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Customers First! urges the Commission to establish mechanisms that will allow fair consideration of projects using clean coal technologies to compete with gas-fired projects.

II. The Tabors Study Understates the Degree of Concentration in WUMS and Overstates the Efficacy of its Proposed Remedies.[1]

A. The Tabors study understates the degree of concentration in WUMS and, therefore, the extent of market power problem, because it assumes that all transmission import capability into the state, now and in the future, will be available on a pro rata basis to competitors outside of Wisconsin (p. 16, sec. 3.1.2.3). For this reason, none of the transfer capability is added in the study to the resource concentration levels of the eastern Wisconsin utilities.

The Bushnell study made a similar assumption for ease of analysis and because the assumption favors the incumbent utilities that are most likely to contest any study finding market power. However, the Bushnell study notes that this assumption is not accurate and renders its results understated. It is unclear if the Tabors study's authors recognize this problem. It is essential for the Commission to understand that this important assumption is not correct and therefore the problems identified are understated (Bushnell study, p. 7). All existing firm transfer capability into Wisconsin is already under contract through utility tariffs or grandfathered agreements. Requests on the OASIS today for any firm imports from the west will be denied because all existing capacity is gone, and is not available to competitors. Requests from the south are also being denied, despite improvements Commonwealth Edison has made to the system,

[1] The revisions to the study filed on November 14 are not discussed in detail because they do not change the result. There is very little explanation of the changes. The only one identified appears to be the price cap, although it is not clear what the original study assumed.

because of limiters within Wisconsin and at the western interface which is affected by loop flow from southern imports.

It also is very important to recognize that under FERC's OATT (the Open Access Transmission Tariff), companies that have procured firm transmission service for one year or greater have a roll-over right of first refusal to renew those reservations indefinitely (FERC OATT, sec. 2.2). None of the import capability into Wisconsin, at this point, is in the hands of marketers or competitors outside of the WUMS market. The FERC roll-over right means that the incumbent WUMS utilities that are purchasing firm service for more than one year can retain that capability indefinitely and it will not be available to competitors outside of the market.

For this reason, any divestiture analysis also must look at possible divestiture of transmission rights under the OATT tariff for those utilities found to have market power. Such an initiative will create significant controversy because resource commitments have been made based upon obtaining transmission service, and those resources could suffer significant devaluation (stranded costs) if the related transmission is taken away. Obviously, those who have secured firm transmission will fight hard to retain the economic value of their commitments.

The assumption that all new transfer capability produced by new transmission improvements will go to competitors outside of Wisconsin is also questionable. Incumbent utilities like WEPCO claim that the FERC OATT allows them to reserve import capability for projected native load growth, and that they have taken steps to secure such reservations. If granted by FERC, these reservations will eat up new transfer capability. At this point, all of the import capability produced by new transmission improvements may well be taken either with tariff transactions by the incumbent utilities, subject to the same roll-over right as the existing capacity, or by load growth reservations. This means that without decisive action in restructuring, virtually no import capability into Wisconsin would be in the control of competitors outside of Wisconsin. Certainly, much less than 3,000 MW will be.

B. The study does not state how much import capacity is assumed for the first few years, but it appears to be about 2,000 MW (see p. 26). This is considerably greater than the actual summer 2000 import capability, which was about 1,400 MW.

C. Another assumption that is optimistic is that the transfer capability produced by improvements will rise to 3,000 MW in 2004 and stay at that level over time. Experience with additions to the transmission system is that they often result in less actual capability than anticipated because new constraints develop on the system and limiters are shifted elsewhere. For instance, early this summer, when Commonwealth Edison added a 345 kV line from Lockport to Lombard in northern Illinois, initial estimates were a significant increase in import capability into Wisconsin from the south. However, that increase has not actually occurred. Recent requests on the OASIS for minor amounts of transmission -- 50 MW -- have been turned down because of new limiters within Wisconsin and because associated loop flow through Iowa and Minnesota violates limits on the MAPP-WUMS interface. Unfortunately, due to the highly integrated nature of the grid, limiters also may develop in Nebraska, Iowa, Minnesota, Illinois and elsewhere in the future that will take away transfer capability into Wisconsin.

It is also important to recognize that the current FERC regime for reserving transmission capacity is on a first-come, first-served basis. Major sales from northern

MAPP south into Illinois, SPP or TVA will create loop flow into Wisconsin and take away transmission capacity into eastern Wisconsin that was supposed to benefit Wisconsin customers. There is no way that Wisconsin can protect itself against these loop flows under current transmission arrangements.

Finally, transfer capability into the state, particularly from the west, will decline as loads grow in the western and northern part of the state. This means that without continued transmission construction, the transmission capability assumed by the study is likely to go down.

D. The study predicts that the cost of power in 2007 will be lower than the cost of power in 2001 in 1999 dollars. This is the result of assumed natural gas prices. The study assumed that in 2001, gas would cost $2.56 per MBTU in 1999 dollars. By 2007, the price is projected to increase only to $2.82 per MBTU in 1999 dollars. This means that the study estimates the production cost of a new combined-cycle plant with a 7,000 BTU/kWh heat rate in 2001 to be only $18 per MWh. By 2007, this cost rises to only $21 per MWh in 1999 dollars.

In contrast with these assumptions, the current gas price in Wisconsin is over $7. This summer it rose to over $5. As the winter progresses, some are projecting even higher prices. Demand for gas will only increase in the future with all of the new gas-fired generation being added in the Midwest and elsewhere. If a $7 gas price is assumed, the production cost of a combined-cycle plant will rise to $49 per MWh, as compared to $18 in 1999 dollars. Customers First! is not suggesting a $7 gas price should be assumed. However, $2.56 is clearly too low. This is an area where sensitivity runs are essential.

Customers First! also notes that the baseline simulation in Table 2.3 projects capacity prices of $0 per MWh in 2001, rising to a $1.44 per MWh in 2007. This projection, which is not explained, is substantially below the market price in Wisconsin for capacity in 2001, which Customers First! estimates at much closer to $60 per kW year, or $11.40 per MWh, assuming a 60 percent load factor. The price could come down if a surplus develops, but not as low as projected, and it will certainly be higher in the next several years.

These low projections substantially distort the projections of future costs in a competitive market, as well as leading to a potentially major understatement of the stranded benefits associated with existing generation.

Finally, we note that the capacity prices shown in Table 2.3 for WUMS are very low compared to projected MAPP capacity prices. There is no explanation for this difference.

E. Another key assumption that unfortunately may be incorrect is that all of the Midwest will be on a single-transmission system with no pancaking. As the Commission is aware, the Midwest Independent System Operator (MISO) is in jeopardy as a result of the attempted withdrawal of all three Illinois utilities. No RTO/ISO is currently being created in the MAPP region. As a result of the Illinois withdrawal, it is unclear if the upper Midwest is going to be fractured between two RTO/ISOs with Wisconsin pancaked either from Illinois or MAPP.

For instance, if Commonwealth Edison is successful in moving to the Alliance, the rate for deliveries into Wisconsin will go from $0 per MWh under the MISO license plate tariff to $2.10 per MWh under the Alliance tariff. This will have a significant impact on the competitive viability of Illinois resources in the market. Conversely, if the ATCLLC also ends up in the Alliance, but MAPP does not, WUMS customers will be pancaked from the west. Either alternative will increase the costs of competitors outside Wisconsin to serve WUMS load, increase prices in WUMS and increase the value (stranded benefits) of WUMS generation.

In addition, the MISO is moving toward congestion pricing, as are all RTOs. It is very likely that FERC will require congestion pricing across the Eastern Interconnect in some form. As a highly constrained area, Wisconsin will be adversely affected by congestion pricing. The only issue is the magnitude of the harm. The market power problems experienced in New York this summer can be tied closely to constraints and congestion. It is unclear if the study has taken appropriate notice of these problems. Congestion pricing also will increase the value of generation inside of constraints and thus stranded benefits.

F. The study appears to assume that all new generation will be independent merchant generation and available to serve Wisconsin customers in all hours. In reality, a significant portion of that generation, including merchant generation built in Wisconsin, such as the proposed PGE plant, may end up under contract for sales into Illinois or elsewhere, taking it out of the Wisconsin market. What impact does this potential have on the concentration analysis and strategic behavior opportunities?

G. The study assumes retirements of utility units that will decrease the concentration of existing owners. However, the owners are all looking at life extension projects, given the current tight supply and the economics of life extensions with rising gas prices. A sensitivity should be run on this point.

H. The study states that there has been no analysis of market power and its potential impact in capacity, reserves or ancillary services markets. We assume that such an analysis was beyond the scope of the study. However, this analysis will be essential to formulate any actions to be taken to solve market power problems in the state. Huge problems related to market power in the ancillary services market have been experienced in California and New England. The Wisconsin situation could be worse.

I. The study seems to assume functional, rather than structural, separation of generation, transmission and distribution in the future. There is no discussion of whether functional separation -- that is, whether ownership of different functions within the same holding company structure can work effectively, or whether structural separation would be more desirable and less risky for customers.

J. It is unclear what price cap is assumed by the Tabors study. The revisions suggest it may have been $300 originally. These sheets now show a $1,000 cap like the Bushnell study. A cap assumption is probably valid, given the fact that caps are being imposed because of market power in most places. The cap assumption necessarily reduces the estimate of stranded benefits and the magnitude of harm to customers from the exercise of market power. Caps are very controversial and there is no guarantee that FERC will continue to impose them. It would be important to run the study without a cap to see the implications for Wisconsin customers of a truly deregulated market. In this regard, we would point out the prices rose in the state for a few hours in 1999 to over $6,000 per MWH, not $300 or $1,000.

K. The study compares prices in a perfectly competitive market against a base case, but does not project where regulated prices would be in comparison. The assumption that the marginal cost of electricity will decline in the future is a result of projected low gas and capacity costs. If one assumes instead that the marginal cost of new generation will be higher than embedded cost, a regulated model that averages costs may look better, since a competitive market will price based on the marginal cost of the last unit built and the last unit running. In this regard, Customers First! projects that if all new generation serving Wisconsin in the future is fueled with natural gas, gas will drive the marginal cost in about 48 percent of the hours by 2010 compared with less than 15 percent today. The implications of this possibility are staggering in terms of potential price volatility and marginal cost increases. Certainly, sensitivities should be run in this regard before any major restructuring actions are recommended to the Legislature.

L. The identified differences between the Bushnell study and the Tabors study are as follows:

1. **Structural Analysis.** The Bushnell study found an HHI of 2,700 for WUMS and a WEPCO market share of 50 percent, <u>assuming no transmission capacity into WUMS is allocated to a firm within WUMS.</u>[2] For its comparable summer peak case, the Tabors study found an HHI of 2,160 and a WEPCO market share of only 40 percent, again allocating all transmission capacity into WUMS to firms outside of WUMS. We believe that the difference in concentration levels shown stems primarily from three factors:

a) <u>Differences in generation capacities</u>. Tabors has put WEPCO's capacity at 5,900 MW, as opposed to roughly 6,500 MW used by Bushnell. The Bushnell number comes from PSCW Advance Plan 7, PSCW Bulletin 46 and FERC Form 1. The Tabors study lists the Southern Company Neenah Plant as a WEPCO plant in Appendix A.3, but does not include that plant in the allocation of WEPCO assets for a divestiture on Table 4.4. We cannot tell if this plant is included in the WEPCO capacity concentration numbers. The plant is under the control of WEPCO through at least 2008. The contract may give WEPCO an option to purchase the plant at that time.

The 250 MW Whitewater cogeneration unit is apparently not included in the Tabors study as a WEPCO plant. It is included in the Bushnell study. This plant is under WEPCO's control under a long term contract.

The 500 MW Polsky RockGen plant is included by Tabors as a fringe unit.

b) <u>Differences in transmission capacity</u>. The Tabors study assumes that the import capability into WUMS will increase to 3,000 MW in 2004, but it is unclear what capacity is assumed prior to that date. On page 26, there is a reference to overall transfer capability in WUMS not exceeding 2,000 MW. Bushnell used 1,400 MW as the current number based on OASIS reservations and available transmission capacity .

c) <u>Differences in methodology.</u> Since the Tabors study looks only at plants with costs below about $82 per MWh, the mix of plants in the concentration calculation is different.

If one adds the 500 MW Polsky plant as a fringe unit and drops 600 MW off WEPCO's capacity (LS and Southern), and increases current WUMS import capability to 2,000 MW, the HHI from the Bushnell study would drop to about 2,120, accounting for the differences. We believe the Bushnell numbers are more accurate.

2. Behavioral Analysis. The two analyses are similar. However, the Tabors study uses oligopoly price levels that are at most only double perfectly competitive levels. It is unclear if the Tabors study focuses on monthly average peak mark-up or

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[2] This number is understated because all existing transmission capacity is controlled by WUMS utilities.

mark-up for a single hour, so it is difficult to know what load level or combination of load levels from the Bushnell study to use in making a comparison. The Bushnell study base case found price levels with a price cap -- specified in the study of $1,000 per MWh -- to be 25 to 50 times the competitive price for all demand levels. In other words, the Tabors oligopoly simulation appears to have found significantly lower prices than the Bushnell study for comparable market conditions.

The results from Tabors' divestiture of WEPCO into three firms shows a significant decrease in market power, much more so than the Bushnell examination of a similar divestiture scenario. Some of the reasons appear to be as follows:

a) Demand function. The Tabors study assumes a demand elasticity of -0.2, which the study attributes to industrial load, but then extrapolates to be the price responsiveness of all demand (see p. 27.) Thus, the study takes an estimate of the elasticity of the most price-responsive segment and assumes that all demand is equally responsive to price. The Bushnell study used an elasticity of -0.1, which we believe is a more accurate estimate.

The functional form of the demand curve is also relevant, but the Tabors study does not describe what form its demand function takes. The Bushnell study used a constant elasticity demand function. This means that the elasticity of demand does not change over the range of prices and quantities observed. The other most commonly modeled demand functions, such as a linear demand function, become more elastic as prices get higher (and quantities decline). Therefore, if the Tabors study is assuming something besides a constant demand elasticity function, it would be much less likely to see price spikes as demand would drop much more quickly as prices rise. As a reference point, a -0.2 elasticity of demand implies, if constant, a drop in demand of 1,850 MW off the peak when the price goes up 80 percent. This is obviously a crucial area where sensitivities are needed.

b) <u>Behavioral model</u>. The Tabors algorithm apparently uses a combination of Cournot and Supply Function Equilibrium (SFE) oligopoly concepts. The general theory on SFE shows that these equilibria will yield somewhat lower prices than Cournot models. Just how much less depends upon the specific SFE implementation, and there is no way to determine that factor from the study. These differences can be expected to matter much more in the divestiture scenarios than the base case, since one can think of the base case as almost a monopoly model. In a monopoly model, it does not really matter how firms interact with each other, since there is only one firm that counts.

c) <u>New generation for 2001 and beyond</u>. The new plants beyond 2001 appear to make the market more competitive, although the plants added in 2001 mostly belong to WEPCO.

d) <u>Price cap</u>. The Tabors initial study does not mention whether there is a price cap assumption in the market simulation. However, a rough estimate of market outcome indicates that in the base case, prices with a constant elasticity of demand of -0.2 would be undefined without a cap. The revision indicates that the initial cap may have been set at $300, which is substantially below the $1,000 used in the Bushnell study. The revision now shows a $1,000 cap.

All of these differences in modeling assumptions require more analysis and sensitivities for the Commission to gauge their importance. The differences in results suggest that the assumptions are very important, even though both studies show major market power problems.

e) Results of the divestiture scenario. The Tabors study shows the divestiture scenario having a much more significant impact on market power than the Bushnell study. When 5 or 6 firms are modeled competing in a market, the differences in the behavioral models identified above can be much more important. This probably accounts for much of the difference of relative outcomes. However, other more subtle factors may be at work. For instance, when the Bushnell divestiture scenario is run with an elasticity of -0.2 from the Tabors study, and transmission capacity is increased from the Bushnell base assumption of 1,400 MW to the Tabors assumption of 2,000 MW, the results show a significantly bigger impact of divestiture. However, prices are still 80 percent above competitive levels at a load above 8,000 MW. This contrasts to the very modest 5 to10 percent increase above competitive levels shown by the Tabors simulation.

There are a number of judgments that must be made in any simulation and important differences between models. This is why such simulations should be used more as a qualitative tool for picking up potential problems rather than a quantitative tool for predicting prices with any kind of certainty. At best, we believe one can conclude that a divestiture scenario with a -0.2 elasticity (which is high), and 3,000 MW of transmission capability (which is optimistic), could produce a reasonably competitive market, coupled with fixed price contracts for most customers. It also could produce a market that still has a lot of serious problems. Clearly, it is not in the customers' interest to take that risk on the basis of the current data.

In this regard, it is worth pointing out that there are two other studies that provide a reference point for these simulations. Bornstein, Bushnell and Wolak have found that the prices experienced in California were 16 percent above competitive levels from June, 1998 through September, 1999.[3] Very importantly, this was a market with a $250 per MWh price cap. Things, of course, have gotten much worse in California since then. The California market is one in which no strategic firm has a 10 percent share of ownership control of generation and with transmission import capability significantly above Wisconsin. The other study is a Wolfram analysis of the UK, in which she found prices to be 25 to 30 percent above competitive levels.[4] That market was dominated by two firms, but those firms had a significant amount of their generation under long-term contracts during the time period studied by Wolfram.

III. Comments on Remedies

A. A primary remedy proposed is breaking Wisconsin Electric up into three independent generating companies of a size comparable to WPS or Alliant. Customers First! agrees that if a competitive retail market is to be achieved in Wisconsin, two things must happen: substantial new transmission must be built and Wisconsin Electric must divest generation. However, the divestiture proposed by the Tabors study will still result in concentration levels significantly higher than exist in California at this time. It is

[3] (Borenstein, S., J. Bushnell and F. Wolak (2000), "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market. Power Working Paper PWP-064, p. 34, University of California, August 2000.

probable that WPS and Alliant also should divest some generation to lessen the risk to customers of strategic behavior.

Divestiture remedies raise a number of significant issues, which need to be addressed for the remedy to be pursued. First, of course, is whether forced divestiture is a politically feasible alternative in Wisconsin. In other states that have pursued divestiture, with mixed results, utilities that have divested have been given the carrot of recovering their stranded costs from customers. Since there are virtually no stranded costs in Wisconsin, this carrot will not exist, and therefore, divestiture will be extremely controversial with the owners unless the state offers to allow the utilities to retain all or a substantial portion of the associated stranded benefits. In that case, it is extremely difficult to see how customers can win.

It is unclear from the study at what price divestiture is anticipated. In other states, plants have sold at significantly greater multiples of book value than predicted by Commissions and some economists. Customers First! believes that these prices are based on expectations of market power by the new owners, not only in the hourly energy market, but in ancillary services as a result of control of must-run units. Clearly, sensitivities are needed on the price that will be paid for WEPCO generation in any divestiture. The higher the price new owners pay, the higher the price they will have to charge in the market to recover their costs and the less likely customers are to realize a net benefit.

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[4] Wolfram, C.D. (1999), "Measuring Duopoly Power in the British Electricity Spot Market," American Economic Review, 89(4), p. 814.

Another key issue is where the profits on sale on divestiture go. It would appear that the Tabors study assumes stranded benefits will flow entirely to shareholders. This will, of course, be controversial.

Also, no cost-benefit analysis has been done of this remedy. What synergies will be lost through divestiture that customers currently realize in regulated rates? Also, will not a substantial portion of any gain go to the federal and state governments in income taxes? Any stranded benefits associated with existing units are currently captured by ratepayers through average embedded cost rates. Will they be better off by monetizing these benefits and sharing them with shareholders and government? How?

Finally, one of the most important and difficult issues with respect to divestiture is how the benefits achieved initially can be retained, so that effective competition is sustainable. How will the state prevent re-aggregation of generation? Certainly, there will be tremendous incentives for such re-aggregation to occur in order to reap market power benefits. We believe that for divestiture to work, there will have to be a strong and enforceable provision in the law that prohibits any market participant from owning or controlling more than 15 percent of the generation serving the WUMS market at any time. Ownership may be relatively easy to police, although to the extent key facilities are located out of state, it may be much more difficult to effect. Control is even more difficult practically. Marketers can aggregate portfolios confidentially so that it will be very hard, perhaps impossible, for the state to police.

B. The second key remedy is contracts from the existing generation back to most customers in the state at fixed prices. In a way, this remedy is similar to continued regulation. If regulation must continue for most customers, one can question why the change should be made at all. However, as we understand it, the remedy assumes that the price under these contracts will not be a regulated average embedded cost where the higher cost of new generation[5] will be averaged with the cost of old capacity and energy prices will be based on an average production cost over the relevant time period. Instead, the contracts assume pricing at marginal production cost -- that is, at a gas-fired cost during an increasing number of hours (Tabors study, p. 34).

Will these contracts benefit or harm the substantial number of customers who will have to take service under these contracts for the remedy to work? Customers First! believes that gas prices will be substantially higher than are projected in the study and that prices based on marginal costs may well end up higher than prices based on average costs. If we are right, this remedy would appear to have a real risk of substantially disadvantaging customers that are required to take under contracts. It also should be noted that if the marginal cost of service is driven by gas, and the price of gas is much higher than projected, these contracts would result in significant windfall profits for the owners of existing generation; that is, a realization of stranded benefits for shareholders, rather than customers. On the other hand, if customers start to leave in higher percentages than anticipated, the remedy will not work to mitigate market power. Existing generation will be freed up to game the competitive market and prices in that market can be expected to substantially exceed competitive levels. The result would appear to be that prices in effective competition will be no lower than marginal cost, and if marginal cost is higher than average costs, it is hard to see the benefits of the remedy.

Another issue with respect to the contract remedy is the term. Is seven years sufficient? What happens if transmission capacity is not available to competitors as

[5] The study assumes a lower cost.

assumed? What happens if scarcity continues in the generation market? Will the state have the ability to extend these contracts for the benefit of customers? Will the contracts not be wholesale transactions subject to FERC regulation, rather than state regulation? The FERC may have policies that are directed at the norm within the country, rather than special circumstances such as a highly constrained Wisconsin market.

Finally, the contract remedy seems to assume that all the baseload generation under these contracts will be tied up and not available to game the system. However, to serve customers, a mix of generation -- base, intermediate and peaking -- will be needed. If high load factor industrial customers leave the system, this will free up baseload energy for strategic behavior in the market.

IV. End State

A. The problems with the study's end state projection of benefits from moving to a competitive market have been outlined above. The most important is the questionable projection of a lower real dollar price for power in 2007 than at the start of the study. This is driven by a number of factors -- the projection of future gas prices and capacity costs, disregarding the potential for significant congestion rents and maintenance of at least 3,000 MW of transfer capability into the state. This is the weakest part of the study, and goes beyond the scope of what was requested in the statute. The question of whether moving to a competitive market will benefit customers and where prices may end up deserves much more detailed and substantial analysis, and is the fundamental policy question that the PSC must address. There is some risk to consumers in maintaining the status quo, but it appears minimal compared to the risk they would face if remedies of uncertain and speculative value were relied upon to mitigate known potential market power abuses.

B. The end state also seems to assume that stranded benefits of existing generation will be retained by the owners; that is, that WEPCO retains the proceeds of any divestiture at above net book cost and any other stranded benefits that are realized under the fixed rate contracts, which may allow the utility to charge prices which are significantly higher than average embedded costs. There are obvious legal and policy issues associated with these conclusions that require analysis and debate. What happens if the price WEPCO receives is substantially higher than anticipated? Note that WEPCO's stranded benefits are projected to be the lowest of each of the utilities, although it has the most market power. What happens if the fixed price contracts proposed result in substantial windfalls for shareholders?

C. The end state also assumes no scarcity in generation in the future due to siting or construction controversies, and no increasing scarcity because planned transmission is not actually built or results in substantially less import capability than expected. Finally, the cost of congestion rents for Wisconsin customers that will substantially disadvantage competitors from outside the state and enhance the stranded benefits of existing generation are not analyzed.

D. Clearly, regardless of the success of the remedies proposed for the end state, there will be must-run units that confer significant market power, and there may be market power at specified locations, such as in Milwaukee or Green Bay, because of internal transmission constraints.

V. Conclusion

The Tabors and Bushnell studies provide a starting point for Wisconsin's consideration of its next steps in the move toward competition in the electric industry. Both studies identify severe market power problems that could prevent the successful transition to retail competition. While possible market power remedies are advanced, the remedies need further analysis and debate. At the same time, Wisconsin needs to solve its current infrastructure problems to ensure reliable and reasonably priced electricity regardless what changes take place in the industry or in regulation. The interests of all stakeholders in the process must be taken into account. The Customers First! Coalition urges that the Commission recommend to the Legislature that it take no action as a result of these studies, and that the Commission itself proceed to seek answers to the questions raised.

Dated November 30, 2000.

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Xcel Energy

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November 30, 2000

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RE: Northern States Power Company – Wisconsin's (d/b/a Xcel Energy) Comments on the Market Power Study for Retail Competition Report Prepared by Tabors, Caramanis and Associates

Dear Ms. Dorr:

On November 3, 2000 the Public Service Commission of Wisconsin (PSCW or Commission) issued a 'Notice of Proceeding and Request for Comments' for a report prepared by Tabors, Caramanis and Associates (TCA) regarding a market power study for retail competition in Wisconsin. In the original notice these comments were due on Wednesday, November 22, 2000. A subsequent revision to the notice for comments extended this deadline to Thursday, November 30, 2000. Following are the comments of Northern States Power Company – Wisconsin's (NSPW's), d/b/a/ Xcel Energy, comments on this report.

While NSPW supports the Commission's efforts to assess the potential for market power in a competitive electric energy market in Wisconsin, the Company does have significant concerns with the findings of this report. The Company's concerns are related to two basic issues – the certainty with which the findings are presented and the characterization of market power in the NSPW/Mid-America Power Pool region of Wisconsin.

Certainty of the Findings

In the report, TCA indicates significant market concentration exists in eastern Wisconsin, i.e., the Wisconsin Upper Michigan System, and moderate market concentration may exist in the NSPW region under certain market conditions. TCA states the only way to effectively deal with the market concentration and potential market power issues in Wisconsin is to implement a two step process for divestiture. NSPW believes the assumptions that lead to this finding are flawed, and as a result, questions the veracity of the findings.

Some of the assumptions used by TCA to establish the baseline market simulation under perfect competition include:

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- future structure of the Wisconsin wholesale electricity market,
- on-line dates of new generating units,
- scheduled retirements of existing generating units,
- assumed increase in transmission system capacity effective 2004,
- fuel prices, and
- other operating costs.

These assumptions were used to develop hourly average marginal costs of electricity, i.e., the price of electricity under perfect competition.

NSPW's main concern with these assumptions is their static nature, i.e., they do not allow for any change that may be due to outside forces or to changes in the electric utility industry as restructuring is implemented. They represent the market, as it exists today, not the market as it may exist at the time Wisconsin actually deregulates. Over the past few years the State Legislature has introduced significant change to the electric utility industry. Unless we deregulate tomorrow, it is very likely that additional significant change will occur before deregulation actually takes place.

In addition, some assumptions, while reasonable at the time the analysis was conducted are outdated and if revised, could significantly affect the outcome of the study. For example, in Appendix A, TCA used the Annual Energy Outlook 2000 (AEO-2000) to estimate natural gas and fuel oil prices for the study. It is doubtful that the AEO-2000 (prepared pre-2000) correctly forecast the significant rise in natural gas prices that occurred during the summer and fall of 2000. The accuracy of this assumption is important because changes in fuel cost would directly impact the marginal cost of electricity, i.e., the price of electricity in a perfectly competitive market, and thus the basis for the findings.

In another example, TCA addressed environmental concerns by considering sulfur dioxide and nitrogen oxides emissions, only. TCA used the 22-state nitrogen oxides state implementation plan call (NOx SIP call) issued in 1997 as the basis for NOx emissions. Implementation of the NOx SIP call will at a minimum impact the marginal cost of electricity and at a maximum could hasten the retirement of certain generating units[1]. As part of its assumption, TCA allowed for a one-year delay in the implementation of the 22-state NOx SIP call due to litigation that occurred after the regulatory package was issued. However, because of its static nature, TCA was unable to modify this assumption when the D.C. Circuit Court of Appeals removed Wisconsin from the NOx SIP call, i.e., potential compliance costs related to the NOx SIP call remained in the analysis. By keeping this assumption in the analysis the marginal cost of electricity is once again impacted influencing the basis for the findings.

Because of the static nature of these and the other assumptions used by TCA, NSPW believes the analysis has serious flaws and the results merely represent the questionable assumptions used in the analysis. Therefore, NSPW encourages the Commission to consider this report as a

[1] No planned unit retirements were included in this study, however.

characterization of potential market concentration issue under very explicit market conditions only.

Market Concentration in the NSPW/MAPP Region

In the results and conclusion section of the structural analysis phase of the study, TCA indicates NSPW's service territory has market concentration values, as characterized by the Herfindahl-Herischman Index (HHI), ranging from 800 to 1250[2] for all product markets. This statement implies a moderate market concentration issue in all product markets. However, the data in the report indicate the moderate market concentration occurs only in two of nine electric product markets, i.e., during the winter season with the off-peak conditions and during the shoulder season with the off-peak conditions.

In the report, TCA states an HHI value greater than or equal to 1000 and less than 1800 indicates the region in question has a moderately concentrated market. In the two electric product market scenarios mentioned above, the market concentration value for the NSPW service territory, as measured by the HHI, is very near the minimum threshold value of 1000. In the worse case scenario, the winter season with the off-peak condition has an HHI value that starts at a high of 1263 in 2001 and drops every year to a low of 1035 in 2007. In the shoulder season with the off-peak condition, the HHI value does not exceed 1035 and only occurs in 2006 and 2007. Yet, later in the conclusion section of the 'Behavioral Analysis' phase of the report, TCA indicates these market concentration values translate into a moderate market power issue that is 'significant' for the MAPP region (emphasis added). The report goes on to indicate this 'significant' moderate potential market power issue in the MAPP region can be addressed by implementing the findings of the analysis, i.e., divestiture of eastern Wisconsin generation and mandated fixed price contracts.

NSPW objects to the characterization of the potential "moderate" market power issue in the MAPP region as "significant". By definition, how can the phrase 'moderate market power' be "significant"?

In addition, the analysis performed by TCA does not take in to account the flaws in the assumptions described earlier - nor does the analysis consider the potential for other actions NSPW, other energy providers, or an independent transmission organization might take to ensure reliability of the distribution or transmission systems.

As a result of these severe limitations in the analysis, NSPW believes all reference to a potential "significant moderate" market power issue in the MAPP region should be removed from the report. In addition, a statement should be added to the report indicating that the potential market concentration and market power issues in the NSPW service territory and MAPP region, respectively, could be the result of inherent error in the analysis.

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[2] TCA rounds NSPW's maximum HHI value down from 1263 to 1250 in the discussion section of the report.

<u>Conclusions</u>

Northern States Power Company – Wisconsin, d/b/a Xcel Energy, supports the efforts of the Commission to try and assess the <u>potential</u> for market power issues in a competitive electric energy market. While the Company supports this effort, it is concerned that the results from the analysis performed by Tabors, Caramanis and Associates are flawed due to the static nature of the assumptions used and the lack of any sensitivity analysis to consider the affect of changing assumptions. In addition, NSPW does not believe that "moderate" market power in the MAPP region can be legitimately characterized as a "significant" market power issue.

NSPW strongly encourages the Commission to consider the analysis and report prepared by TCA as a characterization of the potential market concentration and market power issues under <u>very explicit</u> market conditions. With that caveat, the report could point out issues that might need to be reviewed once a competitive electric energy market is developed in Wisconsin. Because of these concerns, NSPW disagrees with the recommendation that the mitigation strategies contained in the report should "….be implemented as part of any electricity market deregulation initiative in Wisconsin." Rather, NSPW believes implementing these strategies and the characterization of potential market power issues in the MAPP region should be avoided.

NSPW would like to thank you for the opportunity to comment on this report. If you have questions regarding these comments, please contact David Donovan at (715) 839-4684.

Sincerely,

John D. Wilson BRZ

John D. Wilson
V.P. Public and Regulatory Affairs

c: D. Donovan
D. Reck
B. Zelenak
F. Stoffel
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05-EI-120

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WISCONSIN PUBLIC SERVICE COMMISSION
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Hand Delivered

November 29, 2000

Ms. Lynda L. Dorr, Secretary to the Commission
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, WI 53707-7854

Re: Market Power Study for Retail Competition 05-EI-120
Comments of Wisconsin Electric

The Public Service Commission of Wisconsin was directed by the Legislature to hire an economics expert to study horizontal market power, make recommendations and analyze the effect of each recommendation on public utility workers and shareholders. A report to the Legislature is due January 1, 2001.

The Commission has requested comments on the "Market Power Study for Retail Competition" performed by Tabors, Caramanis & Associates. While Wisconsin Electric is directly affected by the recommendations contained in the study, a thorough analysis of the study was not possible because of the study's incomplete assumptions and contradictory results. Furthermore, as required by the Legislature, the required assessment of impacts of each recommendation on public utility workers and shareholders was not included in the study.

After a comprehensive review of the original November 2 study and the November 14 errata, Wisconsin Electric believes that the only conclusions that can be drawn from the study are:

1. Contracts between generators and customers are a very effective form of mitigation and are far less disruptive and expensive than divestiture.

2. Complete and immediate wholesale and retail deregulation is not in the public interest at this time.

3. Prospects for a competitive market in Wisconsin are improved after significant transmission improvements are made.

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A detailed description of Wisconsin Electric's analysis is included in the attached document. Please direct questions to Jeff Knitter at (414) 221-4643.

Sincerely,

Roman A. Draba (DR)

Roman A. Draba
Assistant Vice President
State Regulatory Affairs

attachment

cc: Randel Pilo

Tabors Market Power Study
PSCW Docket Number 05-EI-120
Comments from Wisconsin Electric
November 29, 2000

Wisconsin Electric's comments are:

1. Forced Divestiture would adversely affect workers, utility stockholders and customers -- negative impacts which are totally ignored in the study
2. Tabors study recognizes the value of contracts as mitigation.
3. Stranded benefits are a mirage - seen at a distance but elusive on closer examination.
4. The premise of immediate and complete wholesale and retail deregulation is extreme and unprecedented and exaggerates problems.
5. Perfect competition price model defies logic within WUMS
6. Why are prices within WUMS, where there are no transmission constraints, so different across the utilities?
7. Serious flaws in the Tabors study analysis lead to contradictory findings: regulated cost-based prices are $36/MWh, and simply moving to perfectly competitive conditions drives prices down to $22/MWh (or $26-34/MWh in the errata), yet utilities have no stranded costs and remain profitable?
8. If the Tabors study competitive prices are to be believed, some of the required 40 percent (or 20 percent in the errata) reduction in costs is surely going to come from labor cost savings. How can the study conclude that labor is unaffected by this result?
9. Study ignores the mitigating effect of new entry when prices are high.
10. Analysis of market value of Wisconsin Electric's power plants has obvious flaws
11. Tabors' provides little information about the COMPEL model used to estimate market power or the sensitivity of that model to key assumptions.
12. Detailed analysis of the Tabors study is impossible without more information - the study is tantalizingly vague on specifics of new entry and new and existing generator profitability, key issues in establishing a reasonable perfect competition price.

These comments are expanded upon below and divided into two sections: policy level comments are first, followed by several more detailed, technical comments.

POLICY LEVEL COMMENTS

1. Forced Divestiture would adversely affect workers, utility stockholders and customers - - negative impacts which are totally ignored in the study

Forced divestiture is radical surgery, best reserved for only the most dire and urgent of circumstances due to its predictable and serious side-effects. Fortunately, divestiture is also unnecessary. As described in the Tabors report and in Wisconsin Electric's comments below, contracts are a very effective form of mitigation and have no adverse side effects.

Divestiture reduces the economies of scale inherent in Wisconsin Electric's generating fleet including plant operations and maintenance staffing, fuel procurement, administrative functions, and technical expertise. Wisconsin Electric's fleet includes two of the best power plants in the country, Pleasant Prairie and Oak Creek, in terms of low operating costs and high fuel efficiency, respectively. With a large power plant fleet, Wisconsin Electric can shift its operating, maintenance and technical staff quickly for outages and projects while spreading the costs out over a large base of operations. This saves Wisconsin Electric's customers money and keeps plant reliability at optimum levels.

Divestiture forces Wisconsin Electric out of the generation business. Forcing Wisconsin Electric to divest its power plant fleet into three parts creates generating companies that will not survive on their own. Instead, out-of-state corporations will purchase the pieces and will move jobs and revenues out of Wisconsin. While selling the pieces to small, in-state companies or even plant employees might be an appealing concept, a corporation's fiduciary responsibility requires it to find and take the best deal that it can.

Divestiture will result in out of state owners of generation with no load serving responsibilities. Based on the California experience, one can expect these generation-only players to be much more aggressive in opportunistically raising prices.

Divestiture threatens the existing labor agreements by ending the relationship between Wisconsin Electric and the labor unions, and replacing Wisconsin Electric with an unknown out-of-state corporation.

Forced divestiture is very disruptive.. Utility workers in the generating business unit and all of its support groups turn their attention to the loss of their current employer and their uncertain prospects at the hands of an unknown out-of-state corporation. Neighbors, local government officials and regulators of the soon-to-be divested power plants will also lose their solid working relationships with Wisconsin Electric. Capital expenditures with long payback periods prior to the sale of assets become uneconomic at the plants being sold. For example, if upgrades to a piece of equipment have a three to five year payback and it is not clear that the a new owner of the plant would put the same value on the plant improvement, the upgrade is likely to be abandoned and left up to the new owner to evaluate several years down the road.

Finally, forced divestiture threatens reliability. Wisconsin Energy is certainly not going to invest large amounts of time and money into building the state's critically needed power plants, particularly long lead time and expensive coal power plants, just to have them sold at "fire sale", forced divestiture prices.

2. Tabors study recognizes the value of contracts as mitigation.

The Tabors study achieves over 60 percent of its mitigation using only a 30 percent contract cover. This is a significant finding yet not surprising since the Tabors model assumes customers under contract cover get all the benefits of a perfectly competitive price yet take no market price risk, their good price is locked in. What is surprising is that anyone would choose anything else! Why do the uncovered customers choose the higher, non-contract market prices modeled in the contract cover scenarios? Why were they forced to move out from under the protection of contracts? The study does not say.

Contract cover, mitigates market power and its effects in two ways. First, customers who receive service under a fixed-price contract are protected directly for the duration of the contract. Whatever might be happening in the market, those customers pay prices fixed by contract. Second, when a strategic supplier of generation commits to sell a portion of its output at fixed prices, the potential profit it can realize from either withholding capacity or bidding strategically is reduced or eliminated. As a consequence the generation owner has no incentive to engage in strategic behavior that would raise prices in the market.

The Tabors study is somewhat misleading in its description of the amount of load covered by contracts in the contract cover scenarios. The Tabors model tried to cover 90 percent of residential, 60 percent of commercial and 60 percent of industrial load. What they effectively covered, however, was 30 percent of WE's generation and 30 percent of WE's load with reserves. For example, the Tabors study assumes the peak month contract cover is 2,030 MW which is 30 percent of the study's projected peak load in 2001 of 6,662 MW (5,646 MW plus 18 percent reserves).

While covering only 30 percent of load, the contract cover scenario results in 60 percent less price impact than without contract cover. This result appears consistent throughout the study, even after significant additional transmission import capability lowers overall prices.

While the Tabors study stops at 30 percent contract cover, increasing the amount of contract cover could yield results for a "contracts only" case very similar to the Tabors "contract plus divestiture" case. In fact, contract cover approaching 100 percent would leave very little residual market power, relegating divestiture to a disruptive option of little marginal value and high marginal cost.

3. Stranded benefits are a mirage - seen at a distance but elusive on closer examination.

For stranded benefits to exist, one of two possible events must take place. Either power plant assets must be sold at a price above their book value or the current basis for pricing electricity must change. As long as the power plant assets are included in cost-based rates at their current book value, no stranded benefits (or stranded costs) are created because nothing meaningful has changed. There must be an internally consistent relationship between market price for the product of an asset and market value of the asset.

The Tabors study assumes both events take place: power plants are sold at market values that are substantially above the book values and electricity pricing becomes based on market prices, which are lower than the existing cost-based, regulated price. This violates a basic economic tenet: There is no free lunch! The logical inconsistency within the Tabors study is simple - how can the market value of the units of production be so much higher than their cost basis when predicted market prices for their output are so low relative to regulated prices?

The Tabors study implies (but does not address specifically) that the low, perfectly competitive prices are unaffected by the sale of power assets at several times their book value. This is impossible. At current regulated prices, Wisconsin Electric is covering its costs, including a fair return on the book value of its generation assets. In the competitive world, if assets are divested, the new owners of the power plants will have to recover their fixed costs, which would now include financing costs several times higher than the previous utility owner's financing costs, through higher-than-current market prices in order to remain profitable. Or alternatively, if the new owners anticipate low market prices, they will pay only book value for the assets since any higher plant price would be unprofitable. Therefore, either the Tabors study price predictions are too low or, in the aggregate, the portfolio of power plant's market value is too high. In either case, the mirage of a free lunch will disappear.

For example, if Wisconsin Electric's entire power plant fleet were sold at twice book (about $2.6 billion), and the after tax proceeds, $800 million (value above book, $1.3 billion minus 40 percent for taxes), were hypothetically split evenly between the power plant asset owners, Wisconsin Energy stockholders and Wisconsin Electric customers, each group would receive about $400 million as a one-time lump sum payment. The downside of the deal is that the new owners of the power plants assets would need about $200 million in added revenue per year for twenty years to recover their investment of $2.6 billion, which means prices (or margins) must go up accordingly (roughly a 25% price increase, in effect for 20 years!). Obviously, this is not a good deal for customers (it's also not a good deal for stockholders, but that's a separate issue).

4. The premise of immediate and complete wholesale and retail deregulation is extreme and unprecedented and exaggerates problems.

For all its flaws, the Tabors study does prove the obvious: Complete and immediate wholesale and retail deregulation is not in the public interest at this time.

On the other hand, the Tabors study misses an equally obvious conclusion: The state needs additional generation to increase reliability more than it needs deregulation. Tinkering with the workings of a healthy and fully supplied marketplace is one thing. Reworking a market before it has sufficient supply, leads one down California's path. The Commission should ensure an adequate supply of power for the state before designing an alternative retail marketplace for the state's electricity customers.

Wisconsin's transmission infrastructure is inadequate to support the level of inter-state electricity trading that the rest of the Midwest uses to support the slowly evolving mix of deregulated wholesale and retail activity. As expected, the Tabors study shows dramatic decreases in prices once the state has 3,000 MW of transmission import capability. The obvious prerequisite for a scenario of decreasing market prices is a robust supply picture relative to predicted levels of demand. To get to a robust supply situation will require additional generation and transmission facilities thereby increasing both the ability to transfer power into the state, and the amount of available generation located in the state.

The Tabors study fails to point out that a phased-in introduction of competition would reduce the opportunity to exercise any alleged market power and create a more orderly transition. This obvious point is the primary reason behind the wide variety of deregulation timetables in Midwestern states and across the country. The Tabors study's premise of immediate and complete deregulation exaggerates problems in the market as evidenced by the steady decrease in modeled wholesale prices over time, even before more transmission capacity is added to the model.

TECHNICAL COMMENTS

5. Perfect competition price model defies logic within WUMS

While the errata may have corrected some problems, the newly added footnotes highlight another: If a market has adequate supply and market participants are forced to bid their marginal costs, none of which exceed $100/MWh, why are prices in the model's summer months frequently ten times the maximum marginal cost ($1,000/MWh)? If, on the other hand, the market does not have adequate supply and high prices are a result of running out of generation during peak periods, why does the Commission's Strategic Energy Assessment anticipate a planning reserve margin of 18 percent for the state in 2001? Our suspicion (but like many issues in the Tabors report, it is impossible to pin this down from the information given) is that the Tabors study model is under-supplied in the early years resulting in high peak prices.

It is difficult to determine how many high-priced hours the Tabors study has in its analysis. However, logically there were quite a few. The Tabors study errata noted that the increase in market prices shown in the revised Table 2.3 (p. 13) results from increasing the cap on market prices from $300/MWh to $1,000/MWh. To account for the average price change reported for 2001, 92 hours would have to have gone from $300/MWh to $1,000/MWh (or more hours if there was an intermediate price level between \$300/MWh and \$1,000/MWh). In 2002 it would require 76 hours and in 2003 it would require 56 hours to move from the \$300/MWh level to the \$1,000/MWh level.

In referring to "dispatchable demand units" (page A-7), Tabor notes that "...these units run in our model as the high energy prices they require are assumed to indicate a supply shortfall and prompt entry to meet local demand." In the GE MAPS model, which is a cost-based model, prices will rarely rise above \$100/MWh unless dispatchable demand units are activated. Therefore, dispatchable demand units must have been activated, but the Tabors study did not assume entry until 2008 (i. e., it did not find new entry economic). Thus, there appears to be another fundamental inconsistency in the modeling in the Tabors study.

Reference: See p. A-7 and revised Tables 2.1-2.3 and associated footnotes.

6. Why are prices within WUMS, where there are no transmission constraints, so different across the utilities?

Why is there any variation at all in prices across the WUMS utilities with uniform marginal cost bidding and no transmission constraints? Logic and experience within WUMS dictates the opposite: There should be a single price (or close to it) for all of the utilities within WUMS. Similar GE MAPS analysis undertaken by PA Consulting (Wisconsin Electric's economics consultant for these comments) show no appreciable difference in prices across WUMS utilities. This anomaly is unique to the Tabors study and not the normal or expected result for a WUMS analysis.

Reference: See data on p. 13 (original or errata), Tables 2.1 and 2.2 showing competitive market prices in 2001 and 2007 for WEPCO, WP&L, WPSC and MGE. Note average off peak shoulder prices varying by over \$4/MWh (\$13.22 to \$17.29) during a time period where there is very little difference in the marginal costs of a very large number of units within WUMS and across the Midwest (i.e., a very flat section of the supply curve). Note also peak prices varying by almost 100% (\$67.28 to \$114.63) on average. Data for 2007 shows a similar unexpected pattern of inter-utility variation but at a lower average price.

7. Serious flaws in the Tabors study analysis lead to contradictory findings: regulated cost-based prices are \$36/MWh, and simply moving to perfectly competitive conditions drives prices down to \$22/MWh (or \$26-34/MWh in the errata), yet utilities have no stranded costs and remain profitable?

Can eliminating regulation really reduce prices 40 percent (or 20 percent in the errata)? While the errata make the problem less dramatic, the contradiction still exists. If market prices are going down, how can there be stranded benefits (i.e., if utilities are earning less revenue, how can their assets be worth more after deregulation)?

Reference: See p. E-2 Unbundled Wisconsin Electric Generation cents per kWh of 3.61 or $36 per MWh.
p. 13 Table 2.3 WUMS Wholesale Price of approximately $22/MWh and $30/MWh in the same table in the errata.
$36-$22 = $14 or about a 40 percent reduction.
$36-$29 = $7 or about a 20 percent reduction.

8. If the Tabors study competitive prices are to be believed, some of the required 40 percent (or 20 percent in the errata) reduction in costs is surely going to come from labor cost savings. How can the study conclude that labor is unaffected by this result?

Fixed O&M represents a large portion of plant total O&M costs yet the Tabors study makes a significant assumption about fixed O&M. The study states that fixed O&M costs are assumed to be 20% lower under competition. Utility worker wages are a part of the fixed O&M costs being reduced 20%. Certainly utility workers would notice and be affected by a 20% wage or staffing reduction.

Reference: See p. A-2, "Fixed O&M costs are…reduced by [20%] to account for competitive market response."

9. Study ignores the mitigating effect of new entry when prices are high.

If prices in the "no contracts" cases are so high, why isn't there new entry over time? If new entry was profitable at competitive prices, it would certainly be even more profitable at elevated prices. While new entry can not occur immediately, the Tabors study seems to completely ignore this market driven mitigation.

The study seems to use the odd assumption that all currently planned capacity is both perfectly economic and exactly sufficient to meet demand despite widely varying market scenarios. Since new entry (assuming it is economic) always reduces average energy prices, the study's rigid adherence to a fixed new entrants list directly affects market prices.

In fact it appears that the Tabors study should have shown significant entry beyond the planned capacity that is included. If the Tabors study has the large number of hours at $1,000/MWh or hours between $300/MWh and $1,000/MWh) that is implied (as discussed above), then the analysis should have supported additional economic entry in each of these years. As we have seen in recent years, entry occurs quickly when market prices are supportive.

Reference: See p. A-3. Under the production cost modeling paradigm, it is unclear why more entry does not occur, and why it is always CTs. This may relate to the planned Wisconsin generation which is shown on page A-3.

10. Analysis of market value of Wisconsin Electric's power plants has obvious flaws

There are a number of flaws in the Tabors study that are present in the unit specific spreadsheets provided. First, the Tabors study does not appear to properly calculate 2003 and 2005 net revenue. The pattern of cash flows used to calculate market value is inconsistent with the components of value in the same spreadsheet. The individual components of value appear to be inconsistent with the market prices, but the revenue in the calculation of value are much higher. This error is very significant. For example, this apparent error overstates the value of the Pleasant Prairie Plant by about $83 million.

Second, the Tabors study does not appear to have used its own estimate of 2006 market prices when they developed the cash flows. For example, average energy market revenues rises 33 percent for Pleasant Prairie unit 1 and 36 percent for Pleasant Prairie unit 2 from 2005 levels, but reported market prices rise less than 3 percent. Since these units are low-cost base load units, one would expect that energy market revenue would closely track average market prices. In the case of Pleasant Prairie this apparent error overstates the value of the Pleasant Prairie units by about $30 million.

Third, the Tabors study does not seem to use its own parameters for SO_2 and NO_x allowance costs. This apparent error overstates the value of the Pleasant Prairie units by about $89 million

Fourth, the allowance prices that the Tabors study uses for SO_2 are unrealistically low ($200/ton in all years). A more realistic forecast starts at about $200/ton and rises to about $400/ton by 2005. For Pleasant Prairie this problem overstates value by $40 million.

Fifth, the fixed O&M assumed in the Tabors study is very low compared with historical levels. For example, the Tabors study assumes a very low fixed O&M estimate of $26/kW-year for Port Washington. By comparison, the 1999 total O&M for Port Washington was $43.4/kW-year. A dramatic reduction in O&M of this magnitude could only be achieved by reducing plant staff. With this correction, Port Washington's market value decreases by about 40 percent

Sixth, given that the market prices in the Tabors study for the early years are so high (indeed, high enough to support additional new entry),a significant portion of the market value estimates comes from early year revenue. Of the total market value of $2.1 billion for Pleasant Prairie, for example, 9.4 percent is derived from revenues in 2001 and 27.6 percent from revenues in 2001 through 2003.

Lastly, there appear to be a fundamental flaw in the GE MAPS modeling that may extend to the COMPEL modeling of market behavior. This can be seen in the unusual reported dispatch of many of the coal units. For example, Port Washington historically has had a capacity factor ranging from 29 percent to 38 percent in 1996-1999. The results in the Tabors study show a capacity factor of 8 percent for Port Washington in 2001, declining to 6.6 percent by 2003. The capacity factor then rises to 8.6 percent in 2004, while average energy prices fall 11 percent and Port Washington's variable costs of operation rise in 2004 because of new NO_x regulations.

It is difficult to conceive of the modeling in the Tabors study that can so dramatically understate Port Washington's level of generation. Further, the results show an average 2001 generation cost of $18.70/MWh for Port Washington. Relative to the predicted energy market prices, Port Washington should be generating at least all of the super and on-peak hours, which would produce a higher capacity factor than projected in the Tabors study

This counterintuitive capacity factor/price pattern also seems to be present in the modeling of all of WE's coal units, except Pleasant Prairie. For example, for Edgewater 5, the capacity factors is 53.6 percent in 2001 and 75.1 percent in 2005. During this period, the Tabors study projected market prices fall nearly 30 percent. Since the Tabors study does not assume different unit availability assumptions across years, there is no logical explanation for the observed pattern.

The unusual pattern of coal unit operation could reflect underlying flaws in the GE MAPS modeling. It is likely that similar inexplicable patterns occur for many units. These observations call into question the validity of the modeling in the Tabors study for purposes both of calculating market value as well as estimating market power.

Reference: Tabors' spreadsheet "WEPCO Assets.xls," Revised Tables 2.1-2.3.
PA Consulting spreadsheets (attached).

11. Tabors' provides little information about the COMPEL model used to estimate market power or the sensitivity of that model to key assumptions.

The COMPEL model prices have allegedly been benchmarked against the GE MAPS prices, but there is no basis to evaluate how well the baseline matches. There were no sensitivity analyses conducted with the COMPEL model (or the GE MAPS model, for that matter).

It is well know that the results of behavioral market power models are quite sensitive to the elasticity of demand assumed. The Tabors study uses a rather low estimate (–0.2) for the elasticity of demand, relying on a 1976 study for the source of this assumption, while at the same time acknowledging the uncertainty of this assumption ("One can only guess the level of industrial price elasticity of demand in Wisconsin."). We do not know if the Tabors study evaluated alternative assumptions for elasticity. Lower elasticity results in less customer response to high prices and a greater degree of potential market power.

The Tabors study does not discuss how the elasticity parameter is used. The study cited by Tabors contains estimates of short-run elasticity, essentially doing without electricity when prices rise. A more appropriate measure is the ability of customers to manage their demand by shifting consumption to non-peak hours. Time of use rates, demand bidding programs, DSM and new technologies that are likely to enter the market over the next few years make it increasingly possible to shift demand.

References:

In a 1997 report Severin Borenstein, James Bushnell and Christopher Knittel explored equilibrium price levels in New Jersey for three elasticity of demand assumptions ranging from –0.1 to –0.9. They found that the number of hours of elevated prices and as well as the level of potential price rise decreases dramatically as the elasticity goes from –0.1 to –0.9. Page 27; Severin Borenstein, James Bushnell and Christopher Knittel, *A Cournot-Nash Equilibrium Model of te New Jersey Electricity Market*, POWER, University of California Energy Institute, November 1997.

Robert Earle reports that "while it is clear that the retail, end-user demand for electric power remains very inelastic, there appears to be significant elasticity in the day-ahead market of the California Power Exchange". (Robert L. Earle, *Demand Elasticity in the California Power Exchange Day-Ahead Market*, The Electricity Journal, October 2000). Using the residual demand curve, it was calculated that 27% of the hours had an elasticity less than –1.0. For high priced hours (prices over $40/MWh) 16% of the hours had elasticities less than –1.0.

In 1993, the US Department of Energy commissioned a study by Professor Carol Dahl of building sector demand elasticity. Professor Dahl found that short-run residential electricity elasticity was between 0 and –0.8 and that commercial short-run electricity elasticity was between –0.17 and -1.18. Tabors notes that the –0.2 elasticity that they used is for "...those whose response could be the most significant: industrial customers." If more recent data (Professor Dahl's work) are representative of the less responsive sectors (residential and commercial), the –0.2 used by Tabors is far too conservative an assumption to use for the ability of customers in Wisconsin to respond to prices.

A Supply Function Equilibrium (SFE) is an extension of a Cournot model. Frame and Joskow have noted that they "... are not aware of any significant empirical support for the Cournot model providing accurate predictions of prices in any market, let alone an electricity market." (Rod Frame and Paul Joskow, Testimony in the State of New Jersey Board of Public Utilities Docket No. EX94120585Y, 1998.)

A SFE model (like COMPEL) has some of the same problems regarding sensitivity to demand specification as do Cournot models. Baldick et. al. note "The SFE approach is not immune to the problem of sensitivity to specification of the market demand..." They go on to say that a major problem associated with the practical use of both the SFE and the Cournot model is the representation of demand. The plausibility of price forecasts with these models depends substantially on how the demand curve is specified." They note that "although there is little demand-side response in the E&W [England and Wales] market, low values of demand elasticity have typically yielded poor fits to the observed data. For example, when GN [Green and Newbery] used very low slopes for the linear demand curve they estimated prices that were very much higher than what was subsequently observed." "In their calculations of the impacts of the 1999 divestitures in the England and Wales markets, they used linear demand curves with a range of slopes (0.10, 0.25 and 0.50) implying a range of elasticities. They note that "the price change predictions of divestiture, i.e. the difference in average prices, are greater at low elasticity than at high elasticity regardless of the cost curve characterization." (Ross Baldick, Ryan Grant, and Edward Kahn, *Linear Supply Function Equilibrium: Generalizations, Application, and Limitations*, University of California Energy Institute, August 2000.)

In a 1998 paper, Severin Borenstein and James Bushnell (*An Empirical Analysis of the Potential for Market Power in California's Electricity Industry*, Severin Borenstein and James Bushnell, University of California Energy Institute, December 1998) calculated the price change using a Cournot model with several elasticities. Recognizing the impact of elasticity on their results, they used a wide range of elasticities of demand (0.1, 0.4 and 1.0) in their analyses. In their base case they found that with an elasticity of –0.1, peak September prices in California rose by about 3,767% (from $124.88/MWh to $4829.2/MWh) while with an elasticity of –0.4 by 31% (from $68.62/MWh to $89.6/MWh), and with an elasticity of –1.0 by only about 1% (from $59.77/MWh to $60.55/MWh). They conclude that "perhaps the greatest impact on the severity of market power comes from increase price responsiveness in the market" and go on to state that "policies that promote the responsiveness of both consumers and producers of electricity to short-run price fluctuations can have a significant effect on reducing the market power problem. Such policies may be more rewarding, and less contentious, than other approaches…"

12. Detailed analysis of the Tabors study is impossible without more information - the study is tantalizingly vague on specifics of new entry and new and existing generator profitability, key issues in establishing a reasonable perfect competition price.

There is just no way to reconcile the questions discussed above given the data and descriptions provided in the study. One must conclude that it is unwise to base any detailed or specific findings on a study that leaves so much of the analysis undocumented yet reaches paradoxical and erroneous conclusions about a theoretical Wisconsin electricity market of the future.

One just can't tell what would happen if the analysis and modeling problems were fixed. The entire market power analysis engine is simply a black box and apparently not available for review (despite National Science Foundation funding). The errors and contradictory results discussed above have an uncertain effect on the key result areas. Of particular significance are the problems associated with determining the perfect competition price, since it forms the basis for all other results.

In the one study area where a detailed analysis of the Tabors study was possible, the calculation of market values for existing power plants, obvious flaws were found, reflecting both a lack of familiarity with the plants in question and basic methodology errors. As described above, plant value analyses are fairly straightforward, yet, in this study, they were not executed correctly. Errors of this type makes one question what serious problems might underlie the much more difficult and complicated tasks of modeling pricing behavior in a regional marketplace.

Horizontal Market Power in Wisconsin Electricity Markets:

A Report to The Public Service Commission of Wisconsin

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Executive Summary

The Public Service Commission of Wisconsin (PSCW) has identified the development of a robust wholesale electric market as one of its primary policy objectives in the electric restructuring process underway in Wisconsin.

Market power

Market power has been defined by the PSCW as the ability of a seller to maintain prices above competitive levels for a significant period of time. The Wisconsin Legislature has identified the potential for generation owners to exercise horizontal market power, and thereby "...frustrate the creation of an effectively competitive retail electricity market", as a concern in any restructuring of the state's electric markets. In response to that concern, the PSCW retained Tabors Caramanis & Associates (TCA) to analyze the potential for the exercise of horizontal market power during the period 2001 through 2007, to evaluate potential measures to prevent that market power and to assess the impacts of those mitigation measures on stakeholders.

The study used both structural analysis and behavioral analysis to assess the potential for the exercise of market power, and further used behavioral analyses to evaluate measures for preventing that market power. The study also assessed the measures for preventing or mitigating market power in terms of their impacts on retail rates, stranded costs and employment in the generation sector.

Baseline market simulation

The study began with a simulation of market conditions and prices under perfect competition over the study period. The outputs of this baseline market simulation, prepared using a production cost model, provided the foundation for the structural and behavioral analyses as well for the assessment of rate impacts and stranded costs.

The baseline market simulation was based on a comprehensive set of assumptions regarding such key factors as the future structure of the Wisconsin wholesale electricity market, the on-line dates of new generating units, scheduled retirements of existing generating units, an assumed increase in transmission system capacity effective 2004, fuel prices and other operating costs. The baseline market simulation developed hourly, locational marginal prices that were then averaged across two distinct wholesale markets, the Wisconsin Upper Michigan System or WUMS and Northern States Power Wisconsin (NSPW).

Structural analysis

The structural analysis determined market concentration, a standard measure of the potential for exercise of market power. The markets considered for this analysis were defined in terms of utility service territories, season and load levels within each season. Market concentration was measured using the Herfindahl-Hirschman Index (HHI), an indicator that has been applied to analyses of the electric industry by the Federal Energy Regulatory Commission (FERC) in two tests, Economic Capacity (EC) and Available Economic Capacity (AEC). The EC test assumes that generator owners have no obligation to reserve their least-cost generation to serve native load, while the AEC test assumes that some generator owners have such an obligation.

Behavioral Analysis

While the structural analysis provides a measurement of market concentration but provides no indication of the actual exercise of market power or its impacts on stakeholders, the behavioral analysis simulates the exercise of market power directly. The behavioral analysis addresses two key policy questions:

- What is the potential increase in wholesale electricity prices resulting from strategic behavior on behalf of generators?
- How effective are market power mitigation options in preventing and/or reducing the impact of strategic behavior on wholesale electricity prices?

The behavioral analysis was prepared by simulating two types of strategic behavior generation owners could pursue in a deregulated generation market. The first behavior, strategic bidding, involves generating firms bidding prices above the variable production costs of their units, with the intent of forcing the market clearing price above competitive levels. Generating companies may be able to bid their units into the market at prices significantly above the variable production costs, while maintaining the merit order and often at no risk of being undercut by competitors. The second behavior, capacity withholding, involves firms removing some of their capacity from the bidding process or from the market for a certain period of time, in an effort to cause more expensive units in the system to set the market clearing price. As is the case with strategic bidding, capacity withholding strives to increase the market-clearing price. Unlike strategic bidding, capacity withholding changes the merit order in which units are dispatched. Both of these have the effect of increasing the market price of electricity.

The behavioral analysis was performed using COMPEL, a computer model developed at TCA based on Supply Function Equilibrium (SFE) and the Cournot methodology. Simulations were run for a Base Case, in which the market was deregulated without changes in the current structure or policy framework, and for three cases testing potential mitigation measures: Contracts Case, Divestiture Case, and Contracts plus Divestiture Case.

Impacts on rates

The impact of mitigation measures on public utility customers and electric cooperative members was assessed in terms of changes in unit revenues, a proxy for retail rates. Unit revenues by rate class were calculated for each utility each year as the sum of two unbundled components, the average unit cost of transmission, distribution and customer services by major customer class and the system-wide unit cost of generation.

Impacts on shareholders, electric cooperative members and employees

The impact of mitigation measures on public utility shareholders, electric cooperative members and employees was assessed in terms of stranded costs as well as qualitatively. Stranded costs equal the value of existing generating units in the restructured market less their book value. If that difference is positive, and the resulting stranded costs are not fully recoverable from ratepayers, utility shareholders and cooperative members will view this as an adverse financial impact. In contrast, if market value exceeds book value the stranded costs are negative and are, in effect, stranded benefits. The study estimated the market values for each generating plant using an asset valuation model and data from the baseline market simulation, i.e., a perfectly competitive market.

Conclusions.

The structural analysis indicates that

- Potential exists for the exercise of market power by generation owners within WUMS over the study period;
- This potential is greatest under existing transmission limitations, but potential remains even after transmission capacity is assumed to increase to 3,000 MW effective 2004.
- Wisconsin Electric Power (WEPCO) has the largest market share in all geographic and product markets within WUMS.

The behavioral analysis indicates that:

- Under the current market structure, the level of market power in the WUMS region would prevent the creation of an effectively competitive retail electricity market;
- A workably competitive retail market could be achieved by implementing two changes to the current market structure. These are:
  (1) require divestiture of WEPCO generation assets among three independent owners and thereby reduce market concentration, and
  (2) require owners of existing generation to commit a significant portion of their capacity under fixed price contracts, for example as the source of generation for retail customers on standard offer service.

The assessment of mitigation measure impacts indicates that

- Using fixed price contracts and divestiture to achieve workably competitive retail markets will result in significantly lower rates than would prevail if market power was not mitigated;
- Workably competitive retail markets would not result in positive stranded costs but instead would result in significant stranded benefits;
- Workably competitive retail markets should not have adverse effects on employees of existing generating units since those units will remain profitable.

Recommendations.

To ensure an effectively competitive electricity market, the deregulation of electric markets in Wisconsin should include the combination of mitigation measures modeled in the study. Specifically:

- WEPCO generation assets should be divested among three independent owners, and
- A significant portion of existing generation capacity should be committed under fixed price contracts. One option for accomplishing this would be to contract for generation from this capacity to be used as the source of generation for retail customers on standard offer service.

Table of Contents

1 Introduction

The ability of generator owners to exercise horizontal market power in energy markets has been a concern for regulators, customers and other participants in the energy markets throughout the process of deregulating generation. In March of 2000 the Public Service Commission of Wisconsin, responding to a request by the Wisconsin Legislature, contracted with Tabors Caramanis & Associates (TCA) to conduct a study on the potential for horizontal market power of electric generators to frustrate the creation of an effectively competitive electricity market in the state, and also to make recommendations on measures to eliminate any market power on a sustainable basis. This report is the product of the study conducted by TCA to model and analyze possible horizontal market power in the Wisconsin electricity sector, and to quantify the impacts of strategic behavior on the development of competitive energy markets.

1.1 Objectives of This Study

Tabors Caramanis & Associates (TCA) prepared this report on behalf of the Public Service Commission of Wisconsin (PSCW). The PSCW has identified the development of a robust wholesale electric market as one of its primary policy objectives in the electric restructuring process underway in Wisconsin. An essential prerequisite of a robust wholesale electric market is the absence of undue market power. The objectives of this study are to:

- Identify the extent and impact of market power in Wisconsin's electricity markets, and
- Evaluate and recommend measures to eliminate or mitigate that market power.

The potential for electric utilities in Wisconsin to exercise market power was analyzed in two stages. First with a structural analysis that focuses on calculating individual companies' market shares and concentration indices (specifically the Herfindahl-Herschman Index), and second with a behavioral analysis that examines the ability of individual companies to behave strategically through bidding strategies and/or withholding generation capacity.

The objective of the first stage is to report results in an industry standard format, as defined by FERC in Order 592, the Merger Policy Statement. The objective of the behavioral stage of analysis is to provide a more quantitative analysis of the ability for electric generators to exercise market power over market price or the available electricity supply. Using the results from both the structural and the behavioral analyses, the report makes recommendations for eliminating horizontal market power on a sustainable basis in order to facilitate the development of competitive electricity markets in Wisconsin.

1.2 Definition of Market Power

Market power is generally defined as the ability of a particular seller, or group of sellers, to significantly influence the market price of a product to their advantage over a sustained period of time. The major objective of a horizontal market power analyses is to assess the potential for generation owners to exercise market power in a deregulated competitive environment -- wholesale and/or retail.

The PSCW's proposed rules[1] define market power as the ability of a seller to maintain prices above competitive levels for a significant period of time. This definition clearly reflects the notion that meaning of market power is indicative rather than predictive: possessing market power is possessing both the incentive and ability to raise prices. In general, the latter does not necessarily imply that prices will be raised. However, given the experience with electricity markets in the United States and other countries, it is clear that the threat of market power is real and that the incentive and ability to exercise market power more often than not result in prices well above the perfectly competitive level.

There are numerous negative implications when the market power is exercised, such as:

- Harm to consumers financially through higher prices
- Inefficient operation of the electric power system as out of merit order (expensive) generators are dispatched in the process of companies exercising market power,
- Insufficient incentives for technological innovations as a result of distorted market signals, and
- Compromised system reliability in the long run resulting from distorted market signals and subsequent insufficient investment and system expansion.

All of these factors can result in political backlash against the deregulation of the electric power industry.

Market power is often equated to market concentration, as it is in Appendix A to the FERC Merger Policy Statement, Order No. 592. However, there is no direct theoretical link between the Herfindahl-Hirschman Index (HHI) indicator or other measures of market concentration, and measures of market power. Therefore, although HHI can be used as a simple indicator for the *potential* exercise of market power, it does not measure market power directly.

Market power can be directly measured with a Price-Cost Margin Index (PCMI). The PCMI quantifies the degree to which the actual price of a product in a market differs from the estimated price of that product in a "perfectly competitive market." The PCMI is a direct indicator of market power, defined as:

$$PCMI = \frac{(\text{Price under Strategic Behavior - Price under Perfect Competition})}{\text{Price under Perfect Competition}} * 100$$

1 Clearinghouse Rule 98-174, Chapter PSC 100, Subchapter II, Affiliated Wholesale Merchant Plant Market Power.

In a deregulated electric market the "perfectly competitive market" price is equal to the marginal cost of electricity generation.[2] The PCMI is similar to the well-known Lerner Index, in which the actual price is used (in the denominator)[3]. In our analysis, we use the PCMI rather than the Lerner Index, since it has the "perfectly competitive" price in its denominator, and thus facilitates comparison across various scenarios that may have different actual prices.

The balance of this report is organized as follows:

Section 2 discusses the modeling methodology for analyzing market power.

Section 3 provides a detailed description of our methodology, assumptions underlying the structural analysis and key results.

Section 4 summarizes the methodology and results of the behavioral analysis.

Section 5 assesses potential implications of market power mitigation options on stakeholders in terms of rate impacts and stranded costs.

Section 6 presents conclusions and recommendations of this study.

The Tables and Figures for each Section are located at the end of the section.

The technical appendix offers a detailed description of modeling assumptions, technical aspects of our modeling methodology and provides detailed results of simulation analyses.

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[2] The PCMI has a minimum value of zero -- implying a perfectly competitive market -- and an unbounded maximum value. A PCMI value of 100%, for example, means that the price of a product is twice the price that would be expected if the market were perfectly competitive.

[3] The PCMI and Lerner Index are connected in the following way: Lerner Index = PCMI/(1+PCMI).

2 Market Power Analysis Methodology

2.1 Baseline Market Simulation

A baseline simulation, using the GE MAPS production cost model, was developed as a starting point for both the structural and the behavioral analyses. The baseline scenario is run for the years 2001 through 2007 and is assumed to represent the system conditions and prices that would result under perfect competition. The output from the GE MAPS model is used to provide input into both the structural and behavioral stages of the market power study. The structural analysis uses the perfectly competitive prices calculated by GE MAPS in each utility service territory to determine the scope of the geographic market (the number of suppliers). The behavioral analysis uses the perfectly competitive prices to calculate the Price Cost Margin Index, PCMI. In addition, the production cost baseline will be used to "benchmark" the behavioral analysis study.

2.1.1 Assumptions

The input assumptions to the baseline case reflect current expectations regarding the structure of the Wisconsin wholesale electricity market, including:

- on-line dates for new generating units;
- scheduled retirements of existing generating units;
- on-line date and capacity of transmission expansion;
- timetables for phasing out native load commitments in states that implement retail access.

These assumptions are discussed in detail in Appendix A and elsewhere in this report.

The PSCW emphasized the importance of accurate representations of the Wisconsin market in both the structural analysis and the behavioral analysis. TCA maintains up-to-date databases of key generating unit and transmission system parameters for all major wholesale markets in the United States on an ongoing basis. This database was reviewed for this project, with particular emphasis placed on ensuring the accuracy of the technical, economic and market structure data for existing and proposed generation and transmission facilities in Wisconsin and neighboring regions. In particular, the database was updated to ensure consistency with generation ownership and the effective control of generating facilities through contractual arrangements.

In addition to generation, the input assumptions for the Wisconsin transmission system were examined and updated. TCA models the generation and transmission system for the entire Eastern Interconnect. Using this database, transmission constraints and essential loop flows throughout the Eastern Interconnect were modeled in the baseline scenario, with special attention placed on those constraints that have been most binding in the past and those that may become binding as a result of new developments.

One fundamental assumption in this analysis is that the total transfer capability into the WUMS market will increase to 3,000 MW effective 2004. This assumption was based on recent reports on the Wisconsin transmission system[4] and on discussion with Public Services Commission staff.

2.1.2 Calculated competitive market prices

The prices calculated by GE MAPS are hourly, locational marginal prices for every node in the model. As discussed below, the structural analysis is performed for 9 time periods each for the years 2001 through 2007. For the structural analysis, the competitive prices from GE MAPS are averaged across utility service territories and used to determine geographic market boundaries. Summaries of these market prices for years 2001 and 2007 are presented in Tables 2.1 and 2.2. The complete sets of prices, along with the time period definitions, are presented in Section 3, The Structural Analysis.

The behavioral analysis is performed for every hour of each year, rather than being limited to discrete time periods as in the structural analysis. Starting with the locational marginal prices from the GE MAPS baseline competitive market analysis, the behavioral analysis then averages the hourly prices across larger regions of Wisconsin. The regions considered for this stage of the study are WUMS (Wisconsin Upper Michigan System) and NSPW (Northern States Power Wisconsin). Annual summaries of these hourly averages are presented in Table 2.3.[5]

2.2 Structural Analysis Overview

Structural analysis is used to determine market concentration, which is one measure of the potential for exercise of market power. A "market" in this context refers to the collection of all entities that can provide power to a geographic region under a specific set of conditions. In this analysis, the product markets in each utility service territory are deliverable energy under nine market condition scenarios—off-peak, on-peak and super-peak power, for each of the winter, summer and shoulder seasons. This analysis is performed for both the long-term capacity and the short-term energy markets, as described in Section 3.

Though useful as an initial screen, structural analysis is limited because it is inherently a snapshot analysis that does not take market dynamics into account. It is a measure of how access to the market is apportioned given a certain set of market conditions. If conditions change, for example through a change in price or transmission system state, the market concentration can change as well.

The standard U.S. Department of Justice anti-trust measure of market concentration, and the index calculated in this analysis, is the Herfindahl-Hirschman Index (HHI). The data needed to calculate the HHI for an electricity market include:

- Market price of electricity,
- Marginal cost and ownership of potentially participating generators,
- Obligation of market participants to serve native load,

[4] "Report to the Wisconsin legislature on the Regional Electric Transmission System," September 1998, "Wisconsin Interface Reliability Enhancement Study, WIRES Phase II Report," 1999.

[5] All prices presented in Tables 2.1, 2.2 and 2.3 are in 1999 dollars and are load weighted averages.

- Transmission costs, and
- Available transmission capacity.

Once all of these variables have been evaluated, the economically and physically deliverable capacity of each generator can be determined. The generators are then assigned to the market participant that controls their output, either the owner of the plant or the purchaser in a long-term contract. The aggregate market participant shares are then used to calculate the HHI as detailed in Section 3.

2.3 Behavioral Analysis Overview

A structural analysis of market power ends with the calculation of concentration indices. However, there is no causal connection between the level of market concentration and the actual exercise of market power. The behavioral analysis continues from the structural analysis, with a direct examination of market power and the related policy questions, such as:

- What is the potential increase in energy prices resulting from anticipated strategic behavior on behalf of generators?
- Are generation withholding and/or strategic bidding of generators profitable strategies?
- What are the direct rate impacts from strategic behavior?
- How efficient are market power mitigation options in reducing the price and rate impact on electricity consumers?

We performed the behavioral part of the analysis using COMPEL, a TCA software tool for simulating strategic behavior of generation owners in deregulated markets for electricity. Section 4 of this report deals with the methodology, assumptions and results of behavioral analysis of market power.