Testing the Effects of Inter-Regional Transfers of Real Energy on the Performance of Electricity Markets

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Abstract

Since deregulation of the electric utility industry began in the USA, there has been a substantial increase in the quantity of power transferred over long distances. Both thermal and voltage constraints on transmission have been experienced in regions that previously were rarely congested. One solution to this type of problem is to expand the capacity of transmission networks, but it is likely that market forces will still cause congestion (in new locations) on an expanded network. The objectives of this paper are 1) to test how power transfers through a network affect congestion and market performance, and 2) to explain the complications and limitations of treating an AC network like a pipeline as a way to compensate transmission owners.

The tests use graduate students to represent suppliers on an AC network in an electricity market. The nodal prices and optimum dispatch are determined by POWERWEB (a computer platform for testing different types of electricity auction). The results of the tests demonstrate that the students can respond effectively to changing conditions on the network and earn excess profits when they have market power. In particular, the tests show 1) power transfers can cause additional congestion in different parts of the network, 2) this congestion increases the market power of some suppliers, 3) these suppliers are able to identify and exploit the auction when they have market power, 4) average market prices are substantially higher when congestion occurs, 5) in most cases, the effects of power transfers are localized and the effects on different suppliers are highly varied, and 6) some power transfers can reduce congestion and lower prices.

The results of the tests demonstrate that monitoring the physical effects of transfers on a network is complicated because additional congestion can occur in surprising locations. In addition, the amount and location of congestion change as local load patterns change even if the quantity of real energy transferred remains constant. Consequently, it is generally impractical to try to treat a network like a pipeline and pay transmission owners in proportion to the flows on their lines. The most important complication is that a transmission network plays an essential role in maintaining the reliability of supply as well as transferring power. Since reliability is a public good, the owners of an AC network should continue to be regulated. Market incentives to reduce congestion can be implemented, but transmission enhancements should be based on joint decisions by all transmission owners and subject to meeting reliability standards set by regulators. A formal planning process is needed because there is no guarantee that decentralized decisions by individual owners will make the network operate efficiently and meet reliability standards effectively.

1. Introduction

In a recent report on "Long-Term Reliability Assessment" (September 2004) generation and transmission adequacy by the North American Electric Reliability Council (NERC), the section on "Transmission Issues" raises some concerns about the future adequacy of the transmission grid. The report states (op. cit. p. 34):

> *Over the past decade, the increased demands placed on the transmission system in response to industry restructuring and market-related needs are causing the grid to be operated closer to its reliability limits more of the time.*
>
> *The demand for electricity continued to grow in the 1980s and 1990s, but transmission additions have not kept pace. The uncertainty associated with transmission financing and cost recovery and the impediments to siting and building new transmission facilities have resulted in a general slow-down in construction of new transmission. In some areas of North America, increases in generating capability have surpassed the capability of the transmission system to simultaneously move all of the electricity capable of being produced. In addition, market-based electricity transactions flowing across the grid have increased, as has the incidence of grid congestion. The result is increased loading on existing transmission systems and tighter transmission operating margins.*

This conclusion by NERC reflects the complicated state of the electric utility industry in North America at this point in time when the industry is in the process of deregulating. This process involves moving away from the use of central planning in different regions to determine the investments needed in generation and transmission towards more decentralized decisions and a greater reliance on market forces. In the deregulated markets, there is still a lot of uncertainty about the best way to replace the regulated system and provide the right incentives to maintain system adequacy and get new generation and transmission built.

The existing transmission networks now cover both regulated and deregulated regions and are owned and operated by both private and public entities. Since flows on these networks must obey the laws of physics, there is a fundamental need to provide a consistent set of rules about how the networks should be organized and operated in both real time and for long-term planning and investment. However, the strategy followed by the Federal Energy Regulatory Commission (FERC) has been to allow a wide variety of approaches to deregulation in different regions. This strategy may work for generation, but it is definitely not appropriate for transmission. While it is unlikely that a "one-size-fits-all" structure is the best solution for deregulated markets, it is clear that more coordination of decisions about transmission is needed than it is for decisions about generation. (It was unfortunate that the efforts made by the FERC to lay the foundation for a Standard Market Design (SMD) coincided with the "energy crisis" in California and the corresponding increase in doubts about the potential benefits of deregulation.) The primary reason for more coordination is that the transmission network plays a central role in maintaining the reliability of supply for customers. Unlike real energy, the levels of reliability are shared by all users of the network and are difficult to allocate to individual users or specific components of the network.

There are two objectives of this paper. The first is to show how valuable it is to use experimental economics to test the performance of deregulated markets for electricity and to gain insights into the complicated role played by the transmission network. In particular, this paper addresses the interaction of an increased transfer of real energy through a network on the market outcomes. The results show that the increased congestion caused by a transfer increases the real costs of supplying load and also makes it easier for suppliers to exploit market power. The testing platform, POWERWEB, is described in Section 2 and Appendix B, and the results from a series of tests conducted in the fall of 2004 by graduate students at Cornell University are summarized in Section 3 and Appendix A.

The second objective is to explain the limitations of trying to treat a transmission network like a pipeline for natural gas. "Pipeline thinking" does not work for transmission networks because it only deals with the transfer of real energy and does not account for the benefits of reliability. Since it is generally impractical to partition the costs of a network between reliability and transfers of real energy in a meaningful way, the conclusion reached in Section 4 is that the transmission system should continue to be regulated. An exception can be justified for a DC intertie, but the interdependencies that exist on an AC network make it appropriate to pay a regulated rate of return on capital investment to the owners of the network. This is the basic procedure followed in the National Electricity Market (NEM) in Australia. Section 5 provides a summary and the conclusions.

2. The Experimental Framework for Testing Electricity Markets

A smart market for electricity has been developed to account for the operational constraints imposed by the physical transmission network. In this context, the suppliers and the buyers are connected by a transmission network which must be operated at all times in a manner consistent with the laws of physics governing the flow of electricity on an AC network. The operation of the network is also constrained by the physical limitations of the equipment used to generate and transmit the power. This results in two phenomena that may affect the outcome of an auction: (1) transmission losses and (2) congestion.

Our experimental platform, POWERWEB, handles the effects of losses and transmission system constraints by determining the nodal price for each location that represents the shadow price of adding one MW of load at each location. Generating units are chosen to satisfy specified loads in the least expensive manner while still satisfying the operational constraints of the transmission system. In previous experiments, we have shown how congestion on transmission lines leads to high prices by limiting the number of effective suppliers in a load pocket. For the experiments discussed in this paper, there are also binding transmission constraints as well as transfers of real energy. High market prices may be caused by reaching the thermal or voltage limits of the network as well as by suppliers exploiting market power.

For each trading period, suppliers submit price/quantity offer curves to a central auction, and an Optimal Power Flow (OPF) is used to determine the least cost pattern of dispatch to meet load. Units are dispatched, starting from the low priced units and moving toward the higher priced units, until the supply reaches the total load plus transmission losses. The remaining, higher priced units are not dispatched. In this experiment, the market price is set to the offer of the last (most expensive) unit chosen in the auction. Nodal prices vary from one location to another because these prices include components for congestion. With no congestion and no losses, all nodal prices would be the same. In prior research when individual suppliers had multiple units and load was held constant, paying the Last Accepted Offer (LAO) in a Uniform Price Auction performed as well, or better, than a Vickrey auction and a similar auction that paid the First Rejected Offer (FRO). (Unlike most auctions, electricity markets typically dispatch most of the capacity offered and relatively few units are rejected.

Consequently, the conventional result from auction theory, that paying the FRO is more efficient than paying the LAO, is no longer a reliable rule for designing electricity markets.)

It is important that participants in an experiment receive "salient" rewards that correspond to the incentives assumed in the structure of the market. Performance related payment tends to reduce variability in outcomes and improve the quality of results from the experiments. Davis and Holt (Experimental Economics, 1993) define saliency to require:

1) subjects perceive the relationship between decisions made and the payoff outcomes

2) induced rewards are high enough to dominate the subjective costs of making decisions.

In our experiments, participants receive monetary rewards based on their profits in the experiments. During the experiment, each participant sees their own earnings expressed in both experimental dollars and in real dollars. Real dollar earnings are calculated through the following formula:

*Real Dollars = Exchange Rate * Experimental Dollars*

The exchange rate can be different for different suppliers and experiments. The purpose of the exchange rate is to balance actual earnings for different suppliers when they have different cost structures and therefore different opportunities to make profits. There is, however, no fixed limit on the potential level of profits once the market rules have been set. Student subjects make about $30 for a two-hour experiment, while utility professionals, who are given a more lucrative exchange rate to assure salient rewards, could make more than $100 for the same experiment. Two hours is a reasonable upper limit for running an experiment, and this allows for 50 to 75 trading periods for testing an auction, depending on the complexity of the market.

POWERWEB is designed to be a flexible Internet-based platform for testing the performance of electricity markets, and in particular, on determining how the participants deal with the interactions between the market rules and the physical transmission network. The Internet-based architecture eliminates the need for participants to be physically present in a specially equipped laboratory, but a laboratory setting is desirable for training inexperienced users. The POWERWEB server handles application logic, data handling and computation. Users interact with POWERWEB through a standard web browser (e.g. Explorer or Netscape).

In the experiment presented in this paper, each participant in a session represents the owner of a number of blocks of generating capacity. For every trading period, these suppliers choose the prices (offers) for selling their capacity in an auction run by an independent system operator (ISO). All suppliers know the true costs of their own capacity, the total installed capacity of all generators, the forecast of total system load for the next trading period, and the maximum offer allowed in the auction (i.e. there is a hard cap on prices). The objective of all suppliers is to submit offers that maximize their own profits. In some cases, suppliers may choose to withhold capacity from the auction. POWERWEB collects the offers from all suppliers and solves the corresponding OPF that determines the optimal nodal prices and the dispatch schedules for each supplier to meet a specified pattern of loads. Nodal prices are determined for each location using the Last Accepted Offer in a Uniform Price Auction. These prices also include the appropriate cost of losses and congestion at each location. A summary of the market outcome for each supplier is provided at the end of a trading period, and the cumulative results and a history of the results in all previous trading periods are also available. The suppliers can use this information to determine how to modify their offers in the next trading period.

3. Testing the Effects of Transfers of Real Energy

During the fall semester, 2004, a class of 18 graduate students from Electrical and Computer Engineering and from Applied Economics and Management at Cornell University participated in testing a series of eight different types of electricity market. One test in this series dealt with the effects of transferring real energy from an external source through a network to an external sink. The standard AC network used in POWERWEB has 30 buses and six suppliers (*firms*), and the one-line diagram is shown below in Figure 1. Appendix B shows the documentation that was distributed to the students prior to conducting the experiment on transfers. In addition, the students had tested a similar market with no power transfers one week earlier as part of their training to become effective traders in an electricity market. To limit collusion among the students in a test, each student was assigned randomly to one of the six firms to form three groups of six (*sessions*). The experiment on transfers was conducted in three parts (*markets*) on the same day, and each student stayed in the same session and represented the same firm throughout the experiment. Consequently, the experimental design was a balanced three-way layout for six firms in three different markets and three different sessions.

The three markets tested were:

1. **No transfers.**
2. **A 40 MW transfer from bus 28 to bus 14 (NW to SE).**
3. **A 40 MW transfer from bus 14 to bus 28 (SE to NW).**

Market 1 (with no transfers) was tested for 15 periods. These results were used as a benchmark for evaluating the effects of transfers in Markets 2 and 3. Since Market 1 repeated the test from the previous week, the other two markets were each tested for 25 periods, and the first 10 periods in each case were treated as learning periods.

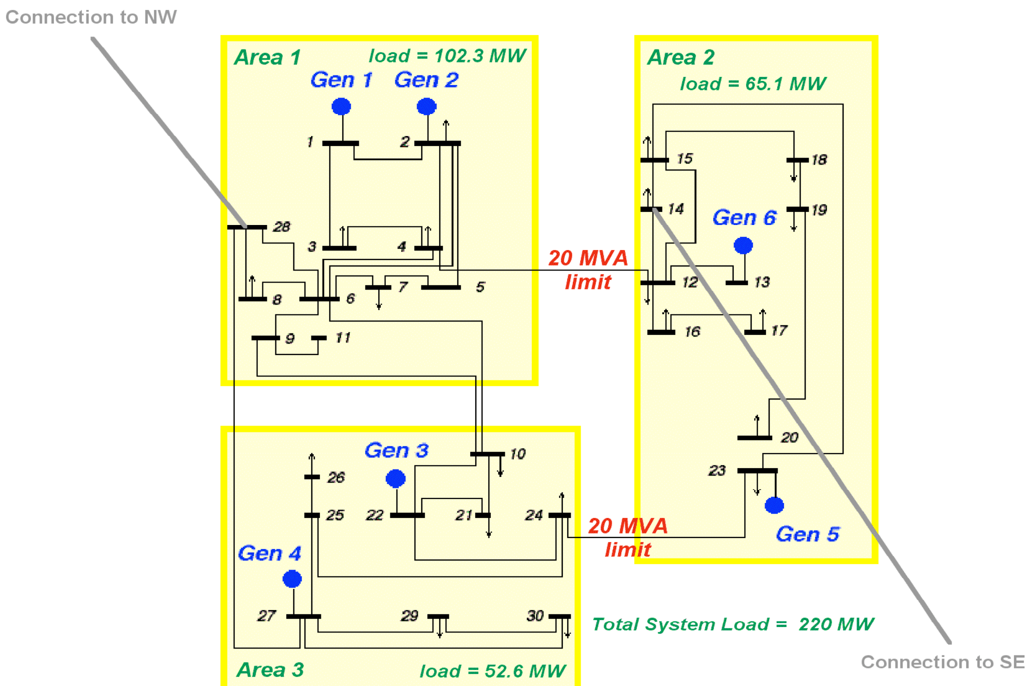


FIGURE 1: The AC Network Used in POWERWEB to Test Electricity Markets

For any given variable, such as the nodal price, the observations used in the statistical analyses are the average values over the last 15 periods for the nine combinations of market and session. (Using the results for individual trading periods as observations is complicated because these observations are generally correlated within sessions, and the structure of these correlations is likely to be substantially different from one session to another.) For variables like the nodal price that vary by firm, there are 6x3x3 = 54 observations.

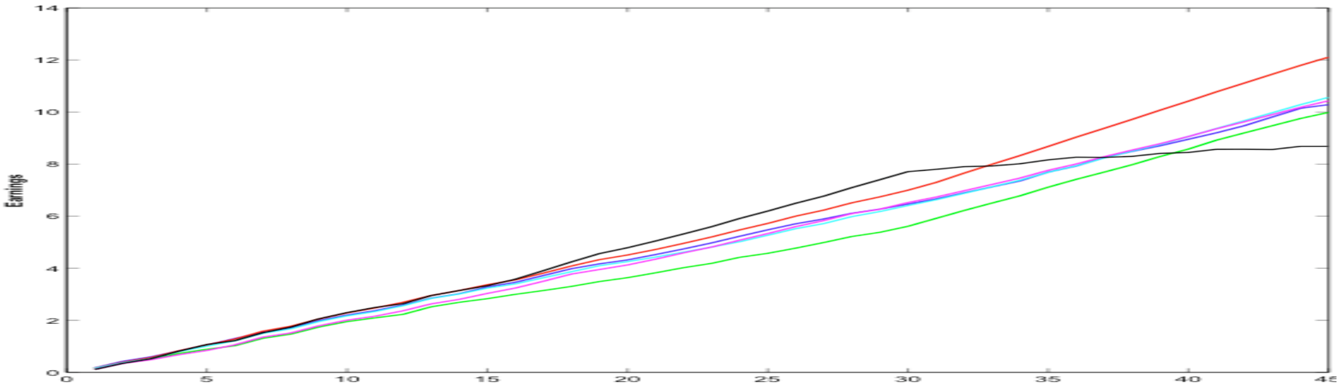
The total load on the system for the next trading period is forecasted by the ISO and sent to each supplier along with the actual load and other results from the last trading period. The actual load varies from period to period, and the forecasted load is within 20MW of the actual load (<10% error). The patterns of the actual load in the three markets tested were similar but not identical (if the patterns of load had been identical in the three markets, some students would inevitably realize this and be able to predict the actual loads correctly by the end of the experiment.)

The overall results for the three different markets are summarized in Table 1 in terms of the average earnings, nodal price and capacity offered into the auction. The average earnings for the six firms and the average nodal price paid are both higher when transfers occur, particularly in Market 3 when the transfers are from the South East (bus 14) to the North West (bus 28). In contrast, the average amounts of capacity offered into the auction by a firm are quite similar in the three markets, and they correspond to just over two thirds of the installed capacity (60MW). The nodal prices are substantially higher than competitive levels of roughly $41/MWh (when all firms submit offers equal to the true marginal costs of generation). This implies that the six firms were able to exploit market power even when there were no transfers, and when transfers occur, the market was even easier to exploit because the transmission lines are more congested. However, the results in Table 1 do not show the highly differential effects of the power transfers on individual firms. Some firms benefit from the transfers and are able to increase their earnings, but other firms can be adversely affected.

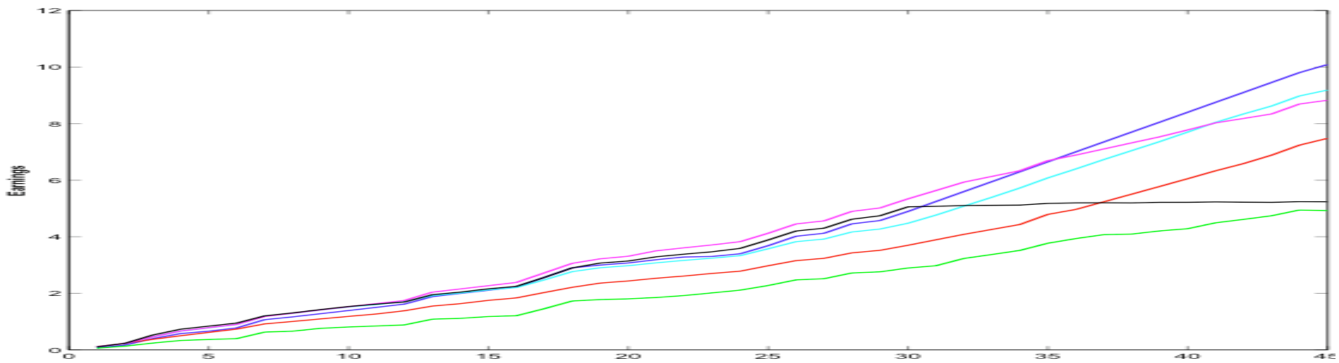
TABLE 1: Average Values of Earnings, Nodal Price and Offered Capacity

Type of Market	Earnings ---------->		Nodal Price -------->		Capacity Offered --->	
	$/firm/period	% from #1	$/MWh	% from #1	MW/firm/period	% from #1
1. NO Transfers	1584	-	75.59	-	43.28	-
2. NW->SE Transfers	1839	16	81.50	8	43.83	1
3. SE->NW Transfers	2066	30	87.74	16	44.49	3

To illustrate the differential effects of power transfers on individual firms, the cumulative earnings of the six firms in the three sessions for the 45 trading periods used in the statistical analysis are shown in Figure 2. Periods 1-15 correspond to no transfers (Market 1), periods 16-30 to NW->SE transfers (Market2) and periods 31-45 to SE->NW transfers (Market 3). The transfers in Market 2 tend to reinforce the existing congestion on the network, and the transfers in Market 3 tend to relieve the congestion. While there are differences in the relative positions of firms in the three sessions, the main feature of Figure 2 is that the growth of earnings by Firm 6 was much lower than the growth of the other five firms in Market 3 (periods 31-45). Since Firm 6 (Gen 6) is close to bus 14 (see Figure 1), the physical limitations of the network limit the amount that can be generated by Firm 6 because 40MW of real energy are being imported at bus 14 in Market 3. This is true even if Firm 6 submits very low offers. In Market 2, however, Firm 6 is in a stronger position because exporting 40MW at bus 14 can lead to congestion on the two interties into Area 2, creating a load pocket for Firms 5 and 6.



Session 1



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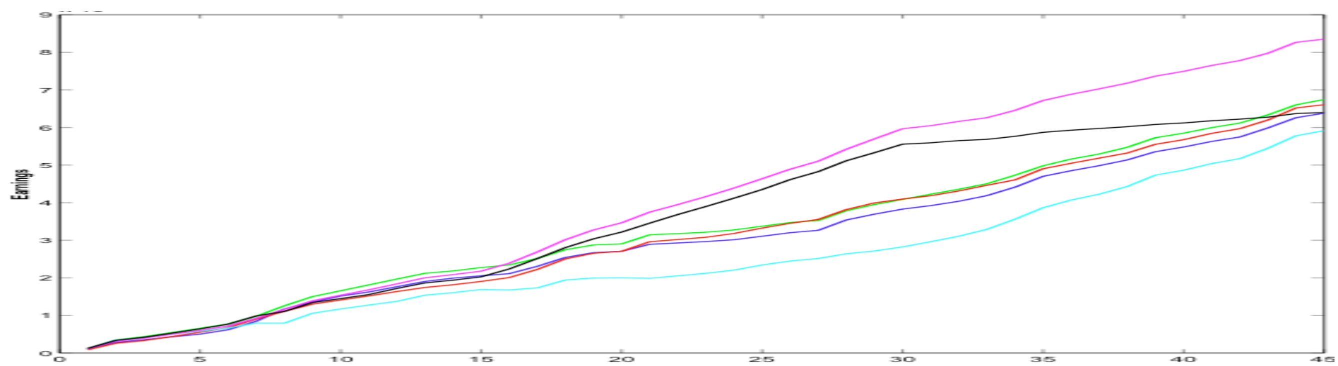


Session 3

FIGURE 2: Cumulative Earnings by Firm

Market 1(Periods 1-15), Market 2 (Periods 16-30), Market 3 (Periods 31-45)

Even though the 40MW transfers in Markets 2 and 3 can be supported on the network, the results presented in Figure 2 imply that the economic consequences for suppliers like Firm 6 can be very substantial. Trying to assess the true costs/benefits of the transfers to different firms on the network is not trivial because it is inevitable that suppliers will modify their offers if market conditions change. Hence, it is definitely not correct to simply resolve the OPF with no transfers using the same set of offers. At the very least, realistic models of how offer behavior is affected by changing the quantity of transfers would be needed to do these calculations correctly. The current practices promoted by the FERC for allowing and pricing transfers through a network ignore most of the real operating and financial complications that the transfers cause for other users of the network. For example, an important policy issue is to identify the circumstances when transmission owners should upgrade a network to accommodate transfers. This issue is discussed again in the next section.

There are many other examples of the differential effects of transfers on the operating characteristics of a network (e.g. line flows and voltage levels). This paper will focus on the main economic variables of the Earnings of a firm, the corresponding Nodal Price and the quantity of Capacity Offered into the auction. For these three variables, the results from an analysis of variance of each variable are summarized in Table 2. In this model, there are three sets of main effects (3 Markets, 6 Firms and 3 Sessions) and three sets of two-way interactions. The coefficients for each set of main effects are restricted to sum to zero, and the corresponding two-way zero restrictions are imposed on each set of interactions.

For each combination of Market, Firm and Session, there is one observation measuring the average value for 15 trading periods. The three-way interactions are treated as random residuals in the model. Since the data are balanced, the zero-restrictions on the coefficients make it possible to partition the total sum of squares of a variable into seven distinct components (3 main effects, 3 two-way interactions and the error). These sums of squares for each component are presented in Table 2, and the corresponding F statistics are computed to test the null hypothesis that the coefficients in a particular component are identical (equivalent to testing that the coefficients do not explain any of the observed variability of the dependent variable). The estimated coefficients and other standard regression results are presented in Appendix A. The models explain most of the variability, and the R^2 are 93%, 95% and 90% for Earnings, Nodal Price and Capacity Offered, respectively.

The results for Earnings show that most of the explanatory power came from the main effects and the MarketXFirm interactions. In fact, this latter set of interactions explained 40% of the total variability. The importance of the Session effects shows that there were consistent differences among the three groups of students in their ability to exploit the three Markets. The Market effects were also important, and the results in Appendix A imply that the typical Earnings of a firm were 13% below average ($1830/firm/period) in Market 1, about average in Market 2, and 13% above average in Market 3. In addition, the Firm effects show that Firms 2 and 6 made substantially less (12% and 18%) than average, and Firms 1 and 5 made substantially more (8% and 12%). The MarketXFirm coefficients are relatively large (positive and negative), which underlines the complicated effects that changes in the quantities of transfers have on Firms in the three Markets. The location of a Firm on the network does matter. Compared to Market 1 with no transfers, Firms 1-4 gain in Market 2 and lose in Market 3. The opposite is true for Firms 5-6. By far the largest of the interactions affects the Earnings of Firm 6. These Earnings were 22% and 48% above average in Markets 1 and 2, but 71% below average in Market 3 (reflecting the trading periods with slow growth shown in Figure 2).

The results for the Nodal Price are similar to the results for Earnings, but the percentage effects are generally much smaller. In particular, the Firms effects are not statistically significant, and over 50% of the total variability is explained by the Session effects. In other words, the abilities of the students to raise prices in the three groups were very different. Session 1 did well (14% above the average of $82/MWh) and Session 3 did poorly (11% below average). Even though the Firm effects are not significant, the MarketXFirm interactions of Firm 6 with Markets 2 and 3 are statistically significant (12% above average in Market 2 and 11% below average in Market 3). These are the largest interactions for the Nodal Price. Although the signs of the interactions match the corresponding interactions for Earnings, the percentage changes of the Nodal Price are much closer to zero.

The results for the Offered Capacity in Table 2 are different from the results for the other two variables, and the three sets of main effects are relatively small (the Market effects are not statistically significant). Over 50% of the total variability is explained by the MarketXFirm interactions. The FirmXSession interactions are also relatively important and explain 22% of the variability. Once again, the largest interactions affect Firm 6 in Markets 2 and 3. The Capacity Offered by Firm 6 is 24% above average (44MW/firm/period) in Market 2 and 45% below average in Market 3. This implies that the corresponding interactions for Earnings, Nodal Price and Capacity Offered (i.e. for Firm 6 in Markets 2 and 3) have consistent signs and they are all large compared to other interactions. The Earnings of Firm 6 relative to Firms 1-5 are affected by the quantity of transfers and the corresponding physical capabilities of the network. Transfers in Market 2 allow Firm 6 to sell more capacity because there is an

TABLE 2: Analysis of Variance of Earnings, Nodal Price and Offered Capacity
Dependent Variable: EARNINGS BY FIRM (15 periods)

Source	Sum of Squares	%	Df	Mean Square	F stat.
Market	2,088,953.00	7.73	2	1,044,476.50	**10.426**
Firm	2,188,433.00	8.10	5	437,686.60	**4.369**
Session	6,288,920.00	23.28	2	3,144,460.00	**31.387**
MarketXFirm	11,012,835.00	40.77	10	1,101,283.50	**10.993**
MarketXSession	789,204.00	2.92	4	197,301.00	1.969
FirmXSession	2,637,876.00	9.77	10	263,787.60	**2.633**
Error	2,003,690.00	7.42	20	100,184.50	
Total	27,009,911.00	100.00	53		

Dependent Variable: NODAL PRICE (15 periods)

Source	Sum of Squares	%	Df	Mean Square	F stat.
Market	1,329.41	17.11	2	664.71	**33.476**
Firm	64.23	0.83	5	12.85	0.647
Session	4,017.61	51.72	2	2,008.80	**101.167**
MarketXFirm	955.96	12.31	10	95.60	**4.814**
MarketXSession	551.22	7.10	4	137.80	**6.940**
FirmXSession	452.93	5.83	10	45.29	2.281
Error	397.13	5.11	20	19.86	
Total	7,768.49	100.00	53		

Dependent Variable: CAPACITY OFFERED (15 periods)

Source	Sum of Squares	%	Df	Mean Square	F stat.
Market	13.12	0.27	2	6.56	0.261
Firm	555.62	11.59	5	111.12	**4.427**
Session	188.90	3.94	2	94.45	**3.763**
MarketXFirm	2,427.98	50.66	10	242.80	**9.673**
MarketXSession	53.40	1.11	4	13.35	0.532
FirmXSession	1,051.71	21.94	10	105.17	**4.190**
Error	502.01	10.47	20	25.10	
Total	4,792.75	100.00	53		

A **BOLD** F statistic rejects the null hypothesis that the corresponding main effects or interactions are all identical at the 5% level of significance.

extra 40MW of "load" nearby at bus 14. The transfers in Market 3 have the opposite effect and make it harder for Firm 6 to sell capacity. The import of 40MW at bus 14 is equivalent to have a new competing generator on the network with a guaranteed level of dispatch.

The overall conclusion from the statistical analysis is that the MarketXFirm interactions are always important and explain larger amounts of the total variability of Earnings and Capacity Offered than any of the main effects or other interactions. Firm 6, in particular, can make substantial gains in Market 2 but cannot sell nearly as much capacity in Market 3. These differences reflect the location of Firm 6 on the network. The observed changes in behavior by Firm 6 (e.g. lower Capacity Offered in Market 3) were in response to physical changes on the network and were not the primary cause of the change in market outcomes (e.g. lower Earnings by Firm 6 in Market 3). In general, the firms were able to adjust their behavior effectively when conditions on the network changed.

In this experiment, the differential effects of the power transfers on individual firms are just as important as the standard market effects of market power on prices. Faced by a long-term contract for transfers in either Market 2 or 3, it is not obvious how or if the transmission owners should improve the capabilities of the network. More importantly, there is no guarantee that the net social benefits of the transfers for all users of the network will increase with the contract. The physical ability to make a transfer is a necessary condition for allowing such a trade, but it is definitely not a sufficient condition for improving the supply system. Even if both parties in a bilateral trade benefit, the existing accounting procedures established by the FERC for allowing such trades will not necessarily lead to greater market efficiency. In addition, a network does a lot more than simply make transfers feasible. A network also plays a central role in maintaining the reliability of the supply system when contingencies occur (e.g. a generator has an unexpected outage). In the next section, a simple example of providing reserve capacity to cover the possible failure of an intertie is presented. This example shows why it is misleading to view the support of power transfers between regions as the primary role of a transmission network. Furthermore, it also shows that it is incorrect to assume that the net revenue accrued by the system operator from a power transfer (i.e. the difference in nodal prices times the contract quantity) belongs exclusively to the transmission owners. This revenue should be used to maintain the overall reliability of the supply system. Increasing the capacity of a transmission line is only one of the possible ways of improving reliability, and in some circumstances, greater transmission capacity for long-distance transfers could have an adverse effect on reliability.

4. The Limitations of Pipeline Thinking

4.1 Paying for Reliability

The delivery of natural gas through pipelines to final customers supports a market structure based on allocating the capacity of a pipeline to different suppliers. Measuring the amount of gas supplied by each pipeline and the cost of transporting this gas is straightforward. In fact, the oversight of gas pipelines in the USA in support of a competitive market is the responsibility of the Department of Transportation. Applying the same sort of rules to the supply of electricity is feasible in a few limited circumstances, but in general, it is simply not appropriate. The main reason why the analogy to a pipeline does not work is that an electric power network provides the infrastructure for maintaining the reliability of supply and makes the supply system relatively robust to a wide variety of equipment failures.

The flow of real energy on an AC network obeys the laws of physics, and it adapts immediately to changing circumstances, such as the loss of a generator. Hence, unlike a pipeline for natural gas where the control of the flow is independent of the sources of gas, it is impractical to predict and assign the future flows of real energy on individual transmission lines to specific generators or specific loads. As a result, it is intrinsically difficult to support point-to-point contracts for the physical delivery of electricity in a deregulated market. Nevertheless, the life of physical bilateral contracts for electricity lingers on in the USA. The primary manifestation of this is when payments for transmission services are based on flows of real energy (e.g. paying wheeling charges). This type of payment completely ignores the dynamic effects of congestion and the essential role that a network plays in supporting the reliability of the supply system. The primary economic issue for transmission is how to pay for reliability and not how to pay for transfers of real energy.

In an electric supply system, the performance of the network and the level of reliability are shared by all users of the network. Reliability is a “public” good (All customers benefit from their level of reliability without “consuming” it. In contrast, real energy is a “private” good because the real energy used by one customer is no longer available to other customers.) Markets can work well for private goods but tend to under-supply public goods, like reliability (and over-supply public bads like pollution). The reason is that customers are generally unwilling to pay their fair share of a pubic good because it is possible to rely on others to provide it (i.e. they are “free riders”). Some form of regulatory intervention is needed to make a market for a public good socially efficient.

If a public good or a public bad has a simple quantitative measure that can be assigned to individual entities, it is feasible to internalize the benefit or the cost in a modified market. For example, the emissions of sulfur and nitrogen oxides from a coal generator can be measured. Requiring every generator to purchase allowances for the quantities emitted makes pollution another production cost. Putting a cap on the total number of allowances issued in a region effectively limits the level of pollution. Independent (decentralized) decisions by individual generators in the market determine the pattern of emissions and the types of control mechanisms that are economically efficient. For example, the choice between purchasing low sulfur coal and installing a scrubber is left to market forces in a "cap-and-trade" market for emission allowances. Unfortunately, when dealing with the reliability of an electric supply system, it is impractical to measure and assign reliability to individual entities on the network in the same way that emissions can be assigned to individual generators.

Even if the desired level of reliability on a network is specified by a regulatory agency, such as the Federal Energy Regulatory Commission (FERC), or by an industry oversight organization, such as the North-American Electric Reliability Council (NERC), it is still difficult to measure and allocate the benefits of reliability to individual Transmission Companies (TransCo). As a result, there is no obvious way to assign a specific revenue stream for reliability to an individual TransCo. Furthermore, there is no logical reason to expect that decentralized decisions made by TransCos will lead to economically efficient ways of meeting a required level of reliability. Reliability is a systems concept, and all TransCos (and regulators) should assess the implications of proposed additions to network capabilities to form a single comprehensive plan for providing transmission services. This process should also consider planned additions by generators, loads and Distributed Energy Resources (DER). Finally, the overall plan should be reevaluated and updated on a regular schedule (e.g. yearly).

If the transmission network happens to be owned by a single TransCo, it is possible, in theory, for this TransCo to make efficient decisions about how to meet a given reliability standard. In reality, the three transmission networks in the USA (the Eastern and Western Interconnections and Texas) have many owners. Even the large public supply systems, such as TVA and Bonneville, are affected by power transfers through their networks and by changes in the characteristics of the network in adjoining regions. Additions to the capabilities of an AC network require coordination among all of the TransCos on a network. The responsibility for this coordination and the final decision to adopt a coherent plan for transmission that meets reliability standards must rest with the regulators. In Australia, for example, the

National Electricity Market Management Company (NEMMCO) has the primary responsibility for transmission planning and reliability.

Since the reliability of a network cannot be assigned to individual TransCos, the cost of maintaining reliability should be paid by allowing TransCos to earn a regulated rate of return on transmission investments. In other words, it is appropriate to treat network reliability as a regulated service provided by the TransCos, and the new market in the UK represents one example of how Performance Based Rates of Return (PBR) can be implemented for transmission. This is a viable method of payment for a public good because, in this case, there is no effective way to divide a given level of reliability into distinct pieces and assign them to individual companies.

It should be noted that this rationale for regulating transmission services is not the traditional reason for regulating the electric utility industry in the USA. When regulation was originally introduced, individual utilities were vertically integrated and relatively self-sufficient in generation capacity. The original objective of regulation was to deal with the potential problem of regional market power that could be exploited by a vertically integrated company.

4.2 Paying for Transfers of Real Energy

The next issue is to determine if it is appropriate to supplement the regulatory payments for reliability with earnings from transferring real energy from low cost regions to high cost regions. This type of operation replicates the role of transporting natural gas on a pipeline. In general, the answer is no because it is seldom possible to divide the total cost of transmission services between reliability and transferring real energy. One obvious exception is a DC intertie because this type of transmission only provides transportation services. In effect, a DC intertie appears to be a load in the low cost region and a generator in the high cost region. A merchant TransCo can evaluate an investment in a DC intertie on the basis of projections of the future price differences between the two regions. From an economic point of view, this type of transmission is just like a pipeline for natural gas in terms of the type of analysis that a prospective investor would use to evaluate a DC intertie.

Merchant TransCos are allowed for DC interties in Australia, but not for additions to the AC network. In stark contrast, the rationale in FERC Order No. 888 in the USA is to facilitate physical bilateral transfers of real energy throughout the Eastern and Western Interconnections (note that Texas is not regulated by the FERC because the AC network in Texas does not cross state boundaries, thus making it immune from Federal regulations.). The FERC procedure involves identifying a transmission path between a generator and a load, and paying the regulated wheeling charges to individual TransCos along this path. As long as a transfer can be supported on the network without jeopardizing reliability, it is allowed. This is true even though the specified contract path is only an accounting mechanism. The actual flows of real energy may be very different, and they will change over time in response to changes in the patterns of dispatch and load. The difference between the contract path and the actual flows is likely to increase at times when parts of the network are congested. More importantly, it is also likely that the true cost of accommodating a bilateral contract on a congested network is substantially higher than the regulated wheeling charges.

One way of dealing with physical bilateral contracts on a congested network is to identify "Flowgates," and to require the parties in a contract to purchase a share of the appropriate Flowgates (Hung-Po Chao and Stephen Peck, "A Market Mechanism for Electric Power Transmission," Journal of Regulatory Economics, Vol. 10, No. 1, 1996, pp. 25-59). Flowgates are transmission paths identified by the TransCos that may become congested for some significant amount of time. In essence, this procedure is equivalent to treating the network like a pipeline. It is, however, much easier to use the concept of Flowgates on a radial network, like the Western Interconnection, than it is on a dense network, like the Eastern Interconnection, because there are always multiple and variable pathways associated with a physical bilateral contract.

Hogan has shown that a Financial Transfer Right (FTR) can be used instead of a Flowgate right to hedge the price difference between two regions on a congested network. As a result, physical bilateral contracts can be replaced by a portfolio of financial contracts to provide the same reduction of financial risk in a forward contract for real energy between two regions. However, even though the volume of trading in forward financial instruments is growing, a large proportion of the supply of electricity is still covered by physical bilateral contracts.

An important reason for the prevalence of physical bilateral contracts is that they were common when the industry was fully regulated. Following the rulings of the US Supreme Court on the Mobile and Sierra cases in 1956, the sanctity of forward contracts was upheld and the "public interest standard" replaced "just and reasonable" as the criterion for regulating forward contracts. As a result, the cost of (revenue from) purchases (sales) of real energy in a bilateral contract was treated like any other production cost (income) for regulatory purposes. Many of these contracts still exist or have been renewed, and they often form the basis for determining the scheduled levels of transfers from one Independent System Operator (ISO) to another.

It is likely that accommodating the prevalent form of physical bilateral contract, used by the incumbent utilities when the industry was first deregulated, was an important objective when FERC Order 888 was issued. Nevertheless, since that time, there has been relatively little initiative taken by federal regulators to foster the replacement of physical bilateral contracts by financial instruments. What is needed is a viable institutional structure that supports financial hedging and investment decisions throughout the nation, and provides incentives for all generators and loads to become full participants in the market. It will be very difficult to eliminate pipeline thinking for transmission services as long as physical bilateral contracts continue to be treated as an essential feature of a deregulated market for electricity.

Our overall conclusion is that our preferred way of paying for the AC network is to follow the examples of Australia and the UK and to allow a regulated rate of return (performance based) for all transmission services (i.e. for both reliability and transfers of real energy). One exception to this rule, following the practice in Australia, is for a TransCo that owns a DC intertie. In this latter case, setting revenue equal to the flow of real energy times the price difference on the intertie is an appropriate method of payment, but paying a regulated rate of return is also perfectly viable.

4.3 Some Illustrative Examples

In some locations, the topology of an AC network does resemble the form of a pipeline. The Western Interconnection in the USA is one example because it is dominated by radial links between the Pacific Northwest and California, and between New Mexico and California. Transferring real energy into California is essential during the summer months because the state has developed over time into a net importer. Since long-distance transfers are large and follow predictable patterns, trading hubs for the delivery of real energy have become active on the borders of California (e.g. at Palo Verde and COB).

In contrast to the Western Interconnection, the three northeastern markets (ISO-New England, New York ISO and PJM) share a much denser AC network and are relatively self-sufficient in terms of generation capacity. More trading is done using financial instruments that do not require the physical delivery of real energy. For example, the New York Mercantile Exchange (NYMEx) currently supports trading at three locations in New York State (West, Hudson Valley, and New York City). Although the New York ISO determines different prices for about 400 nodes in the state, an analysis of the Eigen values and Eigen vectors (using the nodal prices from May 1, 2002 to October 31, 2002) shows that 97% of the total price variability can be captured by only four combinations of the nodal prices. These combinations correspond to the whole state, the Hudson Valley, New York City and Long Island, and they are consistent with the three locations chosen by the NYMEx (Long Island is not traded because supply in this region is controlled by a public power authority). The NYMEx contracts are purely financial swap options (contracts-for-differences in which the buyer pays Max [0, Contract Price – Spot Price] and the seller pays Max [0, Spot Price – Contract Price]). However, it is possible to use this type of financial instrument in a portfolio to hedge against the price risk of physical deliveries effectively, even if they involve transfers of real energy from low-cost to high-cost regions.

The overall conclusion is that NYMEx has established a viable market structure for trading financial contracts for real energy in New York State. By trading at three carefully chosen locations, it is possible to hedge price risk throughout the state. In addition, by trading at only three locations, the market is likely to be liquid, and therefore, to provide a viable public source of price discovery for evaluating other forms of contract. This is achieved by facilitating secondary trading in response to new information about the market conditions. Getting a reliable public source of up-to-date forward prices is the fundamental advantage of using a regulated exchange rather than over-the-counter trading. A reliable source of price discovery is essential for managing a portfolio of forward contracts and for making sound investment decisions in a deregulated market. Unfortunately, the general structure of forward markets for electricity in the USA is far from satisfactory at the present time.

The example of the NYMEx forward market for New York State is still an exception in the USA. In addition, the effectiveness of this particular market is undermined by inconsistencies with other markets, such as the auction for Transmission Congestion Credits (TCC) operated by the New York ISO. A TCC gives the owner the right to the revenue from the congestion price difference between two specific locations for a specified time period. In the Summer 2002, TCCs for 173 different nodal/zonal pairs were traded, far too many to support a liquid secondary market. In addition, only one third of the TCC corresponded to trades between the three major price zones identified by the Eigen analysis (there were no TCCs for nodes on Long Island), implying that relatively few TCC were used to hedge the large price differences that really did exist for inter-regional transfers (see the average nodal prices (LBMP) for high loads in Figure 3).

The revenue from the TCC auction in New York State is used as income for the TransCos, and the total number and locations of TCCs sold is restricted by the physical limits of the network. Even though the earnings of the TransCos are still fully regulated in New York State, the structure of the TCC auction is also consistent with pipeline thinking. Payments equal to the quantity times the price difference are made for transferring real energy. Payments for reliability are treated implicitly as a secondary issue. To reiterate our earlier conclusion, the primary role of an AC network is to provide a reliable supply of real energy for all customers on the network that can withstand equipment failures. In some cases, regular transfers of real energy from low cost to high cost regions are also supported, but in some of these cases, the transfers are actually made over DC interties and paying the quantity times the price difference is an appropriate way to compensate the TransCos.

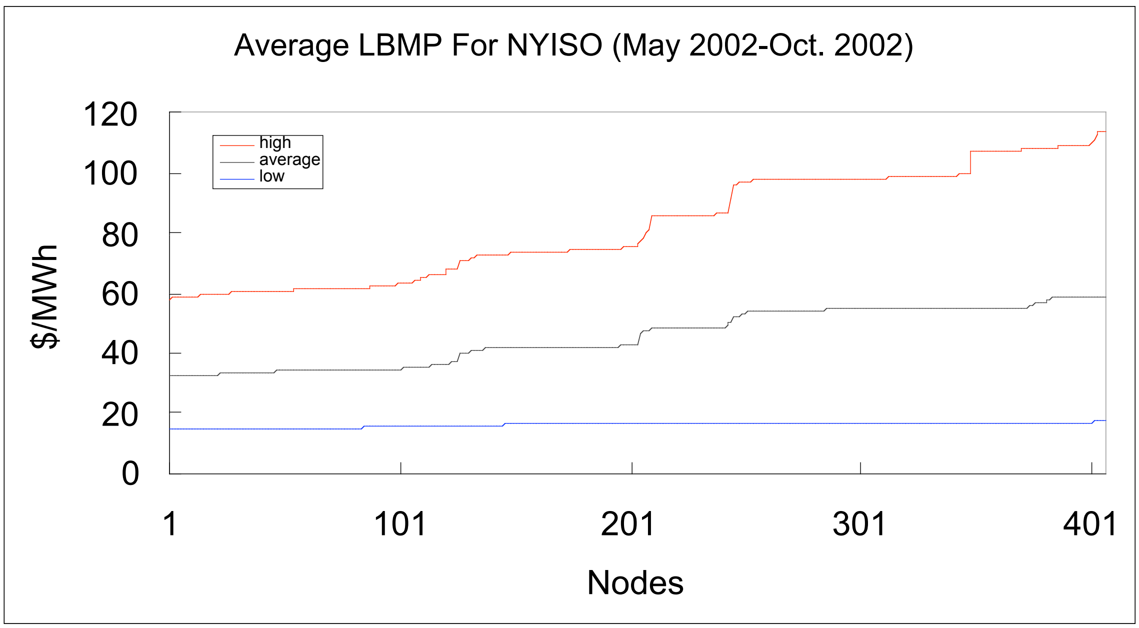


FIGURE 3: Location Based Marginal Prices (LBMP) in New York State.

The nodes are ranked by the average levels of the hourly LBMP for all loads (average). This ranking corresponds approximately to numbering the nodes from the west (Niagara Falls) to the southeast (New York City and Long Island). The same order of the nodes for the average LBMP is used for the 10% highest loads (high) and for the 10% lowest loads (low).

Assigning the revenues from a TCC auction for an AC network to individual TransCos on the basis of the size of the price differentials provides a potentially perverse incentive. On an ideal network, there would be no price differentials (e.g. the nodal prices for low loads in Figure 3). If the income of a TransCo was not regulated and depended exclusively on the size of the price differentials, there would be an incentive to create more congestion. Looking at Figure 3, there is no real economic justification for paying a TransCo less for transferring real energy from Niagara Falls to the Hudson Valley (about 300 miles, from node #1 to node #120) and paying more to other TransCos for a few miles (corresponding to the increases of the nodal prices around node #120 in the upper Hudson Valley and around node #210 in the lower Hudson Valley).

There are real costs associated with transfers of real energy, such as supplying reactive power (VArs) and trimming trees. In addition, there are other costs associated with maintaining the reliability of supply. For example, reliability standards require that there must be a substantial amount of reserve capacity (80% of the load) close to New York City to cover the possibility that some of the transmission lines from other regions may fail. These are major costs that are needed to maintain a regulated level of reliability, but these costs are effectively treated as a secondary issue by pipeline thinking.

A simple example follows to illustrate the interdependencies that exist between the dual roles played by transmission in supporting transfers and reliability. Consider a region with two levels of load (High and Low) and three types of generation capacity (Baseload, Shoulder and Peaking). The (reverse) supply curve and the corresponding market prices for the two levels of load are shown in Figure 4. There are no imports and the market price ($60/MWh) is equal to the Short-Run Marginal Cost (SRMC) of Peaking capacity in both cases. The Shoulder and Baseload capacity have positive net revenue (shaded in Figure 4) that can be used to cover capital costs, but Peaking capacity earns zero net revenue to cover capital costs. (This is a standard financial predicament for SRMC pricing in traditional regulatory economics that is addressed by Boiteux, Turvey and many others.)

It is possible to prorate the annual cost of capital over the number of MWh generated to determine the Long-Run Marginal Cost (LRMC). The results are summarized in the upper half of Table 3 for the three types of capacity. It is assumed that the High load in Figure 3 occurs 20% of the time and the Low load occurs 80% of the time during the three summer months. The total capital cost of Peaking capacity must be collected during the summer, but the Shoulder capacity only collects half of the total cost of capital in the summer and the Baseload capacity only one third of the total. The corresponding LRMC are 55, 70 and 146 $/MWh for Baseload, Shoulder and Peaking capacity, respectively. The LRMC for Peaking capacity is over twice as high as the SRMC in this example because the annual capacity factor is only 11.67% (100(30x0.2 + 10x0.8)/30/4) to give a LRMC of $146/MWh (60 + 88000/0.1167/8766).

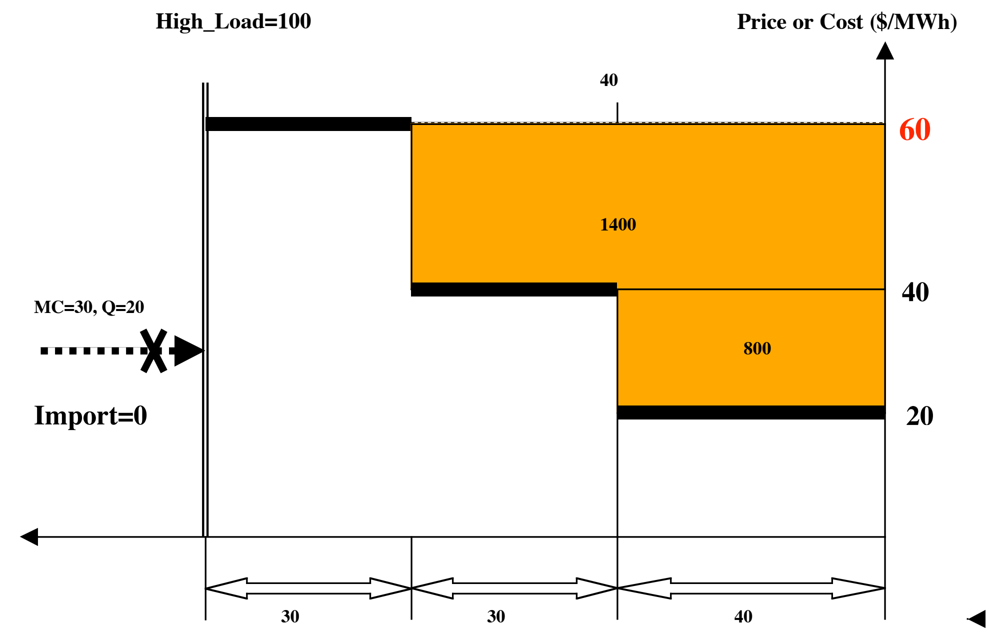
When 20MW of imports at a cost of $30/MWh are included in the example, most of the generation from the Peaking capacity and some from the Shoulder capacity are displaced. The supply situations for the two levels of load are shown in Figure 5. Compared to Figure 4 with no imports, the market price for the High load in Figure 5 is still $60/MWh, but the amount of Peaking capacity needed is reduced by two thirds to 10MW. For the Low load, the market price is now only \$40/MWh instead of \$60/MWh, and this represents a potential benefit for customers in the region (and a corresponding loss of net revenue for the owners of Shoulder and Baseload capacity). No Peaking capacity is needed with the Low load and the generation from Shoulder capacity is reduced by one third to 20MW.

The imports create true cost savings for both levels of load that are initially collected by the ISO (20x(Price – 30), corresponding to \$600 for the High load and \$200 for the Low load). An important policy question is how should these revenues (cost savings) be distributed? If there is a TCC market, the answer is that the revenue belongs to the owner of the appropriate TCC, and therefore, indirectly to the TransCos that own the intertie. However, this practice ignores the cost of maintaining the reliability of supply and covering the possibility that the intertie fails.

With 20MW of imports, all 30MW of Peaking capacity are needed for the High load to meet 10MW of load and provide 20MW of reserves, and for the Low load, 10MW are needed for reserves (plus another 10MW of Shoulder capacity). If the 10MW needed to meet the High load are prorated to the 30MW of installed Peaking capacity, the annual capacity factor is only 1.67% (100(10x0.2 + 0x0.8)/30/4). Consequently, the LRMC increases from \$146/MWh without imports to \$662/MWh with imports (60 + 88000/0.0167/8766). The results in the lower half of Table 2 show the LRMC with imports, and they are now 55, 81 and 662 \$/MWh (compared to 55, 70 and 146 \$/MWh without imports) for Baseload, Shoulder and Peaking capacity, respectively. In contrast to the 350% increase of LRMC for Peaking capacity with imports, the LRMC for Baseload capacity does not change and the LRMC for Shoulder capacity is only 16% higher.

Since the annual capital cost of the Peaking capacity does not change, the LRMC depends on how often the transmission line fails. The LRMC for each type of generator is a weighted average of the values in the upper half of Table 3 (corresponding to a transmission failure) and the lower half (corresponding to the intact system). Since the probability of a transmission failure is likely to be small (e.g. <1%), the LRMC will be close to the higher values in the lower half of Table 3 that correspond to the case with imports. This makes the LRMC of peaking capacity (>\$650/MWh) over ten times higher than the highest spot price in the summer (\$60/MWh), and this high spot price only occurs 20% of the time with imports. As a result, the financial incentives for Peaking capacity, using expected revenue from the spot market exclusively, are completely inadequate for covering the capital cost of maintaining reliability.

No Imports, High Load



No Imports, Low Load

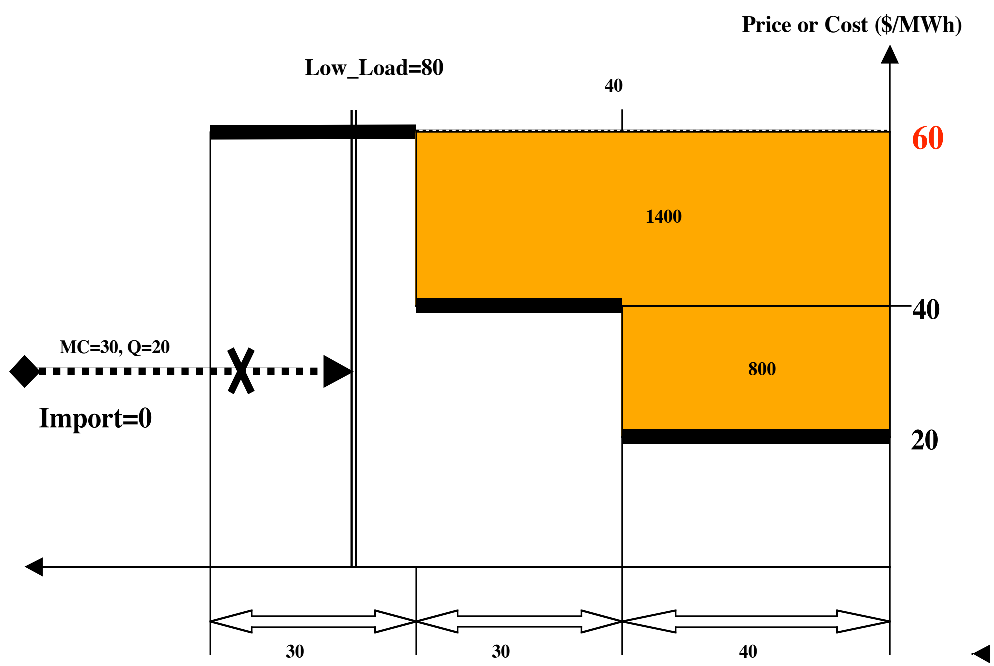
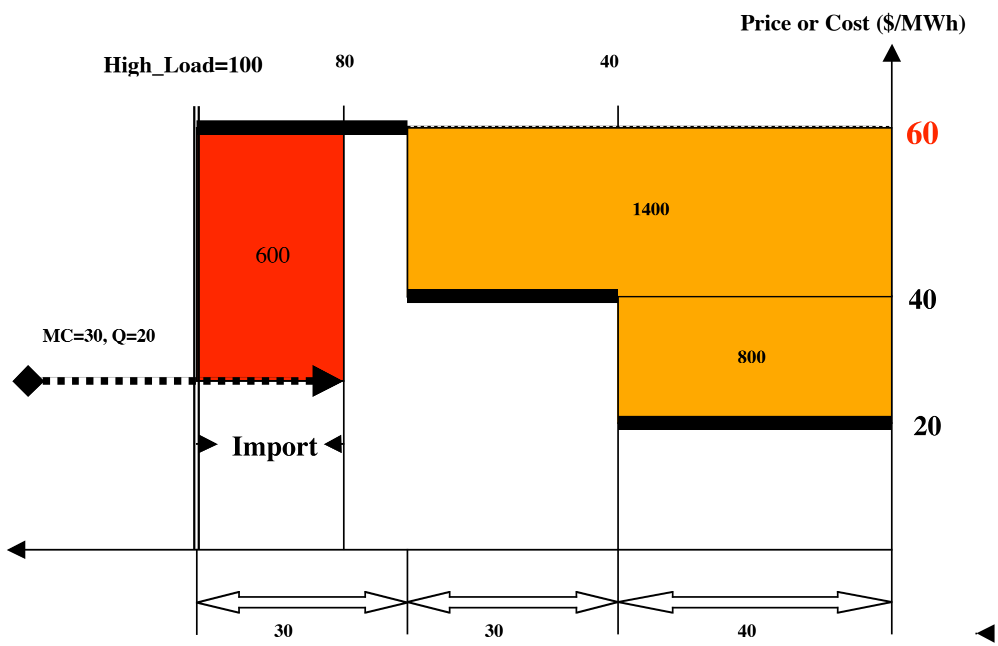


FIGURE 4: Supply Conditions Without Imports

With Imports, High Load



With Imports, Low Load

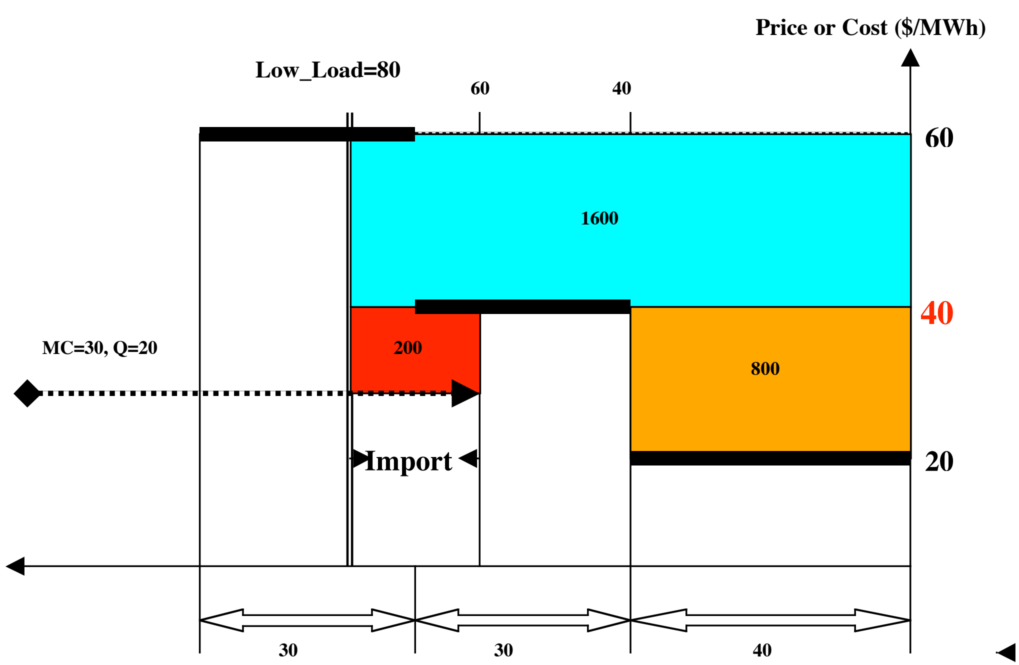


FIGURE 5: Supply Conditions with Imports

TABLE 3: Long-Run Marginal Costs of Generation With and Without Imports

WITHOUT IMPORTS **Specified Characteristics**	**Baseload** **(40MW)**	**Shoulder** **(30MW)**	**Peaking** **(30MW)**
1. Fuel Cost ($/MWh)	20	40	60
2. Prorated Capital Cost ($/MWh)	35	30	86
3. Total Cost ($/MWh)	**55**	**70**	**146**
4. Summer Capacity Factor (%)	100	100	47
5. Annual Capacity Factor (%)	75	50	12
6. Annual Capital Cost ($/kW)	230	131	88
WITH 20MW IMPORTS **Specified Characteristics**			
1. Fuel Cost ($/MWh)	20	40	60
2. Prorated Capital Cost ($/MWh)	35	41	602
3. Total Cost ($/MWh)	**55**	**81**	**662**
4. Summer Capacity Factor (%)	100	73	7
5. Annual Capacity Factor (%)	75	37	2
6. Annual Capital Cost ($/kW)	230	131	88

It is expensive to maintain the reliability of the supply system. Having generators available to cover contingencies results in higher capital costs for each MWh generated. In our simple example, two thirds of the capital component of the high LRMC for Peaking capacity can be attributed to the cost of maintaining reliability. In more realistic examples, it would be necessary to consider many different contingencies to maintain a required level of reliability. The role of the transmission system is to ensure that new sources of real energy can be delivered to the loads when contingencies occur. Having reserve capacity is ineffective if the transmission network cannot deliver the real energy. There must be some of level of redundancy in a robust network so that there are different pathways for supplying loads.

Since different contingencies affect different parts of a network in different ways under different patterns of load, it is impractical to divide the cost of transmission between transferring real energy and maintaining reliability. The pipeline model simply does not work for an AC network. It is inappropriate to ignore reliability and to assume that the revenues from the flow times the price difference of an inter-regional transfer (like the imports in Figure 5) belong exclusively to the owners of that particular transmission line. There are other costs needed to maintain the reliability of supply associated with these imports. Hence, it is more logical to follow the example of Australia and to put the revenue from the imports into a pool that is used to compensate all TransCos for providing transmission services, and to recognize that reliability is a shared responsibility of all users of the network.

5. Summary and Conclusions

Sections 2 and 3 of this paper describe a series of tests of the performance of an electricity market when there are changes in the quantity of transfers of real energy through an AC network. The tests were conducted over the Internet on a software platform (POWERWEB). Using graduate students to represent suppliers in a uniform price auction, the results show that the market prices were substantially above competitive levels. Prices were higher when there was more congestion on the network due to transfers because the market was easier to exploit. For example, load pockets can occur when transmission lines reach their thermal or voltage limits, and this effectively reduces the number of suppliers competing in a region.

The most important result from the market tests is that interactions between the level of transfers (referred to as Markets in Section 3) and individual suppliers (Firms) explain a large part of the variability in Earnings among firms. The effects of changing the level of transfers are very different at different locations on the network. Even though a single source and a single sink are used to represent a transfer through the network, the consequences are surprisingly complicated. Congestion at one location interacts with flows throughout the network. There is no consistent pathway for the transfers when the levels of load vary, as they do in our experiments. Hence, it is misleading to assume that the transfers of electricity on a network can be treated in the same way as the transfers of natural gas on a pipeline. In spite of this, the basic procedures established by the FERC for transfers in deregulated markets support point-to-point contracts for electricity and implicitly treat the network like a pipeline. This is true even though the actual flows of real energy on the network may be completely different from the accounting pathways used to justify a contract.

Overall, the results in Section 3 show that experimental economics is an effective way to evaluate the effects of transfers of electricity on a network. Using POWERWEB, the market outcomes are determined by the combined effects of changes in the physical characteristics of the network and changes in the behavior of suppliers. The behavior of suppliers adapts to changes in the characteristics of the network, and the students were able to exploit market power effectively whenever the opportunity occurred. Both types of change affect how well a market works, and in a more elaborate experiment, it would also be possible to demonstrate how transfers affect the reliability of the supply system. Most economic models of deregulated electricity markets simplify the physical characteristics of a network, and most planning models used by electric utilities simplify the adaptive behavior of suppliers. However, the physical properties of any particular AC network impose real limits on the performance of a deregulated market. This poses a major challenge for any analysis of market performance, but it is essential to consider both the physical characteristics of the network and the realistic behavior of suppliers in the market simultaneously to get a full understanding of the role of transmission. Experimental economics, using a platform like POWERWEB, is a practical way to accomplish this objective.

The dual roles of the transmission network for maintaining reliability and enabling inter-regional transfers of real energy are highly interdependent. Section 4 explains why it is inappropriate to use pipeline principles to pay for transmission services. The conclusions are:

1) Maintaining the reliability of a transmission network is a shared responsibility of all users of the network and the final responsibility for planning rests with regulators (e.g. following the Australian example). Maintaining system reliability should not be left to decentralized decisions made by transmission owners and other users of the network.
2) Since it is impractical to allocate the transmission costs of an AC network between transferring real energy and maintaining system reliability, the TransCos should receive performance-based rates of return for capital and some form of incentive payment for operating costs (e.g. following the UK example).
3) Federal regulators should be more proactive in encouraging the conversion of physical bilateral contracts to financial contracts for inter-regional transfers, and establishing an effective structure of forward markets (e.g. following the example of NYMEx in New York State).

Our overall conclusion is that the problem of paying for the reliability of a supply system for electricity must be addressed directly. This is an important objective for future research. At the present time, the process of deregulation in the USA deals with reliability indirectly by, for example, using proxy standards such as fixed regional requirements for reserve capacity, and therefore, it implicitly ignores the central role of the transmission system. As a result, the solutions proposed by regulators, such as paying more to generators in a capacity auction, are probably expensive and relatively ineffective ways to maintain system reliability. Some generators do not contribute to maintaining system reliability and do not “need” additional income from a capacity auction, and other generators, like the Peaking capacity discussed in Section 4, are needed primarily to maintain reliability but are not compensated adequately to stay in the market. An additional unfortunate consequence of treating a reserve margin as synonymous with reliability is that the responsibility for maintaining “reliability” (i.e. the specified reserve margin) is transferred from regulators to load serving entities. In this way, regulators are able to duck their main responsibility in a deregulated market, which is to ensure that the supply system is reliable and that the costs are just and reasonable. The main problem facing the deregulation of electricity markets in the USA at the present time is that there is no longer a reliable way to pay for a reliable supply system.

6. References

TO BE COMPLETED

APPENDIX A

TABLE A1: ANALYSIS OF VARIANCE

Dependent Variable: EARNINGS BY FIRM (15 periods)

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	33	25006220	757764	7.56	<.0001
Error	20	2003690	100185		
Corrected Total	53	27009911			

Root MSE	316.51937	R-Square	0.9258
Dependent Mean	1829.91056	Adj R-Sq	0.8034
Coeff Var	17.29699		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	1829.91056	3.07283	42.48	<.0001
m2	1	9.32611	60.91418	0.15	0.8799
m3	1	236.08833	60.91418	3.88	0.0009
f2	1	-225.61722	96.31378	-2.34	0.0296
f3	1	110.70944	96.31378	1.15	0.2639
f4	1	71.63833	96.31378	0.74	0.4656
f5	1	215.48167	96.31378	2.24	0.0368
f6	1	-324.44056	96.31378	-3.37	0.0031
s2	1	-135.51222	60.91418	-2.22	0.0378
s3	1	-333.39167	60.91418	-5.47	<.0001
MF22	1	-211.01278	136.20825	-1.55	0.1370
MF23	1	-223.40611	136.20825	-1.64	0.1166
MF24	1	-429.94500	136.20825	-3.16	0.0050
MF25	1	246.32167	136.20825	1.81	0.0856
MF26	1	888.18722	136.20825	6.52	<.0001
MF32	1	174.18167	136.20825	1.28	0.2156
MF33	1	358.00167	136.20825	2.63	0.0161
MF34	1	520.07944	136.20825	3.82	0.0011
MF35	1	-108.26389	136.20825	-0.79	0.4360
MF36	1	-1297.22167	136.20825	-9.52	<.0001
MS22	1	-61.24444	86.14566	-0.71	0.4853
MS23	1	75.85333	86.14566	0.88	0.3890
MS32	1	223.19167	86.14566	2.59	0.0175
MS33	1	-171.98722	86.14566	-2.00	0.0597
FS22	1	-374.55444	136.20825	-2.75	0.0123
FS23	1	228.30167	136.20825	1.68	0.1093
FS32	1	-142.71444	136.20825	-1.05	0.3072
FS33	1	-138.84833	136.20825	-1.02	0.3202
FS42	1	275.78667	136.20825	2.02	0.0565
FS43	1	-253.29389	136.20825	-1.86	0.0777
FS52	1	51.77000	136.20825	0.38	0.7079
FS53	1	144.17278	136.20825	1.06	0.3025
FS62	1	-206.02111	136.20825	-1.51	0.1460
FS63	1	250.12500	136.20825	1.84	0.0812

TABLE A1continued: ANALYSIS OF VARIANCE
Dependent Variable: NODAL PRICE (15 periods)

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	33	7371.36278	223.37463	11.25	<.0001
Error	20	397.12759	19.85638		
Corrected Total	53	7768.49037			

Root MSE	4.45605	R-Square	0.9489
Dependent Mean	81.61074	Adj R-Sq	0.8645
Coeff Var	5.46013		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	81.61074	0.60639	134.58	<.0001
m2	1	-0.10963	0.85757	-0.13	0.8996
m3	1	6.13093	0.85757	7.15	<.0001
f2	1	-0.16741	1.35593	-0.12	0.9030
f3	1	-1.26296	1.35593	-0.93	0.3627
f4	1	-0.36963	1.35593	-0.27	0.7880
f5	1	0.49148	1.35593	0.36	0.7208
f6	1	2.11704	1.35593	1.56	0.1341
s2	1	-2.69074	0.85757	-3.14	0.0052
s3	1	-8.95852	0.85757	-10.45	<.0001
MF22	1	-4.36370	1.91758	-2.28	0.0340
MF23	1	-2.60481	1.91758	-1.36	0.1895
MF24	1	-4.11148	1.91758	-2.14	0.0445
MF25	1	4.60074	1.91758	2.40	0.0263
MF26	1	10.09852	1.91758	5.27	<.0001
MF32	1	3.59907	1.91758	1.88	0.0752
MF33	1	2.68463	1.91758	1.40	0.1768
MF34	1	3.18796	1.91758	1.66	0.1120
MF35	1	-4.34981	1.91758	-2.27	0.0345
MF36	1	-8.62870	1.91758	-4.50	0.0002
MS22	1	-1.43870	1.21278	-1.19	0.2494
MS23	1	2.23741	1.21278	1.84	0.0799
MS32	1	5.69074	1.21278	4.69	0.0001
MS33	1	-4.84481	1.21278	-3.99	0.0007
FS22	1	4.37407	1.91758	2.28	0.0336
FS23	1	-3.46148	1.91758	-1.81	0.0861
FS32	1	0.39963	1.91758	0.21	0.8370
FS33	1	-0.03593	1.91758	-0.02	0.9852
FS42	1	2.31630	1.91758	1.21	0.2412
FS43	1	-2.24259	1.91758	-1.17	0.2560
FS52	1	-4.59481	1.91758	-2.40	0.0265
FS53	1	2.83296	1.91758	1.48	0.1552
FS62	1	-5.90704	1.91758	-3.08	0.0059
FS63	1	4.72407	1.91758	2.46	0.0229

TABLE A1continued: ANALYSIS OF VARIANCE
Dependent Variable: CAPACITY OFFERED (15 periods)

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	33	4290.74216	130.02249	5.18	0.0001
Error	20	502.00953	25.10048		
Corrected Total	53	4792.75168			

Root MSE	5.01004	R-Square	0.8953
Dependent Mean	43.86852	Adj R-Sq	0.7224
Coeff Var	11.42058		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	43.86852	0.68178	64.34	<.0001
m2	1	-0.03352	0.96418	-0.03	0.9726
m3	1	0.61981	0.96418	0.64	0.5276
f2	1	1.91370	1.52451	1.26	0.2238
f3	1	-0.13407	1.52451	-0.09	0.9308
f4	1	1.22815	1.52451	0.81	0.4299
f5	1	1.61481	1.52451	1.06	0.3021
f6	1	-6.96185	1.52451	-4.57	0.0002
s2	1	0.17204	0.96418	0.18	0.8602
s3	1	2.19981	0.96418	2.28	0.0336
MF22	1	-2.36870	2.15598	-1.10	0.2850
MF23	1	-2.65426	2.15598	-1.23	0.2326
MF24	1	-6.79648	2.15598	-3.15	0.0050
MF25	1	2.91352	2.15598	1.35	0.1917
MF26	1	10.41352	2.15598	4.83	0.0001
MF32	1	4.33130	2.15598	2.01	0.0582
MF33	1	7.00241	2.15598	3.25	0.0040
MF34	1	7.35019	2.15598	3.41	0.0028
MF35	1	-0.67315	2.15598	-0.31	0.7581
MF36	1	-19.75981	2.15598	-9.17	<.0001
MS22	1	-0.67370	1.36356	-0.49	0.6266
MS23	1	1.69185	1.36356	1.24	0.2291
MS32	1	0.14463	1.36356	0.11	0.9166
MS33	1	-1.50148	1.36356	-1.10	0.2839
FS22	1	-3.85426	2.15598	-1.79	0.0890
FS23	1	4.35463	2.15598	2.02	0.0570
FS32	1	-7.45981	2.15598	-3.46	0.0025
FS33	1	0.22241	2.15598	0.10	0.9189
FS42	1	-1.04870	2.15598	-0.49	0.6320
FS43	1	4.48352	2.15598	2.08	0.0506
FS52	1	7.16796	2.15598	3.32	0.0034
FS53	1	-2.32315	2.15598	-1.08	0.2941
FS62	1	-0.89204	2.15598	-0.41	0.6835
FS63	1	-3.92981	2.15598	-1.82	0.0833

APPENDIX B

GENERAL INSTRUCTIONS FOR TESTING AN ELECTRICITY MARKET USING POWERWEB

INTRODUCTION

PowerWeb is a computer program that allows you to use your skills in economic decision-making to test an electricity market. You will have the opportunity to earn money through your actions in this test. Any money that you earn will be yours to keep, and you should try to make as much money as possible. Other people in the test will be competing directly against you in the market. Please do not communicate with any of the other participants. It is important to us that you understand these instructions. If you do, it will improve your chances of earning more money in the test and will improve the quality of the data we gather. If you have questions at any time, please raise your hand and an instructor will answer your question. When testing a market, it is essential that we have your full attention. Do NOT open other windows or check your email.

THE OBJECTIVE

For a standard test of an electricity market, you will be one of **six** different suppliers. (You do not need any prior knowledge of this type of market to participate in the test.) In each market, there is a single buyer of electricity who has the obligation to meet demand (load) at the least cost. As a supplier, you can generate a maximum of **60 megawatts (MW)** of electricity, and this production capacity is divided into five blocks (generators) with different operating costs. The size and operating cost of each of your generators will be revealed to you at the start of the test. The cost structures of all suppliers are very similar to each other.

Each test will last for a specified number of trading periods. In each period, **your goal is to maximize your own earnings**. The amount of money you keep at the end of the test will be proportional to your total earnings over all periods. In each period of the test, you will participate in an auction and submit offers to sell each of your generators. An offer represents the minimum price at which you are willing to sell each MW from that generator.

THE TRANSMISSION NETWORK

In this experiment, the suppliers and the loads are connected by a transmission network, shown in Figure 1, which must be operated at all times in a manner consistent with the laws of physics governing the flow of electricity. A small percentage of the energy produced is dissipated by the transmission lines. These **transmission losses** imply that the total amount of power the buyer must purchase is slightly greater than the total demand and the exact amount is dependent on where the power is produced.

The operation of the network is also constrained by the physical limitations of the equipment used to generate and transmit the power. This implies that there are limits to the amount of power that can be transmitted from one part of the network to another. **Congestion**, which occurs when these limits are reached, can make it impossible for the buyer to utilize inexpensive generation, forcing it to purchase more expensive power from a different location.

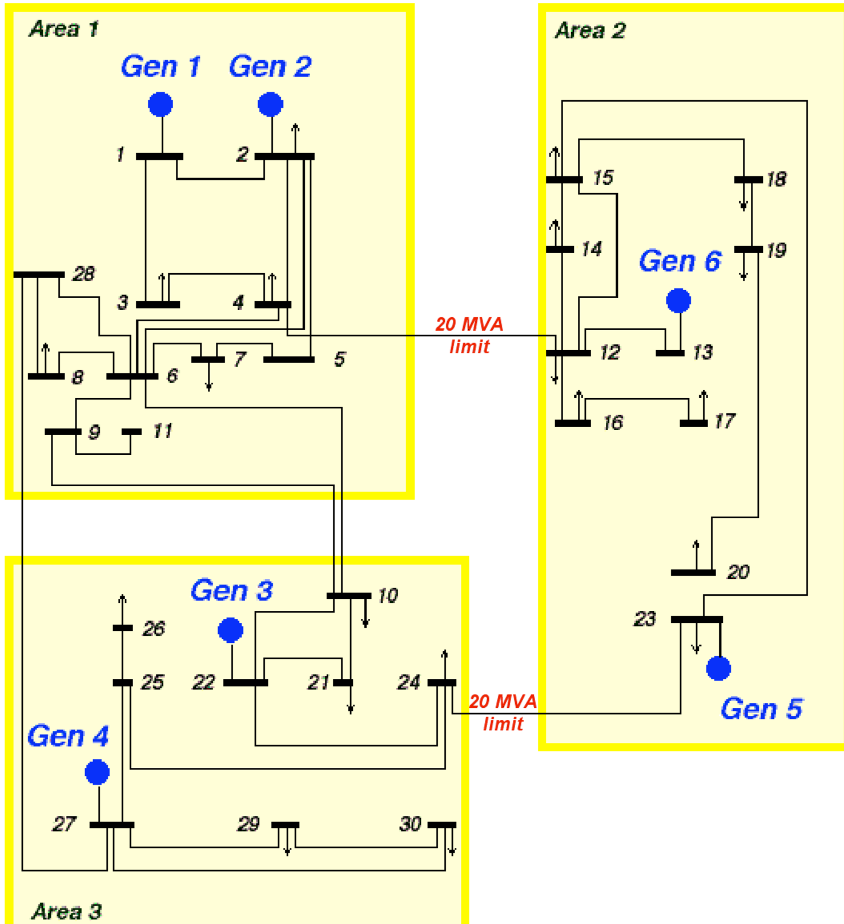


Figure 1 30-bus transmission network

HOW THE AUCTION WORKS

After all the offers have been collected from the suppliers, the buyer will choose to accept the least expensive offers which are able to meet the load while satisfying all of the constraints of the transmission system. The prices paid to each supplier **nodal prices**, specific to their location. Each nodal price is equal to the marginal cost to the buyer of meeting an additional unit of demand at the corresponding node.

In a network without congestion and with minimal losses, this can be approximated by a **Uniform Price Auction** paying the **Last Accepted Offer**, which works as follows. The buyer ranks the supplier's offers from the least expensive to the most expensive. The buyer then accepts offers in order from the lowest to highest offer price until sufficient capacity is purchased to meet the load. The buyer pays all purchased generators the same price, and this price is equal to the offer for the most expensive generator purchased.

However, as losses and congestion increase, the buyer is forced to accept offers out of order (some expensive units may be accepted while less expensive ones are rejected), and the prices at the various nodes move away from a single uniform price.

THE RULES OF THE MARKET

(1) You may submit an offer for each of your five blocks of capacity in every period up to the maximum of 60MW. If you choose to submit an offer on a block of capacity, you will have to pay a fixed **Standby Cost of $5/MWh** regardless of whether you actually sell any of that block. (The standby cost is a simple way to represent the opportunity cost of being available in the market. These costs could include postponing maintenance activities, not selling energy in another market and paying wages to part of the workforce.)

(2) You may choose not to sell a block of capacity by clicking the **shutdown** checkbox, and in this case, the standby cost is automatically set to zero.

(3) The maximum price (**the price cap**) that the buyer is willing to pay for electricity is **$100/MWh**. If you offer a block of capacity above $100/MWh, the buyer will disregard your offer. You will receive an error message, and this will allow you to resubmit your offers.

(4) You will never receive less than your offer price for the capacity you sell. As a rule of thumb, if your offer price is less than the final clearing price then you will sell that block of capacity. If your offer is greater than the clearing price, you will not sell that block of capacity.

(5) There is a **fixed cost of $300/period** that must be paid in every trading period to cover the finance cost of capital investments.

(6) At the start of each trading period, the buyer will post the forecasted load, but the actual load need not be the same as the forecasted level. You will be told the range of possible values for the actual load.

(7) Since there are incentives for suppliers to withhold some capacity from the auction, it is possible that the total capacity submitted into the auction is insufficient to meet the actual load. Hence, some scheme for dealing with capacity shortfalls is required. In this market, the following procedure is used:

> **The nodal prices are set to the highest offer submitted into the auction, adjusted for location. The buyer meets the shortfall of capacity by contracting with suppliers in another power pool. The actual load reported does *not* include these imports, and consequently, it may be substantially below the forecasted load (i.e. outside the normal range of forecasting errors).**

SUBMITTING AN OFFER TO THE AUCTION

Each period of the auction begins with an **Offer Submission Page**. The screen shot for Seller 1 in Period 1 will help you understand the information presented and show you how to enter your offers into the auction. The parameters in this example are not necessarily the same as in the actual test. In this example, the seller has chosen to submit the first four blocks of capacity (Gen 1-4) and to withhold the last block (Gen 5). Every block submitted to the auction pays a standby cost of $5/MW, but the variable costs will only be paid on blocks that are purchased by the buyer.

POWER WEB

Name: [my@e.mail] Test User Logout
Session: [2] Example Session
Representing: [8] Seller 1

Period **1**

SYSTEM DATA	
Forecasted Load (MW)	519.0
Installed Capacity (MW)	600.0
Price Cap ($/MW)	$100.00

GENERATOR DATA	Gen 1	Gen 2	Gen 3	Gen 4	Gen 5
Min Generation (MW)	0.0	0.0	0.0	0.0	0.0
Max Capacity (MW)	50.0	20.0	10.0	10.0	10.0
Variable Cost ($/MW)	$20.00	$40.00	$48.00	$50.00	$52.00
Standby Cost ($/MW)	$5.00	$5.00	$5.00	$5.00	$5.00
Fixed Cost ($)	$600.00	$300.00	$100.00	$100.00	$100.00
MY OFFERS	**Gen 1**	**Gen 2**	**Gen 3**	**Gen 4**	**Gen 5**
Shutdown?	☐	☐	☐	☐	☑
Energy Offer ($/MW)	$ 20	$ 40	$ 50	$ 60	$
			Submit Offer		
Standby Costs ($)	$ 250	$ 100	$ 50	$ 50	$ 0

The upper table of the **Offer Submission Page** gives the following information about the **SYSTEM DATA**:

1) The **forecasted load** in MW will typically vary from period to period (the yellow background indicates that the forecasts may change).
2) The **installed capacity** in MW gives the total of the maximum generating capacity of all suppliers in the market.
3) The **price cap** in $/MWh is the maximum price paid in the auction, and offers above this price will not be accepted by the buyer.

The columns in the lower table on the **Offer Submission Page** correspond to the five different generators (**Gen 1 – 5**) that you control as a supplier. For each generator, the rows for the **GENERATOR DATA** are:

1) The **minimum generation** in MW for the generator to operate.
2) The **maximum capacity** in MW of output from the generator.

3) The **variable cost** in $/MWh (for fuel etc.) of generating electricity.
4) The **standby cost** in $/MW (the opportunity cost of being available for all capacity submitted to the auction).
5) The **fixed cost** in $/trading period (the cost of financing capital investments, such as interest payments on bonds).

The corresponding rows for **MY OFFERS** are:

1) A check box for **shutdown?** (i.e. withholding a generator from the auction), and if a generator is withheld, the offered price in the next row is disabled and the standby costs are set to zero.
2) The **energy offer** in $/MW that you must specify for each generator that is not withheld (your offer is the minimum price that you are willing to accept for generating electricity).
3) The actual **standby costs** in $/trading period that are paid whenever a generator is submitted into the auction (these cost are computed automatically and cannot be edited).

The **submit offer** button is used to submit a set of offers to the auction after you have specified an offer for (or decided to withhold) each of your five generators. NOTE: submitting a blank offer for a generator that is not explicitly withheld corresponds to submitting a zero offer --- be careful.

AUCTION RESULTS

After you have submitted your offers, PowerWeb will inform you to wait until all of the other suppliers have finished submitting their offers. The auction results will then be calculated by PowerWeb and presented to you in an **Auction Results Page**. The number of the trading period for these results is shown at the far right of the banner at the top of the screen. The top table gives information about the **SYSTEM DATA.** The first row repeats the **forecasted load** in MW from the **Offer Submission Page,** and the second row gives the **actual load** in MW.

The top section of the middle table under **GENERATOR DATA** repeats the **variable cost** in $/MW and the **standby cost** in $/MW for each one of your generators from the **Offer Submission Page.** The middle section under **MY OFFERS** summarizes the outcome of the auction for each one of your generators. The first pair of rows for **energy capacity** show the **offered** quantities in MW submitted to the auction, and the corresponding quantities **sold** in MW are shown underneath. The second pair of rows for **energy price** show the **offered** prices in $/MW for each generator, and the corresponding market prices **paid** in $/MW are shown underneath (market prices are also shown for generators that were withheld). If a generator was withheld, the capacity values and the offered price are blank and colored gray. A green background implies your offer was accepted (market price > the offer), a red background implies your offer was rejected (market price < the offer), and a yellow background implies your offer set the market price (market price = the offer). The last column of the table summarizes the total quantities and the average price paid for all five generators.

POWER WEB

Name: [my@e.mail] Test User Logout
Session: [2] Example Session
Representing: [8] Seller 1

Period
1

SYSTEM DATA	
Forecasted Load (MW)	519.0
Actual Load (MW)	520.0

GENERATOR DATA		Gen 1	Gen 2	Gen 3	Gen 4	Gen 5	
Variable Cost ($/MW)		$20.00	$40.00	$48.00	$50.00	$52.00	
Standby Cost ($/MW)		$5.00	$5.00	$5.00	$5.00	$5.00	
MY OFFERS		**Gen 1**	**Gen 2**	**Gen 3**	**Gen 4**	**Gen 5**	**Total (or Avg)**
Energy Capacity (MW)	Offered	50.0	20.0	10.0	10.0		90.0
	Sold	50.0	20.0	10.0	10.0		90.0
Energy Price ($/MW)	Offered	$20.00	$40.00	$50.00	$60.00		
	Paid	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
EARNINGS		**Gen 1**	**Gen 2**	**Gen 3**	**Gen 4**	**Gen 5**	**Total**
Revenue from Energy Sales ($)		$3000.00	$1200.00	$600.00	$600.00		$5400.00
Variable Costs ($)		$1000.00	$800.00	$480.00	$500.00		$2780.00
Standby Costs ($)		$250.00	$100.00	$50.00	$50.00		$450.00
Fixed Costs ($)		$600.00	$300.00	$100.00	$100.00	$100.00	$1200.00
Total Earnings ($)		$1150.00	$0.00	($30.00)	($50.00)	($100.00)	$970.00

Continue >>

MARKET HISTORY																			
Period		Load (MW)		My Sales (MW)	Market Share	Capacity (MW)					Energy Price ($/MW)					Avg Price ($/MW)		Earnings ($)
		Forecast	Actual			Gen 1	Gen 2	Gen 3	Gen 4	Gen 5	Gen 1	Gen 2	Gen 3	Gen 4	Gen 5	Mine	Market	
1	In	519.0	520.0	90.0	17%	50.0	20.0	10.0	10.0		$20.00	$40.00	$50.00	$60.00		$60.00	$60.00	$970.00
	Out					50.0	20.0	10.0	10.0		$60.00	$60.00	$60.00	$60.00	$60.00			
Cumulative Earnings																		$970.00
Cumulative Earnings * Exchange Rate(0.00025)																		$0.24

The bottom section of the middle table under **EARNINGS** summarizes the revenues and the costs for each generator. The five rows represent:

1) The **revenue from energy sales** in $/period is equal to the capacity sold times the market price paid.
2) The **variable costs** in $/period are equal to the capacity sold times the variable cost/MW.
3) The **standby costs** in $/period are equal to the capacity submitted into the auction times the standby cost/MW.
4) The **fixed costs** in $/period are the same in every period and are not affected by the outcome of the auction.
5) The **total earnings** in $/period are the difference between the revenue in row 1 and the sum of the costs in rows 2-4 (any value colored RED in parentheses is a LOSS).

The last column of the middle table under **EARNINGS** summarizes the revenues, costs and earnings for all five of your generators (if the value of **total earnings** is colored RED in parentheses, you lost money in this trading period). Clicking on **Continue >>** will send you to the **Offer Submission Page** for the next trading period.

The bottom table on the **Auction Results Page** gives a **MARKET HISTORY** of the previous auctions for up to five trading periods (in reverse order, with the results from the last trading period in the first row). There is also a link to the complete auction history. The columns display the following information:

1) The number of the **period**.
2) The **forecasted load** in MW.
3) The **actual load** in MW.
4) The amount of your capacity sold in MW (**my sales**).
5) Your percentage **market share** (100xMy Sales/Actual Load).
6) The **capacity** in MW offered (top row --- **In**) and sold (bottom row --- **Out**) for each one of your generators.
7) The **price** in $/MW offered (top row --- **In**) and paid (bottom row --- **Out**) for each one of your generators (including generators that were withheld).
8) The **average price** in $/MWh paid for your capacity (**mine**) and paid for all capacity purchased in the auction (**market**).
9) The total **earnings** in $ for the trading period.

At the bottom of the **MARKET HISTORY**, the **cumulative earnings** over all trading periods are shown. The cumulative earnings are in "PowerWeb dollars", and these earnings are converted to real dollars using an explicit exchange rate. Once again, RED values of real dollars in parentheses mean that you are losing money and not earning enough to cover your fixed costs.

Testing Markets for Electricity Using PowerWeb

Test 4: Energy Market with Quantity/Price Offers and Power Transfers through the Transmission Network

You will represent one of the six firms in the 30 bus network. Each firm owns 3 generators at a single location, with a total capacity of 60 MW. In each period you will be given a forecast of the total system load, which varies from period to period. The actual load will be within 20 MW of the forecast, and is scaled uniformly from the values shown on the network diagram. You will submit, for each generator the minimum price at which you are willing to sell the capacity of that generator and the quantity you wish to offer for sale. There is a Price Cap of $100/MW. All offers submitted must be less than or equal to the Price Cap.

All firms submit offers for energy into a central auction run by an Independent System Operator (ISO), and the ISO selects the least expensive combination of offers to meet the system load and satisfy the operational constraints of the system.

In this test, the 30 bus network is connected to neighboring systems which may at times arrange to transfer power through the 30 bus network. The test will be divided into 3 sections as follows. In section A, consisting of 15 trading periods, there will be no power transfers through the system. In section B, which will run for 30 periods, there will be a 40 MW transfer from the NW (entering at bus 28) to the southeast (leaving at bus 14). In section C, another 30 periods, there will be a 40 MW transfer in the opposite direction, from the SE to the NW (from bus 14 to bus 28). The amount and direction of the transfer will be displayed on the screen for each period.

In each trading period, after all offers have been submitted, the ISO will determine the optimal allocation of capacity for each generator submitted to the auction, and the corresponding nodal prices paid. These results and your earnings will be reported on the *Auction Results* screen (see pp. 5-7 of the Instructions).

For this market test, your objective is to **maximize your earnings** over the series of trading periods. Please do not communicate with any of the other participants during the tests. Collusion is not allowed in these markets. In real markets, any evidence that prices and market shares have been fixed by prior agreements will lead to prosecution by the Department of Justice.

To log in, follow the following instructions:

1. Point your browser to: http://powerweb.pserc.cornell.edu/
2. Click the link to Join a pool as a returning user (assuming you are already registered on PowerWeb)
3. Type your e-mail address, password and the pool number you will be given