Large-Scale Market Power Modeling: Analysis of the U.S. Eastern Interconnection and Regulatory Applications

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Abstract— **This paper presents results from a large-scale Cournot model of the US Eastern Interconnection using a DC load flow network. There are 100 network locations (at the level of control areas) along with 2725 generators owned by 99 Cournot firms and 200 competitive fringe suppliers. These results demonstrate that this modeling approach can analyze potential generation market power with a reasonable approximation of the actual transmission network over a large integrated region. While such models have been used to analyze market design alternatives, their application to regulatory decisionmaking concerning generation market power mitigation has been more controversial. We suggest that such large-scale market price simulations could improve upon aspects of the existing generation market power screening methods used in the United States for mergers and market-based rates, illustrating such applications using this model.**

Keywords— **Cournot model, electric power, generation market power, mergers, market-based rates.**

I. Introduction

Market power monitoring and mitigation are key policy issues in the design of the competitive wholesale electric power markets now operating in the US and other countries (e.g., [1], [6], [27]). While national and international (e.g., European Union) methods for monitoring and controlling generation market power differ in their specifics, all regulatory authorities can intervene in the power markets to promote competition and limit high market prices due to market power in some circumstances. Often those circumstances are not well defined up front, leading to ongoing adjustments in market structure and market rules or after-the-fact penalties or refunds (for example, the lengthy process in the US to determine refunds following the California market crisis of 2000-01). This process increases the regulatory uncertainty faced by market participants (both sellers and buyers). For this reason, government regulators, such as the US Federal Energy Regulatory Commission (FERC), and other market monitors – such as the non-governmental market monitors authorized in the US to provide oversight of the centralized, or "organized," power markets operated by the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) – are continually searching for better tools to screen for market power. Their objective is to establish effective and transparent market rules that are consistent with short-run and long-run competitive market results and minimize the prospect of subsequent regulatory interventions.[1]

One of those tools is quantitative market modeling through simulation. For actual markets (as opposed to theoretical examination), where the regulator or market monitor has data of sufficient quality or can make reasonable assumptions about costs of production, transmission network properties, and demand response, this can be performed in two ways. First, market prices can be simulated *ex ante* through models that assume specific types of strategic market behavior. For example, equilibrium market models, such as the models presented here, are developed on the basis of assumptions about how suppliers might adjust their prices or outputs, or both, to increase profit up to the point that they can no longer profitably affect the market price given their belief about what other suppliers are doing in response. Alternatively, agent-based *ex ante* simulations make assumptions about what market actors will do in particular situations, but do not impose equilibrium conditions. Second, the regulator or market monitor can simulate the market after the fact, and examine the difference between the actual market prices and the simulated competitive market prices. Such *ex post* comparison of competitive market simulated prices to actual prices is now a regular feature of market monitoring in the US.[2]

Unfortunately, any regulator turning to the research literature on applied electric power market modeling will immediately find a debate over what should be inferred from quantitative analysis for regulatory decisions. These include disputes within the academic literature concerning the *ex post* measurement of market power in California following the price spikes of 2000-01 (e.g., [33], [34]) and ongoing discussion about the assumptions that are used in *ex ante* market price simulation models and whether such models are ready for specific regulatory applications [40],[47], [2]. In the US, FERC undertook an inquiry into the use of large-scale simulation models for *ex ante* merger analysis in 1998 that was intended to advance the use of such models [19], [23]. But although this question has been periodically examined for both merger analysis and the closely related issue of market-based rate authorization, under which individual suppliers are approved to sell

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[1] Under the Federal Power Act (FPA), FERC has the statutory obligation to ensure that market prices are 'just and reasonable', which has been interpreted by the US courts as ensuring that markets are well functioning and market pricing sufficiently competitive such that suppliers make normal profits but not monopoly profits [27].

[2] See, for example, the annual market performance reports of the California ISO, ISO-New England, or PJM, all available on these organizations' web-sites.

at market prices rather than at cost-based rates (e.g., [20], [21]), FERC has recently concluded that game-theoretic market price simulations are not viable for purposes of screening for market-based rates [22]. We do not dispute that market price simulation modeling has limitations as a regulatory decision tool and that the research community does not at present have a common approach to such modeling (e.g., [40]). Nevertheless, as we discuss here, in general, such market models have certain advantages (and disadvantages) for *ex ante* regulatory decision-making over the alternative market power metrics, such as types of concentration indices, and more recently "pivotal supplier" tests, now used by FERC and other regulators [22]. In particular, as has long been understood, market price simulation can more accurately consider the effects of the transmission network on generation market power than concentration indices [4]. Large-scale market price simulations also inherently avoid the need to define geographic markets, a major element of the current US generation market power screening of applications for mergers and market-based rates [23].

To illustrate the potential for such modeling, this paper examines the results of a large-scale, transmission constrained model of U.S. wholesale power markets. The market is simulated using a linear complementarity model [10], [29], and contributes to the growing complementarity-based literature on spatial equilibrium of electric power markets under different market designs (e.g., [11], [50]). The region modeled is the U.S. Eastern Interconnection and the transmission network is represented with a DC load flow approximation aggregated at the level of control areas. The period examined is June 2000, divided into 24 scenarios representing average hourly demand in each hour of the month. The entire region is assumed to be organized as a single independent system operator (ISO), or multiple ISOs without seams, with vertical disintegration and locational marginal pricing of energy. Hundreds of suppliers are modeled simultaneously as strategic with respect to generation output, known as the Cournot conjectural variation, and they can sell power at any location in the region, subject only to (endogenous) congestion charges.[3] The data set was constructed largely from public sources. The original purpose of the model was to informally test uses of large-scale simulations for market power screening of mergers and market-based rates at FERC circa 1999-2004, but as noted, this type of simulation approach has not yet been adopted at FERC.

This paper makes two contributions. First, it provides a review of how market simulation models could be used by regulators to design and monitor markets (Sections II and VIII). In Section II, we review three possible uses: *ex ante* evaluation of the potential for market power in new markets or from changes in market structure (e.g., mergers or allowing cost-based regulated firms to sell wholesale power at market-based rates); calibrating the *ex ante* short-term market power screening tools in operating spot auction markets; and *ex post* evaluation of wholesale market outcomes. Then, after briefly introducing large-scale market equilibrium modeling in Section III, followed by the case study in Sections IV-VI, we return to regulatory uses of such models in Section VIII by discussing specific applications and issues raised in those applications. That section illustrates those issues by referring to the results of the case study.

The second contribution of the paper is the case study itself, which presents a set of analyses that is new to the literature. Section IV reviews the data and assumptions in the Eastern Interconnection model. (The mathematical model itself is summarized in the Appendix.) Section V presents price results and validation for a benchmark model of perfect competition across the entire interconnection. Section VI then presents the results of the market power simulations, in terms of price-cost mark-ups and other indicators, while Section VII analyzes the results qualitatively and statistically. The unprecedented geographic scope and detail of the case study (the eastern U.S., modeled with thousands of power plants and hundreds of generation companies and transmission interfaces) allows an analysis of competitive conditions in different subregions while allowing for imports and exports, as well as a comparison of different indices for measuring market power. We confirm, for instance, that traditional concentration indices are poor predictors of the ability of generators to raise prices above marginal cost in an electric power network model, mainly because of transmission congestion.

II. Regulatory Applications of Market Modeling

The models and applications in this paper were initially developed with the objective of potentially using them in US regulatory proceedings. Because electric power markets in all countries of the world are subject to generation market power, it is important that regulators have sophisticated, but also well understood, tools to anticipate and monitor market power and in particular to identify the situations – system-wide or locational – in which market power of suppliers might require structural or behavioral remedies.

In general, equilibrium market models offer a robust framework for examining the effects of alternative market designs and multi-market interactions on market prices. We are concerned here primarily with generation market power analysis. In the US, there are currently three potential categories of regulatory uses of detailed spatial equilibrium models for generation market power analysis. These are introduced here and discussed in more detail in Section VIII. Table I summarizes the various methods.

The first category is *ex ante* long-term screening of market power, such as merger analysis and market-based rates

[3]Cournot-based models are not the only alternative for simulating oligopoly on a transmission network, but based on our experience using other approaches, including supply-function [3], Bertrand [28], and tacit collusion models [25], it is the most practical. However, a newer approach based on conjectural variations [36] or, equivalently, conjectured supply functions [12] can be as computationally efficient, if defensible estimates of the conjectures can be obtained [36]. For a review of alternative game-theoretic frameworks for modeling transmission-constrained markets, see [12].

authorization. In other countries, divestiture policy might fall into this category. In the US, both these regulatory decisions rely heretofore on calculation of market concentration measures to determine generation market power, such as market share, the Hirschmann-Herfindahl Index (HHI) of market concentration, and pivotal supplier analysis.[4] Mitigation is prospective in that passing the screens (and undertaking any additional measures required by the regulator) is intended to limit the ability to exercise generation market power for a long period of time. Prior to restructuring, when the industry was largely vertically integrated, the performance of these screens as predictors of generation market power was less important than their role in facilitating other aspects of federal wholesale power policy, such as increasing transmission access (see, e.g., [27]). As restructuring unfolded, there has been an ongoing evaluation as to what function these screens should play in the restructured markets. The market price simulations presented here are more detailed and can provide greater insight into competitive analysis of changes in market structure or design than the existing generation market power screening methodologies. But they do face barriers to their adoption in regulatory and legal proceedings in that they are data intensive (although the existing screens can also be data and modeling intensive) and require introducing game-theoretic behavioral assumptions and other assumptions for purposes of finding solutions (such as negatively sloped demand curves) that when varied are suggestive of alternative market outcomes. We discuss these issues further below.

The second category of interest is in providing additional tools to evaluate the methods for *ex ante* market power screening of supply offers in the organized spot markets. There are a number of such methods implemented in the different ISOs and RTOs, all of which roughly follow the procedure of using a pre-defined market or system condition (e.g., presence of congestion at particular locations, possibly for some number of hours; or market price above some threshold; or determination that a generator is a pivotal supplier) to trigger mitigation of spot supply offers [27]. As will be discussed, the spatial market power models presented here could, if further developed, provide insight into aspects of this type of mitigation that are not well captured (currently) by some of these existing methods.

Finally, a third category could be *ex post* evaluation of wholesale market outcomes, both outside the organized spot markets and possibly within them. For example, one application could be to address a counterfactual that can't easily be addressed by *ex post* empirical analysis, which is the degree of market power in the organized markets that exists in already tightly mitigated locations, such as load pockets. Such modeling might help assess situations where market power mitigation is claimed to be excessively or, alternatively, insufficiently stringent.

[4]In both cases, the model-based screen is one aspect of the analysis of market power, which also includes evaluation of the applicant's transmission market power, the presence of barriers to entry and the possibility of dealing among affiliates. For an early analysis of HHIs on a transmission network, see [45].

TABLE I
Analytical methods of market power measurement

	Ex Ante	**Ex Post**
Long-Term	Structural measures: e.g. Market share, HHI, pivotal supplier; Simulation models of strategic behaviour	Simulation of competitive benchmark prices over time; Evaluation of physical withholding
Short-Term	Comparison of accepted offers with benchmark offer prices or costs	Monitoring of physical withholding

III. Modeling Large-Scale Power Markets

Oligopolistic market modeling applicable to power markets has increased in sophistication and capability over the past few years, due to the increased commercial availability of efficient, robust algorithms for computation of equilibrium for large-scale problems, new approaches to market modeling, and in some cases access to data available for simulation models. The linear complementarity problem (or the more general variational inequality formulation) provides the mathematical framework for most of the large scale equilibrium market simulations (e.g., [10], [5], [11], [29], [30], [46], [51]).[5] The basic spatial Cournot, or quantity, network game used here remains a rich source of insight, particularly where the complexity of the application makes the simplicity and computational tractability (under some assumptions) of the game an advantage for analysis. Some variants of the Cournot game fit readily into the complementarity framework for equilibrium market modeling, facilitating computation for large systems.

A basic distinction in electric power market modeling using the Cournot model is between games with suppliers that are naive with respect to transmission congestion (i.e., price-taking with respect to transmission costs) and those in which suppliers are modeled as actively seeking to manipulate congestion as a means to maximize profits [30]. Although the latter type of game is arguably more realistic (particularly when there are very few players), the former approach is currently more compatible with modeling large numbers of strategic players simultaneously and is the basis for the research presented here. In the complementarity framework, the former approach also has a substantial body of theory to assist in determining existence and uniqueness of equilibria [10], [38]. An extension of this spatial Cournot market model is the inclusion of price-taking arbitrage firms, which can be used to replicate the outcome of a fully arbitraged centralized spot market (or "poolco" market) with imperfect competition [29],[38].

On the data front, one difficulty that FERC faced in earlier years was lack of data on the US transmission network (particularly transmission line capacity) and the ability to

[5]For example, the typical size of the market models solved in this paper as linear complementarity problems is about 12,000 variables and an equal number of corresponding equations and complementarity conditions.

calculate power flow approximations that are tractable for computable equilibrium models. That gap has been increasingly filled in recent years for some parts of the US by commercial vendors of power flow models. However, clearly any use of such models on an interconnection-wide basis, as presented here, would require much work on network representation. Another consideration is the decreasing public availability over time of some types of data on the supply side of the market that used to be reported for public purposes under the prior regulatory regime, but are increasingly kept confidential by market suppliers. Most notably, this includes data, such as heat rates, that can be used to estimate generation production costs. For regulators and regional market operators (ISOs or RTOs) and their market monitors, this data might be available or can be obtained on a confidential basis. Hence, the implementation of large-scale, data-intensive market models should not face the same data constraints for these governmental or quasi-governmental entities and their contractors as might face non-governmental researchers. The data in this research were almost all in the public domain at the time that the model was developed.

IV. The U.S. Eastern Interconnection model

The Eastern Interconnection includes most of the transmission network in the United States and Canada east of the Rocky Mountains. While equilibrium market modeling has been undertaken for several large regions of the continental United States (and Europe),[6] until this research, analysts had not assessed the Cournot equilibrium of an entire US interconnection with thousands of power plants and hundreds of transmission interfaces. Our focus is on the US portion of the interconnection; trade with Canada for the period analyzed will be considered as fixed inputs into the U.S. region (based on actual data). Although this region is not uniform in terms of market design, types of firms, and market operations, useful insights can be obtained from modeling of the entire system.

As will be discussed below in more detail, the Eastern Interconnection network is represented in the model at the level of control areas. The pricing results presented in the paper are further aggregated to the level of NERC regions and subregions, as they existed in 2000.[7] The exceptions to this for the period modeled were the three organized markets in the Middle Atlantic and Northeastern region, the Pennsylvania-New Jersey-Maryland Interconnection (PJM) ISO (under its 2000 boundaries), New York ISO and ISO-New England. Each of these is operated as a single control area and hence there is no averaging of the simulated prices. In the Midwestern region, the control area prices are averaged under the 2000 boundaries of the reliability regions of East Central Area Reliability Coordination (ECAR), Mid-American Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP) and the Southwest Power Pool (SPP). Finally, in the Southeastern region, control area prices are averaged for four subregions of the Southeastern Electric Reliability Council (SERC)—Entergy, Southern Company (SOCO), the Tennessee Valley Authority (TVA), and Virginia-Carolinas (VACAR); Florida is represented in the model as a single location and its price is not averaged.

There are two basic market organizations in the Eastern Interconnection: the centralized spot markets operated by ISOs or RTOs and the decentralized or bilateral markets. The ISOs (some of which later became RTOs) that existed in 2000 in PJM, New York and New England shared a common background as tight power pools and have operated voluntary, bid-based spot markets since 1998-9. For the period examined, PJM and New York calculated hourly locational marginal prices of energy, while New England determined a zonal average price that excluded most so-called out-of-merit generators – those generators “re-dispatched” outside the zonal model solution due to transmission constraints which were paid individually on an “as-bid” basis, but subject to bid mitigation. In the Midwest and Southeast, the power pooling arrangements, where they existed, were looser than in the Northeast and under the transmission open access regime of FERC Order 888 [17], utilities and non-utility energy suppliers and arbitragers have heretofore traded bulk power on a purely decentralized basis. Day-ahead forward prices for energy, based on surveys, were published in these regions in the trade press, while utilities reported hourly “system lambdas” under regulatory reporting requirements. Another distinction is that by 2000 there has been substantial divestment of generation by the utilities in the Northeastern states, but much less so in PJM and the Midwest. The utilities in the remainder of the region were largely vertically integrated (and remain so to this date). Even where Eastern US utilities had divested generation assets, there was substantial forward contracting, although this is not public data. The greater the degree of vertical integration or forward contracting, the smaller the motivation for restricting output and raising prices, as has been shown through simulation and in empirical analysis (e.g., [8], [39]). As noted above, the simulations here do not account for this, although the modeling framework can accommodate either designation of actual contracted supply (or supply dedicated to native load obligations, as done in [8]) or sensitivity analyses that apply more generic assumptions about percentages of forward contracting. Rather, in this market model all supply competes for all demand. The market model allows for trade throughout the Eastern Interconnection subject only to congestion costs—akin to an interconnection-wide pool-type market.

A. Electricity Demand and Supply

The Eastern Interconnection as a whole is a summer peaking system (although northern parts of the system may have winter peaks). In 2000, demand in the U.S. portion of the interconnection peaked at 508,204 MW in July [41].

[6] See, e.g., [5] on the Western grid, [12] on the United Kingdom, and [32] on continental Europe.

[7] It is worth noting that these regional aggregations are not intended to imply that they necessarily coincide with “geographic market” boundaries.

The demand scenarios used for the benchmark results are the average actual hourly control area demands, by hour, for June 2000.

We modeled 24 demand periods, each the average for the particular hour over the 30 days in the month for each control area in the system (but not differentiating weekday and weekend). For the remainder of the paper, the daily off-peak hours will refer to the individual model scenarios corresponding to the loads of actual average June hours 1 a.m. to 9 a.m. and 7 p.m. to 12 p.m., while the daily peak hours will correspond to the hourly scenarios modeling 10 a.m. to 6 p.m. For brevity, only the even hours are shown in the tables of results.

On the supply side, there is approximately 600,000 MW of generation capacity (summer available capacity) in the Eastern Interconnection—on average, roughly a 15% margin over peak summer demand. This capacity is represented in the model by 2725 separate generation units. Ownership of almost all generation capacity was identified. Joint ownership was also represented. Table II compares the total installed capacity in the model by region (row 1) to published capacity assessments for the year 2000 by NERC [41], regional reliability councils and ISOs (rows 2 and 3). The table shows that the modeled capacity is quite close to the actual reported capacity (often slightly overestimating the capacity); the difference in MAIN between the regional assessment and the other estimates is probably due to small municipal generators counted in the regional assessment.

Some further adjustments were made to the generator data to reflect forced outage rates (FOR), actual outages, and capacity factors that reflect the actual usage of hydroelectric resources. No downward adjustments were made for capacity devoted to operating reserves; during periods of short capacity, this omission could bias prices downwards. The theoretically correct way to handle such reserves is to add market clearing conditions for reserve markets, each with its own price variable; capacity that is devoted to reserves then cannot be used for energy. However, in all hours simulated in our model, there was ample excess capacity, so the effect of this omission is, we believe, negligible in this case. Although we model a 24 hour period, each hour period is a separate static model. There is no endogenous unit commitment in the model nor are the 24 hours subject to intertemporal production decisions, with the exception of assumptions made for pumped storage units, whose output was approximated by scheduling production during the peak hours. The output that resulted was checked against report monthly output and found to be very similar. All conventional hydro was assumed to release equally in each hour, limited by an capacity factor estimated from data on the total monthly energy output of each plant and state-level averages where such data was not available. Hydroelectric resources were modeled at a positive but small marginal cost.

Supply from outside the U.S. Eastern Interconnection is negligible to most parts of the system, with a few exceptions, such as New England and New York. The average hourly interchange at the boundaries of the U.S. Eastern Interconnection (to the WSCC, ERCOT and Canadian provinces) was based on either actual hourly import and export data or on average seasonal data in summer 2000 (where there was no public hourly data available). These flows were fixed at their net imports for the hour in question.

TABLE II

Generation Capacity (MW) in Model, Summer 2000.

	ECAR	**MAPP**	**MAIN**	**SPP**	**PJM**
Modeled Capacity	108,130	36,084	55,729	42,415	58,104
Regional Assess.	108,377	33,260	63,238	42,367	
NERC Assess.	107,628	41,218	54,776	42,367	58,256
	New Eng.	**New York**	**SERC**	**FRCC**	
Modeled Capacity	25,947	37,552	163,068	39,580	
Regional Assess.	25,628	34,699	153,471		
NERC Assess.			161,459	38,948	

B. The Transmission Network

The Eastern Interconnection transmission grid is represented here using a DC load flow network model that consists of power transfer distribution factors over 840 monitored transmission constraints (usually a transmission line, set of lines, or a transformer), or flowgates,[8] that determine the flows among 85 control areas (in June 2000) internal to the system and 15 boundary locations.[9] Each flowgate has a flow limit (estimated or reported physical or contingency limits, depending on availability). Some of the network data are available publicly, but some are not.

The control areas vary widely in geographical scope, varying in size from the transmission system of a single small utility to large, integrated systems encompassing several utilities, such as PJM. Because transmission congestion internal to control areas is not captured, this network representation will not reflect the market power that might result from internal redispatch of the ISO or RTO system.

V. Perfect Competition Benchmark

A benchmark model of perfect competition was used to calculate locational shadow prices (or marginal costs) for energy at each control area. Table III shows the modeled wholesale generation prices aggregated in the manner described in Section IV. Prices are highest among the Northeastern ISOs and in parts of the Southeastern region, while

[8]The flowgates were defined by the North American Electric Reliability Council (NERC). NERC flowgates are used for bilateral transmission scheduling to monitor transmission elements that create limits to inter-control area transfer, whereas intra-control area congestion not due to such transfers is assumed to be handled by each utility through redispatch.

[9]Some additional control areas that were formed in 1999 to 2000, such as several individual generator control areas operated by Enron in the Midwest in that period, are not represented in the transmission network data, but their supply and demand are located in the prior control area. Only one small control area in the Midwest is not represented in the model.

TABLE III

Regional Load-Weighted Average Perfect Competition Prices, Hours 2 to 24 ($/MWh)

Hours:	**2**	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**	**20**	**22**	**24**
Middle Atlantic and Northeastern Region												
PJM-ISO	14.31	14.31	14.31	17.88	20.32	33.1	37.34	38.81	37.82	38.47	37.61	17.88
NE-ISO	24.49	18.4	19.27	32.12	32.12	35.85	36.28	36.28	35.33	36.69	36.63	27.81
NY-ISO	24.88	18.6	19.48	28.63	28.63	32.22	35.85	36.91	35.94	35.85	35.85	28.27
Midwestern Region												
ECAR	12.53	12.24	12.57	13.37	13.78	15.34	17.53	16.79	16.59	16.08	15.55	13.14
MAIN	11.71	11.13	11.71	12.57	13.36	14.08	16.21	15.95	15.85	15.44	14.47	12.42
MAPP	9.89	9.34	9.90	10.40	12.16	11.08	10.95	11.01	10.98	10.68	10.67	10.38
SPP	23.10	19.33	20.10	28.24	33.30	36.80	37.73	39.25	38.52	37.25	36.81	30.37
Southeastern Region												
Entergy	29.79	23.05	23.03	30.14	40.62	43.98	45.28	49.03	47.22	44.12	43.12	35.00
Southern	17.50	16.12	16.19	18.10	20.46	24.65	43.49	47.96	46.53	46.13	31.26	19.07
TVA	13.71	13.94	14.06	14.65	14.6	18.89	43.53	47.12	45.49	41	24.46	14.32
VACAR	14.39	13.68	13.92	14.53	15.42	19.16	34.89	40.83	40.49	51.59	32.92	15.43
FRCC	35.6	28.33	34.44	40.34	46.98	49.61	51.53	53.05	51.53	49.61	47.29	40.76

most of the Midwest has the lowest prices, with the exception of some areas of SPP.

For the period examined, the modeled energy prices were compared for (rough) validation purposes to reported ISO prices and utility "system lambdas" (see [26], Tables 8.5-8.6). However, the often poor quality of the reported lambdas in some control areas (e.g., little variation in the reported lambda across the month) means that the usually modest divergences between lambdas and our prices in those regions should not be of concern. As examples, the average (across hours) percentage difference between our competitive simulations and the reported ISO prices and system lambdas are as follows: PJM (+1.7%), ISO-NE (-23.3%), NYISO (-9.6%), AEP (+13.2%), Duke (+9.9%), TVA (-17.7%), Florida (+5.1%). The average of these values is 3%. In the Northeastern markets, the benchmark prices corresponded well to the reported ISO prices during the off-peak hours. However, from hour 10 to hour 18, roughly the daily peak hours, the deviations between the benchmark prices and the higher actual prices grow in New England and New York, but remain relatively small in PJM. At the level of aggregation of this model, it is difficult to explore this divergence in price results, since they could be the result of many factors, including intra-zonal congestion, unit commitment constraints, environmental restrictions, and market power. At the least, since some of the latter are additional constraints, it would be expected that the benchmark prices would be consistently lower than the ISO prices; this is indeed the case in each ISO for the peak hours. In the early morning hours, the benchmark prices are often slightly higher than the actual prices. This may be because, in general, the dynamic constraints that we do not model, including ramping limits (MW/min), minimum run levels (hours), and other unit commitment constraints, can depress prices in markets. For example, minimum run constraints can result in negative prices at night, while ramping constraints during ramp down periods can lower prices; our model, which considers each hour separately and disregards such constraints, would yield higher prices than if these constraints are considered.

In the Midwestern region, ECAR, MAIN and MAPP benchmark prices are the lowest due to the prevalence of large nuclear and coal plants in these areas, and, with some exceptions, hourly benchmark prices correlate fairly closely to reported hourly system lambdas. In SPP, about half of the control areas had prices similar to the rest of the Midwest (less than $20/MWh), while the other half, where gas-fired generation was often on the margin, had among the highest prices in the region. This detail is not evident in the average SPP prices in Table III. The SPP benchmark prices were poorly correlated with reported system lambdas, perhaps reflecting poor network representation, other constraints on trade, or poor data. In 2000, some SPP supply functions had very sharp jumps in cost between coal and gas generation and these jumps took place at the average load levels that we modeled, making the model prices very sensitive to changes in demand data.

In the Southeastern region, benchmark prices and system lambdas generally tracked reasonably closely in the off-peak hours but then diverged quite markedly in the peak hours. In general, again, the benchmark price was lower than the system lambdas. Given the poor quality of the public data on system lambdas, at least for purposes of validating simulation models, as well as the limitations of our model, we could not explore the divergence of the benchmark prices and system lambdas in much detail. Obviously, if such a model was developed for regulatory purposes, the benchmark simulation would have to be done at a much higher level of accuracy (and even then, the subsequent market power simulations would introduce additional errors). Nevertheless, we were quite satisfied with the results that we obtained from the public data.

VI. Market Power Simulations

As noted, the objective of this research was to demonstrate a large-scale application using relatively simple models of strategic behavior that could be used alongside the existing market power screens used by regulators. To facilitate the computations, we made some further simplifying assumptions that would not be necessary if a regulator were to invest in actual model development. For example, to reduce the size of the model, we divided the firms into strategic (Cournot) firms and competitive fringe firms.[10] In this analysis, each firm is modeled as Cournot if it has total generation capacity in the Eastern Interconnection of equal to or greater than 1000 MW (not all of which is necessarily in one control area). This size requirement (equivalent to one large baseload unit) is quite small relative to the scope of the regional markets being simulated, and is a reasonable lower bound for the size of market power-exercising companies. This arbitrary cut-off results in 99 Cournot firms and over 200 competitive fringe firms (along with a category of non-utility generators (NUGs) that includes many individual generators) represented in the Eastern Interconnection. Consequently, 87% of the model's generation capacity is modeled as under Cournot firm ownership.

A requirement of the Cournot model is that the demand curve must be negatively sloped; morevoer, our use of linear models requires linear demand functions (i.e., with nonconstant elasticity). Since we cannot fully specify the demand curves for wholesale power using actual data, the normal recourse is to conduct sensitivity analysis on the assumed linear demand curves. In this analysis, we defined demand curves for each control area based on the nodal price-quantity pairs from the perfectly competitive solution. Four different demand elasticities are considered in the sensitivity analysis, ε_D = -0.2, -0.1, -0.05, and -0.01, as shown in tables IV - VI. The full mathematical formulation of the model is provided in the appendix and related formulations are described in [26], [29], [30], [38].

In each hourly scenario that we examined, price-cost margins (PCMs), defined as the Cournot model price minus the perfect competition model price divided by the Cournot model price, are calculated. This resulted in PCMs at 85 locations within the Eastern Interconnection, which is a substantial level of spatial detail even at the level of control area aggregation.

A. Middle Atlantic and Northeastern United States

Although this analysis was not intended to provide insight into actual markets (but rather to provide illustration of potential applications), the results are worth examining as roughly suggestive of the actual situation in July 2000 in the Eastern Interconnection under the stated assumptions.

We begin with our results for PJM, New England and New York. In these regions, the high degree of divestiture and the general practice of scheduling all generators through the spot market makes the modeling assumption that generation is fully separate from load more tenable than in other parts of the Eastern Interconnection (although at least in PJM, the continued vertical integration would presumably dampen generation market power). Unfortunately, as noted above, each of these markets is a single control area, and so is represented as a single network location in the model. Hence, the often severe localized market power problems, for example in New York City and the Boston area, are not reflected in our spatial results, nor are the countervailing effects of local market power mitigation measures that are in place in such areas. Such local problems can arise in load pockets, where transmission constraints into an area of high demand can bestow market power on local geenration, or in other situations where complex network effects mean that only a few generators are able to relieve a particular transmission constraint. This modeling shortcoming can be partially overcome by modeling generators in load pockets as competitive suppliers, given that offer caps in actuality mitigate much of their locational market power. But we did not have sufficient network data to make such a distinction feasible in our modeling. Despite these shortcomings, when comparing our results to the actual estimates of market power in those areas, as done below, we can safely assume that given the offer caps addressing locational market power, we can roughly interpret our model PCMs as comparable to the parts of the system outside load pockets and assume that the lack of load pocket transmission constraints in the model diminishes the locational market power to a level comparable with that exerted by the offer caps. Ideally, the network model would be refined to reflect the load pockets.

The Cournot models' prediction for market power in this region, as summarized in Table IV, is largely in keeping with prior expectations and empirical evidence where available (e.g., [7], [43]). With low and declining concentration of ownership, there were few large dominant firms in 2000. The internal control area HHIs, incorporating imports, as calculated by ISO market monitors (and also calculated in this model by us), are reasonably low [42], [43]. The lowest concentration occurs in New England, which also has the lowest simulated PCMs. Also, in 2000 the region experienced mild summer weather. The resulting PCMs are low throughout the region, only rising above 10% (with a few exceptions) at an elasticity of ε_D = -0.01. Due to network effects, there are negative PCMs of a small magnitude in a number of hours; however, the load-weighted average PCM in each subregion and in the Eastern Interconnection as a whole is always positive.[11]

Returning to the results in such a network model, while it will require work to interpret the results, the level of detail does allow the analyst to see interesting relationships, some intuitive, some not, that could have implications for market monitoring and regulatory decisions. As one example, we examine the simulation results for PJM (prior to its market expansions in 2004) in more detail. As modeled, there are 12 Cournot firms with plants in the region (with 8 of these located solely in PJM) and up to 15% of the capacity is provided by competitive fringe firms. PJM also

[10] Competitive fringe firms are modeled as price takers whose profit maximization problems result in fewer first order conditions than the strategic firms, thus reducing model size (see the appendix). Small size relative to the market is the simplest economic measure for determining which firms could be price-takers, although this is a less straightforward rationale in the presence of transmission constraints.

[11] There are several examples in the literature in which network effects causes counter-intuitive movements in prices in response to changes in market concentration. For instance, [3] describes how breaking up a large generating company at a location that is close to a congested interface results in the company producing more power, exacerbating congestion and actually increasing prices in much of the network and lowering overall consumer surplus.

can import (or export) up to about 4-5% of its hourly load during the period modeled. PJM is a net exporter during the off-peak hours of the day, when power flows from and through PJM to New York, and a net importer during the peak hours of the day. This hourly trading relationship is captured in the benchmark model results and in the market power scenarios. An interesting market power result is that modeled PJM PCMs, while low generally, are higher in the (average) off-peak daily hours than in the peak daily hours. This dilution of market power in the peak hours is likely due to three main factors. Two result in a leftward shift in the effective demand curve facing PJM suppliers in the daytime: the effect of actual trade, as imports rise over the day and potentially dilute the market power of the internal PJM suppliers, and the release of 1300 MW of pumped storage from hours 10 to 18. (However, in theory, pumped storage could also increase the elasticity of night-time effective demand by refraining from pumping, but we only consider fixed pumpage schedules in this model. Consequently, we may slightly overestimate price mark-ups.) The third factor is greater potential supply rather than actual supply: in particular, what we have designated as fringe, or competitive, supply, has a larger share of total market capacity at marginal costs above $30/MWh, allowing fringe output to diminish the Cournot firms market power more as the hourly price rises over the day.

B. Midwestern United States

In areas outside the ISO markets in 2000, our interpretation of the price results becomes more problematic because we did not consider forward contracts or "native load", both of which would clearly influence the short-term market power of the primarily vertically integrated utilities in these regions. Nevertheless, our results are roughly indicative of the prevailing market structure as reflected in ownership of generation capacity. Thus, these results should be interpreted as indicating a high potential for market power in this region if restructuring is not accompanied by measures to encourage significant forward contracting.

In 2000, the wholesale power market in the Midwestern United States was largely composed of vertically integrated utilities making bilateral sales, with some significant non-utility generation in parts of ECAR [48].[12] Without considering the effects of transmission constraints, market concentration based on installed capacity was highest in the ECAR region, which included large multi-state utilities such as American Electric Power (AEP) and First Energy, followed in rank order by MAIN, SPP, and MAPP. This market concentration is reflected in the differences in the average regional PCMs shown in Table V. However, it is important to understand that the PCMs in this area are calculated relative to a regional supply function that is generally much lower cost than the northeastern markets. The reader can get a sense of that from the benchmark price results in Table III. Hence, the PCMs may not reflect much higher modeled prices than the benchmark model.

[12]Since 2000, much of the region has become part of a centralized ISO market with locational pricing under either PJM or the Midwest ISO.

C. Southeastern United States

Like the Midwest, the Southeastern region was in 2000 (as it is today), composed largely of vertically integrated utilities and the publicly owned TVA. Again, we did not account for forward contracts or native load obligations, and under these structural assumptions, the resulting PCMs are shown in Table VI. Notably, TVA modeled as a (very large) strategic firm dominating its control area has in some hours the highest PCMs in the Eastern Interconnection; given that there are restrictions on its ability to market power, it could alternatively be modeled as a competitive supplier (and sensitivity analyses were conducted under this assumption). SOCO and VACAR have similar high PCMs relative to other locations in the region, reaching the 20% range in the ε_D = -0.1 case. Entergy, despite its high ownership concentration, has the lowest PCMs in the Southeastern region at each demand elasticity. Florida also has low PCMs relative to other locations in this region; this is likely due in part to the modeling of the state as one transmission unconstrained zone.

The subregions of SERC differ in which hourly periods have the highest PCMs. In the Entergy subregion, PCMs are generally higher during the peak hours 13 - 18. In contrast, in all the other subregions of SERC, the highest PCMs are in the offpeak hours. This is a result similar to that in PJM.

VII. Discussion of Results

The market power simulations reveal a number of expected and unexpected results. On a regional basis, the model results suggest that in June 2000, the relatively unconcentrated Middle Atlantic and Northeastern region supported the most competitive wholesale market in the Eastern Interconnection. Also, parts of MAIN, MAPP and SPP appeared to be also reasonably competitive under the stated assumptions about market structure. However, the high concentration of generation ownership in parts of ECAR and the Southeastern region underlie the higher PCMs in those regions. Again, these are indices of potential market competitiveness. If vertical integration or forward contracting was taken into account, market power analysis of these utilities would show different results.

One unexpected result that merits further investigation, through sensitivity analysis and empirical analysis of the actual markets, is the finding that in many control areas, daily off-peak PCMs were sometimes higher than peak PCMs. This is assumed to take place generally in the model because of the relatively concentrated ownership of base-load units. Hence, it draws attention to the potential for some degree of market power in unexpected hours of the day. However, this finding's implications for monitoring of wholesale markets could be over-stated, since large nuclear and coal plants are subject to a great deal of regulatory

TABLE IV

Middle Atlantic and Northeastern Region, PCMs at $\varepsilon_D = 0.2$ - 0.01, Hours 2 to 24 ($/MWh)

Hours:	**2**	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**	**20**	**22**	**24**
PJM-ISO												
$\varepsilon_D = 0.2$	7.68	5.61	6.90	3.30	7.13	0.00	1.27	-0.39	1.64	1.71	-0.24	5.75
0.1	14.16	10.39	12.69	9.05	13.20	0.00	0.48	-1.38	1.92	2.01	-1.70	10.87
0.05	23.19	19.02	20.50	18.24	22.94	0.00	-6.17	-5.43	-4.30	1.00	-6.15	18.76
0.01	55.46	52.76	54.56	53.58	52.80	31.71	32.73	31.33	32.86	27.70	26.73	52.47
NE-ISO												
$\varepsilon_D = 0.2$	-1.24	0.05	0.10	2.55	2.43	0.00	0.17	0.08	2.11	0.00	0.00	0.36
0.1	-1.11	0.81	1.48	4.97	4.72	0.77	1.12	1.12	3.15	0.00	0.00	1.00
0.05	-1.62	6.88	6.14	8.52	7.36	1.70	4.25	5.03	3.73	2.11	0.16	1.80
0.01	21.66	37.90	37.70	15.14	23.99	24.19	27.44	27.25	28.07	27.70	25.74	23.87
NY-ISO												
$\varepsilon_D = 0.2$	-1.43	-0.16	-0.10	0.07	1.17	0.22	2.40	-0.03	1.99	2.18	0.50	0.18
0.1	-1.43	0.48	1.17	0.42	2.42	0.43	2.82	0.43	2.84	2.71	-1.27	0.70
0.05	-2.22	6.49	5.71	1.21	3.89	4.67	3.45	2.23	1.51	4.76	-5.50	1.26
0.01	20.84	37.52	37.28	24.66	32.54	32.23	28.50	26.22	27.14	29.80	27.84	23.05

TABLE V

Midwestern Region, Regional (Load-Weighted) PCMs at $\varepsilon_D = 0.2$ - 0.01, Hours 2 to 24 ($/MWh)

Hours:	**2**	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**	**20**	**22**	**24**
ECAR												
$\varepsilon_D = 0.2$	10.03	9.67	9.98	11.86	13.19	10.48	7.01	9.04	8.90	12.05	10.16	11.35
0.1	16.88	15.26	17.14	20.79	23.84	21.41	20.33	22.71	21.77	23.05	20.78	20.01
0.05	26.94	25.60	26.60	32.66	36.75	34.91	33.62	36.09	35.17	34.87	33.49	31.55
0.01	55.31	54.55	55.70	61.41	64.15	63.60	65.21	66.65	65.90	66.21	64.28	59.62
MAIN												
$\varepsilon_D = 0.2$	5.09	7.27	5.37	8.51	8.95	7.66	6.20	7.53	7.12	8.92	7.48	7.66
0.1	11.79	13.21	12.64	15.08	16.06	16.46	16.10	17.50	16.45	17.18	16.29	14.87
0.05	22.22	23.35	22.02	26.67	27.95	28.91	27.25	28.81	27.76	27.65	28.11	26.17
0.01	53.66	55.56	54.62	58.41	60.63	62.83	64.90	65.11	64.65	64.89	63.34	56.92
MAPP												
$\varepsilon_D = 0.2$	-3.87	0.00	-4.11	1.48	-1.98	0.61	3.45	5.47	5.05	5.26	4.98	0.63
0.1	1.09	4.94	1.57	3.75	-6.31	5.21	11.24	11.33	10.57	11.46	9.13	2.61
0.05	9.62	13.83	9.81	12.53	1.86	13.73	21.20	21.19	20.33	20.03	17.43	10.94
0.01	45.59	47.29	45.21	48.85	46.19	54.78	62.10	62.17	61.91	61.68	58.27	47.14
SPP												
$\varepsilon_D = 0.2$	-1.05	-1.40	0.50	1.22	3.20	2.33	3.24	3.03	3.80	4.14	3.47	2.73
0.1	-0.09	5.07	3.24	4.48	5.99	4.64	7.43	6.68	6.52	7.19	7.10	5.74
0.05	9.98	18.36	16.70	10.82	6.90	9.97	14.60	13.29	13.78	14.88	11.74	8.84
0.01	53.59	52.81	56.42	47.75	43.42	47.92	53.27	55.80	55.98	53.51	49.56	46.99

TABLE VI

Southeastern Region, Regional (Load-Weighted) PCMs at $\varepsilon_D = 0.2$ - 0.01, Hours 2 to 24 ($/MWh)

Hours:	**2**	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**	**20**	**22**	**24**
Entergy												
$\varepsilon_D = 0.2$	-0.56	-1.49	-0.74	4.56	4.04	5.47	4.42	3.17	4.96	6.30	4.88	3.41
0.1	0.87	0.80	3.75	7.31	7.43	7.08	9.83	7.15	7.11	8.95	9.78	7.94
0.05	10.84	25.24	27.29	15.83	9.35	14.03	19.03	14.96	16.30	19.04	14.98	10.14
0.01	57.45	62.63	64.98	61.99	55.74	60.51	66.32	65.10	65.73	66.21	62.75	58.52
Southern												
$\varepsilon_D = 0.2$	13.24	13.65	14.05	15.57	14.28	10.18	4.41	2.26	3.80	4.46	6.95	14.19
0.1	26.32	25.10	27.58	30.31	28.50	22.17	8.20	4.51	4.42	6.20	16.10	27.21
0.05	42.48	42.18	44.03	46.55	45.83	40.70	16.40	11.92	13.25	14.58	32.88	44.38
0.01	73.07	72.77	73.96	75.38	76.09	76.54	67.11	64.97	65.05	63.96	71.85	75.34
TVA												
$\varepsilon_D = 0.2$	20.01	18.43	19.57	20.08	21.00	13.15	3.42	2.38	4.15	4.81	9.44	20.75
0.1	36.97	33.11	33.36	35.94	37.87	30.50	6.17	3.92	3.79	4.89	20.84	37.77
0.05	54.39	50.25	50.67	54.47	56.29	51.51	13.56	8.96	10.54	14.12	42.61	56.68
0.01	79.51	77.62	78.53	80.72	83.63	82.92	68.08	66.49	67.08	68.84	78.45	81.86
VACAR												
$\varepsilon_D = 0.2$	11.88	12.72	11.55	13.36	15.14	10.04	6.90	1.05	1.53	2.18	4.06	12.96
0.1	20.30	21.31	20.16	20.79	25.67	21.79	11.30	3.11	3.17	6.16	12.33	24.08
0.05	34.12	33.79	33.46	36.15	37.18	36.93	19.89	15.55	16.03	11.32	25.78	37.59
0.01	68.26	66.60	66.25	70.56	72.53	71.80	59.89	55.67	56.59	45.25	59.62	71.23
FRCC												
$\varepsilon_D = 0.2$	3.31	0.00	0.00	2.65	3.01	4.72	6.70	4.64	6.72	5.00	3.51	3.02
0.1	4.86	0.00	1.63	3.45	6.06	8.89	10.21	10.46	10.23	9.34	7.74	5.95
0.05	7.53	0.00	7.54	5.04	11.68	14.29	20.12	20.38	20.13	17.25	15.17	11.00
0.01	42.02	49.48	41.13	41.53	41.39	49.63	58.67	58.95	59.14	59.27	55.09	44.06

and public scrutiny as well as market rules in the ISOs and RTOs that prevent physical withholding; coal plants are also typically subject to environmental restrictions that make operating at efficient levels, at the higher range of output, necessary. A sensitivity analysis to model these large units as competitive could offer some insight into the degree of market power available to these plants.[13]

When the results are examined at a less aggregated level, there is a great deal of differentiation in the observed relationships between PCMs and traditional explanatory variables, such as market concentration and load levels. Transmission network effects can confound the expected relationships and suggest new ones.

VIII. Regulatory and Market Monitoring Applications

The large number of market power simulation studies conducted in the US, Europe and other regions using various methodologies have borne some fruit for regulatory decisionmaking. Such simulations have informed market design decisions in at least some US ISOs and RTOs [13]. Market power simulation has also been approved by state regulators to assess the benefits of transmission expansion decisions in California [9] (in a cost-benefit analysis).[14] However, our interest in this paper is in the use of equilibrium market modeling, and whether there are approaches to such modeling that could be used in a standardized fashion for regulatory decision-making that requires analysis of large-scale power systems, such as authorization of mergers and market-based rates. There are several reasons why such a development has not taken place despite the early interest expressed by FERC and the research community [19], in the US or elsewhere. One reason is the proliferation of approaches to such market price simulations – and even modeling using a particular "conjecture", such as Cournot. For example, a survey of model developers in Europe applying Cournot models found that there is still substantial difference in the methods chosen, and the results, when asked to model the same network [40], [2]. Other researchers point to the level of simplification inherent in such large-scale simulations and question whether important regulatory decisions, such as divestiture, should be prompted by such modeling [47]. Yet other reasons are discussed below.

[13] As an anonymous reviewer observed, the higher off-peak PCMs do also appear to contradict empirical evidence of higher PCMs when capacity is short, e.g., [6]. The reviewer suggests that the higher PCMs might in part be because the model is a Cournot model, in which PCMs increase linearly with concentration and the level of excess capacity does not matter, despite evidence to the contrary. However, we note that the load levels modeled here are average loads in June, and do not reflect capacity shortages.

[14] Equilibrium market power simulations were tested for this application [35] but eventually not used due to computational problems. The market power analysis that was ultimately used in regulatory applications was based on econometric analysis of price mark-ups [9]. We note further that equilibrium models, such as the ones presented here, that do not have the computational capability to conduct dynamic simulations over hundreds of hours, as is typically done in cost-benefit analysis, could require that benefits due to diminution of market power are inferred from analysis of particular hours or market conditions.

We agree that any application of simulation models in regulatory proceedings should be done carefully, to avoid adverse market or regulatory outcomes. First, we suggest that the equilibrium market power models are only used as "screens" to prompt further analysis before any regulatory decision in authorization of mergers or market-based rates. That is, such models could be an additional screening step concurrent with the calculation of market shares or concentration indices (that is, the applicant would have to pass all screens to get an unconditional approval, but the simulation screen could, if failed, prompt further investigation). We turn next to how the market models used in this paper, or those with similar properties, could be used in the current regulatory procedures and leave it up to the research community and regulators to determine whether and how to proceed.

A. Merger Analysis and Market-based Rates

Merger analysis and authorization of market-based rates are two areas in which market power screens based on market concentration indices have long been used by US federal regulators [18], [49], [27]. Merger analysis is a well established area of regulatory market power screening, which in the US is largely undertaken by the Department of Justice (DOJ), although mergers of electric power suppliers are evaluated by FERC due to its power industry expertise. A full explanation of the market definition and market concentration screens used in FERC's merger guidelines is beyond the scope of this paper and can be found in [18]. Another related type of market power screening conducted by FERC is for approval of "market-based rates," under which individual suppliers can sell wholesale power at market-determined prices rather than regulated cost-based rates.

Oligopoly equilibrium market models can be applied to these types of screening, but would change the methodologies currently used for market definition and the metrics used for inferring potential market power (the market products evaluated should not have to change). There is a well-known academic literature debating the use of Cournot models for merger analysis (e.g., [15], [16], [24], [37], [44]). We do not address that literature here, but note that since the existing electric merger screening models have obvious weaknesses, the more important question is whether the Cournot network model presented here adds insight or is better suited to assessing evolving market conditions. There are clear ways in which it does both.

Turning first to market definition, in the current tests for mergers and market-based rates, FERC uses historical market sales to define the geographic boundaries of the "destination markets" for the former and geographical proximity for the latter [18]. Hence, in both cases, the destination markets are pre-defined and the analysis of market concentration follows. These models use simplified transmission networks that do not accurately represent network flows. In contrast, in the Cournot equilibrium market models developed here, the geographical scope of the analysis is determined endogenously by the extent of the network

[INSERT FIGURE 1 – APPENDED TO DOCUMENT]

Fig. 1. Scatterplot of HHIs and PCMs

representation and supply and demand data. There is no need to establish sub-market boundaries *ex ante*, which is useful given the shifting trade patterns that take place in the actual regional U.S. power markets. Rather, the spatial differentiation of the PCMs alerts the regulator to locations of market power concern under a particular market structure [26], [37]. Using a full interconnection model such as the one in this paper would eliminate all market definition requirements, especially with additional network detail in the areas of the interconnection where the applicant's generation units are located.

A second area of improvement is that the current screens rely on indicators of market concentration—changes in HHIs for merger analysis and market share, pivotal supplier tests or HHIs for market-based rates—which, as discussed above, are poor indicators of potential market power in electric power markets. Figure 1 shows a scatter plot of import adjusted capacity HHIs (i.e., based on ownership of generation capacity) calculated using the model data against simulated PCMs, showing that such HHIs are only weakly correlated with potential PCMs due to the distribution of ownership and transmission network effects.[15] Similar tests on output HHIs (i.e., based on sales by each firm) suggested that they are equally weakly correlated with PCMs across the full network.

A market price simulation model thus changes the market test from a change in concentration indices to a change in PCMs. For merger analysis, the changes in PCMs would result from pre- and post-merger simulations, and their spatial distributions would define the "market" locations of concern. These are likely to be different under different market conditions (e.g., peak versus off-peak hours or days). Figures 2 and 3 show the simulated price changes (not PCM changes) – i.e., pre- and post-merger – that result in the model from a hypothetical merger between two large utilities in the Midwest, located in the reliability region that was known in 2000 as ECAR. Figure 2 shows results aggregated at the level of reliability regions. This shows how the price effects would disperse to some degree over a large region, overall raising prices, but due to network effects also lowering prices in some locations. Since the regulator would have to determine what are significant positive changes in prices for screening purposes, Figure 3 drills down to the level of each control area within ECAR. This figure shows that due to the proximity of these control areas, price changes are closely correlated and possibly sufficient in some locations to raise regulatory interest. In some locations, prices have increased by between 15% - 20% due to the merger.[16]

[INSERT FIGURE 2 – APPENDED TO DOCUMENT]

Fig. 2. Merger Simulation Results by Reliabilty Region

[INSERT FIGURE 3 – APPENDED TO DOCUMENT]

Fig. 3. Merger Simulation Results by ECAR Control Area

For market-based rates, the change of concern to regulators is not in market structure (as in mergers), but rather in presumed behavior when a supplier with market power is authorized to sell at market-based prices. The obvious approach to this analysis in this modeling framework is to model the market with and without the applicant as a "strategic" player. Changes in PCMs would be suggestive of market power capability. Some determination is needed of which other firms to model as strategic; a first cut would certainly be all other firms that already have market-based pricing authority.

In both cases, clearly, the regulator would have to define a change in pre-merger and post-merger simulated prices or PCMs that were considered to fail the screens. We do not offer any judgment about what this measure should be. The current merger screens use thresholds such as 5% - 10% increases in market prices over the long-term.

To adapt equilibrium market modeling methods on detailed network models to standardized regulatory proceedings will obviously be difficult. It appears appropriate that the regulatory agency should at least provide a standard DC load flow network model, or perhaps undertake the full analysis on its own in response to applications. This increased demand on the resources of the regulator is in fact one reason why FERC has not moved towards such modeling over the years. No *ex ante* modeling analysis can forecast all the potential market power implications of changes in market structure or behavior. So the added detail and analytical precision of the equilibrium model should not be taken as a necessarily more reliable indicator of potential generation market power. But in the absence of an organized market environment with market power mitigation, such as found in ISOs and RTOs, reliance on such screens will continue, and more robust replacements for the existing methods sought. Even in organized markets with market power mitigation, mergers that substantially increase market concentration may create subtle effects on the exercise of market power that simulations could help identify ahead of time.

B. Analysis of Spot Market Performance and Market Power Mitigation Methods

As discussed in the prior section, the large-scale network market models presented here were first concieved as advances in merger and market-based rates screening. However, with further development they could be used to evaluate the market power mitigation methods used in centralized ISO and RTO spot auction markets. Spot market mitigation of market power is largely based on two elements:

[15] The correlation coefficient is 0.19. Note that PCMs are expressed as a percentage in the figure.

[16] The particular price change results are, of course, sensitive to elasticity and forward contracting assumptions. However, the general geographic price results (close correlation within a region, diminishing influence further away, and occasional changes in signs of the effects) are more robust.

the monitoring and prevention of physical withholding by suppliers and the prevention of economic withholding by screening price offers submitted by suppliers into the day-ahead and real-time spot markets [27]. In the US markets, all spot offers currently have an absolute cap, which is \$1,000/MWh. The screening of offers below that cap then typically also attempts to prevent locational market power due to transmission congestion. If spot offers subject to locational market power mitigation fail the auction market screen, they are mitigated and the spot market prices re-calculated. Typically, the mitigated bid is based on a reference mitigated value for each market offer, either an estimate of their marginal costs or a proxy value for their marginal cost based on an average of their prior accepted bids.

The *ex ante* screening and mitigation of price offers due to transmission congestion is a type of market regulation that the simulation models presented here could inform. The locations that are subject to mitigation can be pre-identified for periods of time or identified hourly.[17] Market price simulations under different system conditions could be used to check assumptions used in constructing these screens, whether to identify locations that should be subject to mitigation, or more restrictive mitigation, or to those where mitigation could perhaps be loosened (depending on the mitigation approach being employed). It is important to note that FERC has required that ISOs and RTOs implement "scarcity pricing", under which market prices are increased administratively in periods of supply shortage, in part to compensate for the very restrictive hourly offer mitigation that exists in the ISO and RTO markets.

C. Ex Post Market Analysis

With some effort, the regional models presented here could be used to evaluate market price outcomes *ex post*, whether in the ISO/RTO markets or in the bilateral markets outside them (since both types of markets are encompassed in the US Eastern Interconnection). As noted above, some ISO and RTO market monitors calculate *ex post* PCMs, as have some researchers (e.g., [7], [8]). But because of the existing market power screening and mitigation, empirical analysis cannot address the counterfactual question of how much potential locational market power was there in the first place. Network-constrained market power simulation can explore this question, perhaps leading to changes in the calibration of the spot market market power screens over time.[18] Outside the organized markets, *ex post* analysis would have to rely on forward bilateral prices reported in the trade press and the comparison with simulated prices would be more difficult to interpret accurately. Nevertheless, one of the advantages of the modeling presented here is the ability to conduct simulations across a large interconnected region regardless of market organization in different parts of the region.

IX. Conclusions

Large-scale equilibrium modeling of regional wholesale power markets with hundreds of strategic firms represented and locational marginal pricing can improve insight into generation market power in these markets, despite the enormous amount of data and modeling detail that need to be gathered and analyzed. As the transmission network is modeled more accurately, locational PCMs exhibit much greater spatial differentiation and the factors that affect them can be examined with more depth—although one important caveat worth noting again is that suppliers are assumed here to be naive with respect to their ability to influence congestion. In this examination of the U.S. Eastern Interconnection, the assumptions were that generation ownership was separate from retail load and that there were no forward contracts, hence the purpose was not to evaluate actual prices in the period modeled. However, the market power results under these assumptions did suggest that large parts of the region were relatively competitive under these assumptions for the period modeled, while other regions would be vulnerable to market power if not diminished by divestiture, forward contracting or spot market mitigation measures. In the Eastern ISOs, the simulated PCMs were quite small until fairly inelastic demand was assumed. These results correspond to the observed mark-ups in the transmission unconstrained parts of the ISO markets for the period and conditions simulated (but not for conditions of tight supply). Large parts of the Midwest were also relatively competitive, while the areas of the Midwest and Southeast with very large regulated utilities had the highest concentration of supply and hence the highest PCMs under these assumptions. However, in much of this region, the benchmark competitive price was low, hence a high PCM does not necessarily indicate a very high price mark-up in absolute terms.

The advances in large-scale market simulation modeling demonstrated here and elsewhere in the literature may allow such methods to contribute to standardized regulatory decisions with respect to market power mitigation. A possible use illustrated here is for horizontal market power screening of applications for mergers and market-based rates. Reliance on calculations of market concentration indices, as is done currently for these regulatory procedures, has clear shortcomings in electric power markets with AC transmission networks and congestion. In the US, given the failure to advance such uses of market price simulations at FERC heretofore, it appears that any

[17] Pre-identification of locations is usually based on generation shift factors over congested transmission paths. For example, the California ISO mitigates offers from generators with shift factors that affect congestion on pre-identified transmission paths deemed "non-competitive." An example of an approach initially employed by PJM that did not require pre-identification of congested paths, is to mitigate the offers of all "out-of-merit" generators. That is, any hourly offer from a generator that was incrementally dispatched due to congestion would be mitigated.

[18] Perhaps more controversially, where unmitigated supply offers can be analyzed, empirical analysis has been used to infer that market participants were acting under a particular strategic assumption (e.g., [6], [36]). The finding that behavior appeared to correspond to, say, Cournot assumptions, could help validate (or not) the use of particular oligopolistic models for such analysis.

movement toward standard regulatory uses of such models will require a concerted effort by researchers in this field to present a common approach with supporting evidence. There is also the need to find a constituency among market participants that would argue for its benefits. Finally, there may be additional applications of such large-scale models that improve *ex ante* and *ex post* market power monitoring and mitigation in the organized power markets operated by ISOs and RTOs.

Appendix

Mathematical Statement of the Reduced Cournot with Endogenous Arbitrage Market Model

This appendix presents the Cournot network equilibrium model discussed above, based on the POOLCO models in [29] (see also [26], [30], [38]). All the mathematical notation is standard; the symbol $\perp$ defines a complementarity condition.[19]

A. Model Notation

Sets

$t, f \in F$, indices and set of all firms,
$h \in H$, indices and set of generation resources,
$i, j \in I$, indices and set of nodes other than the reference bus or "hub" node,
$k \in K$, index and set of transmission flowgates,

Parameters

C_{fih}, marginal cost (\$/MWh) of firm f's generator h at node i,
P_i^o, price (\$) intercept of demand curve at node i,
$PTDF_{ik}$, power transfer distribution factor from hub node to node i over flowgate k,
Q_i^o, quantity (MWh) intercept of demand curve at node i,
T_{k-}, negative direction capacity (MW) for transmission over flowgate k,
T_{k+}, positive direction capacity (MW) for transmission over flowgate k,
X_{fih}, generation capacity (MW) of generator h,

Variables

a_{fi}, arbitrage (MWh) by firm f from node i to the hub node,
p_{Hf}, price at reference bus or hub node (\$/MWh),
w_i, congestion charge (\$/MW) for wheeling energy from node i to the hub node,
x_{fih}, generation (MWh) by firm f's generator h at node i,
y_i, transmission (MW) from the hub node to node i,
α_{fi}, dual variable for arbitrage constraint (no price discrimination) of firm f at node i,
β_f, dual variable for arbitrage balance constraint of firm f,
λ_{k-}, dual variable for capacity constraint in "negative" direction on flowgate k,
λ_{k+}, dual variable for capacity constraint in "positive" direction on flowgate k,
ρ_{fih}, dual variable for generator capacity of Cournot firm f',
θ_f, dual variable for energy balance constraint of Cournot firm f',

Definitions

$$\bar{x}_{ti} \equiv \sum_{t\in F, h\in H(t,i)} x_{tih},$$
$$x_{fi} \equiv \sum_{h\in H(f,i)} x_{fih}.$$
$$x_{-fi} \equiv \sum_{t\neq f, t\in F, h\in H(t,i)} x_{tih}.$$

B. Cournot Firm's Problem

For each Cournot firm f, the problem is to find x_{fih}, a_{fi}, p_{Hf} to solve:

$$\max \sum_{i\in I}[P_i^o - \frac{P_i^o}{Q_i^o}(\bar{x}_{ti}+a_{fi})](\sum_{h\in H(f,i)} x_{fih}) - \sum_{h\in H(f,i)} C_{fih}x_{fih},$$

$$\begin{array}{llll} \text{s.t.} & x_{fih} \le X_{fih}, & (\rho_{fih}) & \forall i,h, \\ & P_i^o - \frac{P_i^o}{Q_i^o}(\bar{x}_{ti}+a_{fi}) = p_{Hf} + w_i, & (\alpha_{fi}) & \forall i, \\ & \sum_{i\in I} a_{fi} = 0, & (\beta_f) & \forall i, \\ & x_{fih} \ge 0, & & \forall i,h. \end{array} \tag{1}$$

In the case of competitive fringe firms, this problem is greatly simplified. Instead of price as a function of own and rivals output variables, the price variable is instead substituted in the objective function, and the second and third constraints (which represent how a Cournot generator expects that market prices and arbitrage will react to its output changes) are no longer needed. The Karush-Kuhn-Tucker (KKT) conditions of the Cournot firm's problem with respect to x_{fih}, a_{fi}, p_{Hf}, ρ_{fih}, α_{fi}, and β_f, respectively, are:

$$\begin{aligned} 0 \le x_{fih} \perp P_i^o - \tfrac{P_i^o}{Q_i^o}(2x_{fi} + x_{-fi} + a_{fi}) & \\ - C_{fih} + \tfrac{P_i^o}{Q_i^o}\alpha_{fi} - \rho_{fih} \le 0, & \quad \forall i,h, \end{aligned} \tag{2}$$

$$\tfrac{P_i^o}{Q_i^o}(\alpha_{fi} - x_{fi}) - \beta_f = 0, \quad \forall i, \tag{3}$$

$$\sum_{i\in I} \alpha_{fi} = 0, \tag{4}$$

$$0 \le \rho_{fih} \perp x_{fih} - X_{fih} \le 0, \quad \forall i,h, \tag{5}$$

$$P_i^o - \tfrac{P_i^o}{Q_i^o}(\bar{x}_{ti} + a_{fi}) = p_{Hf} + w_i, \quad \forall i, \tag{6}$$

$$\sum_{i\in I} a_{fi} = 0. \tag{7}$$

[19] Given a vector x and a function $f(x)$, $x \ge 0 \perp F(x) \le 0 \equiv x \ge 0,\ F(x) \le 0,$ and $x^T F(x) = 0$.

C. The Regional Transmission Organization's Problem

The RTO's problem is to find y_i to solve:

$$\max \sum_{i \in I} w_i \, y_i,$$

$$\begin{aligned} \text{s.t.} \quad & -\sum_{i \in I} PTDF_{ik} \, y_i \leq T_{k-}, && (\lambda_{k-}) \quad \forall k, \\ & \sum_{i \in I} PTDF_{ik} \, y_i \leq T_{k+}, && (\lambda_{k+}) \quad \forall k, \\ & \textstyle\sum_{i \in I} y_i = 0, && (\nu), \end{aligned} \tag{8}$$

where the objective function is to maximize the sum of congestion revenues from each node i to the hub node, H, and the two constraints maintain physical feasibility by limiting the flow over each flowgate, k, to the transmission capacity of the flowgate.

The KKT conditions of the RTO's problem with respect to y_i, λ_{k-}, λ_{k+}, and ν, respectively, are:

$$w_i - \nu + \sum_{k \in K} PTDF_{ik} \, (\lambda_{k-} - \lambda_{k+}) = 0, \quad \forall i, \tag{9}$$

$$0 \leq \lambda_{k-} \perp -\sum_{i \in I} PTDF_{ik} \, y_i - T_{k-} \leq 0, \quad \forall k, \tag{10}$$

$$0 \leq \lambda_{k+} \perp \sum_{i \in I} PTDF_{ik} \, y_i - T_{k+} \leq 0, \quad \forall k, \tag{11}$$

$$\sum_{i \in I} y_i = 0. \tag{12}$$

D. Market Clearing Condition

$$a_{fi} = y_i, \quad \forall f, i. \tag{13}$$

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