Topological Elements of Transmission Pricing and Planning

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Abstract

Lagging investment in the North American transmission grid, due in part to ISO/RTO decisions, has increased costs to consumers and eroded system reliability. Regulatory policy distinguishes transmission investments that have primarily economic benefits from those that primarily enhance reliability. Economic investments, which benefit a few generators and customers, are to be handled using market incentives. Reliability investments, which benefit all grid participants, are to remain regulated and the costs spread over all participants. We show that the economic-reliability distinction does not hold and that transmission planning requires an analysis of network topology and demand. One ubiquitous network topology allows investors to profit from harming the network by building lines that cause congestion,. More fundamentally, a clear distinction between reliability and congestion seldom exists; the relationship between the two system attributes depends on the level of demand, as well as network topology. Network investment requires a power flow analysis of current and proposed topology and demand. A subsystem analysis focused on specific beneficiaries neglects the risk-management tradeoffs of congestion and reliability.

1. The Transmission Puzzle

The blackout of August 14, 2003, called into question the adequacy of the North American transmission grid. Although the official blackout report issued by the joint U.S.-Canadian task force (Blackout Task Force 2003) avoided laying any particular blame on the restructuring process, others (Joskow 2003, Joskow and Tirole 2006, Ilić 2003) have argued that restructuring had a subtle, yet vital, role to play. Decentralized decision-making has upset the utility hierarchical control paradigm without sufficient new measures to take its place. Regulators and regional transmission organizations (RTOs) have encouraged the nonutility or "merchant" sector to invest in necessary network upgrades, but have not allowed markets to send economically meaningful signals to these investors.

Table 1. Total and average congestion costs in PJM, 1999 – 2005.

	PJM Congestion Costs	
Year	Total ($M)	Average ($/MWh)
1999	53	0.20
2000	132	0.50
2001	271	1.02
2002	430	1.37
2003	499	1.52
2004	750	1.71
2005	2,090	3.05

Source: Blumsack (2006)

In both restructured and traditionally-organized electric systems, there is ample evidence that the transmission network has become increasingly constrained. Table 1 shows congestion costs in the PJM Interconnect; the cost of congestion has risen monotonically in total and on average since 1999. Figure 1 shows transmission loading relief (TLR) actions taken since 1997. The number of Level 2 events (the point at which curtailment of non-firm schedules begins) has increased nearly every year.

While the merchant generation sector has built more than 50 GW of new generation capacity since the onset of restructuring (Joskow 2005a, Blumsack, Apt, and Lave 2005), the merchant transmission sector has seen little activity. Market-based compensation mechanisms for new transmission have been proposed, using either point-to-point financial transmission rights (FTR) (Hogan 1992, Bushnell and Stoft 1996) or path-based flowgate rights (Chao and Peck 1996, Oren 1997), but to no avail. Not a single merchant transmission project has been built in the U.S. using market-based compensation (Joskow 2005b). Largely in response to the blackout of August, 2003, the Energy Policy Act of 2005 allows for the designation of "national interest transmission corridors" on the basis of persistent congestion.[1] Congress has given the Federal Energy Regulatory Commission (FERC) authority to intervene in the permitting, siting, and regulatory approval processes for these lines.

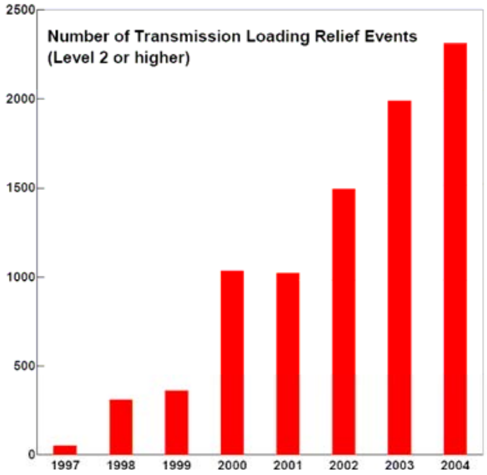

Figure 1. TLR events, 1997 – 2004.
Source: NERC

Several explicit and implicit assumptions underlie both the market-based and regulatory approaches to encouraging transmission investment, particularly for non-utility investment. This paper, which builds on work in Blumsack (2006), Blumsack, Lave, and Ilić (2006), and Blumsack and Ilić (2006), is primarily concerned with two of these assumptions. The first assumption is that locational marginal prices (LMP) can signal the market (or central transmission planners) as to which transmission upgrades might be profitable or socially beneficial. The second is that a clear distinction can be made between transmission upgrades that provide economic benefits to the system, in the form of reduced congestion, and those which increase the reliability of the system.

Problems in using LMP to identify profitable investments have been discussed in Wu, et. al. (1996). The present paper uses a particular network topology known as the Wheatstone network to demonstrate that while LMP may be able to identify the existence of constrained lines in the system, it cannot consistently identify the least-cost method of relieving constraints. Eliminating congestion is more complex that simply upgrading the most congested line or path. Under certain circumstances, removing lines from the network may reduce congestion. The Wheatstone network is also used to demonstrate that the economic and reliability aspects of a given transmission link are rarely independent.

2. Transmission Planning in the Old and New Industry

In the regulated electric power industry, the transmission network serves two physical roles. First, it delivers power to the distribution network and on to end-use customers. Second, it can act as a physical hedge against generator outages.

Thus, system reliability has been the primary driver of utility transmission investment. The transmission planning problem for the regulated and vertically-integrated utility amounts to choosing the least-cost set of transmission links in order for the system to satisfy all reliability criteria. Explicit mathematical formulations of the transmission planning problem are given in Coxe and Ilić (1998) for the case of static demand, and Yu, Leotard, and Ilić (1998) for the dynamic problem with uncertainty in locational demands.

Transmission planning was often performed as part of a two-stage process known as Integrated Resource Planning (IRP) (Coxe and Ilić 1998). In the first stage of IRP, the utility would determine what generation investments it needed to support resource adequacy under a number of different (usually peak) demand scenarios. Upgrades to the transmission infrastructure were then planned to support whatever new generation was needed.

With the introduction of markets and the vertical dis-integration of electric utilities, the transmission network must fulfill a third role of supporting competition among generators. Transmission investment decisions are determined by competitive concerns; market prices serve as the driver for investment plans rather than the outcome of investment plans. Under restructuring, the emphasis has shifted from viewing the transmission system as an asset that enhances reliability to viewing transmission as an asset that relieves congestion and facilitates competition.

Proponents of wholesale competition argued that economically efficient market prices would signal investors to build socially beneficial lines, although there has been some disagreement over what constitutes efficient pricing. Hogan (1992, 1993, 2000) has suggested a system of point-to-point

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[1] Energy Policy Act of 2005, ¶ 1221. The Act amends the Federal Power Act to direct the Department of Energy to conduct periodic reviews of transmission congestion, once every three years. Based on the results of these studies, DOE may designate certain regions or paths as national interest transmission corridors. The first such study is due out in August 2006. See FERC Docket No. RM-06-12-000, "Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Corridors."

financial transmission rights (FTR), which would entitle the holder to the difference in LMP between two specified points in the network. The magnitude of the FTR, in megawatts, would determine the share of congestion rent earned by the FTR's holder.[2] Thus, the value of an FTR is determined as a by-product of the energy market. Analyses by Chao and Peck (1996) and Oren (1997) have favored explicitly tradable flowgate rights, which would limit congestion rents to those occurring on defined congested paths.

Efficient allocation of FTRs require that they be allocated so as to pass a "feasibility" test (Hogan 1992), which would require that the net FTR holdings throughout the entire system respect all of the network constraints. The original purpose of the feasibility rule is to ensure that the RTO (which collects congestion payments in the form of LMPs and redistributes them in the form of FTRs) does not go bankrupt. Bushnell and Stoft (1996) claim that the feasibility rule, combined with a number of other economic assumptions, can also support economically efficient market-based transmission investment, whereas flowgate rights cannot. Rewarding non-utility investment with FTRs will yield new transmission that is both privately profitable and socially beneficial, and creates incentives to prevent the construction of lines that cause congestion.

This "strong" form of merchant transmission has been criticized by Joskow and Tirole (2005). They examine the economic assumptions underlying the merchant model, and find that even small deviations lead to incentive incompatibilities and a loss of economic efficiency. Section 3 of this paper, which summarizes Blumsack (2006, Ch. 3 and 4) and Blumsack and Ilić (2006) demonstrates that even if all of the economic and feasibility assumptions are satisfied, certain network topologies exist which would allow an investor to profit from congesting the network with new transmission lines.

3. Wheatstone Networks and the Braess Paradox

One policy response to increased stress on the transmission grid is to build more transmission lines or increase capacity along congested paths, just as automotive highways are expanded in response to larger and larger traffic jams. However, expanding network infrastructure will not necessarily increase network capacity. Under certain circumstances, adding links can actually increase congestion in the network, thus decreasing capacity. This phenomenon, first studied in the context of traffic networks (Braess 1968), is known as the Braess Paradox. Other networks where the Paradox has been observed and characterized include piping networks (Calvert and Keady 1993), telecommunications (Korilis et. al. 1999), and even crowd control (Hughes 2003).

The Braess Paradox is most often associated with a topology known as the Wheatstone network. An example Wheatstone power network is shown in Figure 2. An inexpensive generator with a capacity of 100 MW is located at bus 1, and a load with a constant real power demand of 100 MW is located at bus 4. An expensive generator is also located at bus 4. Buses 2 and 3 are assumed to be tie-points; they have neither net generation nor load. The transmission lines in the system are rated to 55 MW; the resistances on lines (1,3) and (2,4) are identical and equal to one-third of the resistances on lines (1,2) and (3,4). The link connecting buses 2 and 3 is called the Wheatstone bridge.

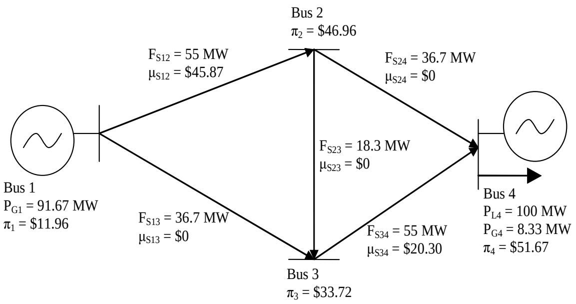

Figure 2. The Wheatstone test network.

Suppose that the network is lossless, and ignore any reactive power demands by the load at bus 4. The cost curves of the generators are parameterized as:

$$C(P_{G1}) = 200 + 10.3P_{G1} + 0.008P_{G1}^2$$

$$C(P_{G4}) = 300 + 50P_{G4} + 0.1P_{G4}^2.$$

A DC optimal power flow was run on the network parameterized in Figure 2. Conservation of energy requires that the flow patterns in the cut sets represented by buses {1,2,3} and buses {2,3,4} be identical. Without the Wheatstone bridge, 50 MW of power will flow along each path from bus 1 to bus 4. The inexpensive generator is able to serve the entire load, and the total system cost is $1,620/hour. Adding the Wheatstone bridge to the network causes congestion in the network along the low-resistance lines (1,2) and (3,4), as shown in Figure 2. Only 91.67 MW can be transferred across the network from buses

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[2] LMP differences define the congestion rent between two locations in the network.

1 to 4; the expensive generator at bus 4 must make up the remainder. This increases the total system cost to \$1,945/hour. The LMPs at three of the four buses adjust to reflect the network congestion; in particular, the LMP at the load bus increases to \$51.67/MWh from \$12.11/MWh. Thus, under market-based electricity pricing, the market-clearing price (and in particular, the amount paid by the load at bus 4) would increase by more than four-fold.

3.1. Implications of the Braess Paradox for Transmission Planning

Milchtaich (2006) examines a wide class of undirected networks and shows that the presence of an embedded Wheatstone sub-network is a necessary and sufficient condition for that network to exhibit the Braess Paradox.[3] As Blumsack and Ilić (2006) show, things are not that simple in power networks; the conditions for the Paradox to hold in power networks are much different than in other types of undirected networks. Neither the necessity nor the sufficiency condition of Milchtaich's analysis holds. In any network topology, it is possible to add a transmission line that will cause congestion; the simplest example is adding a high-admittance, low-capacity line in parallel with an existing line. Further, adding a Wheatstone bridge to an existing network does not necessarily cause congestion; this depends on the level of demand, the relative admittances of the other lines in the network, and their rated limits, as shown in Figure 3. Combinations of Wheatstone bridge susceptance and stability limit on line (1,2) that do not cause congestion in the network (for a real power demand of 100 MW at bus 4) are shown in the "feasible region" above the line; combinations below the line will cause congestion.

Analysis of Wheatstone networks and the Braess Paradox (as in Figure 2) in power systems suggests several additional policy implications for transmission planning.[4]

Result 1: Transmission upgrades must be made across the network.

Just as eliminating only one segment of a transmission bottleneck will simply push congestion somewhere else in the network, localized upgrades in Wheatstone networks may do nothing to relieve local congestion or the system constraint. In the Wheatstone network of Figure 2, adding the bridge to the network congests both lines (1,2) and (3,4). Upgrading the stability limit of just one of the two congested lines will not remove the congestion between buses 1 and 4, and will not lower the total system cost of providing 100 MW of power to the load at bus 4. Both network constraints must be relieved (or the Wheatstone bridge must be disconnected from the network) before the congestion will disappear.

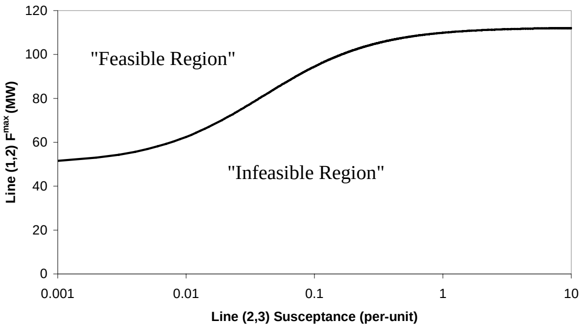

Figure 3: Adding a Wheatstone bridge to a power network does not necessarily cause congestion.
Note: The x-axis has a logarithmic scale.

Result 2: Relieving congestion is more complex than just upgrading the most congested line.

Shadow prices and differences in LMPs may be able to identify the presence of network congestion, but do not always identify how constraints should be relieved. This is a different statement than the well-known property of LMP described in Wu, et. al. (1996), that differences in LMP do not necessarily indicate the presence of congestion. In the four-bus test network of Figure 2, both congested lines sport non-zero shadow prices. For this network, however, these shadow prices do not represent the social value of relieving a single constraint. Since (according to Result 1), both lines must be upgraded to relieve congestion, the sum of the two shadow prices represents the social value of incremental upgrades to both lines.

Result 3: The economic efficiency of market-based transmission investment depends on the network topology.

Economic efficiency normally requires alignment between private incentives and the social welfare, including accounting for any externalities. Investments that are both privately profitable and socially beneficial would be considered economically efficient. Analysis by Bushnell and Stoft (1996) suggests that if transmission investment is

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[3] Undirected networks are those in which traffic is free to flow both ways along any given path. AC power systems (with or without loop flows) are an example of undirected networks. DC power systems, or even AC systems equipped with flow-control devices, may be described as directed networks.

[4] Mathematical proofs may be found in Blumsack and Ilić (2006).

compensated with incremental FTRs, allocated based on the amount of capacity created, and uses Hogan's feasibility rule, then market-based transmission investment can be economically efficient.[5]

This result, however, is limited by the network topology. We will again use the Wheatstone network of Figure 2 as an example. Central to the efficiency results of Bushnell and Stoft is that no individual market participant be left worse off after a change in network topology that changes LMPs. Blumsack (2006, Ch. 4) and Bushnell and Stoft (1996) show that the change in welfare of the *k*th market participant following a change in LMP is given by:

$$(1) \qquad \Delta W_k = \boldsymbol{\pi}^{*\prime}(\mathbf{p}^*_k - \mathbf{p}_k) - \left(C_k(\mathbf{p}^*_k) - C_k(\mathbf{p}_k)\right),$$

where $\boldsymbol{\pi}$ is the vector of network LMPs, $\mathbf{p}_k$ is the vector of net injections or withdrawals by the *k*th market participant, and C_k is the cost function (for generators) or value function (for loads) of the *k*th market participant. Starred variables indicate equilibrium prices and net injections following a change in LMPs.

Consider the generator located at node 1 in the network shown in Figure 4.2. The cost function of the generator is assumed to be $C(P_{G1}) = 200 + 10.3P_{G1} + 0.009P_{G1}^2$. Assume that the only spot market position taken by the generator is to inject power into the grid at node 1. In other words, the **p** vectors for generator 1 contains all zeros except for the real power production of the generator, which is in the first entry of the injection vector $\mathbf{p}_{G1} = (P_{G1}, 0, 0, 0)$, and $\mathbf{p}_{G1}^* = (P_{G1}^*, 0, 0, 0)$.

In addition to injecting P_{G1} MW of real power into the grid, suppose that the generator's contracts match its dispatch; thus, the generator also has an FTR between node 1 and any other node in the network. The size of the FTR is equal to P_{G1} in magnitude.

Suppose that prior to the construction of the link between nodes 2 and 3 of the network in Figure 4.2, the generator at node 1 could supply the entire load at a lower cost than generator 2. Thus, P_{G1} = 100 MW and $\mathbf{p}_{G1}$ = (100, 0, 0, 0). After the construction of the link between nodes 2 and 3, the network becomes congested and generator 1 is only able to supply 91.67 MW (as shown in Figure 4.2). Thus, $\mathbf{p}^*_{G1}$ = (91.67, 0, 0, 0). The vector of nodal prices following the network expansion is $\boldsymbol{\pi}^*$ = (11.96, 46.96, 33.72, 51.67). According to the formula derived by Bushnell and Stoft, the change in net benefit to generator 1 from the construction of line S_{23} is:

$$(2) \qquad \Delta W_{G1} = \begin{pmatrix} 11.96 \\ 46.96 \\ 33.72 \\ 51.67 \end{pmatrix}^{\prime} \left(\begin{pmatrix} 91.67 \\ 0 \\ 0 \\ 0 \end{pmatrix} - \begin{pmatrix} 100 \\ 0 \\ 0 \\ 0 \end{pmatrix} \right) - \left[C_{G1}(91.67) - C_{G1}(100) \right] = -1.05.$$

Thus, generator 1 sees her net benefit decline with the addition of the Wheatstone bridge to the network.

Next, we show that it is possible for an investor who builds a congestion-causing Wheatstone bridge to select a feasible and profitable set of FTRs. We first note that once the Wheatstone bridge is built, the investor is immediately saddled with FTRs equal in magnitude but opposite in direction to the flow of power across the bridge. In the network of Figure 2, the investor would have to take 18.3 MW of FTRs from bus 3 to bus 2. These have a value of 18.3 MW × ($33.72/MWh - $46.96/MWh) = -$242.29/h.

Since the addition of the Wheatstone bridge reduces the effective transfer capability across lines (1,3) and (2,4), both by 13.3 MW, the investor would also need to take 13.3 MW worth of FTRs from bus 3 to bus 1, and from bus 4 to bus 2. The value of this set of FTRs is 13.3 MW × [($33.72/MWh - $11.96/MWh) + ($51.67/MWh - $46.96/MWh)] = $352.05/h. The net gain to the investor is thus $109.76/h.

The RTO could insist that the investor also take 5 MW of FTRs from bus 1 to bus 2 and from bus 3 to bus 4, so that the set of FTRs would match exactly the physical dispatch of the system. This would lead to a negative return for the investor, and the Wheatstone bridge would not be built.[6] However, the feasibility allocation rule would not, in itself, require that the investor take these additional FTRs. Further, requiring investors to absorb enough incremental FTRs to match the physical dispatch of the system would lead to beneficial projects not getting built.[7]

4. Congestion and Reliability are not Independent

Adding a Wheatstone bridge to an existing power network has the immediate effect of causing

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[5] While market-based transmission investment may be efficient, there is no guarantee that it will be optimal, in the sense of solving the integrated resource planning problem.

[6] The loss to the investor would, in this case, be smaller than the increase in generation cost required to serve all 100 MW of load at bus 4. Thus, an investor could pre-emptively threaten to build the line unless she were paid not to.

[7] The reason, as discussed in Blumsack (2006, Ch. 2 and 4) is that compensating investors based on congestion rents (differences in nodal prices) does not fully account for the cost of out-of-merit dispatch due to congestion. Thus, the investor's compensation would not reflect the full benefit to the network.

congestion in the network, unless all the transmission lines have stability limits that are very large relative to demand. Such network configurations would seem to be a losing proposition. Yet, the Wheatstone topology is reasonably common in actual power networks, as discussed in Blumsack (2006).

The benefit of the Wheatstone topology is that under some circumstances, the Wheatstone bridge might enhance system reliability. Consider the example network in Figure 2, and assume that the generator at bus 4 can produce 10 MW of real power, and that lines (2,4) and (3,4) have stability limits of 100 MW. Suppose that an outage occurs on line (2,4) or line (3,4). If the network does not have the Wheatstone bridge, only 50 MW can be transferred from bus 1 to bus 4, resulting in unserved load or blackouts at bus 4. Once the Wheatstone bridge is built, an outage on line (2,4) or line (3,4) will not lead to load shedding. Following the outage, power can effectively be re-routed over the Wheatstone bridge.

Congestion and reliability represent tradeoffs in the Wheatstone example network of Figure 2. During normal operations, the bridge causes congestion. During transmission-line outages, the bridge provides a reliability benefit to the network. Wheatstone networks embedded in larger systems are invariably more complicated to analyze than the simple example in Figure 2. Whether the reliability benefit outweighs the congestion cost of a given network configuration depends on identifying the relevant range of demand. Over some ranges of demand, congestion and reliability may actually be independent. Over other ranges of demand, congestion and reliability may represent tradeoffs or even complements. This section discusses a framework for assessing these costs and benefits, and uses this framework to examine some embedded Wheatstone sub-networks of the IEEE 118-bus test system.

4.1. A Framework for Cost-Benefit Analysis of Transmission Projects

The congestion cost imposed on the system during normal operations is measured by calculating the total cost of serving the demand profile $P_L = (P_{L1},...,P_{LN})$ with and without the Wheatstone bridge in place. Suppose that the generation profile for the network is $\{P^*_{G1},...,P^*_{GN}\}$ with the Wheatstone bridge, and is $\{P'_{G1},...,P'_{GN}\}$ without the Wheatstone bridge. Then the congestion cost associated with the Wheatstone bridge during a single period can be written as:

$$(3) \quad CC = \sum_{i=1}^{NB} \left(\int_0^{P^*_{Gi}} MC_i(P_{Gi})dP_{Gi} - \int_0^{P'_{Gi}} MC_i(P_{Gi})dP_{Gi} \right).$$

Note that for the Wheatstone network in Figure 2, we have $CC \geq 0$, but this need not necessarily be the case.

We measure reliability using the cost of unserved energy (CUE). Other reliability metrics, such as loss-of-load probability, loss-of-energy expectation, and the $N - k$ criteria, are formulated in Coxe and Ilić (1998) and Choi, et. al. (2006). Conditional on an outage on one of the Wheatstone boundary links, let T_W be the maximum transfer capability across a given portion of the network with the Wheatstone bridge in place (in this paper we will restrict our attention to portions of the network representing embedded Wheatstone sub-networks), and let T_0 be the maximum transfer capability across the same portion of the network without the Wheatstone bridge. Let v represent a continuous, differentiable, and non-negative customer value function for consuming electricity. Finally, let U be a Bernoulli random variable equal to one (with probability u) in the case of a transmission line outage in a given period, and zero (with probability $1 - u$) if there is no outage. The cost of unserved energy in a given period is given by:

$$(4) \quad CUE = U \times \left(\int_0^{T_W} v(T)dT - \int_0^{T_0} v(T)dT \right).$$

We consider a particularly simple parameterization of the value function, where v is equal to a constant value of lost load (VOLL). In this case, equation (4) becomes:

$$(4') \quad CUE = U \times \left(VOLL \times T_W - VOLL \times T_0 \right).$$

Combining (2) and (3') yields the expression for the expected net benefit of a given Wheatstone bridge:

$$(5) \quad E(NB) = \underbrace{u \times \left(VOLL \times T_w - VOLL \times T_0 \right)}_{\text{reliability}}$$
$$\underbrace{- (1-u)\sum_{i=1}^{n} \left(\int_0^{P^*_{Gi}} MC_i(P_{Gi})dP_{Gi} - \int_0^{P'_{Gi}} MC_i(P_{Gi})dP_{Gi} \right)}_{\text{congestion}}.$$

4.2. Case Study: The IEEE 118-Bus Network

The cost-benefit metrics in equations (2) – (3) were calculated for four embedded Wheatstone sub-networks in the IEEE 118-bus test system. The locations of the specific Wheatstone sub-networks considered are shown in Figure 4. The network parameters are given in Blumsack (2006, Appendix A). Network parameters and representative power-flow results for the four Wheatstone sub-networks are shown in Table 2.

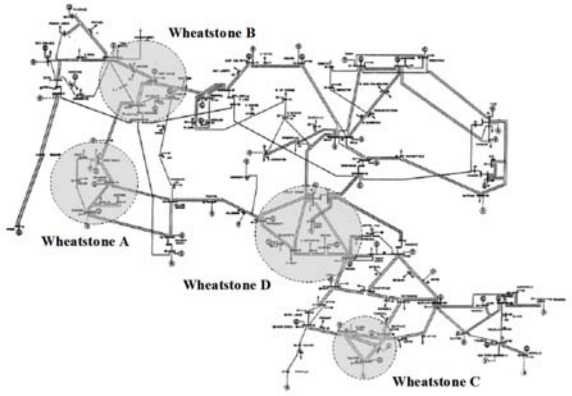

Figure 4. Four Wheatstone sub-networks of the IEEE 118-bus system.

To calculate the congestion, reliability, and net benefit metrics in equations (3) – (5), we further parameterized the network by considering line outage probabilities ranging from 10^{-7} to 10^{-1}. Each line outage was assumed to last for one period. We did not consider the effect of line outages outside each specific Wheatstone sub-network. Demand to transfer real power across each Wheatstone sub-network was assumed to vary between 0 and 500 MW; we chose these range for consistency with demands throughout the rest of the network. Demand at other locations in the network was held constant. We set the value of lost load equal to $1,000/MW-interrupted.

For each of the four Wheatstone sub-networks, we ran four sets of DC optimal power flows for each level of demand between 0 and 500 MW. The four power-flow cases were:

Case I: The “base case” set of DC optimal power flows, where the sub-network has the Wheatstone bridge, and there is no assumed contingency on any of the transmission lines.

Case II: Same as Case I, but the DC optimal power flows are run on the sub-network without the Wheatstone bridge.

Case III: This case assumes an outage on one of the boundary links in the Wheatstone sub-network, but assumes the sub-network has a Wheatstone bridge.

Case IV: An outage is assumed on one of the links, and there is no Wheatstone bridge in the sub-network.

Table 2: Network Parameters for the Four Wheatstone Sub-Networks

		Wheatstone Sub-Network			
		A	B	C	D
S_{12}	Reactance (p.u.)	0.09	0.02	0.12	0.13
	Base-Case Flow (MW)	27	13	220	104
S_{13}	Reactance	0.12	0.02	0.05	0.14
	Base-Case Flow	23	2	186	33
S_{24}	Reactance	0.09	0.05	0.05	0.1
	Base-Case Flow	32	92	121	210
S_{34}	Reactance	0.07	0.01	0.05	0.19
	Base-Case Flow	15	25	257	19
S_{23}	Reactance	0.09	0.04	0.05	0.12
	Base-Case Flow	35	118	151	140

The results from Cases I and II were used to calculate the congestion cost metric in equation (3), while the results from Cases III and IV were used to calculate the reliability benefit in equation (4’). In this paper, we focus on Wheatstone sub-networks C and D

Analysis of Wheatstone C

Wheatstone sub-network C is located in the southern portion of the 118-bus network shown in Figure 4. Wheatstone sub-network C is located in the southeastern portion of the IEEE 118-bus network, as shown in Figure 4. This Wheatstone has two of its four component buses connected to the external network. From the base-case power flow (shown in Figure 10), power flows from the external network through the Wheatstone network towards bus 90. Thus, bus 90 is designated as the downstream node for this sub-network.

Figures 5 and 6 show the congestion cost and reliability benefit of the bridge in Wheatstone C. The real power demand at bus 90 is assumed to vary between 0 and 500 MW; we hold demand constant at all other nodes in the network. The positive value for the congestion cost indicates congestion charges associated with the Wheatstone bridge. At lower levels of demand, Figure 5 shows that the congestion caused by the Wheatstone bridge increases with the level of demand, just as in the four-bus test network shown in Figure 2. At demand levels larger than 450

MW, generation from elsewhere in the network is dispatched to meet the increased load at bus 90, and the congestion cost associated with the Wheatstone bridge declines. The expected congestion cost does not vary widely with the outage probability because we only consider small outage probabilities (less than a 10% chance of an outage).

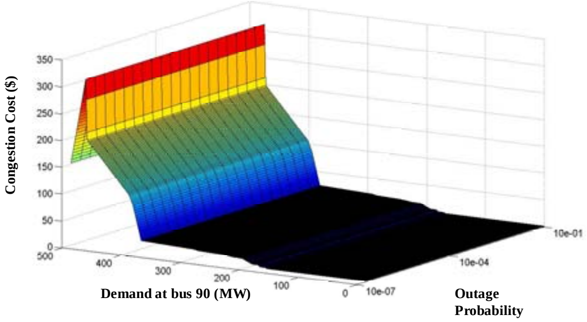

Figure 5: Expected Congestion Cost Associated with the Bridge in Wheatstone C.

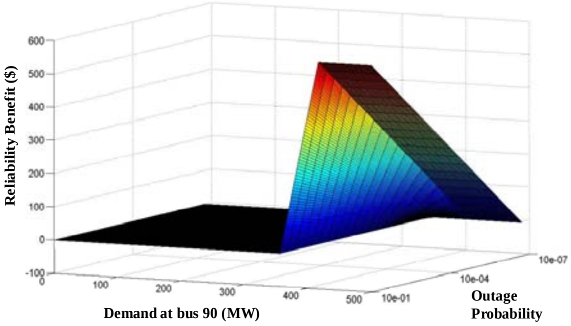

Figure 6: Expected Reliability Benefit Associated with the Bridge in Wheatstone C.

The reliability benefit associated with the Wheatstone bridge is shown in Figure 6. At low levels of demand, the capacity in Wheatstone sub-network C is large relative to demand, so a single line outage makes little difference in the ability of power to be transferred across the network towards bus 27. At larger levels of demand, the expected reliability benefit is highly sensitive to both the level of demand and the outage probability.

The net benefit of the bridge in Wheatstone sub-network C is calculated using equation (5) and is shown in Figure 7. An instructive comparison can be made between the behavior of Wheatstone C and the four-bus test network discussed in Section 2. In Wheatstone C, congestion and reliability are only independent for low levels of demand (150 MW or less). For this range of demand, the Wheatstone imposes a congestion cost while the reliability benefit is zero. Only at higher levels of demand does the net benefit function indicate the tradeoff between the congestion cost imposed by the Wheatstone bridge and its reliability benefit. Once the reliability benefit kicks in, the net benefit function will rise more sharply if the probability of an outage is larger; for low outage probabilities, the congestion component of the net benefit function dominates.

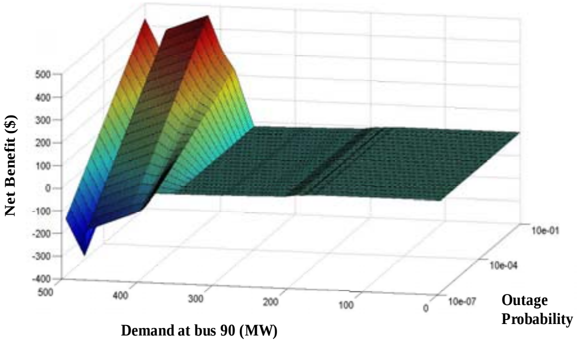

Figure 7: Expected Net Benefit Associated with the Bridge in Wheatstone C.

Analysis of Wheatstone D

The second Wheatstone sub-network discussed here is located in the middle of the IEEE 118-bus network, just northwest of Wheatstone C. Topologically, Wheatstone D appears to be more of an interior Wheatstone than the other three sub-networks, as it is located near some of the system's larger and less expensive generating units located at buses 80 and 65. The congestion and reliability properties of this sub-network should be different than the other three Wheatstone sub-networks. The base-case power flow run on this Wheatstone sub-network indicates that bus 77 should be considered the downstream bus; power flows from the external network through the Wheatstone towards bus 77.

Figures 8 and 9 show the congestion cost and reliability benefit associated with the Wheatstone bridge in sub-network D. The tradeoff between congestion and reliability evident in Wheatstone sub-networks A, B, and C is not as evident. In the other three sub-networks discussed here, the congestion cost rises (more or less) monotonically with demand. However, Figure 8 shows the congestion cost rising and falling in a roller-coaster pattern. For the most part, the Wheatstone bridge in sub-network D has negative congestion costs, meaning that the presence of the bridge reduces congestion rather than causes congestion. The reliability benefit associated with the Wheatstone bridge in sub-network D, as a function of demand and the outage probability, behaves similarly to the other three Wheatstone sub-networks.

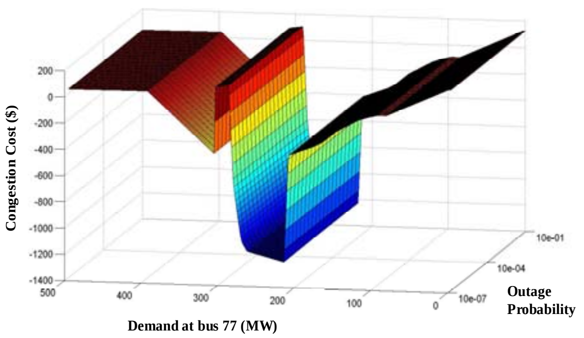

Figure 8: Expected Congestion Cost Associated with the Bridge in Wheatstone D.

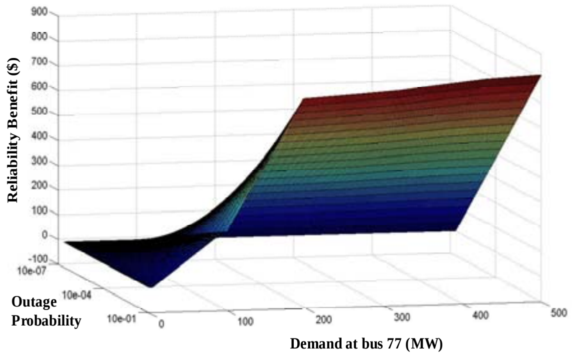

Figure 9: Expected Reliability Benefit Associated with the Bridge in Wheatstone D.

Figures 8 and 9 show the congestion cost and reliability benefit associated with the Wheatstone bridge in sub-network D. The tradeoff between congestion and reliability evident in Wheatstone sub-networks A, B, and C is not as evident. In the other three sub-networks discussed here, the congestion cost rises (more or less) monotonically with demand. However, Figure 8 shows the congestion cost rising and falling in a roller-coaster pattern. For the most part, the Wheatstone bridge in sub-network D has negative congestion costs, meaning that the presence of the bridge reduces congestion rather than causes congestion. The reliability benefit associated with the Wheatstone bridge in sub-network D, as a function of demand and the outage probability, behaves similarly to the other three Wheatstone sub-networks.

The same roller-coaster pattern of the net benefit function can be seen in Figure 10, which shows the total net benefit function as both demand at bus 77 and the outage probability vary. The shape of the total net benefit function is nearly identical to the shape of the congestion cost curve in Figure 8. We conclude from Figures 8 through 10 that congestion and reliability are not independent in Wheatstone D, but neither do they represent tradeoffs. In this case, congestion and reliability are complementary. The Wheatstone bridge could be justified for reliability reasons, but (over a large range of demand) congestion would decrease as well.

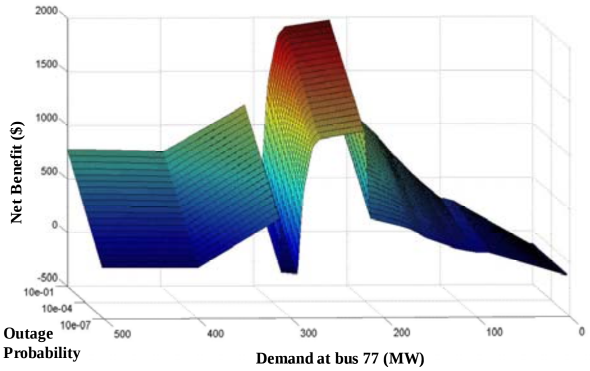

Figure 10: Expected Net Benefit Associated with the Bridge in Wheatstone D.

For a given level of the outage probability, the net benefit of the Wheatstone bridge should be an increasing function of the level of demand. Wheatstones A and C both behave this way, but the relationship is somewhat less clear for Wheatstone B and is virtually nonexistent for Wheatstone D. This highlights the influence of the system, and the importance of location, on a given individual Wheatstone sub-network. Wheatstone sub-networks A and C are located topologically further away from the center of the 118-bus network. More importantly, Wheatstones A and C have fewer connections to the external network. Thus, the external network has less influence over the behavior of Wheatstones A and C than over the behavior of Wheatstones B and D.

The most significant portion of the external network in explaining the behavior of Wheatstones D is the location of large and inexpensive generation in close proximity. Generators at buses 80 and 65 are directly connected to Wheatstone sub-network D; the generator at bus 80 is directly connected to the downstream load bus of Wheatstone D. Empirically, we found that changes in the dispatch of generator 65 had the greatest influence on the congestion-cost function shown in Figure 11. To illustrate the influence of these generators on the congestion cost and reliability benefit associated with the Wheatstone bridge in sub-network D, we artificially increased the marginal cost of the generator at bus 65 by a factor of ten, from $2.5/MWh to $25/MWh. The new net benefit, after the cost increase, is shown in Figure 11. After increasing the marginal costs of the generator at bus 65 to the point where it no longer changes dispatch in response to changes in demand at bus 77, the Wheatstone net benefit function looks much like the net benefit functions from Wheatstone C.

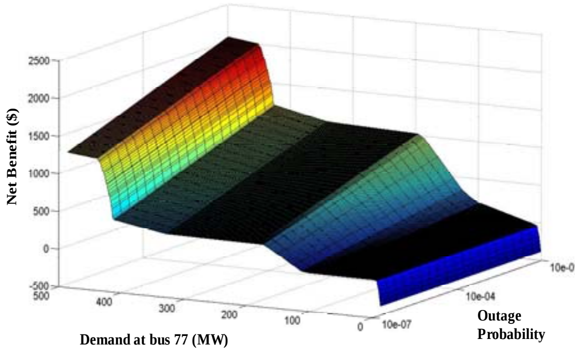

Figure 11: Expected Net Benefit Associated with the Bridge in Wheatstone D, After an Increase in the Marginal Cost of Generation at Bus 65.

5. Conclusions

Regulated, vertically-integrated utilities configure their grids to transmit power from their generators to their customers. It should not be surprising that deregulating the market, requiring the grid to transmit power from any generator to any customer, asks the grid to do something that it was not designed to do. To meet the need for large scale transmission investment, the ISO focused on reliability upgrades, getting the market induce merchant transmission to relieve congestion, paid for by the individual generators and customers who benefits by the congestion relief. ISO tariffs continue to support the concept of merchant AC transmission investment to support competition, while planning efforts have focused on reliability (Joskow 2005). Meanwhile, Congressional transmission policy appears to be pushing the DOE and FERC towards using congestion as the criteria for determining “national interest” transmission projects.

In this paper, we have shown that there is no clear distinction between investments for congestion relief and investment for reliability. Rather, the extent to which an investment benefits either can be determined only via careful examination of power flows over the network, accounting for both topology and demand. Our research offers the following four policy lessons:

First, *a market-based solution to the transmission problem is neither workable nor economically efficient.* The strong form of merchant transmission rests on a stringent set of economic assumptions. While everyone agrees that the stringent assumptions do not reflect the realities of generating or transmitting electricity in the U.S., merchant transmission is defended as being “workable,” although not efficient. Its proponents argue that the system may be sub-optimal, but it is easy to administer and has superior social welfare properties to the transmission planning methods of the regulated utility.

Neither claim is correct. At best, compensating new transmission with contracts based on nodal prices will not result in economically efficient investment. At worst, it encourages investors to build lines that increase network congestion. In power systems that use locational pricing signals to manage congestion and promote investment, the ubiquitous presence of an embedded Wheatstone network drives a wedge between the price signal and the underlying physical state of the grid. Locational prices fail to identify the active system constraint; simply upgrading the transmission line with the highest congestion price fails to relieve physical congestion in the system. One consequence is that even if financial congestion contracts are allocated according to the feasibility condition, investors can still profit from exploiting the Braess Paradox – that is, by constructing transmission lines that cause congestion rather than relieving congestion.

Second, *reducing congestion is a more complex problem than simply upgrading the most congested line*. Current models for pricing and investing in transmission capacity labor under an implicit assumption that eliminating congestion through upgrades along specific paths or through construction of new capacity will have the effect of improving the flow of electricity through the network. In small series-parallel or even triangular networks, this may be true. However, the assumption is not a good approximation in meshed power networks.

In the Wheatstone system, congestion can only be relieved by upgrading multiple lines, or by removing certain other lines. Neither nodal prices nor the shadow prices of transmission identify the correct remediation option. Knowledge of the topological properties of the network is required to identify and deal with these constraints.

Third, *reliability and congestion are interdependent.* In the regulated electric power industry, drawing a distinction between investments for economics and investments for reliability is a meaningless dichotomy. We demonstrate through simulations that the distinction is not only meaningless; in many cases it is incorrect. Transmission lines that appear to congest the system can, in many cases, be justified on reliability grounds, since they add valuable redundancy to the system, and vice versa. Creating a Wheatstone network from a parallel network causes congestion and increases the network cost of serving customers. However, the meshed nature of the Wheatstone network can enhance reliability. In a parallel system, the loss of one transmission line can lead to blackouts downstream of generation. A similar contingency in a Wheatstone network need not lead to any loss of load. Whether creating a Wheatstone is in the public interest can be determined only by a power flow analysis of the network toplogy and level of demand.

The simulations performed in this paper have examined embedded Wheatstone structures in the IEEE 118-bus test network, which is adapted from an actual portion of the eastern U.S. power grid. We find that except for low levels of demand, congestion and reliability are interdependent. For three of the four Wheatstone sub-networks considered, congestion and reliability represent tradeoffs, just as in the simple Wheatstone example network. In the fourth Wheatstone sub-network, congestion and reliability are actually complementary – the Wheatstone structure actually reduces congestion and enhances reliability.

Fourth, *the transmission problem is a systems problem, not a competition problem*. The inherent dependencies between congestion and reliability suggest either a cost-benefit approach or a multi-objective approach to evaluating new transmission infrastructure. Not only are congestion and reliability highly dependent, but the relationship between the two varies critically with the level of demand in the system and the topological state of the network. This is especially problematic for merchant transmission proposals, since nodal prices currently incorporate only congestion externalities, and not reliability externalities. In some circumstances, it may not even yield feasible transmission plans since the total effect of a new line on the network (positive or negative) is more than simply the sum of the congestion rents throughout the network.

Diluted forms of market-based transmission, such as participant funding, are meaningless unless the line between congestion and reliability can be drawn clearly. Merchant transmission contracts signed on the basis of reduced congestion costs for infrastructure that also has significant reliability benefits will result in free-riding and transfers of wealth from investors to those who benefit most from the added system reliability, leading to under-investment in new capacity.

From a policy standpoint, the analysis of Wheatstone networks suggests that the debate over transmission investment, at least in areas that have undertaken restructuring, has been misguided. The principal problem is not with non-utility transmission, but in the way that RTOs have proposed to compensate non-utility transmission investments. RTOs should stop trying to attract transmission investment by offering financial contracts based on locational spot-market prices. RTOs and their regulators also need to realize that the network benefit of a given transmission project depends critically on identifying the relevant range of demand and the state of the system, both at the time of construction and into the future. Under restructuring, the transmission planning problem has been cast as a problem of encouraging competition under peak demand conditions. It should be re-cast as a problem in risk management. The question of who (utilities, non-utility transmission companies, or RTOs) should bear the responsibility for transmission investment is a matter of who can manage this risk at the lowest cost.

6. Acknowledgements

This work was funded by a grant to the Carnegie Mellon Electricity Industry Center from EPRI and the Alfred P. Sloan foundation, and by the Tennessee Valley Authority and Florida Power and Light. Any opinions and errors are those of the authors and should not be ascribed to the grantors.

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