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THE EFFICIENCY OF MARKET COORDINATION:
Evidence from Wholesale Electric Power Pools

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I. Background

The Public Utility Regulatory Policies Act of 1978 (PURPA) opened the door to competition in electric power by defining a new class of non-utility electricity generators, called Qualifying Facilities, with rights to sell to investor-owned utilities at regulated rates. Although considered by many a watershed act in the deregulation of electric power in the U.S., PURPA's effect on the industry was only incremental for two reasons. First, PURPA restricted Qualifying Facility status to small producers using renewable fuels and to cogenerators. Second, PURPA did not promote change in the vertically integrated structure of the industry. Qualifying facilities could sell only to the utility in the service area in which they were located.

The Energy Policy Act enacted in October of 1992 is the most significant legislation affecting the electricity market since the Public Utility Regulatory Policies Act and has the potential for more fundamental change. The Energy Policy Act fills more than 350 pages in the federal register and covers subjects that range from efficiency standards for hot water storage tanks to alternative-fueled vehicles. The sections of the Energy Policy Act with the greatest implications for competition in this industry are those that amend the Public Utility Holding Company Act of 1935 and parts of the PURPA that deal with the Federal Energy Regulatory Commission's (FERC) authority to mandate transmission access.

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Although long entrenched in policy involving transmission access, the FERC had construed its authority in this area to be limited. Accordingly, disputes over access have been settled in the Courts, as in the case of Otter Tail Power (1973), where the Supreme Court held that denying transmission access to a local municipality was an unlawful exercise of a utility's market power. Otter Tail and related cases, however, have not resulted in wide-reaching rules governing the provision of access.

Under the PURPA reform of 1978, the FERC had the authority to mandate transmission access, but only if such access:

(1) is in the public interest
(2) conserves energy, improves reliability, or increases efficiency
(3) would not result in any undue burden, impair ability to render adequate service, or create uncompensated economic loss
(4) does not interfere with existing competitive relationships, and
(5) does not result in retail wheeling

According to Jurewitz (1992), the fourth condition was regarded as a "deal killer" and the FERC has never ordered wheeling under these provisions. More recently, the FERC has used transmission access as a carrot for approval of utility mergers, as in the merger of Utah Power and Light and Pacific Power and Light, and Northeast Utilities with the ill-fated Public Service of New Hampshire. In these cases, the FERC did not mandate access, but rather made it clear that transmission access would be a condition for FERC approval of the merger.

The success of power production from Qualifying Facilities has led many state regulatory commissions to expand the universe of potential suppliers to include additional non-utility sources of supply. However, much concern was expressed that the long term effectiveness of an independent power sector will depend on guaranteed access to transmission services. The Energy Policy Act advanced the development of independent power by making certain non-utility generators exempt from the provisions of the Public Utility Holding Act of 1935, which restricted the ability of electricity suppliers to operate in different regulatory jurisdictions. These "Exempt

Wholesale Generators" are entities that are engaged exclusively in the production of electricity for sale in wholesale markets. In addition, the Energy Policy Act gave the FERC expanded powers to mandate transmission access. Under the EPA, the FERC could mandate transmission access if

(1) voluntary negotiations have been conducted by the requesting entity and transmission owner for 60 days
(2) the order would be in the public interest
(3) reliability of all utility systems affected by the order would be maintained
(4) third-party wheeling is not subsidized by utility's existing customers.

In particular, this amendment deletes the onerous requirement that transmission access not "interfere with existing competitive relationships."

Whether the Energy Policy Act will enhance the performance of the U.S. electricity market depends on the present performance of the wholesale market and on how the FERC and state regulators implement the access provisions of the Act. This paper looks broadly at both of these issues. The mandating of transmission access will allow wholesale buyers and sellers to contract separately for bulk power and transmission services. Section II presents an overview of the regulatory costs and benefits of unbundling these two components of electricity supply. Section III examines the efficiency of the existing wholesale market. Institutions currently exist which provide varying degrees of wholesale market access to their members. These "power pools" range from loose structures of affiliated utilities to highly coordinated organizations that mimic the operations of a centralized firm and effectively guarantee access to their members. The data described in Section III show only limited evidence that these more formal pools achieve greater efficiencies in their use of generation assets, although they may have some positive impact on investment. The implication is that at least for transactions involving assets already in place, the present U.S. wholesale market appears to be reasonably efficient in the use of these assets. The consequences of this result for the implementation of the Energy Policy Act are discussed briefly in the concluding section IV.

II. Is unbundling a good idea?

The movement toward open access of electricity transmission markets parallels the trend in other regulated industries to unbundle the regulated product and limit regulation to certain core activities. Examples are the unbundling of local and long distance telephone services and the unbundling of natural gas production from natural gas transportation.

An argument that is advanced for unbundling is that it promotes competition in markets that do not have natural monopoly characteristics and therefore improves market performance. This argument ignores the possibility that unbundling may aggravate the information asymmetries that are faced by the regulator, and in this manner lead to outcomes that are worse than with a producer of a bundled product.

Gilbert and Riordan (1992) address the question of the regulatory benefits of unbundling when regulated services are produced using complementary inputs. Suppose that it takes one unit of an input with cost α (this can be bulk power generation) and one unit of another input with cost β (this can be transmission services) to produce one unit of a final product. The unit cost of the final product is $C(\alpha,\beta) = \alpha + \beta = \gamma$. If a regulated firm produces the bundled product, the regulator's information problem concerns the magnitude of the total cost, γ. The regulator's optimal policy for this situation is a standard application of the theory advanced by Baron and Myerson (1982), Laffont and Tirole (1993), and others.

Suppose instead that the regulator divides production into two, unbundled components, each supplied by one regulated firm. Now the regulator has to deal with the private information held by each of two different suppliers of the two components. Each supplier, acting independently, will negotiate with the regulator considering his actual cost (e.g. the cost of bulk power) and the expected cost of the input produced by the other supplier (e.g. transmission services). Gilbert and Riordan (1992) show that this behavior leads to an expected cost for the final product (delivered power) that is higher than would occur when a single producer owns both factors of production. Unbundling results in a negative competitive externality when inputs are complements. This would make the regulator worse off if unbundling did nothing to lower the cost of production of one (or both) of the inputs. If an industry is structurally competitive, unbundling should result in lower costs, although the cost reduction would depend on the extent to which the integrated firm exploited the competitive technology. The implication of this research is that regulators should not expect unbundling to improve their lot unless they can expect a substantial increase in competition in one or both of the unbundled products.

III. Should transmission be regulated at all? - results on power pools

In the search for new ways to enhance competition in electricity wholesale markets, a natural question to begin with is whether competition in wholesale markets needs to be enhanced. Is this a system that needs fixing? Transmission is generally viewed as a classic example of a bottleneck market, where control of an essential transmission facility provides its owner with extraordinary market power. We will argue that while bottleneck problems do occur in wholesale transmission, these markets often function rather well, and probably better than regulated retail markets.

In retail electric power markets, state regulators command an elaborate administrative process intended to protect consumers from a local utility's abuse of market power. This process is fortified by decades of legal precedent as to what constitutes reasonable rates of return and prudent investments. Wholesale transactions nominally involve interstate commerce, based in part on the difficulty of tracing the path of electrons. As such they are outside the jurisdiction of state regulators and instead are regulated by the FERC. The official standard of FERC regulation is that firm wholesale transactions are priced at embedded costs and non-firm transactions are priced on a split-the savings basis, equal to the difference between the buyer's decremental cost and the seller's incremental cost. In practice, the FERC has in recent years provided considerable pricing flexibility in its approval of wholesale transactions (see Tenebaum and Henderson, 1991).

It is a reasonable conclusion that FERC regulates wholesale transactions with a lighter hand than states regulate generation, transmission and distribution at the retail level. It is also reasonable to expect that weak regulation by the FERC would risk abuses of market power. This would be evidenced by dispersion in wholesale prices, reflecting the extent of seller and buyer market power. In addition, wholesale market power might lead to inefficient utilization of generation and transmission resources. In what follows, we review evidence on the performance of wholesale markets as revealed by the operations of power pools and by price data on wholesale trades.[1]

Institutions currently exist to facilitate wholesale trades of electric power. The success of these institutions may serve as a measure of the need to promote competition in transmission. The most common of these institutions is the power pool, which can take several forms. In a "tight pool," existing units are dispatched centrally, meaning that a single operator adjusts unit outputs to meet demand at the lowest cost. Tight pools typically also have a formal structure for planning new investment and for establishing and enforcing reserve requirements. Table 1 lists the tight pools in the United States. Listed as a separate group in Table 1 are utility holding companies, which generally organize production decisions centrally.

[1] Another indicator of the performance of wholesale markets is the average level of prices. If, from a consumer perspective, wholesale regulation is less effective, wholesale prices would be higher than retail prices for utilities that generate their own power, after adjusting for relevant transmission and distribution costs. Although we have not made a systematic study of this relation, there are several areas in the U.S. where this comparison would reveal much higher retail prices, despite more stringent regulation at the retail level.

Table 1
Centrally Dispatched Power Pools in the U.S.*

Michigan Electric Coordinating System
New England Power Pool
New York Power Pool
Pennsylvania-New Jersey-Maryland Interconnection

Allegheny Power System
American Electric Power Company
Middle South Utilities (Entergy)
The Southern Companies
Texas Utilities Company

* Source: FERC (1989)

Most power pools, whether "tight" or otherwise, coordinate investment plans and impose reserve requirements on their members. These requirements reflect the economies of joint operations and discourage free-riding on the investments of other members. Pools differ in the extent to which this coordination is organized and enforced, and in the extent to which the pool acts centrally on behalf of its members.

Most of the centrally dispatched pools listed in Table 1 also centralize the commitment of generating units to meet demand. Utilities "commit" a power plant by maintaining the plant in a status that is capable of delivering power on short notice. This usually requires that the plant be operating at light load (in a status as spinning reserve). Commitment is an important aspect of operations. Having too many plants in a standby status wastes resources, having too few plants reduces reliability. Among the centrally dispatched pools, all but the New York Power Pool centralize unit commitment. According to the 1989 FERC transmission task force report, centrally dispatched pools (including holding companies) accounted for about one-third of installed generating capacity in the U.S. in 1989.

Another variant of a power pool is the brokered pool. This is essentially a managed market for power. Brokered pools use auction markets or electronic bulletin boards to facilitate market transactions among their members. Typically, brokered pools do not engage in centralized dispatch or unit commitment. Examples of brokered pools include the Western Systems Power Pool (an experiment lasting from 1987 to 1989), the Mid-Continent Area Power Pool (MAPP), and the Florida pool.

The last category of power pools is the informal pool, which includes all pools that are not centrally dispatched or brokered. These pools vary considerably in degree of coordination, ranging from determined attempts to share resources to little more than a promise to facilitate operations in the event of an emergency.

Power pools can enhance economic efficiency by coordinating investment decisions and by improving the utilization of existing capital. By sharing resources, a power pool allows its members to reduce the cost of preparedness for forced outages and to take advantage of non-coincident peak loads. A centrally dispatched pool only has to plan for the largest forced outage of all its members, while non-integrated utilities have to maintain reserves that are large enough to cover the largest contingency at each firm. The pool also may benefit by producing to meet the demand of the pooled members, rather than meeting demand at each utility. To the extent that demands are not perfectly correlated, the load curve of the pool is likely to be flatter than the load curve for each of its members. This reduces the total maximum capacity that the members firms must maintain and increases resource utilization, so that the member firms can justify investment in a greater proportion of more efficient base and intermediate load generation plants.

Several factors discourage participation in highly coordinated power pools. Power pools interfere with a utility's freedom to make its own investment and dispatching decisions, and thus entail a loss of control. Management may be particularly opposed to loss of control if the utility has dominion over scarce resources that it can use to its own advantage, rather than share with a pool. Regulation discourages pool participation because the benefits of economy wholesale transactions are usually passed through to ratepayers. In addition, regulators may object to multi-jurisdictional pooling arrangements that could lead to conflicts or dilution of authority. A particular example is the sharing of risks from imprudent investments. Participation in a tightly organized pool could involve a sharing of some of these risks, which regulators would resist. One example is the conflict between Pennsylvania and New Jersey regulators over the cost consequences of the Three Mile Island accident. An economic obstacle to pooling is that it involves administration costs that may exceed the savings from increased coordination (see Casazza et. al., 1990)[2]

Some insight into the operation of power pools may be obtained by examining statistics on wholesale trades. Table 2 below shows the extent of wholesale trade, excluding requirements customers, as a fraction of retail sales for different regions. Some areas with strong pooling institutions, such as the Northeast, (which has the New York and New England power pools), and ECAR, (which has a number of holding companies), show a large incidence of wholesale trades. Yet other areas that are dominated by tight power pools show little wholesale trade, and some areas without tight power pools show a high proportion of wholesale transactions. The MAAC is dominated by the tight Pennsylvania-New Jersey-Maryland interconnection, but wholesale trades in this area are below the average for the entire country. The amount of wholesale trade is quite large in the Northwest, but the data in Table 2 precede the adoption of the Western Systems Power Pool experiment in 1987, and so cannot be evidence for enhanced trade from formal pooling arrangements.

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[2] In some cases, pooling may increase the risk of antitrust actions. For example, a tightly integrated pool that refuses to wheel power for a municipal customer may be a bigger target for antitrust action than a single, non-integrated, utility.

Table 2
Retail and Wholesale Sales[3]
1985

	(1)	(2)	(3)
REGION	Sales to Final Customers (MWh)	Wholesale Sales Excluding Requirements Customers (MWh)	Ratio (2)/(1)
Northeast (NYPP+NEPOOL)	224.7	79.2	35.2%
MAAC (Penn-NJ-Md pool)	202.2	27.6	13.7%
SERC	404.5	59.6	14.7%
ECAR	382.0	129.6	33.9%
SPP	202.2	34.3	17.0%
ERCOT	179.8	3.1	1.7%
MAIN	179.8	12.4	6.9%
MAPP (Brokered pool)	67.4	20.5	30.4%
WSCC - North	157.3	103.9	66.1%
WSCC - South	247.2	34.8	14.1%
TOTAL	2,247	505	22.5%

The extent of wholesale trade is an indirect and imprecise measure of the value of pooling. Some wholesale trades are merely wheeling transactions and are not associated with direct efficiency gains. Power may be transmitted across multiple utility jurisdictions through a series of buy-sell agreements, which presents the possibility that a transaction that is really only

[3] The data in Table 2 are reported in FERC (1989) and are derived from an unpublished report to the U.S. Department of Energy. A further complication is that Texas (ERCOT) is a self-contained transmission region that is not subject to FERC jurisdiction, so wholesale data on ERCOT are probably incomplete.

one trade would be counted as several wholesale trades. Conclusions as to the value of pooling institutions depend on further evidence on the efficiency of electricity production. This evidence may be derived from statistics relating to investment and capacity utilization under different pooling arrangements.[4]

Data on Power Pools

The data used for this study cover 277 utilities. They include generation capacity, fuel source, type, heat rate, and operating costs for each plant owned by each utility in 1989, sales to end users, and power pool affiliation, if any, for each utility.[5] Table 3 shows some of the characteristics of the firms that make up the different power pool categories. Each category of power pool contains a large number of utilities of different sizes. Although the average generation capacity of centrally dispatched utilities exceeds the average capacity for utilities in other institutional arrangements, the differences are not statistically significant. The table reports the results of a statistical test for the equality of the mean capacities for group (5), which includes utilities that are in either central and brokered pools, and group (6), which includes utilities that are either in an informal pool or no pool at all. The low t-statistic indicates no statistically significant difference in the group means.

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[4] Standard econometric cost function approaches to the value of pooling, such as Christensen and Greene (1978), have the difficulty that trade among utilities in the pool introduces additional variance and complicates estimation. Therefore, this study focuses on the actual experience of plant utilization by pooled and non-pooled utilities.

[5] Plant-level data are drawn primarily from FERC Form 1 and U.S. Energy Information Administration (EIA) Form 861 reports. Other utility-level data were obtained from various EIA publications listed in the references (DOE 1991a-f).

Table 3
Pool Characteristics, 1989

		Total Number of Utilities	Mean Capacity (MW)	Std. Dev. (MW)
(1)	Centrally dispatched Pool	68	3,502	3,717
(2)	Brokered Pool	63	2,547	4,143
(3)	Informal Pool	27	2,028	1,886
(4)	No Pool	61	2,993	5,839
(5)	Central and Brokered Pools	131	3,043	3,941
(6)	Informal and No Pool	88	2,697	4,977

Test of equality of mean generation capacities:

(5) vs. (6) $T = 0.57$

A benefit that a power pool can provide its members is the ability to satisfy the minimum requirements for system security with a lower generation reserve margin than the members would need if they did not pool their resources. Define the reserve margin of utility *i* by $R_i = \frac{(K_i - D_i)}{D_i}$, where K_i is the total installed capacity and D_i is the peak demand, measured by sales to end users.[6] For utilities that are members of a power pool, represented by "*p*," define the aggregate reserve margin of the pool as

(1) $$R_p = \frac{K_p - D_p}{D_p}$$

where $K_p = \sum_{i \in p} K_i$, the total installed capacity of the pool, and $D_p = \sum_{i \in p} D_i$, the sum of the pool members' non-coincident peak demands. As discussed previously, pooled utilities may be able to maintain a lower aggregate reserve margin because pooling makes the members' single

[6] Data on firm capacities and peak demands are from Electrical World (1991).

largest contingency a smaller fraction of total demand, or because with diverse loads the peak demand of the pool is less than the sum of the peak demands of its members. This does not mean, of course, that each utility in the pool will have a lower reserve margin than it would maintain if it were not in the pool. Some utilities may invest in excess capacity with the intention of sharing capacity with other, generation-deficient, members.

As a test of the hypothesis that pooling may allow members to hold fewer excess reserves, we compare the aggregate reserve margins of pooled utilities with the aggregate reserve margin of utilities that are not pooled. The latter is defined by

$$R_{np} = \sum_{i \in np} \frac{K_i - D_i}{D_i} \cdot \frac{D_i}{D_{np}} = \frac{K_{np} - D_{np}}{D_{np}}, \tag{2}$$

where K_{np} is the total capacity of all utilities that are not pooled and D_{np} is the sum of their non-coincident demands. The aggregate reserve margin is the weighted average reserve margin for all non-pooled utilities, with the weights given by each utility's share of the total non-coincident peak demand. As equation (2) shows, this is consistent with the definition of the aggregate reserve margin of pooled utilities given in equation (1), with K_{np} and D_{np} replacing K_p and D_p.

Table 4 shows the aggregate reserve margins for each class of coordinating institution. These aggregate reserve margins are defined as in equations (1) and (2), except that the pooled utilities are partitioned by class of pooling institution. The table shows a significant variation in aggregate margins across the different pooling institutions. Utilities that are not associated with a formal power pool had an aggregate reserve margin in 1989 that was almost twice as large as the aggregate reserve margin for utilities in centrally dispatched pools.

Table 4
Aggregate Reserve Margins, 1989

(1)	Centrally Dispatched Pool	13.5%
(2)	Brokered Pool	15.8%
(3)	Informal Pool	9.6%
(4)	No Pool	24.0%
(5)	Central and Brokered Pools	14.4%
(6)	Informal and No Pool	20.3%

If the differences in the means in Table 4 are statistically significant, this would be evidence that pooling promotes efficient investment in generation capacity, assuming that the lower reserve margins in Table 4 do not compromise system reliability. Of course the differences in the aggregate margins in Table 4 could be explained by factors other than improved coordination. Figure 1 is a scatter plot of individual utility reserve margins as a function of installed capacity. The diagram shows that there is no meaningful relation between average reserve margin and capacity. This and the earlier result that average capacities are not statistically different for each class of pooling institution lend support to a conclusion that aggregate reserve margins are not primarily a consequence of differences in utility sizes in each coordination class.

It is evident from Figure 1 that utility reserve margins are heteroskedastic. This should be expected. The minimum efficient base load plant size (while decreasing in recent years) was about 500 MW in this relevant time period. The data include many small utilities for which planning errors, given minimum efficient scale, are likely to be very large. In order to test the significance of differences in aggregate reserve margins for the different pooling institutions, we corrected for heteroskedasticity by dividing sample variances by the utility's installed capacity. With this adjustment, Table 5 shows that pooling is associated with statistically significant difference in reserve margins. Note, however, that the results in Table 5 are not strictly comparable to the aggregate reserve margins shown in Table 4. The reserve margins in Table 4 are the aggregate reserve margins for the entire pool category. The reserve margin data used in the regression reported in Table 5 are individual utility reserve margins unweighted by demand shares.[7]

Table 5
Test of significance of power pooling

R_i = reserve margin of utility i
I_1 = centrally dispatched pool
I_2 = brokered pool
I_3 = informal pool

$$R_i = C+\beta_1 I_{1i}+\beta_2 I_{2i}+\beta_3 I_{3i}+\varepsilon_i \qquad \varepsilon_i \sim N(0,\sigma^2/K_i)$$

Variable	Coeff.	St. Error	T-Statistic
C	27.6	2.9	9.46
I_1	- 9.8	3.9	-2.53
I_2	- 7.1	4.3	-1.67
I_3	-11.1	6.1	-1.82

The populations of pooled and non-pooled utilities differ in their distributions of reserve margins. Figure 2a is a scatter diagram of reserve margins for utilities in centrally-dispatched pools and brokered pools. Figure 2b shows the same for utilities in either informal pools or in no pool. The scatter plots show that both groups include small and large firms, although the informal/no pool category have more firms that are very small. Municipal utilities are disproportionately represented in the "no-pooling" category. Municipals often concentrate their investments in local distribution and purchase power from others. This would contribute to low (possibly negative) reserve margins calculated based on owned-capacity for these firms. Many

[7] If the reserve margins used in the regression analysis were weighted by demand shares, then the average in each category of pooling institution would be the aggregate reserve margin reported in Table 4. However, this would complicate the statistical test for equality of means.

of the informal pools are in the Western U.S., where municipal utilities have access to power from Federal hydroelectric projects. This could be a partial explanation for the low aggregate reserve margin for this group.

Our results are consistent with the theory that pooling allows utilities to operate with lower reserve margins by improving the coordination of investment decisions, although the evidence is not overwhelming. Lower reserve margins have a large impact on total cost and would enhance economic efficiency provided that they do not compromise reliability. Improving investment is arguably the most important function of wholesale coordination,[8] however benefits from pooling also may be found in the utilization of existing resources. Benefits from coordination are realized if, accounting for transmission constraints, the marginal costs of generation for different utilities are approximately equal at each point in time. Any differences in marginal cost would allow gains from trade, assuming that power could be exchanged without serious transmission constraints or losses. Unfortunately, data are not readily available to test the hypothesis of equal marginal costs. Instead, we can ask whether pooled utilities are better, on average, in the utilization of their existing resources.

A test for efficiency in resource utilization is whether base load capacity utilization (which has the lowest incremental cost) is higher for pooled utilities, and whether peaking capacity is lower. It is conceivable that utilities that do not belong to a coordinated pool would have fewer opportunities to sell production from excess base load capacity or to purchase power from others instead of relying on their own high cost peaking capacity. However, any meaningful comparison of capacity utilization across different pooling institutions needs to be adjusted for the different demand and supply conditions that face each firm.

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[8] According to a FERC study of power pooling, "The greatest economy potentials of interconnection, coordination and pooling lie in the ability to achieve the economies of scale through construction of large generating units and reduction of reserve margins."

Table 6 shows average capacity utilization of base load plants by pooling institution. The differences (e.g. between pooling categories (5) and (6)) are statistically significant, suggesting that strong pooling institutions are more effective in utilizing their members' least-cost resources. However, the numbers in Table 6 do not account for the previous observation that utilities that do not pool have higher reserve margins. A higher reserve margin means that, *ceterus paribus*, the firm has a large supply of capacity relative to demand. As a consequence, the utilization of the firm's base load capacity may be limited by inadequate demand for production from these resources.

Table 6
Capacity Utilization of Base Load Plants, 1989
(Average plant utilization for utilities in each coordination class)

(1)	Centrally Dispatched Pool	56.6%
(2)	Brokered Pool	54.4
(3)	Informal Pool	55.8
(4)	No Pool	51.7
(5)	Centrally Dispatched and Brokered Pools	55.7
(6)	Informal and No Pool	52.9

To adjust for the impact of demand on base load capacity utilization, we have constructed an index which is the expected percentage of base load utilization for each pool classification under the assumptions that all base load capacity is equally efficient and that the demand for electricity at each utility is normally distributed over time. The Appendix describes the calculation and use of this index in some detail. The point of this index is to normalize base load capacity according to the fraction of the year in which it may be used. Table 7 shows the unadjusted base load utilization numbers, the indices, and the ratio of the unadjusted utilization to the index. The latter is likely to be a more accurate measure of the extent to which utilities utilize their base load capacity after adjusting for different levels of capacity and demand.

Table 7
Capacity Utilization of Base Load Plants, 1989
(Average plant utilization for utilities in each coordination class)

		No capacity adjustment (a)	Demand Index (b)	Ratio (a/b)
(1)	Centrally Dispatched Pool	56.6%	57.9%	1.0
(2)	Brokered Pool	54.4	53.2	1.0
(3)	Informal Pool	55.8	65.1	0.9
(4)	No Pool	51.7	42.8	1.2
(5)	Centrally Dispatched and Brokered Pools	55.7	55.8	1.0
(6)	Informal and No Pool	52.9	48.2	1.1

The numbers in the last column of Table 7 are the ratios of the unadjusted base load capacity utilization from Table 6 to the calculated demand index for the utilities in each pooling category. These ratios are an estimate of normalized base load capacity utilization. The results in Table 7 show that base load capacity utilization is *higher* for utilities that do not pool, *after adjusting for their higher reserve margins.* Therefore, one cannot conclude that pooling institutions allow utilities to make better use of their most efficient resources. If anything, it would appear that those utilities that do not pool have been particularly successful in making arrangements to sell their excess base load capacity to others. This conclusion is tempered by the admittedly imprecise adjustment for demand conditions, but the adjustment is at least sufficient to question any enhanced base load operating efficiencies from pooling.

If pooling does not affect the utilization of utilities' most efficient resources, might it still be beneficial in economizing on the use of less efficient resources? This could come about in two ways. First, if pooling improves a firm's load duration curve (makes the load duration curve flatter), then utilities that pool would not have to install as much peaking capacity.[9] Second, assuming the same amounts and composition of generating capacity and the same peak demand,

[9] Peaking capacity is defined as all oil or natural gas combustion turbine capacity.

a flatter load duration curve would lead to increased utilization of peaking capacity by pooling utilities. These possibilities are investigated in Table 8.

Table 8
Capacity and Utilization of Peaking Plants, 1989

		Peaking as Percent of Installed Capacity	Utilization of Peaking Capacity
(1)	Centrally Dispatched Pool	14.8%	3.3%
(2)	Brokered Pool	18.2	2.8%
(3)	Informal Pool	15.7	0.5%
(4)	No Pool	16.3	2.4%
(5)	Centrally Dispatched and Brokered Pools	15.9	3.1
(6)	Informal and No Pool	16.1	1.8

The first column in Table 8 shows that there is essentially no difference between the percentage of peaking capacity that utilities install, based on their participation in power pools (the differences are not statistically significant). Pooled utilities tend to have a higher utilization of peaking capacity. However, this is almost certainly a result of the fact that pooled utilities tend to have lower reserve margins, which results in a higher rate of capacity utilization for all of their resources.

This review of the effects of power pooling institutions shows little evidence that power pooling has a discernible impact on the utilization of *existing* utility resources. A possible explanation for this result is that resource utilization is almost entirely determined by a utility's native supply and demand and is not significantly affected by wholesale transactions. This explanation is unlikely to be correct. Table 2 shows that many utilities are dependent on wholesale transactions and there is much anecdotal evidence that utilities benefit enormously from opportunities to engage in wholesale trade. A more likely explanation is that utilities are able to capture many of the benefits of integration without formal institutions; power pools have little additional effect in promoting wholesale trade. Utilities appear to do rather well on their own in conducting wholesale market operations, whether or not they are members of closely integrated power pools.

Does efficient utilization mean absence of market power?

Efficient capacity utilization is not sufficient to prove that there is no significant market power in wholesale trades. Utilities may accommodate existing resources, yet refuse to grant the long-term firm transmission access that is needed to risk investment in new generation facilities. Resources may be used efficiently, but the rents from those resource could go disproportionately to the owners of transmission assets. An example is a perfectly discriminating monopsonist. The exercise of monopsony power (e.g., by lowering the purchase price for power after a plant is built) would discourage investment in new capacity whose output is intended to be sold to buyers who have market power. Our results which show that pooled utilities have lower reserve margins neither reject nor support a finding of wholesale market power. Utilities that participate in highly coordinated pools may be less concerned about opportunistic behavior in wholesale purchases and sales, either because they have adopted rules to mitigate strategic behavior or because they have developed long term relationships that discourage opportunism. These firms may be more willing to invest based on the reserve requirements of the pool, rather than on their own needs, and this would be reflected in more efficient (lower) reserve margins. In transactions that are external to the power pool, opportunistic behavior may still be a threat to the development of wholesale trade.

Partial evidence on the ability of transmission owners to collect rents can be obtained from a study of wholesale transactions in the West. The Western transmission market appears approximately as shown in Figure 3. The main transmission lines are the northwest DC and AC interties and the lines leading to Southern California from the Southwest.

Sales of firm energy are based on embedded production costs, and so are largely unrelated to competitive conditions (although the FERC has been somewhat more relaxed about this requirement in recent years). Sales of non-firm energy are based on sellers' incremental costs and buyers' decremental costs, and so should reflect competitive conditions.

Table 9 shows sales and average prices of non-firm wholesale energy in the years 1985 and 1988 for what is termed the Northwest and the Southwest (sub)markets. The Southwest market is the shaded area in Figure 3. The remainder is the Northwest market, except that California utilities with significant transmission holdings are assumed to participate in both markets.

Non-firm energy in the Northwest is dominated by surplus hydropower. In the Southwest, non-firm energy is predominately surplus coal generation. Utilities in each of these markets are reasonably interconnected with other utilities in the same market, but interconnections between the two markets are limited. The exceptions are the California utilities that have entitlements on both the main north-to south and east-to-west transmission systems (mainly Southern California Edison).

Table 9
Sales and Average Prices of Non-Firm Energy

		Sales (GWh)	Average Price ($/MWh)
1985			
	Northwest	43,767	19.9
	Southwest	18,190	26.6
1988			
	Northwest	18,312	18.3
	Southwest	16,479	18.7

If there were no market power in transmission, one would expect prices for non-firm energy to be about the same in both markets. This was approximately the case in 1988, but not in 1985. Many factors determine the demand and supply for non-firm energy, including Bonneville Power, which controls crucial transmission capacity from British Columbia into the Western states. Two events figure prominently in the change in relative prices from 1985 to

1988. Oil and gas prices fell from 1985 to 1988. This had a direct negative impact on buyer's decremental costs, and hence their willingness to pay for economy energy. Although most surplus energy in the Southwest is coal-fired, lower oil and gas prices put downward competitive pressure on the price of surplus coal (Joskow, 1990). Also in 1988, a dry year reduced the supply of hydropower in the Northwest. Thus, arbitrage between these two markets tended to close the gap between non-firm energy prices in the Southwest and the Northwest in 1988. In 1985, fossil-fuel prices were higher and hydropower was in more plentiful supply. As a result, there was a greater scope for buyers to exercise their market power in purchases of hydropower from the Northwest, and arbitrage of these markets was not profit maximizing. Note that while buyers could exercise market power in the purchase of hydropower, other actors, such as Bonneville Power, have seller market power and can act to keep the price of hydropower above its competitive level, so the outcome of this bargaining is not easy to predict.

IV. Conclusions and policy recommendations

The Energy Policy Act of 1992 gives the FERC broad powers to mandate access to transmission for wholesale transactions. If the FERC were to exercise these powers, it would turn the U.S. transmission grid into a system of privately-owned common carriers. Whether such open access would contribute to significant improvements in the efficiency of the wholesale electric power market is questionable. Using data on utility plants and participation in power pools, we have argued that membership in various coordination institutions has not led to substantial improvements in the efficiency of utility operations. If utilities are impeded in their access to wholesale suppliers and buyers, the existence of institutions that are designed to facilitate access (such as centrally coordinated power pools) should lead to observable improvements in operating efficiencies. We see some evidence that utilities that participate in formal pools are able to sustain lower reserve margins. However, this evidence is weak, and there is no support for the conclusion that these utilities are more efficient in the utilization of their generating resources.

We acknowledge that evidence on the utilization of existing assets is not sufficient to determine whether market power at the wholesale level is a deterrent to new investment. Data on trades in the West suggest that there is wholesale market power, which is revealed by large price differences for non-firm energy between contiguous geographical sub-markets. The opportunity for utilities to exercise monopsony power though ownership of transmission resources could be a major threat to the viability of new non-utility wholesale suppliers. This is a primary motivation for the empowerment of the FERC to mandate access. Yet our results underscore the need for regulators to appreciate the efficiencies of the present wholesale market, particularly for non-firm transactions, when designing policies to correct alleged market failures.

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Appendix

The demand index numbers used in Table 7 indicate the expected energy produced by base load resources as a fraction of total energy produced, calculated separately for each utility. This appendix details the algorithm used to calculate these index numbers.

Available data provide the annual peak demand (in MW) and annual total demand (in MWh) for each utility. As a fraction of peak demand, expected hourly demand is a utility's load factor: LF = average demand / peak demand, where average demand is total annual demand divided by 8760 hours per year. We assume peak demand is a certain number, r, of standard deviations above average demand, so that the standard deviation of demand can be calculated as $\sigma = (1 - LF) / r$. A value of $r = 3.1$ is common (LBL 1984) and is used in the calculations.

With the assumption of normally distributed demand, the cumulative distribution function of demand is

$$cnorm(z(x)) \equiv \int_0^{z(x)} \frac{1}{\sqrt{2\pi}} \exp\left(\frac{-t^2}{2}\right) dt$$

where x is hourly demand as a fraction of peak demand, and $z(x)$ is the statistic $z(x) = (x - LF) / \sigma$.

To calculate the demand index number for a utility, we use the cumulative distribution function of demand to calculate the expected utilization rate of capacity classified as base load. This utilization rate is the expected total output of all base load plants divided by the maximum potential supply from those plants.

Base load capacity is assumed to service the first $\alpha \cdot 100\%$ of peak demand, where α = total capacity classified as base load (in MW) divided by total utility capacity (in MW). By construction, the area beneath $1 - cnorm(z(x))$ from $x = 0$ to 1 represents expected demand, as a fraction of the peak; the area beneath this function from $x = 0$ to α represents expected hourly production from only base load units, again expressed as a fraction of the peak. Denoting this latter region as β, the utilization rate is therefore

$$\frac{\textit{expected output}}{\textit{maximum potential output}} = \frac{\beta \cdot (\textit{peak demand}) \cdot 8760 \quad \textit{MWh/year}}{\alpha \cdot (\textit{peak demand}) \cdot 8760 \quad \textit{MWh/year}}$$

and the demand index number for a utility with demand distribution *cnorm*($z(x)$) is

$$\text{Demand Index} = \frac{1}{\alpha} \int_0^{\alpha} [\, 1 - cnorm(z(x)) \,] \; dx \; .$$

The load duration curve is a transformation of the distribution of demand which provides the percent of time actual demand exceeds each possible level of demand. The usual graph of the load duration curve plots demand x on the ordinate and Prob$\{X>x\}$ = 1 - *cnorm*($z(x)$) on the abscissa. Therefore, the demand index number (expected utilization rate of base load capacity) is equivalent to the area beneath the load duration curve serviced by base load capacity relative to the total energy potentially available from all base load plants.

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Figure 1.

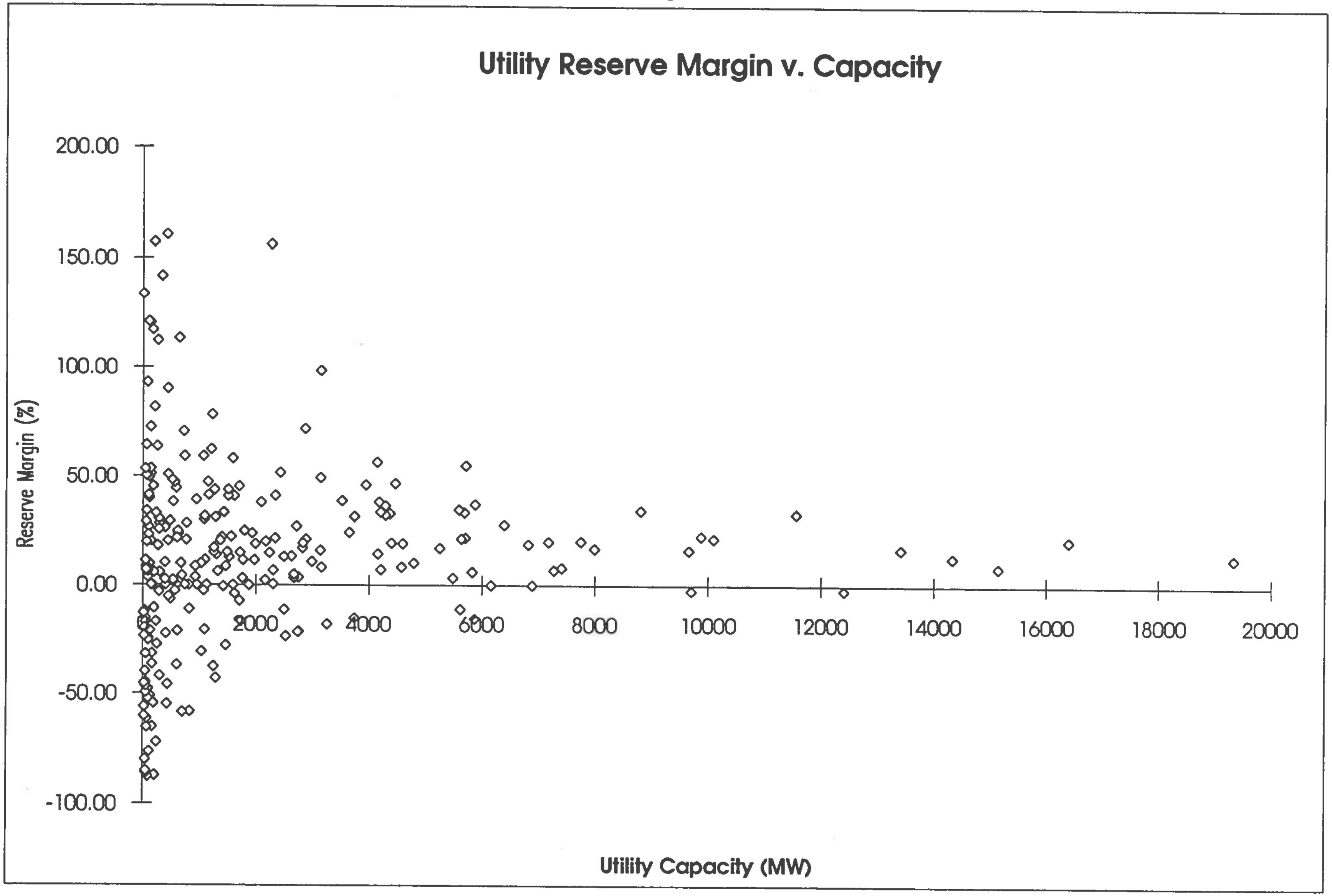
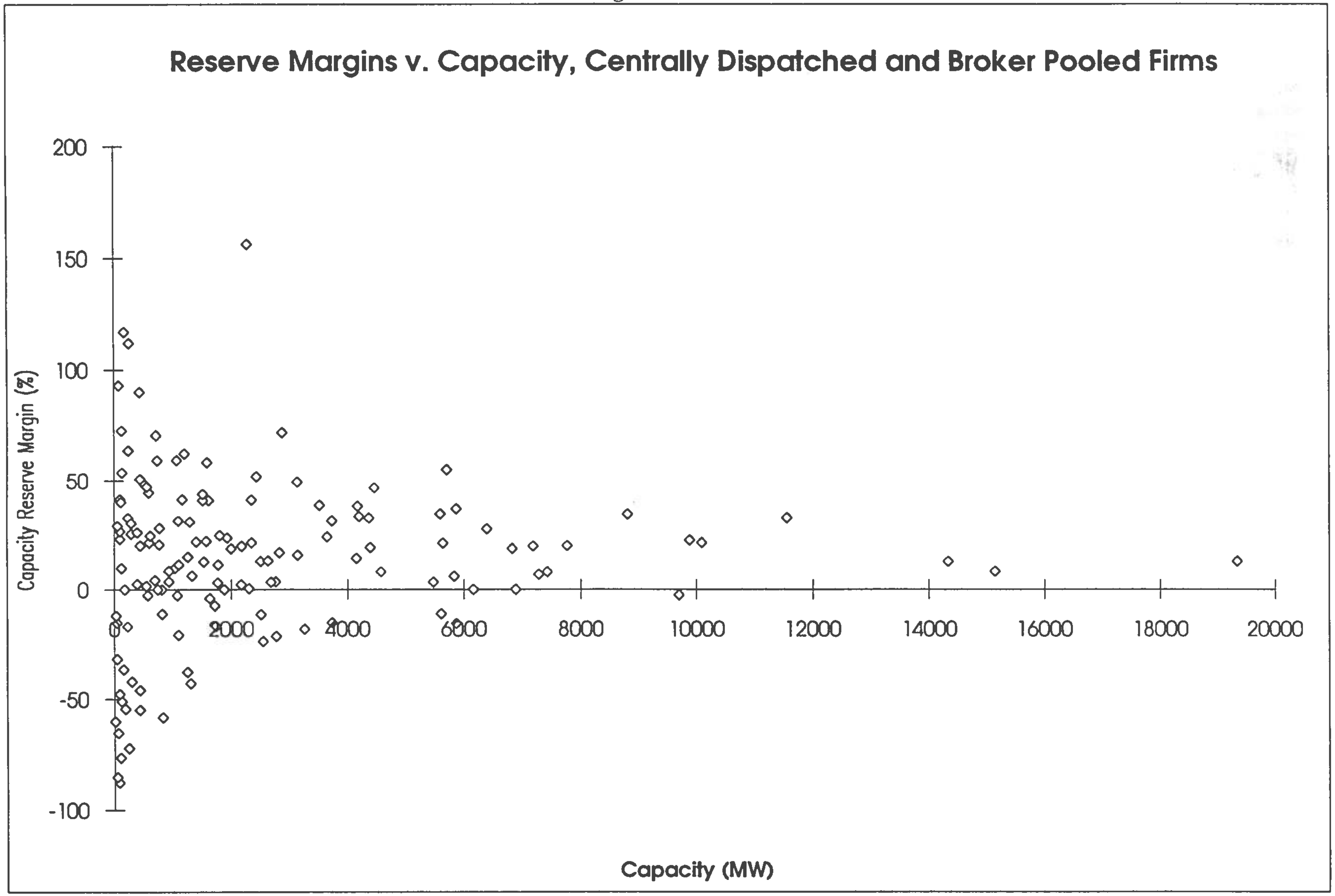

Utility Reserve Margin v. Capacity
200.00
150.00
100.00
50.00
0.00
-50.00
-100.00
Reserve Margin (%)
2000
4000
6000
8000
10000
12000
14000
16000
18000
20000
Utility Capacity (MW)

Figure 2a.



Reserve Margins v. Capacity, Centrally Dispatched and Broker Pooled Firms
Capacity Reserve Margin (%)
200
150
100
50
0
-50
-100
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
20000
Capacity (MW)

Figure 2b.

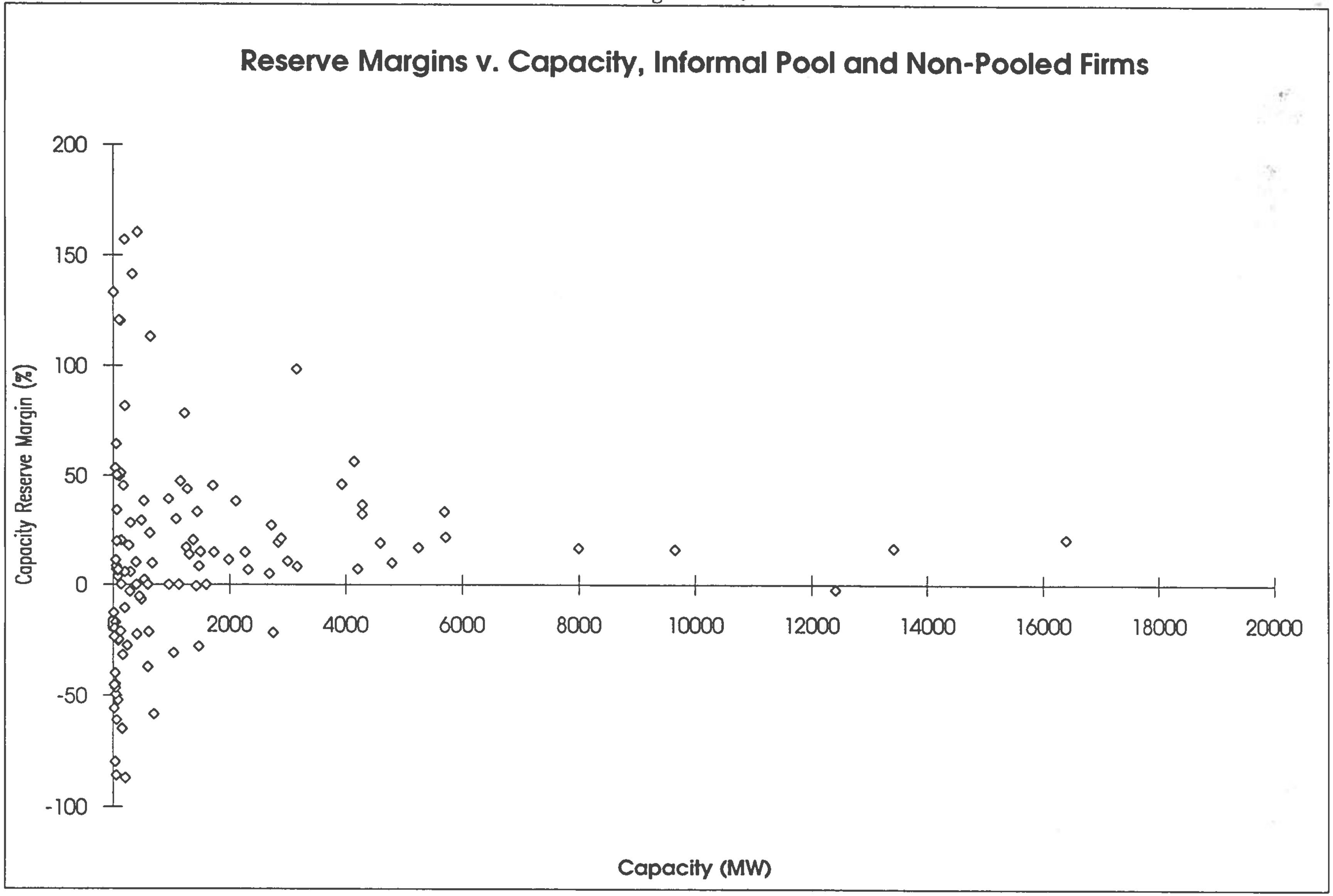

Reserve Margins v. Capacity, Informal Pool and Non-Pooled Firms
Capacity Reserve Margin (%)
200
150
100
50
0
-50
-100
2000
4000
6000
8000
10000
12000
14000
16000
18000
20000
Capacity (MW)

Figure 3

MAJOR TRANSMISSION ROUTES FROM THE NORTHWEST AND SOUTHWEST