6d

2.4 Market Power Analysis Methodology: Tables

Table 2.1: Baseline Market Simulation: Average Competitive Market Prices for 2001[a]				
Time Period	WEPCO	WP&L	WPSC	MGE
Ave SuperPeak Price Winter	$78.28	$110.25	$67.28	$114.63
Ave Peak Price Winter	$30.59	$34.40	$28.47	$35.43
Ave OffPeak Price Winter	$14.45	$16.26	$13.63	$17.83
Ave SuperPeak Price Summer	$81.14	$83.29	$68.18	$95.79
Ave Peak Price Summer	$63.95	$57.48	$51.55	$78.62
Ave OffPeak Price Summer	$21.92	$23.17	$18.26	$23.24
Ave SuperPeak Price Shoulder	$33.19	$30.41	$30.29	$42.65
Ave Peak Price Shoulder	$25.20	$23.59	$22.25	$24.93
Ave OffPeak Price Shoulder	$14.32	$15.55	$13.22	$17.29

Table 2.2: Baseline Market Simulation: Average Competitive Market Prices for 2007[a]				
Time Period	WEPCO	WP&L	WPSC	MGE
Ave SuperPeak Price Winter	$39.65	$35.68	$51.04	$68.45
Ave Peak Price Winter	$31.19	$31.93	$23.64	$33.53
Ave OffPeak Price Winter	$15.44	$17.18	$12.76	$17.68
Ave SuperPeak Price Summer	$54.29	$43.84	$47.56	$57.19
Ave Peak Price Summer	$40.81	$37.74	$30.51	$43.92
Ave OffPeak Price Summer	$21.95	$22.27	$18.01	$22.41
Ave SuperPeak Price Shoulder	$34.39	$29.48	$30.34	$35.58
Ave Peak Price Shoulder	$26.57	$24.95	$21.64	$27.27
Ave OffPeak Price Shoulder	$15.07	$17.43	$12.98	$16.46

Table 2.3 Baseline Market Simulations: Price Summary[b]						
	WUMS			MAPP		
Year	Energy Price ($/MWh)	Capacity Price ($/MWh)	Wholesale Price ($/MWh)	Energy Price ($/MWh)	Capacity Price ($/MWh)	Wholesale Price ($/MWh)
2001	$34.75	$0.00	$34.75	$20.03	$2.63	$22.66
2002	$30.07	$0.36	$30.43	$21.20	$2.91	$24.10
2003	$27.77	$0.02	$27.79	$19.30	$6.54	$25.84
2004	$24.59	$1.11	$25.71	$19.82	$5.90	$25.72
2005	$24.67	$1.45	$26.12	$20.18	$5.00	$25.18
2006	$25.30	$0.84	$26.14	$20.39	$1.71	$22.10
2007	$29.55	$1.44	$30.98	$24.16	$6.51	$30.66

Annual Prices are a weighted average by load
Prices are in 1999 $'s

[a]The energy prices reported in Tables 2.1 and Table 2.2 are from a baseline market simulation prepared using a cap of $300/MWh. These prices are used to prepare the structural analysis presented in Section 3.0 of the report. This cap prevents extreme values in a few hours from distorting the average prices used to define product markets.

[b]The energy and capacity prices reported in Table 2.3 are from a baseline market simulation prepared using a cap of $1,000/MWh. These prices are used to calculate the impacts on stakeholders presented in Section 5.0 of the report. This cap allows the simulation to produce prices representative of a market operating without constraints.

3 The Structural Analysis

This section discusses the first phase of this study, the Structural Analysis, in detail. The structural analysis is based on the Competitive Analysis Screen defined in Appendix A of FERC Order 592, the Merger Policy Statement. This screen test is intended for use in evaluating proposed mergers, to determine if markets concentration is or will become significantly concentrated as the result of a merger. If so, a further analysis of the ability of market participants to exercise market power and raise prices in an anticompetitive fashion is warranted.

The structural analysis is applied here in much the same fashion but for a very different purpose. In this case the goal is not to identify the market power implications of a proposed merger but to predict whether the Wisconsin electricity market will be workably competitive after deregulation. It serves as an indication of whether the electricity market in Wisconsin is sufficiently concentrated to warrant concern about the potential exercise of market power by any one participant. This part of the analysis does not elucidate whether or not the potential exists for significant anticompetitive pricing, or what impact such pricing strategies may have on the price of electricity seen by consumers.

3.1 Implementation

Two separate structural analyses are performed in accordance with the FERC Screen. The first is the Economic Capacity (EC) test; the second is the Available Economic Capacity (AEC) test. The difference is the assumption made regarding the obligation of market participants to reserve their least-cost generation to serve native load. The EC test presumes that there is no native load obligation in the destination market or in surrounding markets, such that all market participants are allowed to sell any portion of their power on the wholesale market. The EC test can be interpreted as representing the long-term capacity market.

The AEC test assumes that at least some market participants are required to withhold a portion of their least-cost capacity from the wholesale market to satisfy their native load obligations, and other long-term wholesale contracts. In this analysis it is assumed that 90% of the residential and 60% of the commercial and industrial load in Wisconsin, or about 69% of total load[6], will be served under native load obligations. The remaining load will be served through the wholesale market. This is consistent with experience in areas that have undergone deregulation. Outside of the deregulated study region it is assumed that all native load must be served. The AEC test can be interpreted to reflect the short-term energy market.

The steps required for performing the structural analysis include:

- Definition of geographic and product markets
- Identification of potential suppliers

[6] Sources:

Energy Information Administration, Class of Ownership, Number of Ultimate Customers, Revenue, Sales, and Average Revenue per Kilowatthour by State and Utility 1998, Tables 14 to 16

Public Service Commission of Wisconsin, Strategic Energy Assessment Draft Report, June 2000, Table 2.04,

- Measurement of supplier concentration in the identified markets
- Screening for potential market power

3.1.1 Definition of geographic and product markets

3.1.1.1 Geographic markets

Nodal prices for all load centers in Wisconsin (from GE-MAPS) were analyzed using a clustering technique to identify geographic regions that behave as individual electricity marketplaces. This clustering analysis was performed to identify the optimal grouping of load centers, and the results were compared to groupings based on existing utility service territories. It was found that existing utility service territories provide adequate boundaries for defining markets for electricity in Wisconsin.

3.1.1.2 Product markets

For each of the geographic markets, nine electricity product markets are defined to represent the range of market conditions under which to screen for market power potential. These product markets are identified as off-peak, on-peak and super-peak load conditions during each of the Winter, Summer and Shoulder seasons.

The product markets within each geographic market are identified based on the maximum single-hour load in that geographic region during the summer, winter or shoulder season. First the maximum seasonal single hour electricity demand is identified for the region. The hours of the season are then categorized as follows:

Super Peak =	Load is at least 95% of maximum
Peak =	Load is at least 80% but less than 95% of maximum
Off-Peak =	Load is less than 80% of maximum

3.1.2 identification of potential suppliers

3.1.2.1 Calculation of price threshold for market participation

Once the hours that comprise each product market in a region have been identified, the price associated with the period is the simple average of the market prices for these hours as calculated by the GE-MAPS production cost model. Consistent with the FERC Competitive Screen Analysis, a price threshold for market participation is set at 105% of the resulting price. The average threshold prices for WUMS service territories are shown in Table 3.1. The summer peak and off-peak threshold prices for all regions during the study period are shown in Figures 3.1*a* and 3.1*b*, respectively.

3.1.2.2 Delivered price test for potential suppliers

A generating unit within the geographic market is considered able to participate in a given product market if its marginal cost is less than or equal to the associated price threshold, which is 105% of the destination market price as described above. A generator outside of the destination market is considered able to participate in a given product market if its marginal cost of electricity, adjusted for losses,[7] plus the minimum transmission cost to the destination market,[8] is less than or equal to the price threshold. Any generating company that owns a generating unit that meets either of these standards is considered to be a participant in the product market.

3.1.2.3 Transmission constraints

Transmission capacity into the geographic markets is limited by the physical capacity of the transmission interfaces.[9] For the purposes of this analysis, it is assumed that transfer capacity at each transmission constraint is apportioned *pro-rata* to the generators on the upstream side of the constraint. A generator that requires transfer across more than one constrained interface to reach the destination market will see its deliverable capacity reduced at each successive constraint. Regardless of the availability of low cost power in the surrounding areas, the total capacity that can be imported from all generators outside of the WUMS region cannot exceed the import capacity of the interties. Generating capacity meeting the price threshold within the geographic market, which is not restricted by transmission constraints, is considered to be 100% available in this analysis.

The total power available in a product market in any geographic region is a function of market price, the price at which generators can deliver power to the market, transmission capacity into the geographic market and, in the case of the AEC test, native load obligations of the potentially participating entities.

3.1.3 Calculation of market concentration.

Market concentration is calculated according to the Department of Justice/Federal Trade Commission Merger Guidelines, which use the Herfindahl-Hirschman Index (HHI). The HHI is the sum of the squared market shares (percentages) of each of the market participants:

[7] Losses are calculated as 2.5% per wheel for the most cost-efficient transmission path.
[8] Transmission charges based on OATT and OASIS transmission rate postings.
[9] ATC and TTC for interregional power transfers based on NERC 1999 Reliability Assessments; Transfer capabilities within WUMS taken from "Report to the Wisconsin legislature on the Regional Electric Transmission System; Wisconsin Interface Reliability Enhancement Study", WIRES Phase II Report, 1999.

$$HHI = \sum_{i=1}^{N}\left(100 * \frac{P_i}{\sum P}\right)^2$$

where:

N = Number of market participants

P_i = Total capacity of participant i which meets the price threshold and is deliverable to the destination market

ΣP = Total capacity of all participants which meets the price threshold and is deliverable to the destination market

Table 3.2*a* and 3.2*b* show the average HHI for WUMS service areas for all market periods for the EC and AEC cases, respectively. (HHI values for individual service territories for all product markets are provided in the Appendix.) Figures 3.2*a* and 3.2*b* show respectively the summer peak and summer off-peak HHI for all WUMS regions for all study years based on the EC test. Figures 3.3*a* and 3.3*b* show respectively the summer peak and summer off-peak HHI for all WUMS regions for all study years based on the AEC test. Note that in these figures the year 2004 is shown both with and without the expected additional import capability from MAPP to highlight the impact of this project on market concentration.

As a screening test, the DOJ interprets HHI values as follows:

HHI < 1000	Unconcentrated Market
1000 <= HHI < 1800	Moderately Concentrated Market
HHI >= 1800	Highly Concentrated Market

3.2 Structural Analysis Results and Conclusions

This analysis suggests that:

- All of the product and geographic markets within WUMS are "highly concentrated" given existing transmission limitations

Before the assumed transmission expansion in 2004, HHI values calculated under the Economic Capacity test range between 1800 and 3000 for all geographic and product markets in WUMS while HHI values under the Available Economic Capacity test can be as high as 3600.

- Expanding WUMS simultaneous import capacity to 3000 MW ameliorates market concentration somewhat, but WUMS product and geographic markets remain either "concentrated" or "highly concentrated"

After the assumed increase in import capacity in 2004, HHI values based on the EC test decrease to the 1500-1800 range while HHI values based on the AEC test are in the1700-2000 range. However, some geographic and product markets remain highly concentrated even with the additional import capacity. For example, the HHI of the winter off-peak market in the WEPCO region is around 2250 based on the EC test and 2550 based on the AEC test.

- In all cases, Wisconsin Electric Power (WEPCO) has the largest share of destination markets within WUMS.

WEPCO's share of deliverable capacity in all geographic and product markets ranges between 30% and 60%. Tables 3.4a and 3.4b show the average share held by WEPCO in WUMS regions for each market period, under the EC and AEC tests, respectively.

- The NSP/Wisconsin service territory has significantly lower market concentrations under both the EC and AEC analysis. The NSP region has HHI values between 800 and 1250 for all product markets. NSP has the largest market share in this region.

It is emphasized that this structural analysis only provides an indication of market concentration; it does not provide a direct indication of the ability of any market participant to impact prices through the exercise of market power. The direct analysis of market power and the resulting price impacts are addressed in the behavioral analysis section.

3.3 The Structural Analysis: Tables

Table 3.1: Average Threshold Price for WUMS Service Areas ($/MW)

	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	$ 75.62	$ 30.86	$ 14.90	$ 78.07	$ 59.97	$ 20.56	$ 33.03	$ 23.87	$ 15.01
2002	$ 37.56	$ 24.00	$ 14.36	$ 87.94	$ 45.21	$ 18.25	$ 30.59	$ 22.77	$ 14.51
2003	$ 44.96	$ 25.14	$ 14.41	$ 65.94	$ 43.25	$ 18.19	$ 27.43	$ 23.64	$ 14.90
2004	$ 53.52	$ 25.62	$ 14.40	$ 56.07	$ 33.97	$ 19.82	$ 33.89	$ 24.17	$ 15.64
2005	$ 32.27	$ 24.21	$ 14.59	$ 48.41	$ 33.55	$ 19.78	$ 28.40	$ 22.43	$ 14.97
2006	$ 43.85	$ 28.56	$ 15.13	$ 52.20	$ 36.77	$ 19.37	$ 30.15	$ 23.49	$ 14.90
2007	$ 44.27	$ 29.03	$ 15.12	$ 56.43	$ 37.38	$ 20.56	$ 31.26	$ 24.75	$ 15.22

Table 3.2*a*: Average HHI Values for WUMS Service Areas (EC Test)									
	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,107	2,106	2,077	2,160	2,169	2,365	2,081	2,228	2,056
2002	2,086	2,365	2,020	2,146	2,123	2,342	2,188	2,367	2,010
2003	2,001	2,076	2,029	2,065	2,021	2,083	1,961	1,987	1,856
2004	1,741	1,848	1,626	1,785	1,685	1,864	1,727	1,780	1,786
2005	1,737	1,864	1,648	1,752	1,688	1,850	1,719	1,803	1,617
2006	1,708	1,792	1,624	1,744	1,702	1,845	1,694	1,779	1,543
2007	1,698	1,780	1,550	1,773	1,690	1,831	1,672	1,773	1,642

Table 3.2*b*: Average HHI Values for WUMS Service Areas (AEC Test)									
	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	2,262	2,299	2,411	2,315	2,326	2,662	2,265	2,456	2,403
2002	2,270	2,617	2,375	2,299	2,288	2,692	2,394	2,638	2,362
2003	2,147	2,273	2,371	2,203	2,167	2,382	2,131	2,180	2,166
2004	1,831	1,983	1,784	1,876	1,788	2,025	1,833	1,911	1,970
2005	1,853	2,005	1,811	1,844	1,793	2,011	1,836	1,948	1,776
2006	1,809	1,921	1,780	1,836	1,806	2,007	1,805	1,916	1,694
2007	1,796	1,907	1,693	1,865	1,791	1,990	1,781	1,905	1,803

Table 3.3*a*: Average WEPCO Market Share in WUMS Service Areas (EC Test)									
	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	38%	39%	39%	39%	39%	43%	39%	42%	39%
2002	38%	43%	37%	38%	38%	43%	41%	43%	37%
2003	35%	39%	38%	35%	35%	39%	37%	38%	35%
2004	31%	37%	32%	33%	33%	37%	34%	36%	37%
2005	34%	38%	33%	32%	33%	37%	35%	37%	33%
2006	33%	36%	33%	32%	33%	37%	34%	37%	32%
2007	32%	36%	31%	33%	32%	37%	34%	36%	33%

Table 3.3b: Average WEPCO Market Share in WUMS Service Areas (AEC Test)									
	Winter			Summer			Shoulder		
Year	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak	Super-Peak	Peak	Off-Peak
2001	40%	41%	43%	40%	40%	46%	41%	44%	43%
2002	40%	45%	41%	39%	40%	46%	43%	46%	41%
2003	37%	41%	42%	37%	36%	42%	39%	40%	38%
2004	32%	39%	35%	34%	34%	39%	35%	38%	39%
2005	35%	39%	36%	33%	34%	39%	36%	39%	35%
2006	34%	38%	35%	33%	34%	39%	35%	38%	34%
2007	33%	38%	33%	34%	34%	39%	35%	38%	35%

3.4 The Structural Analysis: Figures

Figure 3.1*a*: Summer Peak Price in WUMS Regions

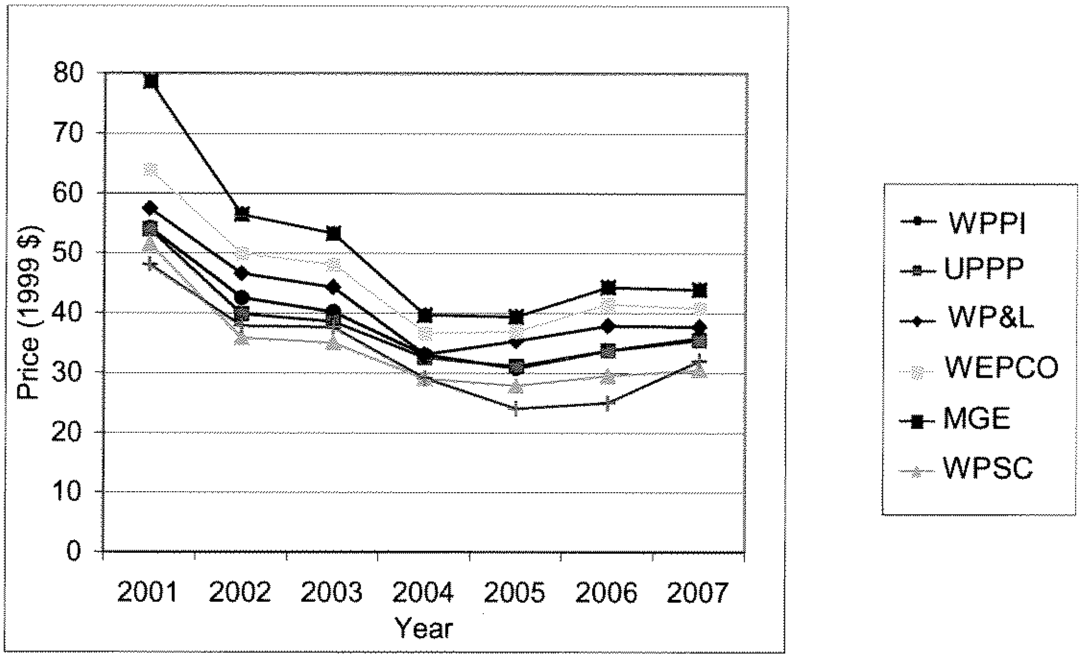

Figure 3.1*b*: Summer Off-Peak Price in WUMS Regions

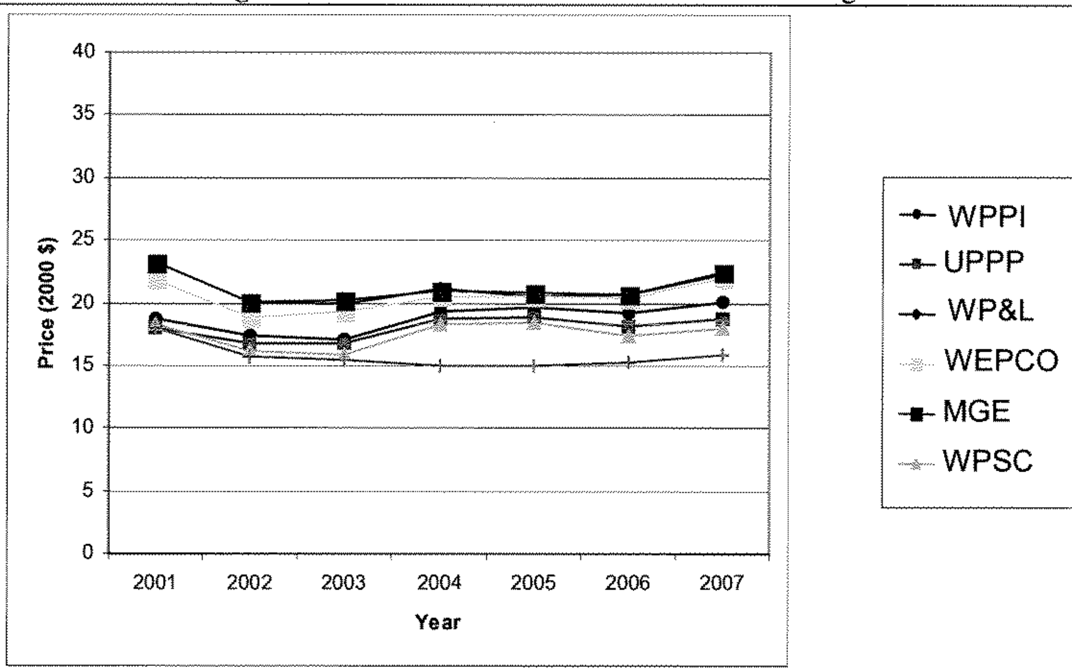

Figure 3.2*a*: Summer Peak HHI by Service Territory
Economic Capacity Test

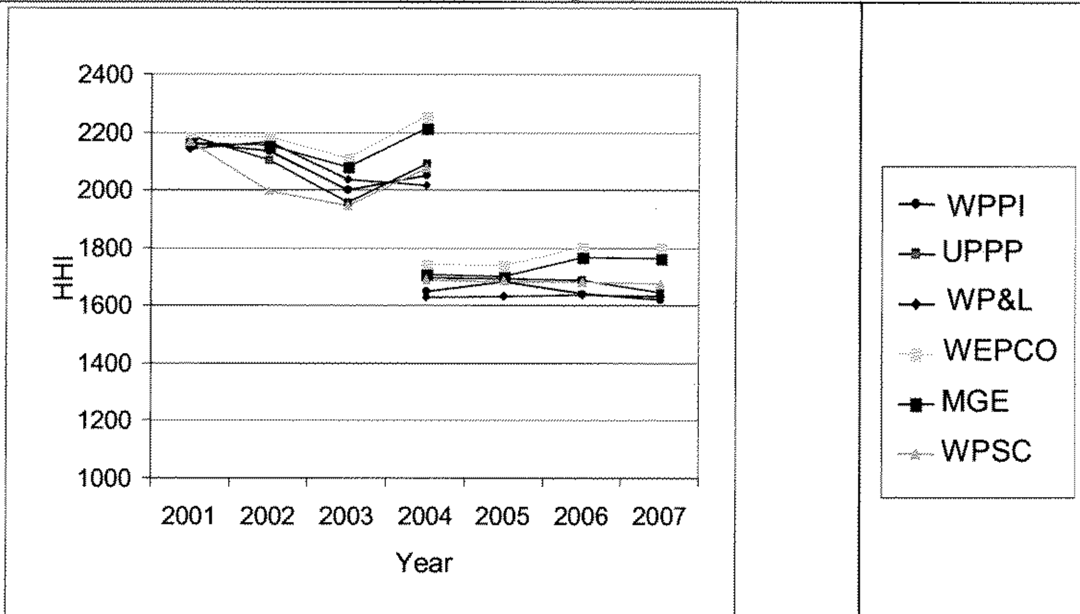

Figure 3.2*b*: Summer Off-Peak HHI by Service Territory
Economic Capacity Test

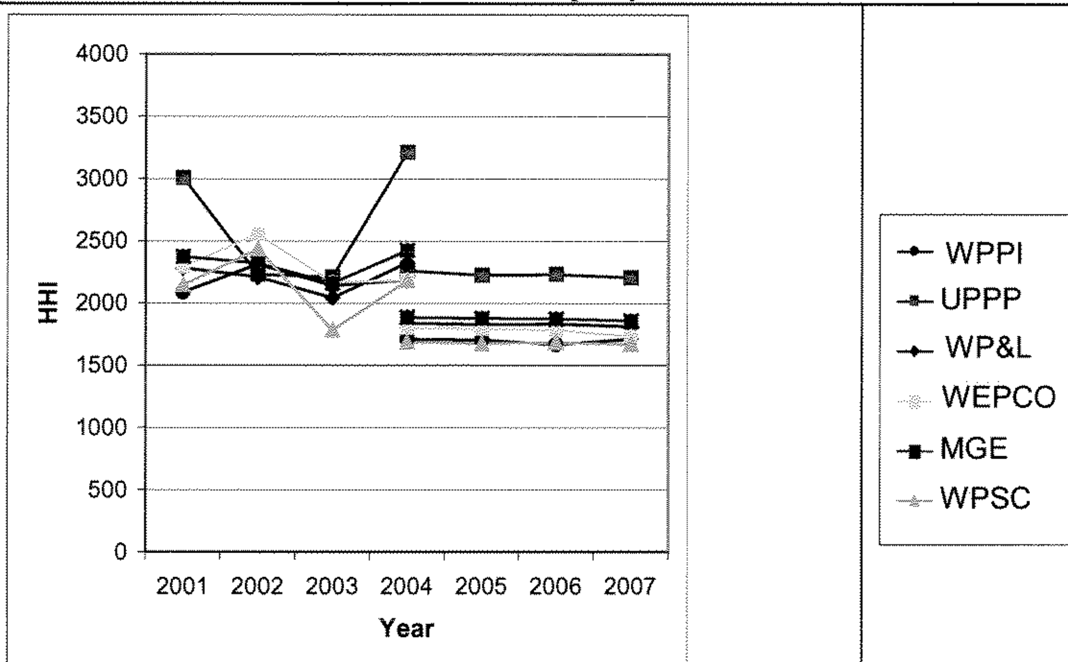

Figure 3.3*a*: Summer Peak HHI by Service Territory
Available Economic Capacity Test

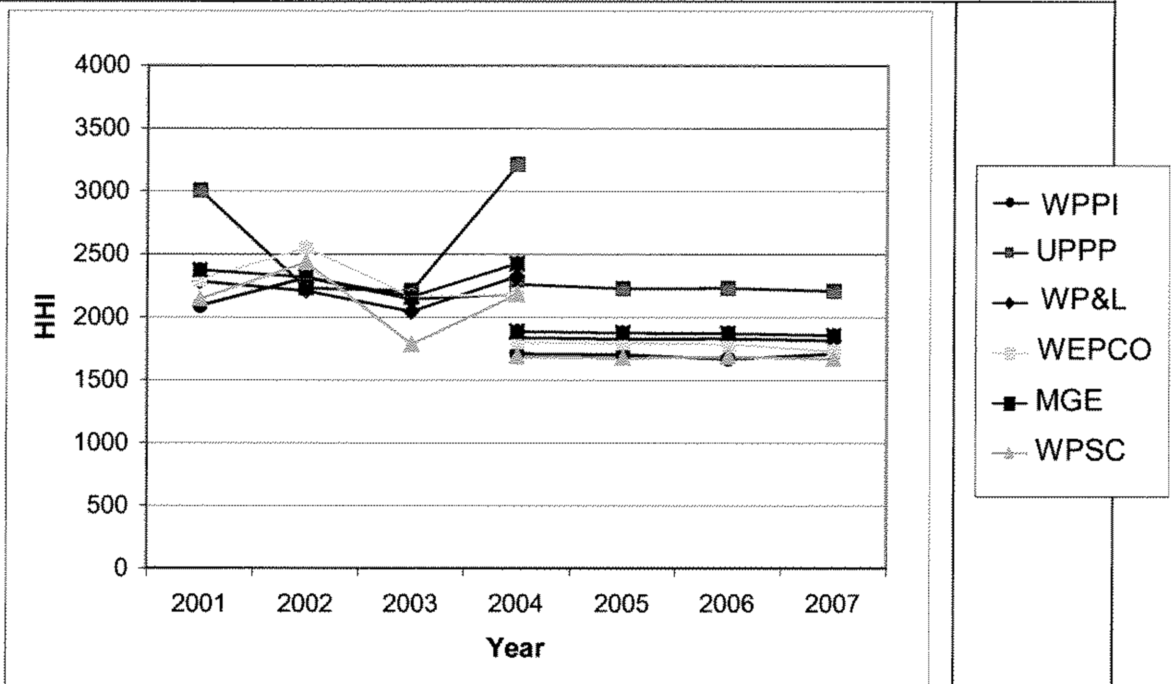

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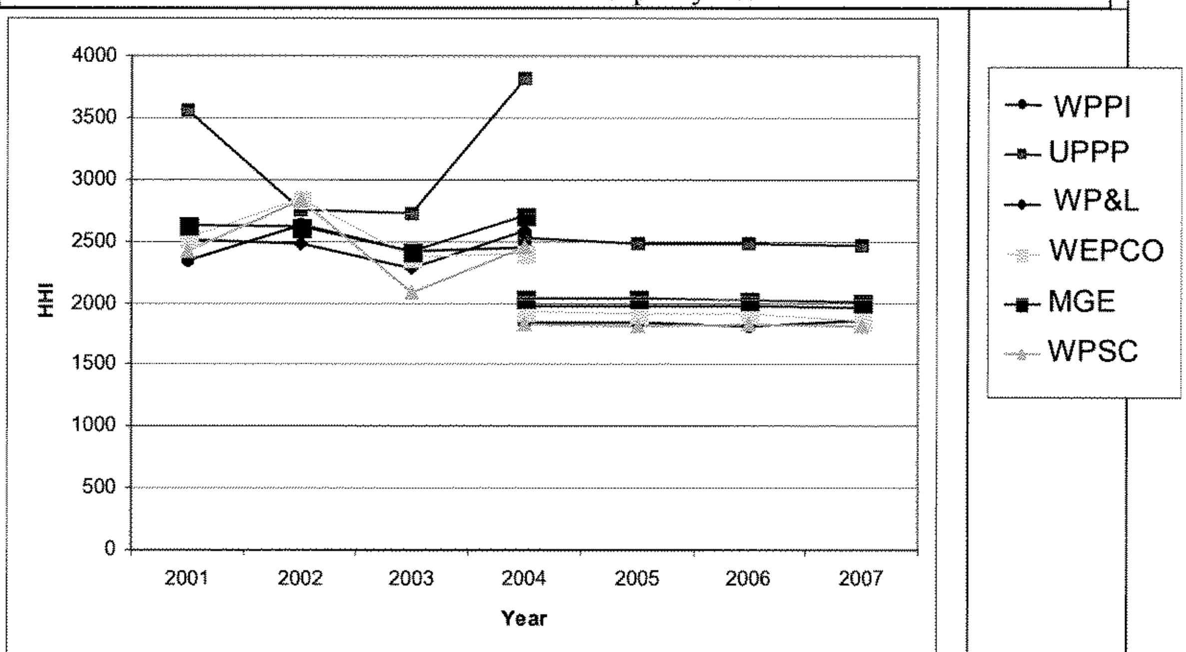
Figure 3.3*b*: Summer Off-Peak HHI by Service Territory
Available Economic Capacity Test



4 The Behavioral Analysis

This section presents the details of the modeling and results of the behavioral analysis.

4.1 Preamble

Recall that market power is the ability of a firm to profitably raise price for a significant amount of time. For a product such as electricity, which faces diurnally and seasonally fluctuating demand, the exercise of market power does not need to occur only during contiguous time periods to raise competitive concerns. Such concerns are also raised if a firm can exercise market power on a recurring basis during similar time periods (or load levels) such as daily peak, shoulder and off-peak periods, and seasonal peak, shoulder and off-peak. A firm is considered to have market power if it is successful in raising the price received for a product, where success is defined in terms of increased profit. Therefore, a behavioral analysis of market power directly examines whether a market participant can profitably maintain a price increase for a sustained, or recurring, period of time.

A behavioral analysis is one that does not assume that all market participants behave in a strictly competitive manner. Assuming that participants behave competitively implies that they do not attempt to manipulate the price they receive for their product. Competitive players *assume* that they cannot influence market price of electricity to their advantage. They offer generation to the market at cost and the market operates at perfectly competitive prices. In contrast, strategic market participants believe that they can affect price through unilateral or joint action with one or more participant. Two types of actions these participants may pursue – referred to as strategic behavior – are direct price manipulation by strategically bidding price above the competitive level, and indirect price manipulation achieved by withholding capacity or restricting the quantity produced.

This part of the study explores, using a specialized simulation model (COMPEL), the feasibility (and profitability for market participants) of such strategic behavior and its impact on both electricity consumers and producers. COMPEL is a model developed by TCA to simulate the strategic behavior of generating companies in deregulated electricity markets.

4.2 Market Structure

As is the case with the structural analysis, one of the critical elements of the behavioral analysis is to identify the relevant geographic and product markets to be modeled with the behavioral simulation model.

4.2.1 Geographical scope of behavioral analysis

Based on the analysis of transmission constraints and congestion patterns available through the baseline market simulation described in Section 2 above, the focus ids placed on two different geographical markets – WUMS and on a combination of the MAPP+WUMS market. Recall that all but one of the large utilities in Wisconsin serve customers located predominantly in WUMS, a subregion of MAIN. The NSPW service territory is located in MAPP. Therefore analysis of both markets is essential for this study.

Simulation of the WUMS market explores the level of market power available to generation owners whose generating facilities are physically located in WUMS and addresses the impact of such market power on consumers also located in WUMS. Indeed, as discussed earlier, the overall transfer capability into WUMS presently does not exceed 2,000 MW and even with the additional transmission line from MAPP to MAIN, if built in 2004, would not exceed 3,000 MW. The level of potential competition to sell power into WUMS across these interfaces is very significant. Therefore, it is safe to assume that generators outside of WUMS are unlikely to be able to exercise any market power in WUMS.

Simulation of the MAPP+WUMS market explores the level of market power available to generation owners whose generating facilities are physically located in the MAPP and WUMS markets and addresses the impact of such market power on consumers located in MAPP (but not in WUMS). Indeed, analysis of transmission constraints and congestion patterns indicate that MAPP is a largely homogeneous electricity market such that the behavioral element of the analysis could ignore transmission constraints both in MAPP as well as leading in and out of MAPP. Moreover, while wheeling power from MAPP to WUMS is significantly constrained, the reverse power flow (from WUMS to MAPP) is much less limited. Therefore, generators located in WUMS could at most times serve the MAPP market after satisfying their native load commitments. However, price results of modeling the MAPP+WUMS market are applicable to the MAPP market only and are not applicable to the WUMS market.

4.2.2 Electricity markets and wholesale price of electricity

The objective of the behavioral analysis is to assess the impact of market power on wholesale prices of electricity. In general, the wholesale price consists of two major components – 1) energy price and 2) capacity and reserves price. It is important to note that the study makes no assessment of the market power potential for the capacity market or for markets for various ancillary services necessary for the robust operation of electricity markets. While the importance of the capacity and ancillary service markets is acknowledged and the possibility for the market power to "propagate" from one type of the market into another is recognized, the study includes no assessment of those markets at this time as it is beyond the scope of the analysis. Therefore, the study makes a conservative assumption of zero market power impact on the capacity and reserves component of the wholesale price.

4.2.3 Demand

Following is a brief description of the COMPEL demand assumptions in terms of the load shape and demand responsiveness to price.

4.2.3.1 Load shape

In defining the hourly load profile in each market simulated by COMPEL the study uses exactly the same data as the baseline market simulation performed with the GE MAPS model as described earlier in the report. In particular, the aggregated hourly load in WUMS is the sum of all load busses in WUMS. The aggregated hourly load in the MAPP+WUMS market is the sum of all load busses in WUMS and in MAPP. Similarly to the GE MAPS modeling, COMPEL simulates hourly chronological load in each year of the analysis (2001 through 2007).

4.2.3.2 Elasticity

In modeling strategic behavior, it is assumed that consumers are capable of responding to price increases by reducing the level of electricity consumption. This phenomenon is reflected in the model parameter known as the price elasticity of demand. Although different categories of consumers have different abilities to change their demand in response to changing prices, the study focuses on those whose response could be the most significant: industrial consumers. For those customers and for the entire market in the COMPEL simulations, the price elasticity of demand of -0.2 is assumed, i.e., a 1% increase in electricity prices causes a 0.2% reduction in electricity consumption.[10]

4.2.4 Supply

In modeling each market the study distinguishes between two groups of suppliers -- strategic suppliers and a competitive fringe.

4.2.4.1 Strategic suppliers

Strategic suppliers are generation owners who can potentially participate in strategic behavior. In case of the WUMS market, the study assumes that strategic suppliers are all companies that own generating capacity physically located in WUMS. Of those the most important strategic suppliers are:

- Wisconsin Electric (WEPCO);
- Wisconsin Power & Light (WP&L);
- Wisconsin Public Service (WPS); and
- Madison Gas and Electric (MGE).

As indicated in the structural analysis section above, the MAPP+WUMS market is much more competitive. Over one hundred of strategic suppliers are simulated in that market, although most of them own a relatively small portion of generation in that area. In addition to the above listed WUMS generators, major strategic suppliers in the MAPP+WUMS market include:

- Northern States Power (NSP);
- Mid American energy Company (MECO);
- Basin Electric Power cooperative (BEPC);
- Nebraska Public Power (NPPD);
- Omaha Public Power (OPPD);
- Alliant West (ALTW);
- Western Area Power Administration (WAPA);

[10] One can only guess the level of industrial price elasticity of demand in Wisconsin under the deregulated market conditions. For comparison, a survey of industrial sector price elasticity quoted in Kenneth C. Hoffman and David O. Wood (1976), "Energy System Modeling and Forecasting," Annual Review of Energy, Vol. 1, 424-453 gives the range between –0.11 and –0.22.

- IES Industries/Iowa (IESC);
- Minnesota Power (MNPO).

Each generating unit owned by a strategic supplier is explicitly represented in the COMPEL model. This representation is based on the same data about this unit as in the baseline simulation using GE MAPS. In particular, in COMPEL, each unit is characterized by the same capacity, average heat rate, fuel cost, non-fuel variable O&M cost, forced and planned outage rates and environmental cost adders. On the other hand, COMPEL's dispatch and commitment algorithms lack certain technical details present in the GE MAPS algorithms which make such information as heat rate curves, quick start capability, and minimum up- and down- time unusable in COMPEL.

The study makes following assumptions with respect to the ownership of generating units:

- Complete functional unbundling of existing electric utilities such that no generating company owns or has control of transmission and distribution capacities (no vertical market power); and
- As a result of such functional unbundling, all generating assets owned by electric utility is owned by a single generating company. For example, generating units owned by Wisconsin Electric in our analysis are owned by the WEPCO generating company.

4.2.4.2 Competitive fringe

As explained earlier, the study assumes that suppliers located outside of each modeled market are unlikely to behave strategically given the high level of competition to access limited transfer capabilities of transmission capacities leading into each market. For practical purposes, supplies from outside of the market areas, referred to as the competitive fringe, are represented in the form of supply curves. These supply curves are constructed on a monthly basis to reflect the monthly changing patterns in fuel costs. In constructing these supply curves the study relies directly on generation costs of each unit located outside of the market in question, transmission charges across all control areas, and transmission limitations as specified in the TCA database (see Appendix A) and as used in the structural analysis portion of the study.

4.3 Strategic Behavior

As introduced above, an approach for identifying market power that is more direct than simple HHI calculations is one that is based upon game-theoretical analysis of strategic behavior by generating firms and/or retail suppliers in various types of power markets, under different market structures and modeling assumptions. A crucial difference between the various game-theoretical modeling approaches is the economic model used to characterize interactions between competing generating firms. These models usually range from intense Bertrand-type competition to the more commonly used Cournot-type competition. The assumptions of the Bertrand-type competition result in a so-called perfectly competitive outcome of market interactions resulting in electricity prices equal to short-run marginal costs of generating power. The assumptions of the Cournot-type competition usually result in prices exceeding short-run marginal costs due to some (often significant) withholding of capacity from the market by generation owners.

However, neither of these sets of assumptions appears realistic enough to capture essential elements of electricity markets. Indeed, in order to achieve a perfectly competitive outcome of the Bertrand-type competition, one would have to assume that in each hour generators first use **all** their capacity to generate electricity and then compete for revenues by setting a price which is low enough to ensure that all generated power is sold but high enough to recover all generation costs incurred. No real electricity market operates this way, largely because electricity cannot be stored in large quantities. Given this sequence of actions, generators are not pressed to set prices as low as the marginal cost of producing power and thus unlikely to achieve the Bertrand-type equilibrium in the market.

The Cournot-type competition is at another extreme. On the one hand, under Cournot-type competition, generators would commit to production only after establishing price requirements. On the other hand, generators are assumed to be able to have a perfectly flexible real-time control of the level of generation they can offer to the market. By using this control, generators can instantaneously change their commitments and influence market-clearing prices. In doing so, generators can maximize their profits through the trade-off between reduced market shares and increased prices. However, in reality, generators neither have the full real-time control of their units, nor the ability to perfectly maximize their profit due to the lack of precise information required to reach such an equilibrium on an hourly basis.

The concept of supply function equilibrium (SFE) has recently emerged as a promising model of interaction in deregulated power markets and as one that lies between these two extremes. SFE recognizes the fact that, unlike the case of the Bertrand-type competition, generators price their output prior to actually producing it. It also acknowledges the presence of the open-loop control in power systems and that the generators are limited in their ability to instantaneously add or withhold capacity to, and from, the market. Under SFE-type interactions, generators are assumed to make commitment decisions day-ahead and then set prices for committed generating capacities that they will not change during the day.[11]

The SFE concept was originally developed by Klemperer and Meyer (1989) as a way of modeling how competitors could achieve profit-maximizing equilibria in the marketplace under conditions of uncertain demand. The SFE approach was then adopted by Green and Newbery (1992) as a model for strategic bidding in a competitive spot market. The Green-Newbery adaptation of the SFE is non-trivial; because demand uncertainty in the Klemperer-Meyer model is not equivalent to the largely predictable, though permanently fluctuating, demand for electricity. Nevertheless, Green and Newbery have shown that under certain assumptions, the Klemperer-Meyer equations can be used to compute the Nash SFE in competitive spot markets. Hobbs *et al.* (1999) used the SFE approach in their simulation of strategic behavior in power networks. Rudkevich *et al.* (1998) contributed to the SFE theory by deriving a closed-form solution to the Klemperer-Meyer equation in a special case of zero price elasticity of demand and by generalizing the model for non-convex step-wise marginal cost curves representing discrete generating units operating in the market. Rudkevich and Duckworth (1998), Rudkevich (1998) applied the SFE concept to modeling actual electric systems in the U.S.

[11] In reality, in many markets generators are allowed to make intra-day changes to their bid prices. However, it would be extremely difficult for them to adjust bids in a rational way due to the lack of the needed real-time information.

The SFE theory and algorithms were further developed at TCA in 1999-2000 thanks to the partial financial support from the National Science Foundation (SBIR Grant DMI 9996157). This development culminated in creation of COMPEL, a software tool for simulating strategic behavior in deregulated markets for electricity based on the SFE methodology.

4.3.1 Strategic bidding

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. Under this strategy the benefit of "bidding up" the market-clearing price typically outweighs the risk of being undercut by competitors. An illustrative example of strategic bidding by two owners each owning three generating units each is presented in Appendix C. As shown in this example, 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 (in this example) at no risk of being undercut by competitors. The strategic bidding algorithm used in the COMPEL model is based on the Supply Function Equilibrium (SFE) game-theoretical approach.

4.3.2 Capacity withholding

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. Firms that attempt this strategy must ensure that the foregone revenues from withholding some of their capacity are more than offset by the higher unit prices paid to their remaining capacity dispatched. Unlike strategic bidding, capacity withholding changes the merit order in which units are dispatched. The capacity withholding algorithm is another important feature of COMPEL.

4.3.3 Cumulative effect and COMPEL algorithms

COMPEL is capable of analyzing the effect of market power resulting from a combination of these two kinds of strategic behavior through the simulation of a two-stage bidding and commitment game "played" by generation owners. These two strategies are interdependent because strategic bids developed by generating companies depend on the set of generating units committed to the market on a given day. On the other hand, the profitability of each commitment decision depends on bids. It is important to note that the two-stage approach to strategic behavior implemented in COMPEL, in fact, combines the SFE and Cournot approach in which intra-day profit-maximizing behavior is captured by the SFE methodology and daily profit maximization is driven by the Cournot-type interactions. Indeed, daily interaction involve withholding of capacity but instead of maximizing instantaneous profit, as is normally the case with Cournot-type interaction, generation owners maximize daily profit.

In conducting market simulations COMPEL:

- Generates equilibrium unit commitment strategies;
- Generates equilibrium bidding strategies;

- Solves a two-stage game-theoretical problem in which unit commitment decisions and bidding strategies are inter-dependent;
- Computes a system dispatch subject to generated unit commitment decisions and bidding strategies; and
- Calculates a wide variety of technical and economic characteristics such as hourly generation levels, costs, revenues, profit margins, spot and average prices, profitability indices and market power indicators. These characteristics are generated at the market-wide, firm and generating unit levels and on an hourly, daily, monthly and annual basis.

4.3.4 Price-Cost Margin Index (PCMI) and other indicators of market power

A behavioral analysis measures the actual impact of the exercise of market power by identifying the extent to which prices exceed levels for a perfectly competitive market. A standard measure of this impact that we will use is the Price Cost Margin Index (PCMI), defined as:

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

In addition, the study assesses the impact of strategic behavior on the system-wide generation output and on the system-wide costs and revenues. To assess the impact of market power on large generation owners relative variations of a firm's generation output, cost, revenue and profit margin are reported.

This study considers the 5% threshold in PCMI as an indicator of market power. Thus, PCMI below the 5% level indicates the absence of market power. PCMI above 5% is indicative of the market power threat.

4.4 Market Power in Wisconsin Regional Markets: Summary and Results

4.4.1 Price and PCMI analysis

- The simulation modeling of strategic behavior performed using COMPEL indicates a very significant level of market power in the WUMS market.

Monthly levels of PCMI in energy prices under the cumulative effect of strategic bidding and capacity withholding for the period 2001 through 2007 are presented in Figure 4.1. As shown in that figure, in WUMS, during 2001, PCMI ranges between 50% and almost 80%.

High levels of PCMI are maintained through the first quarter of 2003 and then decline to the range between 20% and 40% in the rest of that year. Such a decline is caused by a massive amount of new entry of generation in WUMS.

From 2004 onward, PCMI oscillates between 10% and 30%. This further reduction in PCMI is caused by the assumed transmission expansion that increases transfer capability into WUMS to 3000 MW.

However, despite the substantial decline in PCMI levels caused by these two kinds of system expansion, PCMI remains well above the 5% threshold level. Therefore, the price impact of market power remains significantly high during the entire study period 2001 - 2007.

- The simulation modeling of strategic behavior performed using COMPEL indicates a relatively moderate level of market power in the MAPP market.

As shown on Figure 4.1, the PCMI in MAPP ranges between 7% and 10% throughout the entire study period.

Table 4.1 provides details on the impact of market power on total wholesale prices. As shown on that table, the PCMI for total wholesale prices are slightly lower than PCMI for energy prices but still are significantly above the threshold level for WUMS and are close to the threshold level for MAPP.

Detailed PCMI numerical data underlying Figure 4.1 could be found in Appendix D to this report.

4.4.2 System-wide Impact of market power

That section focuses on the system-wide impact of market power in WUMS. Given the modest level of market power in the MAPP market as seen by the low PCMI levels, system-wide deviations from perfectly competitive indicators are not significant and are therefore omitted.

- Due to the price increases caused by strategic behavior of generators, consumers would use less electricity, generators would incur less generating costs but at the same time generators will receive revenues substantially higher than under the perfectly competitive outcome (at the expense of electricity consumers).

Figure 4.2 shows the system-wide loss in generation caused by the assumed consumers responsiveness to price increase resulting from market power. In 2001 the system-wide loss of generation is about 5%. By 2007, generation loss is less significant, close to 2%.

Similarly, Figure 4.3 presents reduction in system-wide generation costs (6% reduction in 2001 and 1% reduction in 2007).

As shown on Figure 4.4, in 2001, generators' revenues exceed perfectly competitive level by more than 50%. In 2007, increase in revenues is smaller but still significant, 17%.

The numerical data underlying Figures 4.2 – 4.4 are summarized in Table 4.2.

4.4.3 Impact of market power on major generation owners

In this section we assess the impact of market power on major generation owners in WUMS: WEPCO, WP&L, WPS and MGE which is summarized in Table 4.3.

- The impact of market power on generation owners substantially varies by company;
- WEPCO appears to be the only generation owner substantially engaged into capacity withholding strategy.

WEPCO's loss in generation (and in sales) compared to the perfectly competitive market outcome ranges between 23% in 2003 and 15% in 2007. In contrast, other major generation owners lose much less in sales and in some cases even gain additional sales volumes to compensate for withholding of output by WEPCO.

Strategic behavior appears profitable for all major generating companies. However, WEPCO's relative profit increase is much less dramatic than for other companies which receive a "free ride" on WEPCO's capacity withholding strategy.

4.5 Market Power Mitigation Scenarios

Given the significant level of market power in the WUMS market, it is unreasonable to expect that a workably competitive electricity market will emerge in that area without implementation of specific market power mitigation measures. In addition to capacity expansion factors (entry of new generation and transmission) that clearly help to mitigate market power, two additional market mitigation measures are studied

- divestiture of generating assets and
- fixed price contracts.

This section provides the description of these measures; assesses the efficacy of each mitigation option on market power in WUMS and of a combination of those options. Finally, the impact of the mitigation proposal on market power in the MAPP region is studied.

4.5.1 Divestiture Case

Significant market concentration in WUMS identified in the Structural Analysis part of this study is one of the key factors behind the high level of market power in that region. Reducing market concentration could help to mitigate market power. Such a reduction in market concentration could be achieved through the divestiture of generating assets. The primary candidate for such divestiture is WEPCO that is the dominant player in the WUMS market as demonstrated through both the structural ans behavioral analysis. Thus, the Divestiture Case assumes that WEPCO's generating units are transferred to three fully independent generating companies, WEPCO-1, WEPCO-2 and WEPCO-3. Distribution of generating units among such companies is presented in Table 4.4.

It is important to note that this divestiture scenario addresses only market power issues and that such a particular distribution of assets may be undesirable or even infeasible. However, it is clear that a similar but feasible divestiture with minor reshuffling of generating units among owners would result in a similar market power outcome. The rationale behind the proposed distribution of ownership is as follows:

- Nuclear units should be owned by a separate entity due to the specificity of the nuclear operations and regulatory issues;
- All units of one power plant should go to one owner;
- Generating companies that get thermal units should receive similar portfolios of such units;
- The size of generating companies resulting from such a divestiture should be comparable to the size of other major generating companies in WUMS such as WP&L, WPS and MGE.

4.5.2 Contracts

Another factor that could potentially mitigate market power is to cover a significant portion of generating capacity owned by a strategic supplier with fixed price contracts. The importance and efficacy of such contracts in mitigating market power was studied by Green.[12] The presence of fixed price contracts reduces the incentive for the generating company to bid strategically as well as to withhold capacity. It is important to note that in order to mitigate market power, contract prices should **not** be indexed or in any way tied to spot market prices, otherwise they would not be fixed price contracts and their ability to reduce incentive to behave strategically will be compromised. Simulations performed in this study assume that all contracts are priced at marginal cost of generation (or at perfectly competitive price).

Determination of the level of contract cover for each company is based on the following logic:

- First, it is assumed that distribution companies in Wisconsin will acquire generation from the wholesale market to serve their retail load. If full retail competition is introduced it is assumed they will acquire generation to serve customers who remain on their standard offer service

- Second, it is assumed that in the process of transferring generating assets to independent generating companies, the latter could be required to enter contracts with distribution utilities to provide generation at a fixed price to meet the load of retail customers served by the utility.

- Third, it is assumed that the utilities would acquire the bulk of the generation required to serve their current level of retail load under fixed priced contracts. Alternatively, under retail competition, it is assumed that the portion of existing customers that will remain on standard offer services during a several year transitional period will be as follows:

Residential	90%
Commercial	60%
Industrial	60%

[12] Green, Richard J. (1997), "The Electricity Contract Market." Paper presented at the Second Annual Research Conference of the Program on Workable Energy Regulation (POWER), Berkley, CA, March 14, 1997.

Our assumptions on the percent of customers that would likely remain on standard offer service is based on a relatively limited history of competition in electricity markets in the U.S. Indeed, as of October 2000 only six states had over one year of actual experience with retail competition in electric markets – California, Massachusetts, New Jersey, New York, Rhode Island and Pennsylvania. In each of those states, customers who did not actively switch to a third-party supplier as of the date the market opened were automatically placed on the "standard offer" generation service provided by their incumbent utility. The level of customer switching in these markets has varied from state to state, from utility to utility within those states, and from customer class to customer class within those utilities. As one might expect, the level of switching has varied by market segment, with larger customers in the industrial and commercial sectors being the most responsive and residential customers the least responsive.

Pennsylvania has experienced the greatest level of customer shopping to date. The Pennsylvania Office of Consumer Advocate reports the cumulative levels of switching by utility and customer class quarterly.[13] A review of those statistics indicates that the vast majority of switching within each class occurred within the first three months of market opening. After the first three months the cumulative level of switching stabilized. Based on the cumulative statistics on customer load switching in Pennsylvania by utility and class as of October 1, 2000, we assumed that the level of load switching in Wisconsin would stabilize at 40 percent of commercial and industrial load and 10 percent of residential load. Thus, we assumed that the balance of load in those classes would remain on some form of standard offer service whose price would be regulated by the Wisconsin Public Service Commission.

Using these assumptions and historical sales statistics of utilities in Wisconsin, we developed the following levels of contract cover for major generating companies specified in Table 4.5.

4.5.3 Divestiture & Contracts

This scenario is a combination of the above two market power mitigation options – divestiture of WEPCO generating units and implementation of fixed price contracts. In this case it is assumed that all three companies which end up owning WEPCO units will have contract cover proportional to their respective levels of generating capacity as specified in Table 4.6.

4.5.4 Mitigation options: summary and conclusions

- Between 2001 and 2003, no single mitigation option is sufficient for bringing the energy price impact of market power to the level below the 5% threshold.

The results of simulation analysis of market power mitigation options are graphically presented on Figure 4.5 for WUMS market and on Figure 4.6 for the MAPP market. As shown on Figure 4.5, PCMI under the Contracts scenario ranges between 10% and 28% in that period. WEPCO divestiture appears more efficient and brings PCMI into the range between 3.5% and 7.8%.

- From 2004 onward, when all assumed system expansion options are in place, WEPCO divestiture appears sufficient for maintaining PCMI under the 5% level almost all the time.

[13] *PA Electric Shopping Statistics.* Sites.state.pa.us/PA_Exec/attorney_General/Consumer_Advocate

- In contrast, under the Contracts scenario, PCMI in that period remains above the 5% level almost all the time: in some months PCMI gets as low as 3.7%, in other months it is as high as 10%.

- Combinations of two mitigation options, Contracts & Divestiture successfully reduces market prices to almost perfectly competitive levels. Under this scenario, PCMI remains well below the 5% threshold all the time.

Table 4.7 summarizes the impact of mitigation option on the total wholesale price (inclusive of capacity price) in WUMS and in MAPP.

- The Contracts & Divestiture market power mitigation strategy targeting WUMS helps also to reduce market power in the MAPP market as shown in Table 4.7.[14]

4.6 Conclusions

Based on the behavioral analysis of market power potential in Wisconsin, we came to the following conclusions:

4.6.1 WUMS market

- Market power in the WUMS region is so significant that the creation of workably competitive market for electricity in that region will not be possible under the current market structure;
- Entry of new commercial generation will help to reduce market power in WUMS but it is not sufficient to fully eliminate the market power threat;
- Increase in transmission transfer capability into WUMS to the 3000 MW level will help to reduce market power but it is not sufficient to fully eliminate the market power threat in that region;
- It is possible to achieve workably competitive market through the implementation of carefully designed market power mitigation and consumer protection measures;
- Fixed price generation contracts covering a significant portion of generation capacity owned by major generation owners in Wisconsin will help to reduce incentives for those owners to behave strategically. These contracts could be used to acquire electricity supply for utilities serving retail load in Wisconsin.

- Divestiture of WEPCO generation assets to three independent generation owners will help to significantly reduce market power in the WUMS region.
- Between 2001 and 2004, none of the above analyzed mitigation options alone will be sufficient for reducing the price impact of market power to acceptable levels (below 5% threshold);

[14] Under the mitigation option, PCMI levels in MAPP appear higher than in WUMS. However, the study was limited to market power mitigation options within the jurisdiction of the Wisconsin Public Service Commission. Should owners of generation within MAPP located outside of Wisconsin become subject to standard offer contracts, similar to that we propose for Wisconsin, the level of market power in MAPP will be negligible.

- Combination of the WEPCO divestiture and fixed price contracts options is sufficient for mitigating market power during the entire study period between 2001 and 2007;
- By 2007, a combination of the assumed system expansion options and divestiture impact appears sufficient for mitigating market power. At that time, the need for fixed price contracts could be revisited and their level could be reduced.

4.6.2 MAPP market

- Market power potential in the MAPP market is moderate, though significant.
- Combination of market power mitigation options proposed for the WUMS region appears sufficient also for mitigating market power in the MAPP region.

4.7 The Behavioral Analysis: Tables

Table 4.1*a*: Market Power Impact on Wholesale Prices: Base Case Scenario- WUMS

Year	Perfect Competition ($/MWh)	Strategic Bidding and Capacity Withholding ($/MWh)	PCMI (Strategic Bid. And Capacity Withholding)
2001	$34.75	$55.74	60.4%
2002	$30.43	$46.60	53.1%
2003	$27.79	$39.63	42.6%
2004	$25.71	$29.91	16.4%
2005	$26.12	$30.54	16.9%
2006	$26.14	$29.71	13.7%
2007	$30.98	$36.59	18.1%

Table 4.1*b*: Market Power Impact on Wholesale Prices: Base Case Scenario- MAPP

Year	Perfect Competition ($/MWh)	Strategic Bidding and Capacity Withholding ($/MWh)	PCMI (Strategic Bid. And Capacity Withholding)
2001	$22.66	$24.05	6.2%
2002	$24.10	$25.70	6.6%
2003	$25.84	$27.35	5.8%
2004	$25.72	$27.17	5.7%
2005	$25.18	$26.64	5.8%
2006	$22.10	$23.76	7.5%
2007	$30.66	$32.75	6.8%

Table 4.2: Impact of Market Power on System-wide Generation, Cost, and Revenues

Year	% Increase in Generation	% Increase in Generating Cost	% Increase in Revenues
2001	-5.4%	-6.1%	53.8%
2003	-3.8%	-3.2%	38.7%
2005	-1.6%	-0.8%	16.7%
2007	-1.7%	-1.0%	17.3%

Table 4.3: Impact of Market Power on Performance of Major Generation Owners				
% Increase in Generation (%)				
Company	2001	2003	2005	2007
MGE	1.0%	4.4%	-1.5%	-0.1%
WEPCO	-17.8%	-22.7%	-17.5%	-15.4%
WP&L	-4.9%	-1.7%	-1.6%	-0.9%
WPSC	-1.2%	4.3%	1.2%	-0.5%

% Increase in Generation Cost (%)				
Company	2001	2003	2005	2007
MGE	4.3%	10.9%	-0.1%	1.7%
WEPCO	-23.1%	-29.2%	-21.9%	-19.3%
WP&L	-5.6%	-1.9%	-1.7%	-1.0%
WPSC	-0.8%	7.6%	3.4%	0.0%

% Increase in Energy Revenue (%)				
Company	2001	2003	2005	2007
MGE	66.0%	52.7%	17.9%	20.3%
WEPCO	31.7%	9.6%	-3.7%	0.3%
WP&L	55.4%	41.0%	16.5%	18.0%
WPSC	62.4%	53.4%	21.5%	19.2%

% Increase in Profit (%)				
Company	2001	2003	2005	2007
MGE	90.5%	75.6%	33.4%	32.2%
WEPCO	50.2%	27.8%	9.0%	10.0%
WP&L	82.1%	67.4%	32.9%	30.3%
WPSC	88.2%	80.5%	37.4%	31.6%

Table 4.4. Distribution of WEPCO Generating Units under the Divestiture					
Plant Name	**Owner ID**	**Capacity (MW)**	**Prime Mover**	**Fuel**	**Heat Rate**
Point Beach 1	WEPCO1	510	NU	Nuc Fuel	10,400
Point Beach 2	WEPCO1	512	NU	Nuc Fuel	10,500
Point Beach 5	WEPCO1	18	CT	FO2	13,000
WEPCO Hydro	WEPCO1	98	Wat	Water	-
Subtotal:	**WEPCO1**	**1,138**			
Valley	WEPCO2	3	CT	FO2	15,000
Edgewater 5	WEPCO2	102	ST	Coal	10,620
Paris 1	WEPCO2	95	CT	NG/FO2	14,100
Paris 2	WEPCO2	95	CT	NG/FO2	14,100
Paris 3	WEPCO2	95	CT	NG/FO2	14,100
Paris 4	WEPCO2	95	CT	NG/FO2	14,100
Pleasant Prairie 1	WEPCO2	605	ST	Coal	10,800
Pleasant Prairie 2	WEPCO2	605	ST	Coal	10,800
Port Washington 1	WEPCO2	80	ST	Coal	10,750
Port Washington 2	WEPCO2	80	ST	Coal	10,270
Port Washington 3	WEPCO2	83	ST	Coal	10,360
Port Washington 4	WEPCO2	84	ST	Coal	10,270
Port Washington 6	WEPCO2	23	CT	NG/FO2	14,790
Valley 1	WEPCO2	140	ST	Coal	11,640
Valley 2	WEPCO2	127	ST	Coal	11,740
Subtotal:	**WEPCO2**	**2,312**			
Concord 1	WEPCO3	95	CT	NG/FO2	12,270
Concord 2	WEPCO3	95	CT	NG/FO2	12,270
Concord 3	WEPCO3	95	CT	NG/FO2	12,270
Concord 4	WEPCO3	95	CT	NG/FO2	12,270
Germantown 5	WEPCO3	78	CT	NG	12,960
Germantown 6	WEPCO3	78	CT	NG	12,960
Germantown 7	WEPCO3	78	CT	NG	12,960
Germantown 8	WEPCO3	78	CT	NG	12,960
Presque Isle 1	WEPCO3	25	ST	Coal	16,020
Presque Isle 2	WEPCO3	37	ST	Coal	14,110
Presque Isle 3	WEPCO3	58	ST	Coal	10,640
Presque Isle 4	WEPCO3	58	ST	Coal	10,640
Presque Isle 5	WEPCO3	87	ST	Coal	10,570
Presque Isle 6	WEPCO3	90	ST	Coal	10,570
Presque Isle 7	WEPCO3	85	ST	Coal	11,490
Presque Isle 8	WEPCO3	85	ST	Coal	11,490
Presque Isle 9	WEPCO3	88	ST	Coal	11,490
South Oak Creek 5	WEPCO3	262	ST	Coal	8,850
South Oak Creek 6	WEPCO3	265	ST	Coal	8,850
South Oak Creek 7	WEPCO3	298	ST	Coal	8,880
South Oak Creek 8	WEPCO3	314	ST	Coal	8,980
South Oak Creek 9	WEPCO3	19	CT	NG/FO2	17,000
Subtotal:	**WEPCO3**	**2,463**			

Table 4.5. Monthly Level of Contract Cover (MW)

(No Divestiture Case)

Month	WEPCO	WP&L	WPS	MGE	NSP, WI
Jan	1,879	739	737	206	422
Feb	1,803	715	713	194	409
Mar	1,789	702	707	197	400
Apr	1,672	664	664	179	380
May	1,711	676	678	185	386
Jun	1,851	724	733	205	413
Jul	1,971	769	777	220	438
Aug	2,030	797	801	223	455
Sep	1,895	749	749	205	428
Oct	1,795	718	712	189	411
Nov	1,756	692	692	192	395
Dec	1,851	732	730	200	418

Table 4.6. Monthly Level of Contract Cover (MW)

(Divestiture Case)

Month	WEPCO1	WEPCO2	WEPCO3	WP&L	WPS	MGE	NSP, WI
Jan	362	741	777	739	737	206	422
Feb	347	711	745	715	713	194	409
Mar	344	705	740	702	707	197	400
Apr	322	659	691	664	664	179	380
May	329	674	707	676	678	185	386
Jun	356	730	765	724	733	205	413
Jul	379	777	815	769	777	220	438
Aug	391	800	839	797	801	223	455
Sep	365	747	783	749	749	205	428
Oct	346	708	742	718	712	189	411
Nov	338	692	726	692	692	192	395
Dec	356	730	765	732	730	200	418

Table 4.7*a*: Market Power Impact on Wholesale Prices: Contracts and Divestiture Scenario- WUMS			
Year	Perfect Competition ($/MWh)	Strategic Bidding and Capacity Withholding ($/MWh)	PCMI (Strategic Bid. And Capacity Withholding)
2001	$34.75	$35.74	2.9%
2002	$30.43	$31.22	2.6%
2003	$27.79	$28.47	2.4%
2004	$25.71	$26.21	2.0%
2005	$26.12	$26.59	1.8%
2006	$26.14	$26.52	1.5%
2007	$30.98	$31.53	1.8%

Table 4.7*b*: Market Power Impact on Wholesale Prices: Contracts and Divestiture Scenario- MAPP			
Year	Perfect Competition ($/MWh)	Strategic Bidding and Capacity Withholding ($/MWh)	PCMI (Strategic Bid. And Capacity Withholding)
2001	$22.66	$23.55	3.9%
2002	$24.10	$25.42	5.5%
2003	$25.84	$26.85	3.9%
2004	$25.72	$26.80	4.2%
2005	$25.18	$26.25	4.3%
2006	$22.10	$23.41	5.9%
2007	$30.66	$32.30	5.3%

4.8 The Behavioral Analysis: Figures

Figure 4.1: Market Power Impact on Energy Prices (PCMI): Base Case Scenario

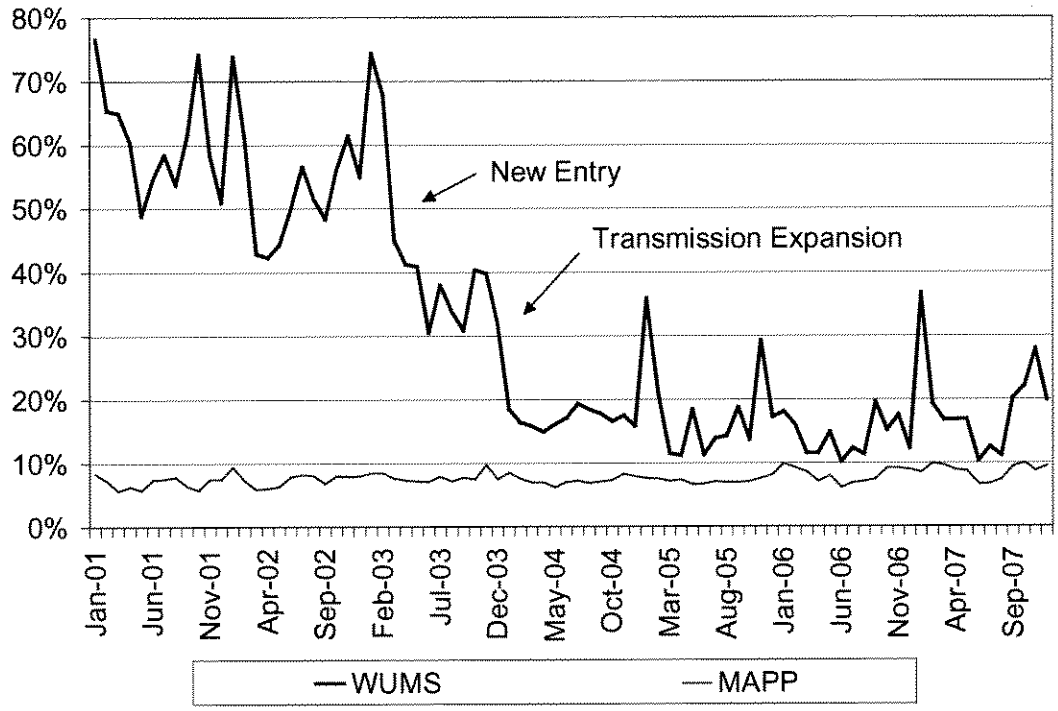


Figure 4.2: Impact of Market Power on System-wide Generation

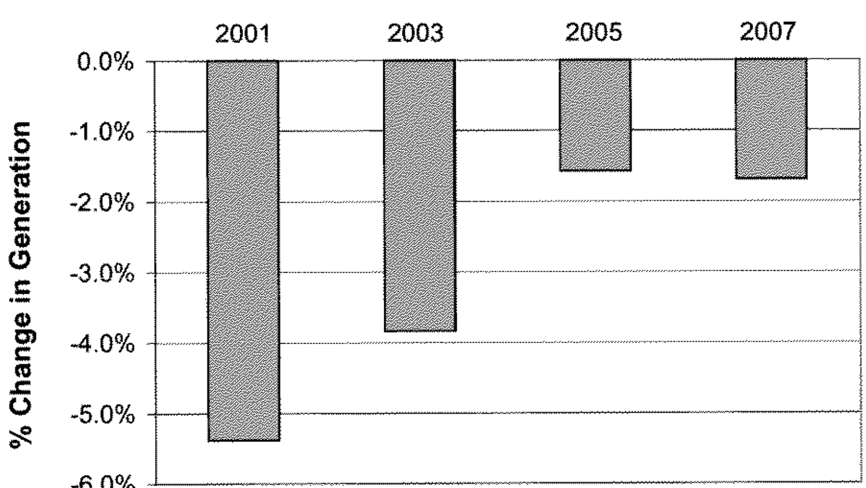


Figure 4.3: Impact of Market Power on System-wide Generating Cost

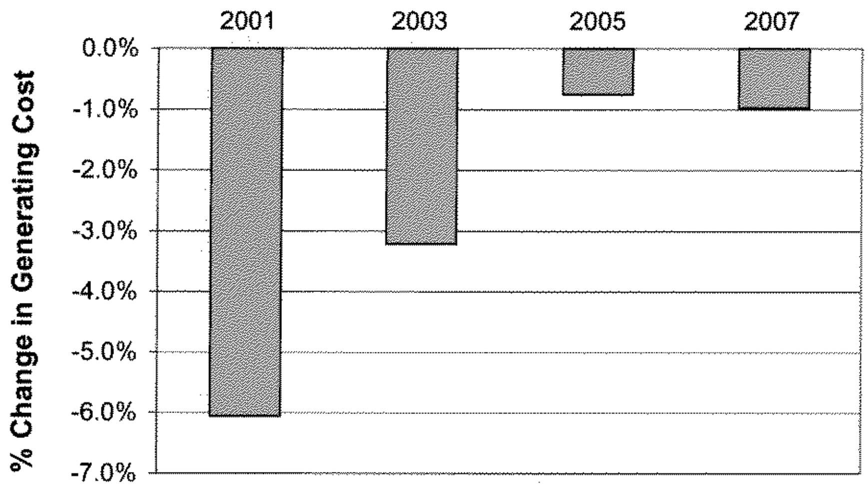


Figure 4.4: Impact of Market Power on System-wide Revenues

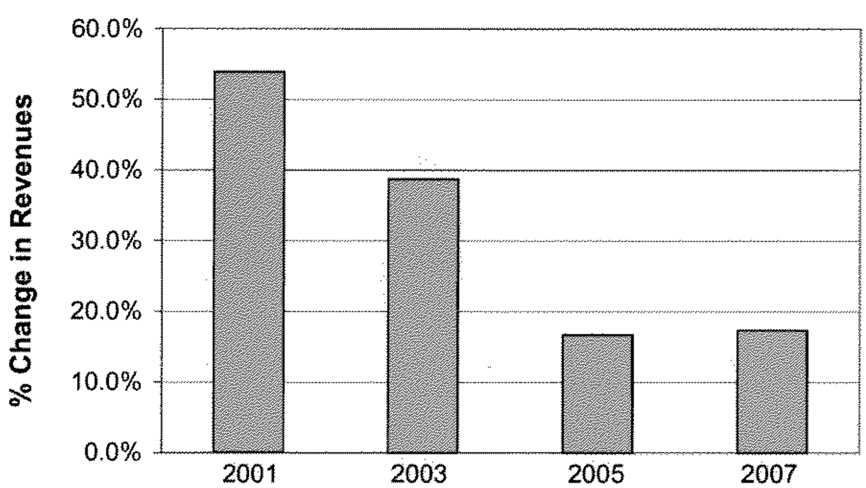


Figure 4.5: PCMI in the WUMS Market: Base Case (No Mitigation) vs. Mitigation Options

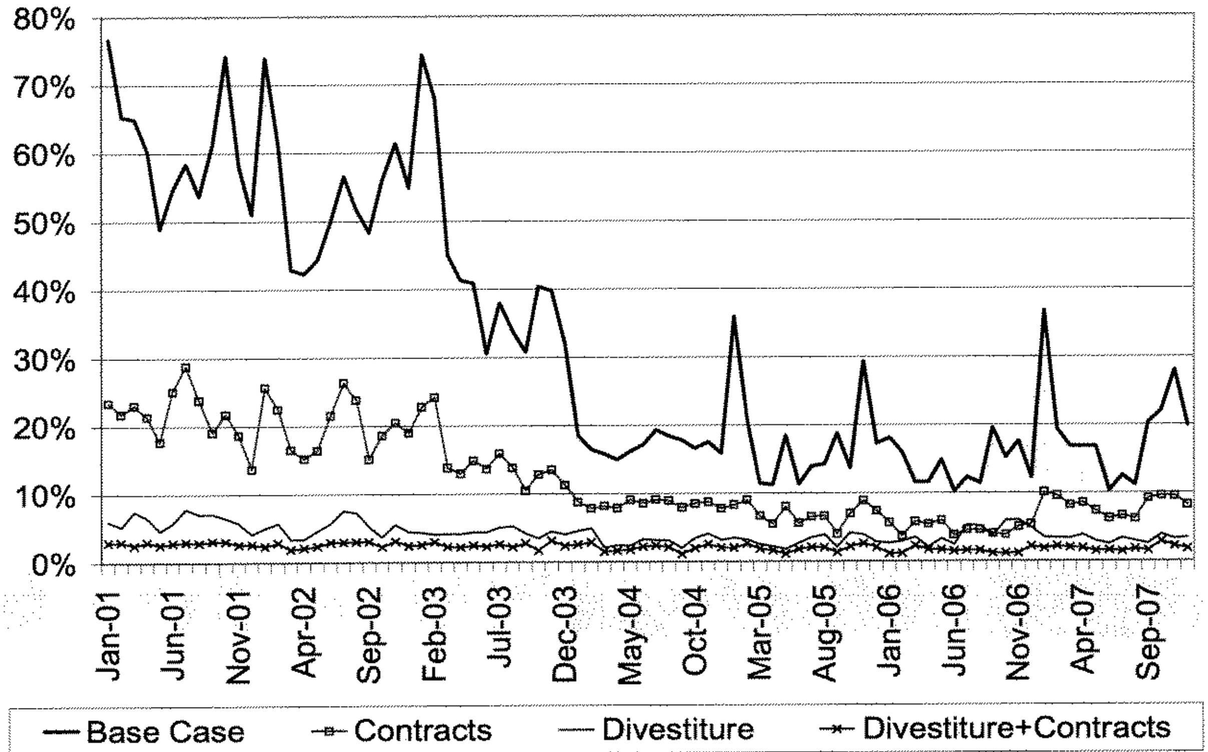
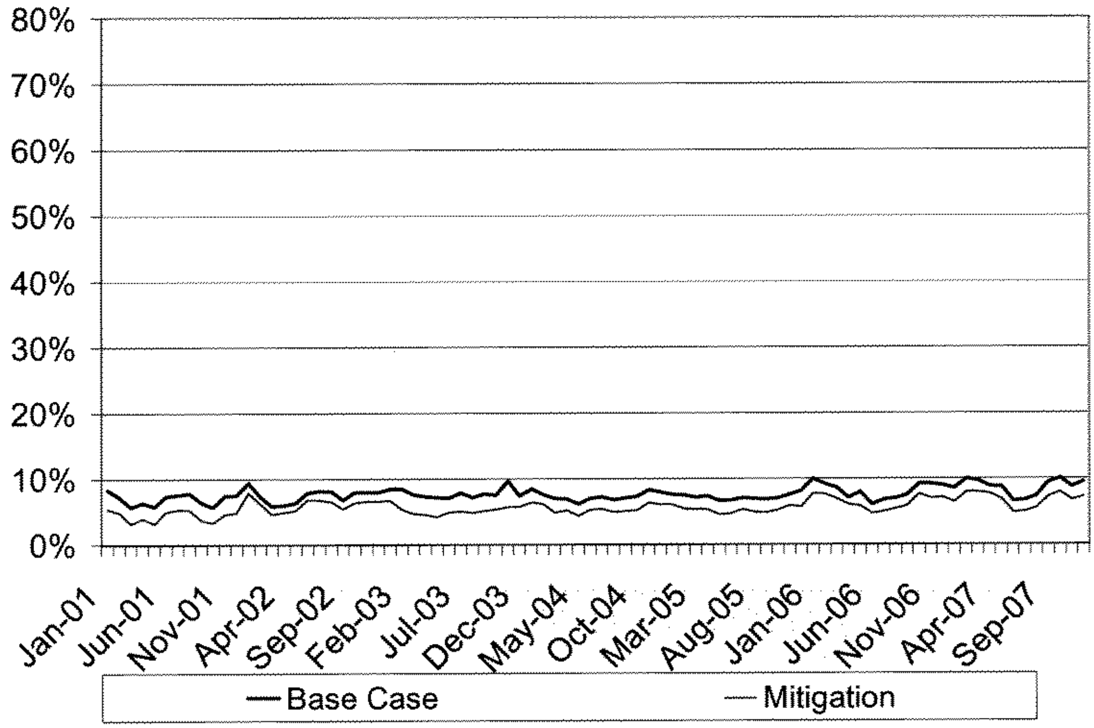


Figure 4.6: PCMI in the MAPP Market: Base Case (No Mitigation) vs. Mitigation Options



5 Impacts on Stakeholders

The study assessed the impacts of market power and market power mitigation measures on three major categories of stakeholders: customers, utility shareholders and workers. 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. The impact of mitigation measures on public utility shareholders and electric cooperative members was assessed in terms of stranded costs. The impact of mitigation measures on public utility and electricity coop workers was assessed qualitatively.

5.1 Rate Impacts

The impact of the proposed mitigation measures on public utility customers and electric cooperative members was analyzed in terms of the effect on electricity rates. Retail rates for electric service provided by utilities are subject to approval by the PSCW. Those rates are set at levels that give the utility or cooperative an opportunity to recover its costs of providing that service, including a reasonable return on its investments, based on data for a representative time period. Those costs can be grouped according to the major distinct functions or services involved in providing traditional, "bundled" electric service i.e., generation, transmission, distribution and customer. If the cost of generation changes, up or down, materially from the level being recovered in current rates, utilities and cooperatives typically file for a corresponding change in their retail rates. Ratepayers generally view an increase in rates as a negative impact and a reduction in rates as a positive impact.

5.1.1 Analysis

The study assessed the impact of mitigation measures on ratepayers in each of the four largest Wisconsin utilities WEPCO, WP&L, WPSC and NSPW. The impact was assessed by comparing the unit revenues (cents/kwh) in each mitigation case to the unit revenues in the Base Case (no market power mitigation.) Unit revenues per rate class were used as a proxy for retail rates. Mitigation measures that result in a reduction in unit revenues relative to the Base Case have a positive impact on ratepayers.

Unit revenues were calculated for each of the four utilities under the Base Case, and under each of the mitigation cases, by major customer class by year. (See Table 5.1, below.) Unit revenues for each utility are the sum of its average unit cost of transmission, distribution and customer services (TDC) for each major customer class and its average system-wide cost of generation. The unit revenues by major customer class are reasonable estimates for the purpose of assessing the impact of mitigation measures on rates; they should not be interpreted as definitive calculations of rates. For example, the study uses the system-wide cost of generation as the generation cost component of unit revenues for each customer class whereas the generation cost component of rates typically varies by major customer class.

The TDC component remains constant across all scenarios since it would not affected by the deregulation of the generation market. The TDC component was estimated for each rate class by subtracting the utility's annual system-wide unit cost of generation in 1998 from its average annual unit revenue by rate class in that year. These estimates were prepared using data reported by the utilities in their 1998 FERC Form 1 reports.[15] The results of the unbundling[16] for each of the four utilities are presented in Appendix E and summarized in Table 5.1.

Table 5.1: 1998 Unbundled Unit Revenues (cents/kwh)

Utility	Component	Residential	Commercial	Industrial
WEPCO	*Generation*	3.61	3.61	3.61
	TDC	3.81	2.48	0.15
WPL	*Generation*	2.80	2.80	2.80
	TDC	3.60	2.66	0.65
WPS	*Generation*	2.57	2.57	2.57
	TDC	3.41	1.90	0.29
NSPW	*Generation*	3.34	3.34	3.34
	TDC	3.42	2.97	1.14

The generation component of unit revenues varies by scenario according to the assumptions made regarding the price at which the utilities would acquire generation to serve their retail customers. In the Base Case and Divestiture Case the study assumed that utilities would acquire generation at the market price in effect when the generation was purchased. Thus the annual unit generation cost for those cases is based on the hourly market prices under each of those scenarios weighted by the quantity of generation acquired in each hour. In the Contracts Case, and Contracts plus Divestiture Case, the study assumed that utilities would acquire generation through "buy-back" or bilateral contracts at prices that would prevail under perfect competition. The annual unit generation cost for those cases is based on the hourly market prices under the simulation of perfect competition, again weighted by the quantity of generation acquired in each

[15] 1998 was the most recent year for which comprehensive data were available for all utilities.
[16] The estimates of unbundled costs are reasonable for the purpose of assessing the impact of mitigation measures on rates; they are not presented as a detailed or definitive unbundling of rates.

hour. The annual average unit cost of generation to utilities used to assess rate impacts are presented in Table 5.2 below.

Table 5.2: Average Annual Cost of Electricity to Load Serving Entities (cents/kwh 1999$)

	WUMS				MAPP	
	Base Case	**Contracts Case**	**Divestiture**	**Contracts & Divestiture**	**Base Case**	**Contracts & Divestiture**
2001	5.57	3.47	3.69	3.47	2.41	2.27
2002	2.97	3.04	3.20	3.04	2.57	2.41
2003	3.66	2.78	2.90	2.78	2.73	2.58
2004	2.99	2.57	2.65	2.57	2.72	2.57
2005	3.05	2.61	2.69	2.61	2.66	2.52
2006	2.97	2.61	2.72	2.61	2.38	2.21
2007	3.66	3.10	3.19	3.10	3.28	3.07

5.1.2 Results

As shown in Table 5.2, the mitigation measures modeled in the study result in lower unit revenues by rate class than in the Base Case. The estimates of unit revenues for the residential, commercial and industrial rate classes in 2001 under each of the cases are presented in Figures 5.1 through 5.3 respectively. These results also indicate that the rates under the mitigation cases could be lower in some utility service territories than the rates paid by customers in 1998.

5.2 Impact on Stranded Costs (Benefits)

The study assessed the impact of mitigation measures on public utility shareholders and electric cooperative members by estimating the impact of those measures on stranded costs. Stranded costs are embedded costs of utility investments that exceed market prices, exceed the amount that can be recovered through the sales of the assets underlying those costs and may not be fully recoverable from ratepayers after the assets are sold or divested. Thus, stranded costs equal the difference between the market value of the assets and their book value. Stranded costs that are not fully recoverable from ratepayers represent an adverse financial impact from the perspective of utility shareholders and cooperative members. In contrast, if stranded costs are negative they represent a positive impact or benefit from the perspective of utility shareholders and cooperative members.

5.2.1 Analysis

The level of stranded costs (benefits) resulting from deregulation of the wholesale generation market was estimated for the non-hydro units of the four largest Wisconsin utilities operating within WUMS - WEPCO, WP&L, WPSC and MGE. An estimate was not prepared for NSP because the capacity booked to NSPW in Wisconsin is not distinguished from the Minnesota capacity. Hydro units were excluded from the calculation because of insufficient data on their fixed costs available for the asset valuation model; however it is reasonable to assume that hydro units will have negative stranded costs.

Net book values of the non-hydro capacity of those utilities was obtained from Staff of the PSCW. Those values are presented in Appendix E.

Estimates of market values for each generating plant were calculated for a market with perfect competition using results from GE MAPS with a specialized asset valuation model. The model calculated the net present value of the income or profit of each generating unit in each year of the study period, 2001 through 2007. The net income each year is equal to the revenues received from selling into the deregulated wholesale market in that year less the operating costs and depreciation for the year. The forecasts of generation and annual revenues by generating unit were obtained from the simulation of the operation of a perfectly competitive wholesale market described in Section 2. The asset valuation model determines pretax revenues less expenses by subtracting variable expenses, fixed expenses and tax depreciation from the annual revenues. Assumptions regarding the level of depreciation of each unit each year were made from the perspective of a new owner, with the units fully depreciated over the lesser of 20 years or their economic life. The model determines after-tax cash flow by subtracting income taxes from pretax revenues, subtracting expenses and adding depreciation. The market value of each unit is the net present value of each year's after tax cash flow. Those estimates are presented in Appendix E.

5.2.2 Results

The study indicates that the market value of each utility's existing generating capacity exceeds the net book value under perfect competition. This implies that stranded costs will be negative even in a perfectly competitive market; in other words, they will be stranded benefits. As market prices under any market power or market power mitigation scenario may be expected to be equal to or greater than perfectly competitive prices, stranded benefits would be realized under any of those scenarios, as well.

The book values and market values under perfect competition of the generating capacity for the four major utilities in WUMS are presented in Figure 5.4. This Figure indicates that the ratios of market value under perfect competition to book value range from 2 to 5. The levels of stranded benefits under perfect competition are presented in Table 5.3.

Table 5.3: Stranded Benefits of Non-Hydro Units under Perfect Competition ($ million)				
	Net Book Value	**Market Value**	**Stranded Benefit**	**Market to Book**
WEPCO	1,295	2,847	1,552	2.2
WPL	195	1,069	874	5.5
WPS	291	874	583	3.0
MGE	65	277	214	4.3

5.3 Impact on Utility and Electricity Cooperative Employees

The study modeled mitigation measures designed to reduce, or eliminate, the potential for exercise of market power in the deregulated generation market. These measures should result in market conditions close to perfect competition. Mitigation measures should not have an adverse impact on public utility and electric cooperative employees relative to the Base Case.

The study found that there would be a significant level of stranded benefits under perfect competition, indicating that existing generating units will continue to be competitive and profitable even with the implementation of mitigation measures. Thus, the mitigation measures modeled in the study do not require power plant owners to reduce labor costs relative to levels in the Base Case. In addition, Wisconsin has passed legislation requiring new owners of generating units to offer employment to nonsupervisory employees for at least 30 months following the transfer at wages, terms and conditions comparable to those in effect prior to the transfer.

5.4 Impacts on Stakeholders: Figures

Figure 5.1: Unit Revenues - Residential

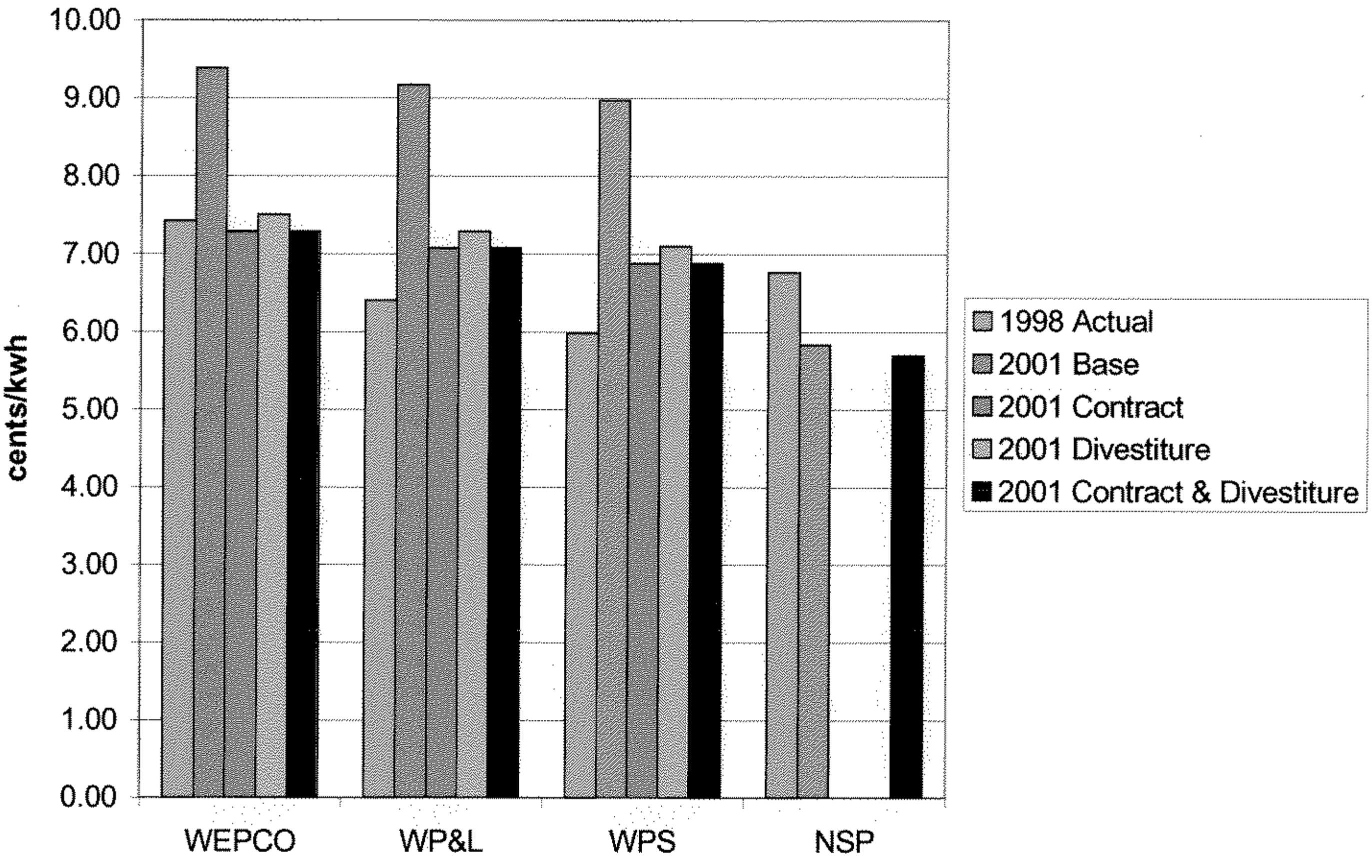


Figure 5.2: Unit Revenues - Commercial

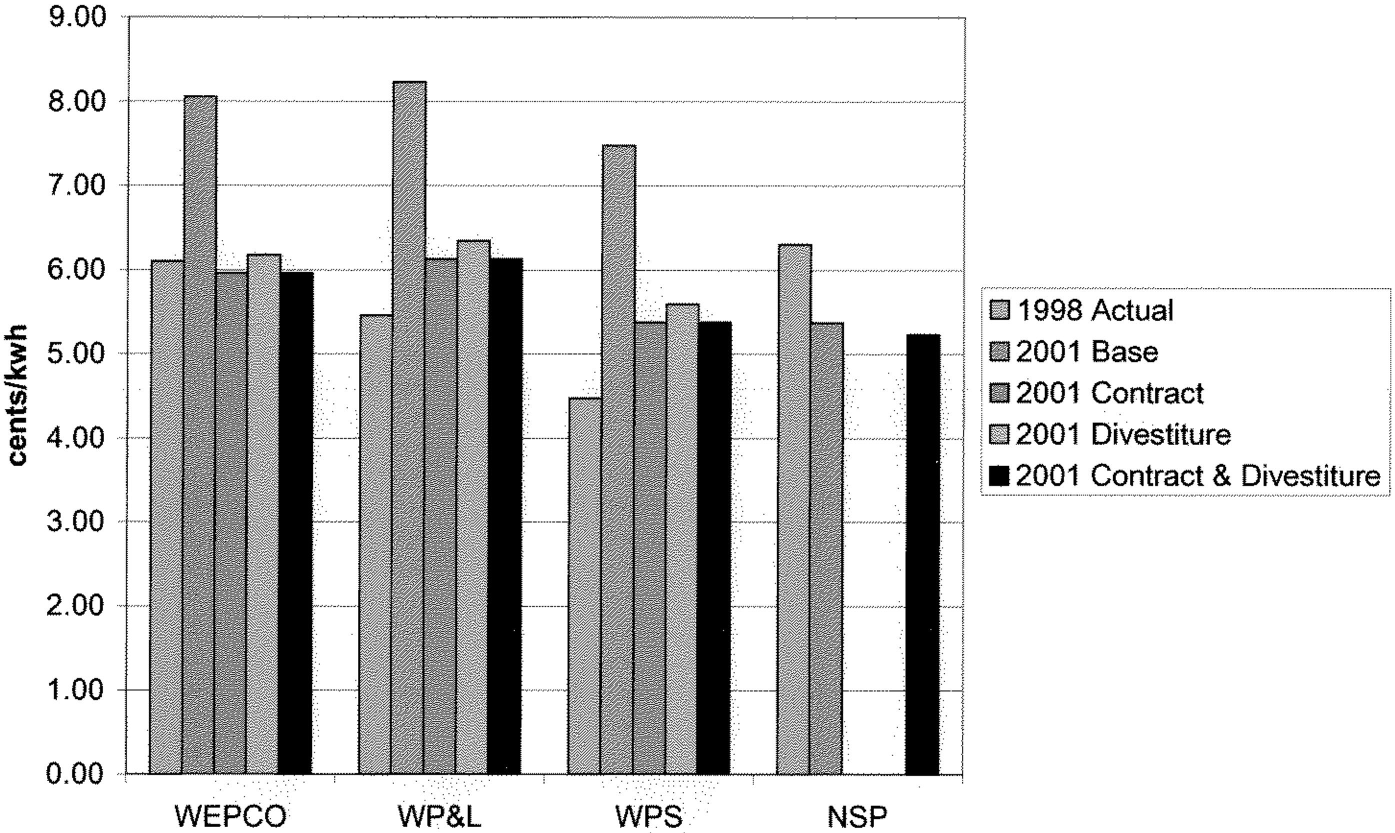


Figure 5.3: Unit Revenues - Industrial

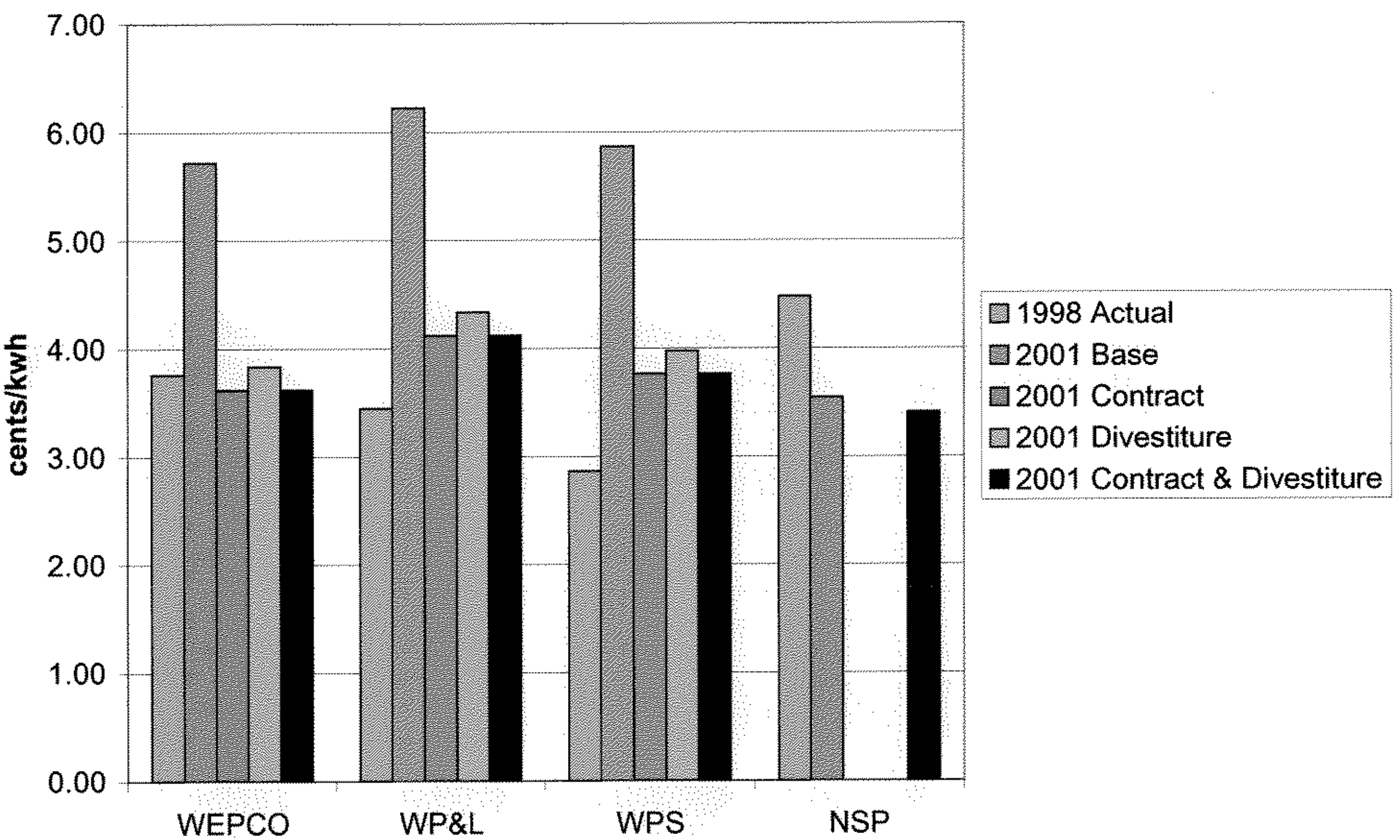
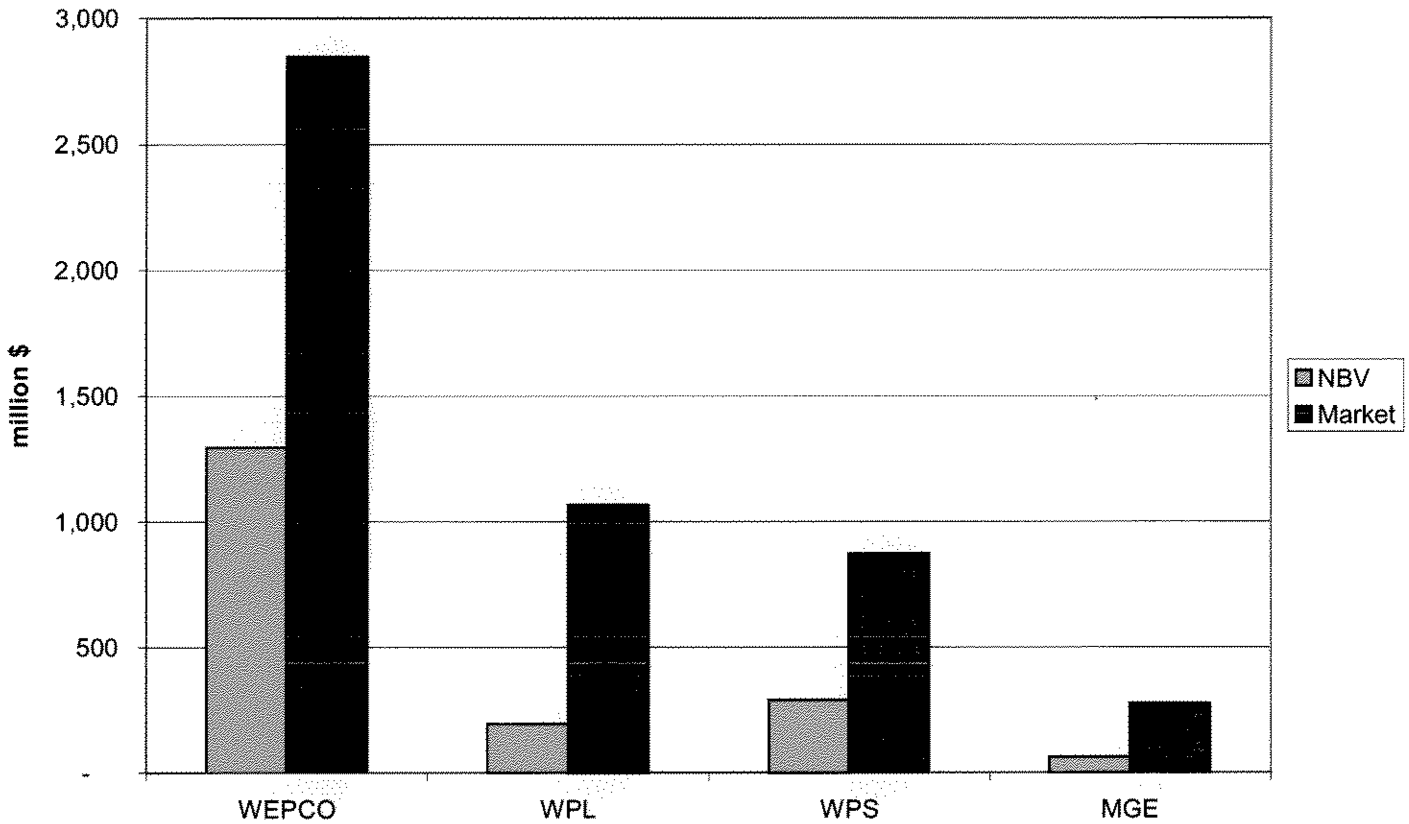


Figure 5.4: Market Value versus Net Book Value (NBV)



6 Conclusions and Recommendations

The Wisconsin Legislature has raised concerns regarding the ability of generator owners to exercise horizontal market power and thereby "...frustrate the creation of an effectively competitive retail electricity market."[17] In response to those concerns, the Public Service Commission of Wisconsin commissioned this study of the potential for the exercise of market power if Wisconsin's electricity markets were deregulated and of potential measures to eliminate that market power. The study assessed the potential for the exercise of market power over the period 2001 through 2007 using a structural analysis and a behavioral analysis.

The WUMS electricity markets are highly concentrated under all market conditions, suggesting that the potential exists for the exercise of market power by generator owners in this region. This potential is greatest under existing transmission limitations, but potential remains even after transmission capacity is assumed to increase to 3,000 MW in 2004. Wisconsin Electric Power (WEPCO) has the largest share of geographic and product markets within WUMS. The electricity market in NSPW region is not sufficiently concentrated to warrant market power concerns.

Under the current market structure, sufficient market power would exist within WUMS to elevate electricity prices significantly above competitive levels. The impact of this market power is reduced, but not eliminated, by expected new generation capacity and new transmission capacity during the study period.

A workably competitive retail market could be achieved in WUMS by changing the current market structure in a manner that eliminates undue market power. This study indicates that two changes, implemented in combination, would achieve this mitigation. The two changes are:

- require owners of existing generation to commit a significant portion of their capacity under fixed price contracts, for example as a source of generation for retail customers (contracts), and
- divestiture of WEPCO generation assets among three independent owners (divestiture).

Changing the current market structure in a manner that prevents undue market power will not have adverse effects on retail customers, public utility shareholders and workers or electric cooperative members and workers, because:

- Using contracts and divestiture to achieve workably competitive retail markets will result in lower rates than would otherwise prevail if market power is not mitigated, and
- Workably competitive retail markets result in stranded benefits, not stranded costs, suggesting that existing generating units will remain profitable in a restructured

[17] Wisconsin Act 9 (biennial budget), 196.025(5)(ar)

marketplace. The owners of those units will not be under undue pressure to reduce labor costs.

We recommend that these mitigation strategies be implemented as part of any electricity market deregulation initiative in Wisconsin.

7 References

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8 Appendices

Horizontal Market Power in Wisconsin Electricity Markets:

A Report to
The Public Service Commission of Wisconsin

Appendices

T C A

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Appendix A. Input data and assumptions

This section summarizes the salient inputs to the TCA locational price-forecasting model (GE MAPS) for the midwestern part of the United States and, specifically, for the state of Wisconsin. The Midwest includes the following NERC regions: ECAR, FRCC, MAIN, MAPP, SERC, SPP and Ontario. Starting with the General Electric generation and transmission database for the Midwestern United States, TCA has verified, refined and/or replaced the data as appropriate, based on its own data sources and with data provided by the Public Service Commission of Wisconsin. We have included in-house analysis to ensure data integrity, validity, and consistency of plant operations with market developments.

The following is a list of the major data components, followed by a description of each component and the associated data sources:

(1) Load Inputs
(2) Thermal Unit Characteristics
(3) Planned Additions and Retirements
(4) Nuclear Unit Analysis
(5) Fuel Price Forecasts
(6) Transmission System Representation
(7) Environmental Regulations
(8) Conventional Hydro & Pumped Storage Units
(9) External Region Supply Curves
(10) NUG Contracts
(11) Dispatchable Demand (Interruptible Load)
(12) Market Model Assumptions

A.1 Load Inputs

Description: GE MAPS takes load inputs on an hourly basis (8760 per year) for every load serving entity. Loads for future years are scaled based on a forecast of annual peak demand and energy. GE MAPS adjusts the load profile in every year to account for the change in the day of the week at the start of every new year.

Data Sources: We use company's FERC 714 filings (1997) and EIA-411 (Load and Capability Report - 1999) from the relevant power pools for both the actual (1995) hourly loads (in EEI format) and the most recent available load forecast series from each power pool. A detailed load forecast for the relevant areas in MAIN is included in Section A.13.

A.2 Thermal Unit Characteristics

Description: GE MAPS models generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly dispatch and prices. These characteristics include: