peak periods than on-peak periods.² Additionally, the highest quality North American wind generation resources are typically located comparatively far from load centers. This means that new transmission is likely to be needed to deliver large amounts of wind energy generation to load centers. These two issues, resource variability and location, are being addressed in a variety of studies that examine how to integrate wind generation into the existing power system.

This paper focuses attention on the methods used in wind integration studies. I contrast five studies using different fundamental approaches for this purpose. To illustrate optimization methods, I review a study by James Bushnell focusing on California and other regions in the western US. To illustrate simulation methods, I examine a study by CRA of conditions in the Southwest Power Pool (SPP) region. I also examine a much simplified simulation approach to transmission planning for large scale renewable generation, the recent ERCOT study designed to optimize network expansion for integrating wind energy, and a large study examining inter-regional wind energy transfers. Each method adds value for particular questions, but each also has limitations, which I will identify. Before reviewing the individual studies, I begin in Section 2 with a brief discussion of terminology and motivation. There can be more than a little semantic ambiguity surrounding some of the topics I address, so I think it useful to clarify what I mean by some of the terms I use, and why I choose the definitions that I do. Next, I turn in Section 3 to the CRA simulation study because these methods are the most commonly used. In Section 4, I address Bushnell's optimization approach. Section 5 summarizes some results from a transmission planning scoping study by Mills, Phadke and Wiser. Section 6 discusses the ERCOT transmission optimization study. While this study does not use an optimization model in the formal sense, it conveys important intuitions about transmission planning. Section 7 examines a creative approach to the design problem of accommodating outage contingency constraints that arise when transmission network expansions must be added to accommodate new large scale wind generation. Section 8 concludes with some recommendation for improving these studies.

2. Terminology and Motivation

"When I use a word,' Humpty Dumpty said in rather a scornful tone, 'it means just what I choose it to mean — neither more nor less.' — [Lewis Carroll \(Through The Looking Glass\)](#)

Let me begin with the term “wind integration study.” In many discussions, this term refers to operational issues primarily associated with wind output variability and the ramping requirements that this imposes on the thermal generators. A number of studies have concluded that these costs are about \$5/MWh.³ My motivation in this review, as an economist, is to find the big money. All of the studies that I examine focus on “large” economic questions. I conclude that for large scale wind integration the big money is in transmission cost expansion. Not all people share this view, at least about the semantics. For example, Black and Veatch write in their “Primer” on this topic:

“Typically, the incremental transmission infrastructure needed to integrate wind generation is not considered a wind integration cost, although there is often a need for new transmission in order to move the output of new wind plants without creating undue congestion on the grid.”(p.2)

I will argue in subsequent discussion that transmission costs for integrating large amounts of wind generation are typically at least \$20/MWh and often more.⁴ A lexicon which defines wind integration by focusing on the smaller operational costs as opposed to the larger transmission costs seems unduly restrictive to me.⁵

Next, I treat renewable generation as primarily wind. To be sure, the solar and biomass technologies can make a contribution to renewable energy policy goals, but the experience base among these technologies is wildly different. The amount of commercial solar thermal generation operating today is quite small compared to the amount of wind generation. Biomass may or may not be slightly more prevalent, but again this difference with wind is an order of magnitude. So the majority of the economic response to renewable energy policy goals has been and will likely continue to be wind generation. Because the best wind sites are typically far from load centers, substantial transmission will be required to integrate this resource.

Finally, let me say a few words about the terms “simulation” and “optimization.” The Encyclopedia of Computer Science defines simulation as follows:

Simulation is the process of designing a model of a real or imagined system and conducting experiments with that model. The purpose of simulation experiments is to understand the behavior of the system or evaluate strategies for the operation of the system.⁶

The algorithms used in a simulation model may include as part of the representation an analytical model that maximizes or minimizes a certain function. So a production cost model has a procedure which minimizes simulated production cost under a number of constraints. While this minimization may be described as an optimization, the overall purpose of the model is to understand system operation and see how sensitive the model results are to changes in inputs.

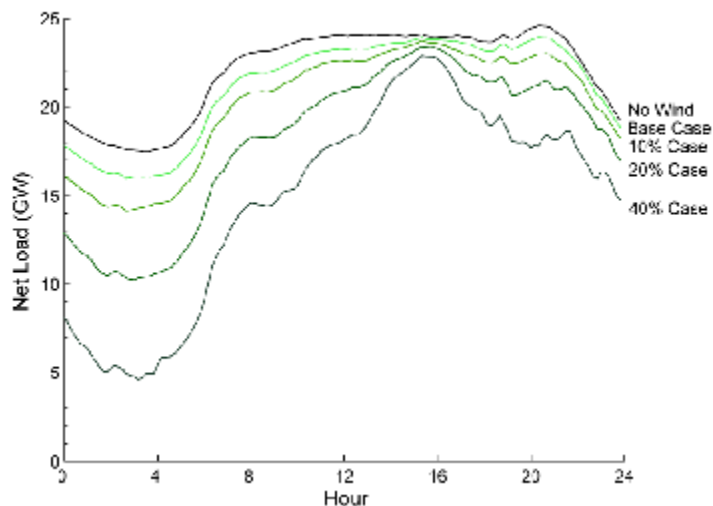
Optimization itself is best thought of as a choice technique. The goal is to decide something. What values for certain specified decision variables satisfy the objective function of the problem at hand optimally. Optimization problems can be difficult to solve when the relevant constraints are non-linear and/or the choice set is complex. So an optimization model may rely on simplifications to make solutions easier. The art of applied optimization is to make useful simplifications, but to retain essential characteristics.

With these matters of conceptual hygiene established, I now turn to the substantive issues.

3. CRA's Simulation Study

To illustrate the mismatch between load and the wind energy resource availability, CRA calculates the net load. Net load is simply the load on a particular day minus expected wind energy generation. Net load is a sensible concept because wind energy has extremely low (basically zero) marginal cost, and therefore would typically be dispatched ahead of all other resources, except when transmission constraints or minimum production constraints on committed thermal generation are binding. As is common in the recent wind integration studies, CRA considers a fairly large range of wind generation. Figure 1 (reproducing Figure 5.2.2-1) shows an example of the very substantial decrease in off-peak net load on a particular day as wind penetration goes from zero to the modest Base Case levels and then to 10%, 20% and 40%.

Figure 1. Net Load – Example for a day in the Spring Season



At the larger penetration levels, net load falls dramatically in the early hours of the day. At such low net load levels, constraints on off-peak operation may begin to appear, along with very significant ramping requirements to meet the large diurnal swings in net load. Thermal generating units typically maintain minimum levels of generation during off-peak periods even if market prices for energy are below operating cost at such times. This occurs because start-up and shut-down costs can be quite substantial, reducing or eliminating any benefit of more flexible

operation. Cullen and Scherbakov (2010) derive the operational inflexibility phenomenon conceptually from the profit optimization model developed in their paper.

Off-peak over generation constraints, i.e. too much generation relative to load, coupled with transmission limitations, can even result in negative energy prices in the export constrained area. This has occurred already in many markets with growing wind generation (Fink et al, 2009). Baldick (2009) shows an example of such negative energy prices in ERCOT in the Spring of 2009. In this example, the West zone, the region where wind generation is primarily located, exhibits negative energy prices. More generation wants to be exported from the West zone to the load centers, the Houston and North zones, than the network can accommodate. Negative energy prices in transmission constrained areas highlight the importance of expanding the transmission network along with increased wind energy penetration.

CRA shows the geographic distribution of wind energy production and other generation in SPP in the 20% wind generation case graphically (see Figure 4.4.1-1). Most of the wind generation is located in the western part of the SPP footprint and most of the thermal generation is located in the eastern part of SPP. Without significant transmission reinforcement the wind generation cannot be utilized. CRA runs a number of power flow simulations to determine whether the flows required to match generation with load are feasible.

It turns out that transmission reinforcements are required to meet reliability requirements, including outage contingency constraints. A reliable transmission network must have enough spare capacity to absorb flows that are re-directed when an outage occurs. An outage contingency list is typically developed by transmission planners to “stress test” the system. While generation and transmission outages are both commonly on such lists, the main constraints are typically line outages, even though line outages are much less frequent than generation outages. Most of the new lines added in the CRA study involve reinforcement of east-west paths. The reinforcements are much more substantial in the 20% wind penetration case than the 10% case (the analysis was not conducted for the 40% case). In particular, the 20% case includes six lines at 765 kV, where there are none at this voltage level in the existing system or in the 10% wind penetration case. The 765 kV lines include a loop configuration. The particular transmission lines added are listed in CRA report in Table 4.3.3-1 for the 10% case and Table 4.4.3-1 for the 20% case. They are divided into those necessary in the pre-contingency case and those required in the post-contingency case. It is interesting to note that very few reinforcements are in the post-contingency category after the 765 kV lines are added in the 20% case. The highest voltage (and therefore capacity) level in SPP currently is 345 kV. The capacity of a 150 mile 765 kV line is approximately six times greater than a 345 kV of similar length.⁷

The transmission reinforcements described in the CRA study were provided by SPP engineers.⁸ The 765 kV additions simulated in the 20% wind penetration case are similar to configurations examined in earlier SPP studies.⁹ Importantly, the authors of the CRA study are clear that it is not an economic analysis, which they define as, among other things, “an analysis of the tradeoff between building transmission upgrades and curtailing wind” (p.1-1). The more fundamental question is how to determine the economic expansion of the transmission network; i.e. what upgrades are optimal.

Despite their acknowledgement that the CRA study is not an economic analysis, they do conduct some production simulations, the tool commonly used for economic analysis. Some results from these simulations are reported in Section 6 of their report. I will discuss some of these results in the next section.

There is much additional material in the CRA study including assessment of wind forecasting error, daily ramping requirements and detailed reliability assessments. These aspects are, in my assessment, secondary to the main themes.

However useful some of this analysis is, the economic questions associated with these topics cry out for more attention.

4. Bushnell's Optimization Study

Bushnell also begins with the net load concept. His net load is slightly different than the concept used by CRA; differences which are not particularly important for this discussion.¹⁰ More fundamentally, the questions that Bushnell addresses are oriented to long run investment rather than to short-run operations. The investment question on which he focuses is electricity generation technology choice. He conducts a variation of “the classic framework of utility investment in which a mix of technologies of varying capital intensity are applied to satisfy fluctuating demand” (p.8). His principal result is “that as the level of wind penetration increases, the equilibrium investment mix of other resources shifts towards less baseload and more peaking capacity” (Abstract).

Unlike the “classic framework” for the capacity expansion problem, which is based on costs only, Bushnell includes a major role for energy market prices in finding the optimal mix of conventional generation. Price in the Bushnell model is the result of a breakeven cost calculation on the amount of capacity added. There is a price equation which results in prices equal to marginal operating costs as long as supply is greater than demand. When demand exceeds supply, price rises subject to a modest price elasticity. At sufficiently high prices, more capacity is added until equilibrium is reached. This formulation results in prices that are much more volatile than what is observed in markets operating today. Figure 5 in Bushnell's paper shows August prices reaching \$5000/MWh occasionally in the California region and exceeding \$1000/MWh occasionally in the other regions. Conversely, in December, prices approach zero in the Pacific Northwest and Rocky Mountain regions (Figure 6). These results characterize what Bushnell calls an “Energy-Only” market; i.e. one with no price caps and no capacity payments. An alternative formulation implements a \$1000/MWh price cap and adds a capacity payment. The result is a flatter distribution of prices, as would be expected, and no material change in the optimal mix of technologies.

To simplify the optimality calculation, the Bushnell model suppresses chronological effects and assumes that capacity does not come in discrete sizes. While the latter assumption is comparatively harmless for the large regions modeled, the neglect of chronology means that the operational issues, such as ramping requirements or forecast error, examined by the CRA study cannot be addressed in principle. Bushnell is quite explicit about both points. More importantly,

however, he does not even address the transmission topic. This is a major omission from anyone’s list of issues relevant to the integration of wind energy. Bushnell’s methods can, in principle, incorporate transmission. In another of his papers a very similar model does this.¹¹ As this model currently stands, however, the lack of transmission potentially calls into question even the type of result that the model claims to find. This point can be illustrated by examining the qualitative results of some of the dispatch simulations reported in the CRA study discussed above.

Table 1 below (reproducing Table 6.1.3-2) from the CRA study shows that transmission affects thermal dispatch (a point illustrated rather dramatically by the negative prices in ERCOT referred to above). Table 1 is not particularly transparent, so I will begin by looking back at Figure 1, the graph of net load. This figure shows substantial declines in off-peak net load as wind penetration increases. The generation we would expect to be displaced by off-peak wind, particularly at higher penetrations, would be the lower cost baseload units. In SPP these are coal-fired steam generators. Oil and gas units, even efficient combined cycle units, have higher costs.¹² These units are less likely to be displaced by off-peak wind generation since they are not typically operating off-peak anyway. Table 1 summarizes the changes in dispatch by reporting how the types of units which are marginal change across the scenarios. When we examine the steam coal units (STc), we see that the fraction of time that these units are marginal is always higher in the wind cases than the base case. This is consistent with an expectation that wind will displace off-peak generation, which is predominantly coal in SPP. This displacement shows up as more hours when steam coal is marginal. Details of the dispatch results are summarized in Section 5.3.3 of the CRA report.

Table 1. CRA Simulation Results

Case Profile	Base Case				10% Case				20% Case			
	2004	2005	2006	Average	2004	2005	2006	Average	2004	2005	2006	Average
C/C	26%	28%	27%	27%	19%	21%	21%	20%	26%	30%	30%	29%
GT	32%	33%	33%	32%	31%	33%	31%	31%	26%	27%	26%	26%
STc	28%	25%	25%	26%	36%	32%	32%	33%	35%	30%	29%	31%
STgo	14%	15%	16%	15%	14%	15%	17%	15%	13%	13%	15%	14%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

When we look at the results more closely, however, the simple story becomes more complex. The change from the 10% wind case to the 20% wind case included the addition of six 765 kV lines and numerous other lower voltage lines. More transmission in the CRA 20% case means more efficient use of thermal generation. This is apparent in Table 1 where the STc marginal share goes down compared to the 10% case. The decrease in the amount of time that steam coal is marginal means that the dispatch is more efficient. The low variable cost generation should be infra-marginal. If it is pushed up onto the margin by transmission constraints that require higher cost generation to operate because that generation is closer to load, then the dispatch is less efficient than it would have been all other things equal. This increased efficiency occurs in the 20% wind generation case even though the net load graph would suggest that coal should be marginal more under more wind because the net load in the off-peak periods is lower, which should displace low cost coal.

The results in Table 1 are not particularly easy to interpret. The STc fraction of marginal hours does decline in the 20% case compared to the 10% case, but not to the level of the Base Case.

The overall use of coal is less in the 20% case than the 10% case. Without trying to parse these simulations very closely, it is at least comparatively clear that the kind of optimal generation mix analysis Bushnell conducts assumes optimal transmission planning to support its results.

It is not clear if this effect is big enough to matter materially in Bushnell’s results. What is important, however, is that a study of large scale wind generation that omits transmission reinforcements does not contribute much to the actual problems at issue.

5. Indicative Transmission Planning

Mills, Phadke and Wisser (2010) develop an interesting analysis of transmission requirements for a 33% renewable energy target in the WECC region. This study does not rely on detailed engineering methods. Instead, the goal is to estimate which renewable resources would be selected to meet a high level of renewable generation. The resource selection includes estimating the transmission costs to deliver the resources to load centers. A number of cases are run to see how results vary with assumptions. Given this model use, it is best to think of the tool as a simulator, even though there is a cost minimization algorithm at the core of its computational engine. The variation in the results found by these authors derive from cost uncertainties associated with solar thermal technology as well as the regulatory uncertainties about the availability of tradable renewable energy credits and federal tax incentives for renewable generators. Although indicative transmission planning may not be the authors’ primary purpose, the structure of their analysis requires that indicative transmission planning be done.

While the methods applied in this study are useful for first approximations, there are two particular issues that call the study’s results into question. First and most importantly, the claim that transmission costs are relatively small for meeting a 33% renewable energy target is questionable. Mills, Phadke and Wisser (hereafter MPW) assume that transmission capital costs are \$1564/MW-mile for a 500 kV line that carries 1500 MW (p. 11). This assumption is optimistic. I assemble some comparable estimates in Table 2 to illustrate this point.

Table 2. Normalized 500 kV Line Costs

Project Sponsor	Type of Estimate	Configuration	Transfer MW	miles	Cost	\$/MW-mile
MPW	generic		1500			1564
AEP	generic			100		2880
SCE Tehachapi	Project specific	Multiple loops 2/3 existing ROW	4350	230	\$2.6B	2600
SCE Devers Palo-Verde 2	Project specific	Parallels existing line	1200	250	\$0.8B	2666
SDG&E Sunrise	Project specific	New ROW some undergrounding	1000	120	\$1.9B	15800

Heyeck and Wilcox (2008), from American Electric Power (AEP), give a generic, non site-specific, cost estimate which normalizes to \$2880/MW-mile.¹³ Their estimate excludes station costs. The Tehachapi Renewable Transmission Project, sponsored by Southern California Edison (SCE), is a collection of eleven segments in a configuration of multiple loops which is currently under construction, and that will deliver about 4350 MW over 230 miles of 500 kV lines.¹⁴ The cost of the project is approximately \$2.6 billion.¹⁵ The normalized cost of the Tehachapi project is therefore about \$2600/MW-mile. SCE is also proposing to build a second line parallel to its existing 500 kV Devers to Palo Verde line. This 250 mile project would increase transfer capacity by 1200 MW at a cost of about \$800 million.¹⁶ These parameters are equivalent to a normalized cost of \$2666/MW-mile. At the opposite extreme of costs is the \$1.9 billion Sunrise project being sponsored by San Diego Gas and Electric Co. (SDG&E) to meet renewable generation goals. This 500 kV project has a rating of 1000 MW, and is approximately 120 miles long.¹⁷ These parameters are equivalent to a normalized cost of about \$15,800/MW-mile, roughly an order of magnitude larger than the MPW estimate.

It is not completely straight-forward to compare these different estimates. Devers-Palo Verde 2 has essentially no right of way (ROW) costs since the design of the original project envisioned expansion at some future time. About 2/3 of the length of the Tehachapi lines use existing ROW. The AEP estimate appears to be based on new ROW, but excludes substation costs. The three California projects include capitalized financing costs (“Allowance for Funds Used During Construction”). I conjecture that the two generic estimates do not include these costs, which can be as much as 20% of the total cost. Line rating is a key determinant of normalized cost. If Sunrise were rated at the 1500 MW level assumed by MPW for a 500 kV line, its substantial normalized cost would be one third less. It is likely that the differences in line rating among projects have to do with reliability constraints associated with outage contingency criteria, as discussed briefly above in the context of the CRA SPP study. The multiple loop configuration of Tehachapi mitigates the burden of outage contingencies and is the likely reason that the rating of this project is so high compared to the others. The scoping methods of the MPW study do not take reliability criteria such as contingency constraints into account.

A second perhaps less important point, which is related to the first, is that the MPW study makes no attempt to evaluate the trade-off between solar photovoltaic at load centers versus renewable generation requiring large scale transmission. This omission was a condition of the study design (Mills, 2010). It is also a logical consequence of under-estimating transmission costs. If transmission is inexpensive, there is not much of a trade-off. I have argued elsewhere, based largely on the Sunrise costs (Kahn, 2008), that this can be an important trade-off.

One of the particularly striking results of the MPW analysis is how variable the transmission requirement might be depending on the relative costs of the different renewable generation technologies and regulatory policies. Figure ES-5 in their report shows a slightly more than two-fold variation in the number of transmission MW-miles required across the fifteen sensitivity cases examined in the study. The largest decrease in transmission expansion comes from policies that would allow load centers to meet renewable energy targets by purchasing credits for renewable energy delivered to other load centers. Such policies would obviously reduce the need for transmission.

Mills (2010) provides two sensitivity cases involving higher transmission costs. These are summarized in Table 3 below. One case (labeled High Cost Tx) doubles the MPW transmission line cost reported in Table 2 and allows the model to select a different pattern of resources. This brings the MPW transmission cost roughly in line with the AEP generic estimate in Table 2. The other case uses the new transmission line cost, but freezes the resource selection to be equal to the Base Case. Table 3 omits the geothermal resource of 28.6 TWh, which is common to all cases.

Table 3. MPW Transmission Cost Sensitivities

Summary	Resource Selection (TWh/yr)						Transmission Cost (\$Billion)
	ADC (\$/MWh)	T&L C Percent Delivered Cost	Hydro	Biomass	Wind	Solar	
(1) Base Case	\$43.19	14.7%	16.7	20.7	144.3	85.5	26.3
(2) High Cost Tx	\$54.63	19.2%	17.3	22.0	136.2	91.7	41.9
(3) High Cost Tx Base case resources	\$55.90		16.7	20.7	144.3	85.5	52.6

The acronym ADC (Adjusted Delivered Cost) is the economic figure of merit. It is defined by MPW as busbar cost plus transmission cost plus (operating) integration cost minus capacity value minus energy value.¹⁸ Raising the estimate of transmission line cost increases ADC by about \$11/MWh, taking into account the resource re-selection. The benefit of shifting away from 8 TWh of wind to hydro, biomass and solar is comparatively small relative to no shift (ADC is \$55.9 vs. \$54.6). The \$10 billion in reduced transmission (comparing Line 2 and 3 in Table 3) goes into the high cost hydro, biomass and solar technologies that are closer to load. These calculations allow us to conclude that the transmission part of the ADC in the sensitivity cases is about \$25/MWh. Doubling the transmission cost with the same resources raises ADC by \$12.71/MWh (comparing lines 1 and 3). So the total transmission cost in the sensitivity case (line 3) is twice that level, or \$25.42/MWh.

Finally, if transmission costs were very high, as in the Sunrise example, then it might be economic to locate storage technologies near the wind resource region and shape the wind profile to correspond better with the load shape. This would result in higher value for the transmission. It would also call into question Bushnell’s conclusion about the optimal thermal generation mix shifting toward more peaking and less baseload.

Scoping studies such as MPW can give a rough impression of transmission requirements, but not much more. In the next section I review a study that addressed large scale transmission plans more concretely.

6. ERCOT CREZ Transmission Optimization Study

While this study calls itself an optimization, there is no formal model in the style of Bushnell, for example, from which optimal results derive. Instead, the study was a collaborative effort between

stakeholder groups and ERCOT staff to identify efficient solutions to integrating various levels of wind energy generation that were identified by the Public Utilities Commission of Texas. The report outlines the thought process which went into the construction of the various scenarios examined. There is a particularly interesting discussion of contingency constraints in the section devoted to explaining Scenario 3 in the study. In this scenario, a 765 kV backbone was being considered.

In most of the scenarios developed, the lack of substations near load centers with sufficient existing transmission capacity led to the use of looped circuits in both the plans developed by ERCOT as well as those submitted by stakeholders. Under contingency, power-flows can move around a closed loop in the other direction to reach the same end-point, whereas each non-looped 765 kV line must terminate at two substations with sufficient transmission capacity. The plan depicted in figure 9 was originally developed with a single termination point in South Dallas in place of the loop around the east side of the city. Based on discussions with stakeholders, it was determined that there was no acceptable and feasible location for such a connection point, and, as a result, the 765 kV loop around the east of Dallas was required in order to disperse the power-flows on the high-voltage backbone (p.32).

The interaction between scale economies and dis-economies of 765 kV technology and the effect of contingency flows is complex. For the purposes of this discussion, the role of closed loops in mitigating the effects of contingencies is most important. The plan actually adopted, known as CREZ Scenario 2, exhibits multiple closed loops. This is also the case for the Tehachapi project listed in Table 2. Other large scale transmission projects designed to integrate wind energy also have this feature. One additional example is Independent Transmission Company's Green Power Express.¹⁹ Multiple loops mitigate the effects of contingency constraints by reducing the amount of excess transmission capacity needed to satisfy these constraints and thereby result in lower cost per unit capacity for projects that incorporate them. These effects can more than offset the extra costs of building looped configurations and therefore represent an economic approach.

Finally, it is worth saying a few words about the CREZ cost estimates. The plan adopted by the Public Utility Commission of Texas was Scenario 2 of the CREZ study. This scenario was estimated to have equipment costs of \$4.9 billion, to accommodate 11,535 MW of incremental wind generation capacity and to involve about 2300 miles of new ROW.²⁰ The cost estimate is based on certain generic assumptions, and may turn out to be higher. Right of way costs are not included. Capitalized financing costs and sponsor overheads do not appear to be included.

A number of adjustments are required to make a comparison to the specific California projects listed in Table 2. First, the CREZ configuration does not have a capacity rating. The nominal level of incremental wind generation MW needs to be reduced for two important factors, diversity and curtailment. Diversity reflects the non-simultaneous occurrence of maximum output. Diversity reduces maximum aggregate output by at least 30%. ERCOT recently reported a maximum wind generation output on the system of 6272 MW out of a total installed capacity of about 9000 MW.²¹ In addition, the design specification for sizing the transmission was to build so that total expected wind energy would be curtailed by 2% compared to the estimated production of the incremental wind generation.²² Because the distribution of potential wind

energy production can be expected to be quite peaked, a substantial number of peak MW need to be curtailed to result in a 2% energy reduction. I have not estimated how the curtailment requirement affects the maximum CREZ injection capacity. For the purposes of a rough calculation, I rely on the diversity data alone, and assume that the maximum CREZ injection capacity is 70% of the rated incremental capacity, or about 8075 MW. The equipment costs quoted in the CREZ report need to be increased for ROW costs, interest during construction and sponsor overhead costs to make it comparable to the project specific costs. These factors should increase the total costs to be recovered in rates to a level that would be at least twice the equipment cost estimate. Taking all these factors into account results in a cost per MW-mile that would be on the order of \$500.²³ This is quite low compared to the Table 2 estimates.

7. EWITS Study

The Eastern Wind Integration and Transmission Study (EWITS), sponsored by the US Department of Energy National Renewable Energy Laboratory is another look at the large-scale wind integration problem. EWITS takes a regional approach, as in the studies of Bushnell and MPW, but with much greater attention to engineering detail. EWITS is an ambitious exercise addressing many issues. Since its focus is on the year 2024, the study must address a version of the capacity expansion problem that is the focus of the Bushnell study. It also purports to do “economic” transmission planning. Addressing the details of the implementation of the EWITS methodology for this task is not necessary for my present purposes. The data uncertainties alone make the challenges of the exercise substantial. The principal result of the exercise is a scheme of five long distance DC lines that move power from the wind rich Midwestern states to the high priced load centers in the eastern US.

There is a very interesting, if somewhat elliptical discussion of the DC system design in a four page section of the report called “Design of HVDC Overlay Transmission” (pp.120-123). It is best to quote a bit from this section.

The HVDC transmission lines and the 765 kV and 500 kV AC systems for the EWITS scenarios form a self-contingent system that is designed not to overload the existing underlying transmission. HVDC lines perform the task of bulk energy transfer.... The AC system is used to collect wind energy and deliver wind energy to the source terminals of the HVDC lines, to distribute energy from the HVDC lines at the sink terminals to the loads, and to transfer energy from an area with an HVDC terminal influenced by a fault or outage to other areas that have HVDC terminals with capacity to increase schedules and their associated AC systems.

To illustrate how this set up might function the study provides a few schematic diagrams. Figure 2 (reproducing Figure 4-22 of the study) shows the post-contingency re-distribution of flows. In this figure, there is an outage on the top-most HVDC line. The 5700 MW scheduled on that line must be re-distributed over the AC system (looped lines on the left) to the other lines. The diagram indicates that the AC lines take about half of the flow to other DC lines and absorb the rest. The ability of the AC system to absorb the contingent flow is precisely the issue

identified in the CREZ study discussed above. In this case, the authors seem to simply assume that capability.

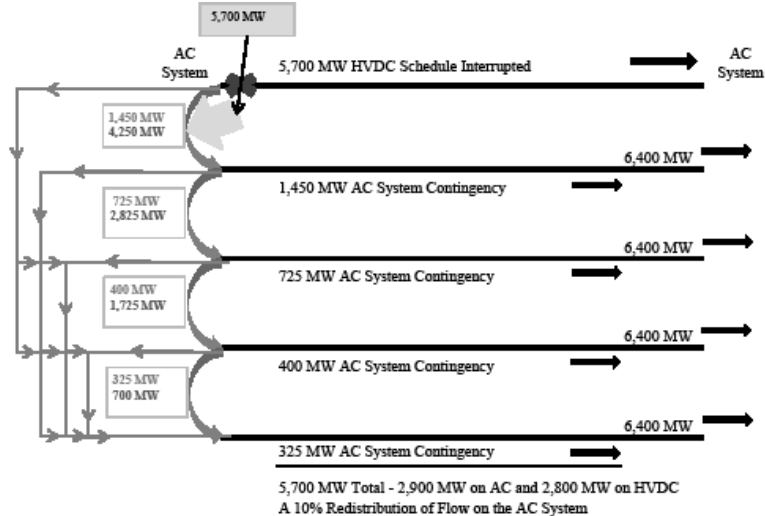


Figure 2. EWITS “Self-Contingent System” – Post Contingency

It is difficult to know how realistic the proposed design may be. At a minimum it is clear that the potential success of the arrangement (from a technical as opposed to a practical and feasible point of view) depends completely on the very specific topology assumed.²⁴ If there were only three DC lines instead of five, would the outage of one be able to be absorbed by the other two plus the AC system? Probably it would be necessary to load the DC lines at much less than 5700 MW each.

8. Suggestions on Advancing the State of the Art

Optimizing transmission for large scale renewable generation is a major integration problem for wind generation, perhaps the major integration problem. Screening tools typically fail to incorporate reliability constraints, which are a big part of the simulation methods used by CRA. Optimization models that address the transmission expansion issue without incorporating reliability issues are of limited use.²⁵ The CREZ study incorporates economic intuitions about reliability issues in an informal manner. However useful this may be in particular circumstances, it does not generalize or illustrate the range of validity for particular intuitions. The planning challenge is to find a way to incorporate reliability constraints in such a way that economic trade-offs can be made in a relatively flexible fashion. One important reason why planning flexibility is important is the inherent uncertainty concerning where the sites for new generation will actually be. Given this uncertainty, the ability to conduct multiple planning exercises efficiently rises in importance.

There are many types of reliability constraints. It is important to rank them by severity. I hypothesize that outage contingency constraints are the dominant effect. The reason they are dominant is that they can affect line ratings negatively, or alternatively increase costs by requiring the construction of additional lines. My impression, subject to further education, is that

a system which can survive contingency constraints will survive other reliability challenges, or at least at costs that are much less than the cost of new transmission lines.²⁶

Therefore, I believe that the research agenda for the integration of large scale wind generation should focus on developing optimization methods for transmission expansion subject to contingency constraints. Optimization methods, i.e. formal mathematical models, are the only way to address the economic trade-offs systematically. Once an optimal solution is found considering only the contingency constraints, the standard simulation methods to test for additional reliability issues can be conducted. It may well turn out that optimization will replicate the intuitive solutions currently being proposed, such as the expansion modeled by CRA for SPP or the CREZ proposals. The ubiquitous occurrence of looped configurations should emerge from a formal optimization. We would like to know how big the conjectured benefits of looped configurations are, what determines their diminishing benefits, and so forth. Given the costs of these expansions, it may provide regulators some comfort to know they are optimal. There are other situations in which large scale expansion proposals compete with one another. Absent some principled way to compare the value of competing projects, it is likely that competitors will argue over their favored simulations which find benefits for their own projects. Simulation wars in such settings may be costly and inconclusive.²⁷

Optimization methods for transmission planning may be difficult to build. Bushnell's model simplifies even the simple problem he addresses for this reason. Nonetheless, one cannot solve a relevant problem if one does not even try.²⁸ Endless unmotivated simulation studies of one alternative plan or another will not be an easy path to follow. There should be some effort put into developing and applying the optimization approach in realistic settings. Given the difficulty of solving such models for "fully realistic" cases, some plausible simplifications of the network configuration should be an acceptable approach. If we are going to undertake a major re-engineering of the US transmission network to accommodate large scale renewable generation, we ought to try to assure ourselves that the plan is, in some sense, sensible.

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Endnotes

¹ See Energy Information Administration, 2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010 available at http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html This table shows lower costs for geothermal and biomass generation, but these resources are not as widely available as wind generation.

² This appears to be the case in most regions. Apparently, off-shore wind generation has a better co-incidence between availability and electric load.

³ See for example Black and Veatch (2009) or the discussion in Mills, Phadke and Wiser (2010).

⁴ Midwest ISO (2009) at p.6 gives unit costs that are \$30-40/MWh on the low end and substantially more at the high end.

⁵ Another topic sometimes included under the heading of wind integration costs is the “capacity credit” appropriate to wind energy. Studies of this topic typically use an index of generation system reliability such as loss of load probability. This topic is discussed at some length in Kahn (2004). Summary discussions are given in Black and Veatch (2009) and Mills, Phadke and Wiser (2010).

⁶ Smith (2000).

⁷ The concept of capacity in high voltage transmission is complex given the variety of technical configurations possible and the role of reliability constraints. The figures cited here are discussed briefly, for example, in American Electric Power, “Interstate Transmission Vision for Wind Integration,” available at <http://www.aep.com/about/i765project/docs/WindTransmissionVisionWhitePaper.pdf>

⁸ Ruiz (2010).

⁹ See, for example, SPP, 2008 SPP EHV Overlay Report, December 19, 2008 available at http://www.spp.org/publications/2008%20SPP%20%20EHV%20Overlay%20Report_DRAFT_12_26_08_FINAL.pdf

¹⁰ Bushnell does not take account of hydro generation or combined heat and power (cogeneration) which are important in some parts of the Western US.

¹¹ See Bushnell and Chen (2009).

¹² Table 6.1.3-4 lists generic variable cost assumptions. Coal plants have a \$20/MWh variable cost and combined cycle gas have \$45/MWh. Peaking units are in the \$72-80/MWh range. The actual values used in the study differ (Tsuchida, 2010).

¹³ Heyeck, M and E. Wilcox (2008) give a table on p.6 which estimates the cost of delivering 2400 MW over 500 kV lines at \$6.9 million per mile, which is equivalent to \$2880/MW-mile.

¹⁴ The project is described on the SCE website. For Segments 1-3 see <http://www.sce.com/PowerandEnvironment/Transmission/CurrentProjects/TRTP1-3/> And for Segments 4-11 see <http://www.sce.com/PowerandEnvironment/Transmission/CurrentProjects/TRTP4-11/> The transfer capacity of the project was determined by the California ISO, see <http://www.caiso.com/1b6b/1b6bb5ca7400.pdf> The project map in this document is more informative than those on the SCE website because it shows the linkage of the Antelope-Pardee line (Segment 1) into other parts of the transmission network in the region.

¹⁵ See California Public Utilities Commission Decision 09-09-33, September 2009 for Segments 1-3 available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/107544.pdf and California Public Utilities Commission Decision 09-12-044, December 2009 for Segments 4-11 available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/111744.pdf

¹⁶ These parameters and the current state of the project are discussed in CPUC Decision 09-11-007 available at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/110360.htm

¹⁷ For background information, including the length of the line along its currently proposed Southern route, see <http://www.sdge.com/sunrisepowerlink/index.html>. The 1000 MW capacity of the line is mentioned in the Overview and Summary section of the SDG&E application to the California Public Utilities Commission (p.1.6) available at http://www.sdge.com/sunrisepowerlink/filings/cpuc/031208/Chapter_1_-_Overview_and_Summary.pdf

¹⁸ The column labeled T&L C Percent Delivered Cost in Table 3 apparently reports the annualized transmission cost divided by the sum of busbar cost and transmission cost without the integration cost and the value adjustments in ADC.

¹⁹ See <http://www.itctransco.com/projects/thegreenpowerexpress/thegreenpowerexpress-map.html>

²⁰ ERCOT (2008) p.2 for incremental MW and p.24 for equipment cost.

²¹ ERCOT (2010). By comparison, the California Independent System Operator (2010) shows hourly aggregate output for 2009 that has a maximum value of less than 1900 MW for an installed maximum nominal capacity of 2935 MW.

²² ERCOT (2008) p.23.

²³ If we assume \$10 billion for the total final capital cost, 8075 MW for the maximum injection capacity and 2300 miles of line, the result is \$538/MW-mile.

²⁴ Another example is Baldick and Kahn (1993). This paper shows how to solve the network expansion problem in an optimization framework where the contingency constraint is taken into account. The solution is formulated for a very specific setting. It is not clear whether it can be generalized.

²⁵ Oh and Short (2009) is an example of such a model.

²⁶ Voltage constraints are another commonly discussed transmission reliability issue; see Baldick and Kahn (1995) for example. Relieving voltage constraints is less expensive than building new lines, see Kahn and Baldick (1994).

²⁷ Kahn (1995) discusses regulatory simulation conflicts in the context of avoided cost pricing in California.

²⁸ The model developed in Choi, Mount and Thomas (2007), for example addresses transmission expansion under contingency constraints, but neglects to incorporate the Kirchoff's laws on power flow. This simplification tends to make the model comparatively useless.