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The impact of coordination on wholesale market participation: The case of the U.S. electricity industry

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ABSTRACT

Coordination costs in a wholesale electricity market are a relevant public policy consideration. The mitigation of coordination costs, all else equal, should increase participation in the marketplace. Since Federal Energy Regulatory Commission (FERC) Order 888 was issued in 1996, the level of trading activity in bulk electricity markets has increased significantly. In 1999, FERC issued Order 2000 to advance the role of regional transmission organizations (RTOs) in the restructured marketplace for wholesale electricity. RTOs have the potential to reduce the coordination costs, while also having the countervailing effect of causing market participants to incur compliance costs. This paper utilizes the diversity of the United States electricity market and a panel data set representing electric utilities for the period 1990–2009 to study the effects that RTOs have had on wholesale electricity exchange. The paper finds that the presence of a transparent wholesale marketplace for electricity has the effect of increasing participation, but this participation is uneven across types of electric utilities. Greater participation is seen for investor-owned and larger utilities. The results have important implications for policy aimed at wholesale markets and the transmission organizations, as the opportunities afforded by transparency may not be uniformly distributed across all market participants.

1. Introduction

On December 20, 1999, the Federal Energy Regulatory Commission (FERC or "the Commission") issued Order No. 2000 in Docket No. RM99-2-000, a docket opened to explore the role of Regional Transmission Organizations (RTOs) in the restructured electricity marketplace. The role of a RTO is to administer the electric transmission system, ensuring open access to the grid for all electricity generators. The FERC noted that since FERC Order 888 was issued in 1996, trade in the bulk electricity markets had increased significantly. FERC also noted that during the Notice of Proposed Rulemaking process for the instant docket, the Commission had "reviewed evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets, and that continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding fully competitive electricity markets."[2] FERC further enjoined utilities, state officials, and affected interest groups to voluntarily develop RTOs. Despite the urging of FERC, there remain substantial portions of the United States electricity grid that are not administered by RTOs or Independent System Operators (ISOs). While there are structural differences[3] between the two types of organizations, the basic function of providing transparency in wholesale electricity pricing remains. Since that is the function analyzed in the paper, the terms ISOs or RTOs as used here are effectively indistinguishable.

Coase (1960) observed that there are costs involved in carrying out transactions in the market, such as the cost "to discover who it is that one wishes to deal with, to inform people that one wishes to deal and on what terms, to conduct negotiations leading up to the bargain, [and] to draw up the contract…"[4] Milgrom and Roberts

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[2] FERC Order 2000, issued December 20, 1999, Page 2 (89 FERC ¶ 61,285).

[3] For example, RTOs have been tasked by the FERC to ensure the long term reliability of the system by managing transmission investment. ISOs are nominally regulated by the Federal government, while RTOs govern themselves.

[4] Coase (1960) p. 15.

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(1992) categorize these costs as either coordination or motivation costs. They define coordination costs in terms of the need to determine the price and other parameters of transactions, make the existence of buyers and sellers known to one another, and bring buyers and sellers together. Motivation costs arise from incomplete and asymmetric information and imperfect commitment. The wholesale market for electricity, where the relevant product is electricity delivered to a particular location at a particular point in time, is prone to coordination costs,[5] as the product has an instantaneous useful life. RTOs and ISOs can have a direct explicit influence on coordination costs in the wholesale electricity market, but the direction of that influence is not always clear. One way in which RTOs can influence coordination costs is by publishing wholesale electricity prices in a manner that provides access to any party.[6] But since the costs of these organizations are recovered from all utilities in their market footprint (Greenfield and Kwoka, 2011), the distribution of benefits is important to assessing the cost-effectiveness and equity of these organizations. This paper employs a panel data set of United States electric utilities spanning the period 1990–2009 to investigate whether transparency increases the degree to which an electric utility participates in the wholesale market. The findings suggest that transparency increases the level of exchange of investor-owned utilities and larger utilities, regardless of ownership structure, but has no significant effect on the level of exchange of municipally owned and cooperative utilities, all else equal. This indicates that the distribution of the benefits afforded to participants in market administered by RTOs is not uniform across all market participants, while the costs are borne by all. The results of the analysis could be used to inform policy that could mitigate this inequity.

The remainder of the paper is organized as follows: Section 2 provides a discussion of the costs and benefits of RTOs, Section 3 provides a review of related literature, Section 4 describes the data utilized, Section 5 describes the empirical model and estimation methodology, Section 6 reports the results of the estimation, and Section 7 offers concluding remarks.

2. The costs and benefits of RTOs

RTOs can impart many benefits to the market in both the short term and long term. FERC Order 2000 identified five benefits that RTOs can offer: improved efficiencies in the management of the transmission grid: improved grid reliability, non-discriminatory transmission practices, improved market performance, and lighter-handed government regulation.[7] One way that ISOs and RTOs can influence the performance of electricity markets is by providing a transparent wholesale market, which this paper defines as a market in which the prices for a unit of electricity delivered to a given location at a given point in time are publicized in a manner that is easily accessible by any interested party, such as a posting on a public web site.[8]

Consider the case of an electric utility, Alpha, operating as an island, isolated from the electricity transmission grid. The utility dispatches generating units to supply electricity to its customers and attempts to do so in a manner that optimizes performance, typically measured in terms of least cost relative to some standard of reliability. If electricity demand and the criteria under which the utility optimizes its portfolio (say, least cost) are taken as exogenous, then the utility's only task is to determine which of its generating units will be dispatched at any given time. To this end, Alpha assesses the hourly marginal costs of its generating units, considers any constraints related to the units' availability or operating characteristics, determines how much electricity to supply, and dispatches units sufficient to meet the prevailing demand at the lowest possible cost.

Now consider the existence of a neighboring electric utility, Beta, which becomes physically interconnected to Alpha. Operating as an island, Beta faces the same decision as Alpha. However, if both utilities seek to minimize costs and, in a particular hour, there is a difference between the utilities' marginal costs of generation that is greater than the cost of coordinated transmission between Beta and Alpha, then an opportunity for Pareto improvement exists. If Alpha has a higher marginal cost of generation than Beta in a given hour,[9] then Beta can generate that marginal kWh and sell to Alpha at a price somewhere between their respective marginal costs, and both utilities have lowered their effective average cost of generation; Alpha by buying the marginal kWh at less than it would cost to generate it with its own units and Beta by realizing a sales revenue offset to its cost to generate the marginal kWh.

But the costs that must be incurred in order to achieve this benefit are not limited to the cost of transmission and the transaction itself. As Milgrom and Roberts observe, coordination costs also arise. Each utility must expend resources to gather information about the electricity system around it. First, each must identify the number of potential trading partners. Second, each must be able to assess the costs and availability of electricity in any given hour and for every one of those potential trading partners, in order to identify profitable trading opportunities. Third, each must know how to make the arrangements necessary to have that electricity delivered to the purchasing utility system for agreed upon transactions. Before the advent of RTOs and ISOs, the first and third tasks were often performed in the U.S. by roughly 140 regional balancing authorities (Joskow, 2005), organizations registered by the National Electric Reliability Council (now the North American Electric Reliability Corporation or NERC) to integrate future resource plans; maintain the balance between load, interchange, and generation; and support real-time interconnection frequency for a given area. The second function was accomplished primarily through bi-lateral contacts between utilities, though confederations of utilities also existed. For example, before ISOs and RTOs existed, the Orlando Utilities Commission, the City of Lakeland, and the Florida Municipal Power Agency formed the Florida Municipal Power Pool in 1988 to centrally commit and dispatch all of the pool members' generating resources to meet the collective load obligations in the most economical manner.

Today, by establishing a transparent wholesale marketplace, the RTO can fulfill the second task either by maintaining a centralized databank of hourly prices, or by collecting hourly bids and offers from utilities and generators interested in participating in the market. While the RTO can lower the costs required to gather this information, other costs to participate in the market still exist. Utilities must incur costs in order to conform to the rules and procedures of wholesale markets and the ability to trade with utilities belonging to other RTOs may be constrained. In a survey of RTO cost-benefit studies, Eto et al. (2005) report that while utilities will incur market participation costs, these costs had not been

[5] Cave and Stern (2013) have explained the role that system operators play as coordinating entities in infrastructure industries.

[6] Further discussions of these costs and benefits follow in Section 2.

[7] FERC Order 2000, issued December 20, 1999, Page 70–71 (89 FERC ¶ 61,285).

[8] Per Bakos (1998). For an example from the Midwest ISO, see https://www.midwestiso.org/MARKETSOPERATIONS/REALTIMEMARKETDATA/Pages/LMPContourMap.aspx.

[9] This might be due to a difference in the fuel used to generate the electricity or the efficiency with which the fuel is used by the marginal generating unit of each utility.