CSEM WP 108

From Investor-owned Utility To Independent Power Producer

Jun Ishii

January 2006

This paper is part of the Center for the Study of Energy Markets (CSEM) Working Paper Series. CSEM is a program of the University of California Energy Institute, a multi-campus research unit of the University of California located on the Berkeley campus.

2547 Channing Way, # 5180
Berkeley, California 94720-5180
www.ucei.org

From Investor-owned Utility to Independent Power Producer

Jun Ishii*
University of California, Irvine

3151 Social Science Plaza
Irvine, CA 92697-5100
jishii@uci.edu

*Jingming Yan had significant input on an early draft of this paper. I would also like to thank Peter Reiss and Frank Wolak for their helpful comments. I gratefully acknowledge the financial support from the Olin Fellowship (administered by the Stanford Institute for Economic Policy Research), the California Public Utilities Commission and the Stanford GRO Program. I would also like to thank EPRI for providing me access to various industry resources. All errors are strictly my own.

Abstract

We examine the issue of why some parent companies of U.S. electric utilities have expanded into domestic independent power production (IPP) but not others. We evaluate the conjecture that the parent companies who have chosen to participate in recently restructured U.S. wholesale electricity markets are those with the most generation cost advantages. Specifically, we empirically investigate the link between apparent advantages in two types of generation costs – operation & maintenance (O&M) and capital – and the IPP participation decision. We use electric utility data from FERC Form 1 and combine it with IPP data collected from various industry sources. The data is analyzed using both a descriptive approach and a simple, empirical competitive entry model. We find that utilities with lower O&M costs are more likely to expand into IPP. Also, utility financial characteristics, reflecting possible capital cost advantages, seem to matter mainly for the largest utilities.

Keywords: independent power producer, investor-owned electric utility, electric utility holding company, divestiture

JEL Codes: L43, L51, L94

1 Introduction

Much of the current academic literature on electricity restructuring has focused on the behavior of electricity generation firms in restructured wholesale electricity markets. Prominent recent works include Borenstein, Bushnell, & Wolak (2002) (hereafter BBW), Joskow & Kahn (2002), and Puller (2001) — all of which examine the bidding behavior and capacity utilization decision of independent power producers (IPPs) in the California Power Exchange (CalPX). In each of these papers, the focus has been on how regulatory restructuring has altered firm behavior in the electricity generation sector. In this paper, we stray from this theme of firm behavior and focus more on the firm itself.

Although the identities of the electricity power producers participating in many of these restructured wholesale electricity markets are now well known, little analysis has been made on why these are the very firms who have become the major participants in the restructured markets. This is an important policy issue considering the original motives underlying electricity restructuring: a major motive was the hope that by opening up the generation sector to competition, less efficient power producers would be replaced by more efficient power producers. As explored in White (1996), a main factor explaining the early adoption of electricity restructuring by some states is the high electricity prices suffered by consumers in those states, especially relative to consumers in neighboring states. While some of the price difference can be attributed to difference in cost advantages inherent to each state (e.g. access to hydro power), much of it has also been attributed to the different vertically integrated investor-owned utilities providing each state's electricity supply. Therefore, some states welcomed the opportunity for out-of-state power producers to come in and replace the local investor-owned utilities (IOUs) in the generation sector.

Thus far, a large majority of the independent power producers (IPPs) that have replaced local IOUs in U.S. wholesale electricity markets have been subsidiaries of parent companies that also own IOUs in other states.[1] In fact, one of the major phenomena observed during the initial transition period for electricity restructuring is the "swapping" of generation assets among IOU parent companies: much of the power plants sold by IOUs in divestiture sales have been bought by subsidiaries of (other) IOU parent companies. There are good reasons why we might expect IOU parent companies, through their IPP subsidiaries, to be the major players in the newly restructured wholesale markets. Given that IOUs have controlled much of the electricity generation business in the U.S. over the past 60 years, IOU parent companies are the firms with the most experience in

[1]The "independent" in independent power producer refers to the fact that the IPP is not operationally affiliated with the investor-owned utility that provides the service in the downstream transmission and distribution (T&D) sector.

providing generation services in the U.S.[2] Moreover, the variation in the costs reported by IOUs in different states raises the possibility that some IOUs may be more efficient than others. Thus, a possible rationale helping to explain the large share of IPP activity controlled by IOU parent companies is that less efficient IOUs are being replaced in the generation sector by subsidiaries run by more efficient out-of-state IOUs.

In this paper, we empirically explore this claim that the IOUs who have expanded their generation activities outside of their regulated franchises and into "out-of-state" independent power production are in some sense the "lower cost" IOUs in the country.[3] While much of the current independent power production is provided by subsidiaries of IOU parent companies, not all major IOU parent companies have chosen to participate in independent power production. Among the 81 major IOU parent companies analyzed in this essay, 32 own IPP subsidiaries. The working hypothesis in this essay is that the remaining 49 firms has chosen (as of 2000) not to participate in IPP because they feel that they cannot compete for the right to provide generation services without regulatory protection. We infer the generation costs that an IOU parent company potentially faces in IPP activities - and thus the level of competitiveness of the firm - from observed information about the utility operations of the IOU parent company. Specifically, we focus on utility operations along two dimensions: the reported operations and maintenance costs for utility generation and the financial health of the utility. The former is used to arrive at some measure of the short-run variable cost that an IOU parent company may face while running an IPP merchant power plant. The latter is used to infer the capital costs that an IOU parent company may incur in order to develop or acquire IPP power plant projects. Combined, they provide an expansive view on the potential IPP generation costs faced by each IOU parent company.

Two empirical strategies are employed to examine the link between observed utility operations and the level of IPP activities engaged by the IOU parent company. First, a descriptive approach is adopted where the focus is the correlation between various utility characteristics and the IPP participation decision of the parent. The descriptive section introduces the utility variables of interest and demonstrates that there is sufficient correlation between these utility characteristics and IPP participation to merit a closer examination. Second, a cost function for making IPP capacity available in a market, based on observed utility characteristics, is estimated using a simple competitive entry model. The purpose of this empirical model is to measure the relative importance

[2]Investor-owned utilities have controlled most of U.S. electricity generation since the passage of the Federal Power and Public Utilities Act in 1935.

[3]Some IOU parent companies have IPP activities in the same state as where they have their regulated franchises. Most state laws only require the parent company to maintain an "operational" separation between IPP and utility, not different ownership.

of each of these utility characteristics, taking into joint consideration all of the capacity investments made by IOU parent companies in a market. Estimates from the entry model reveal that much of the descriptive analysis can be misleading. While at first glance it may seem that "capital cost" factors such as net income and revenue play a significant role in an IOU parent company's IPP participation decision, the estimates from the entry model suggest that it is in fact the prowess of a parent company's utility power plant operations and maintenance that appears to matter. The significant correlation between net income / revenue and IPP participation weakens once such financial characteristics are considered jointly with other utility characteristics that change with the parent company's scale of utility operations.

The paper is organized as follows: section 2 provides an overview of the relevant utility characteristics and examines the correlation between those characteristics and observed IPP activities of the parent company. Section 3 builds upon this descriptive analysis by proposing a simple, empirical competitive entry model for the upstream "generation capacity" market. Estimates from the model, obtained by maximum likelihood, are then used to explain the observed variation in IPP activities by IOU parent companies. The paper then concludes with some final remarks.

2 Overview

Even a casual overview of the major independent power producers participating in the various U.S. wholesale electricity markets reveals a significant presence by IOU parent companies. In California, of the five major IPPs controlling most of the non-utility electricity generation supply, three (Duke Energy North America, Reliant Energy, Southern Energy) are subsidiaries of parent companies that own U.S. investor-owned utilities.[4] The significant and, perhaps more accurately, dominant presence of IOU parent companies in U.S. IPP activity can be further established by examining the outcome of the utility divestiture sales conducted during the recent transition period for U.S. electricity restructuring. Given that divested power plants account for most of the independent power production during the past few years, an analysis of who bought divested power plants provides a good indication of who controls much of the IPP activity right now.

[4] Interestingly enough, the two remaining IPPs (AES, Dynegy) have both bought IOUs in recent years.

Table 1: Divestment by Year and Acquiring IPP		
Year	Capacity (Megawatts)	
	Total Amount of Divestiture	Total Amount Acquired by IPPs Affiliated with U.S. IOUs
1998	24976	17835 (71.4%)
1999	50942	40108 (78.7%)
2000	15689	14204 (90.5%)
Total	91607	72147 (78.8%)
Divestment data from various issues, EIA "Electric Power Monthly"		
Excludes transfers between IOU and affiliated IPP		
IPP classification from various industry resources		

Table 1 shows the amount of divested utility generation capacity acquired by IPPs during each year from 1998 to 2000 (excluding transfers from the utility to non-utility business unit of a parent company).[5] As the table shows, 79 percent of the divested assets overall (71 percent in 1998, 79 in 1999, 91 in 2000) was acquired by subsidiaries of IOU parent companies. These numbers demonstrate the large share of IPP electricity capacity (in the form of acquired assets) controlled by IOU subsidiaries. A possible explanation for this result may be that IOUs, having run similar power plants for their own utility operations, are more familiar with and better at operating and maintaining these aging, divested power plants.[6] Hence, IOU subsidiaries have greater interest in these power plants than non-IOU affiliated IPPs.

Table 2: Divestment by Year and Divesting IOU		
Year	Capacity (Megawatts)	
	Total Amount of Divestiture	Total Amount Divested by IOUs Active in U.S. IPP
1998	24976	15419 (61.7%)
1999	50942	32446 (63.6%)
2000	15689	2561 (16.3%)
Total	91607	50426 (55.0%)
Divestment data from various issues, EIA "Electric Power Monthly"		
Excludes transfers between IOU and affiliated IPP		
IOU classification from various industry resources		
"Active" includes IOUs that merged or were acquired by IPPs		

[5]Some states did not require the local IOUs to divest their generation assets to outside firms. The IOUs were given the option to transfer the assets to a separate subsidiary of the parent company

[6]Ishii & Yan (2003) provides some empirical support for this explanation.

Exploring the flip-side is Table 2. Table 2 shows the amount of utility generation capacity divested by IOUs during each year from 1998 to 2000 (excluding transfers). The table shows that 55 percent of the divested generation capacity was capacity divested by IOUs owned by parent companies who currently participate in U.S. IPP activity. Table 2 shows that not only are IPP subsidiaries of IOU parent companies the major buyers in divestiture auctions, they may potentially be the major beneficiaries of the proceeds from the divestiture sales. Divestiture sales lead to large immediate cash flows for the IOU parent company which can, in theory, be used to finance IPP investments. In fact, examining the timing between the divestment of power plants by an IOU parent company's electric utility and the acquisition of "out-of-state" utility power plants by its IPP subsidiary provide some anecdotal support for such a theory. For example, both Southern California Edison and Pacific Gas & Electric, the two major divesting IOUs in California, announced deals to acquire significant amounts of divested generation capacity (in the Midwest and East Coast respectively) within 6 months of divesting their own California utility plants.[7]

Combining the information from Table 1 and Table 2, we get that 90 percent of the utility divestiture (by capacity) from 1998 to 2000 involved an IOU parent company that owns an IPP subsidiary, either as buyer or seller. The analysis above suggests that [1] possible differences across IOUs in their ability to run and maintain power plants similar to those being divested and [2] proceeds from utility divestiture earned by some divesting IOUs may help explain why some IOUs are more active in IPP, especially as buyers of divested power plants. We explore the former point using cost information reported annually by the major IOUs to the Federal Energy Regulatory Commission (FERC Form 1 Report). The FERC Form 1 Report provides the total annual cost of an electric utility, broken down into useful categories. One of the categories is operations and maintenance (O&M) costs. To the extent that reported utility O&M costs reflect potential O&M costs for IPP activities, the reported utility O&M costs can be used to evaluate the potential short-run variable costs of running merchant power plants faced by different IOU parent companies.[8] Below, we examine reported O&M cost for the 1996 edition of the report. 1996 is chosen as it is the last full year before the introduction of electricity restructuring in any U.S. state – making 1996 the last year in which utility operations are largely comparable with each other.[9] More information

[7] However, at the same time, it should be noted that not all major divesting utilities have acquired out-of-state power plants or otherwise made IPP investments: the parent company of GPU, one of the main divesting utilities in Pennsylvania, has thus far stayed clear of any U.S. independent power production.

[8] O&M costs make up most of an electric utility's short run variable cost. It includes factor payments, such as for fuel and labor, that vary with the amount of electricity supplied. It excludes the amortized capital costs.

[9] Fabrizio, Rose, & Wolfram (2004) and Bushnell & Wolfram (2005) show that incentive changes due to regulatory restructuring can induce greater *utility* plant efficiency. Thus, differences in plant efficiency between utilities in more and less restructured states may not be completely due to differences in the utilities themselves

about these data sources can be found in the Data Appendix.

Table 3a: Top 10 Lowest SRNF			
Investor-owned Utility	Parent Company	IPP	SRNF
Cambridge Electric Light Co	NSTAR	N	-.0036
South Carolina Generg Co Inc	SCANA Corp	N	0.0012
Oklahoma Gas & Electric Co	OGE Energy Corp	N	0.0019
Central Power & Light Co	American Electric Power Co Inc	Y	0.0020
Public Service Co of Oklahoma	American Electric Power Co Inc	Y	0.0021
St Joseph Light & Power Co	UtiliCorp United	Y	0.0022
Southwestern Public Service Co	Xcel Energy	Y	0.0022
Southwestern Electric Power Co	American Electric Power Co Inc	Y	0.0023
Texas-New Mexico Power Co	TNP Enterprises Inc	N	0.0025
West Texas Utilities Co	American Electric Power Co Inc	Y	0.0025

$$\text{SRNF} = \frac{\text{Total Non-fuel O\&M Costs from Electric Utility Steam Power Generation}}{\text{Total Steam Power Generation}} \quad (\$ \,/\, \text{Kwh})$$

Table 3b: Top 10 Highest SRNF			
Investor-owned Utility	Parent Company	IPP	SRNF
Maine Public Service Co	Maine Public Service Co	N	0.0396
Central Maine Power Co	EnergyEast	Y	0.0243
Commonwealth Electric Co	NSTAR	N	0.0236
Bangor Hydro-Electric Co	Emera	N	0.0225
Citizens Utilities Co	Citizens Communications	N	0.0207
Northern States Pwr Co-WI	Xcel Energy	Y	0.0202
Central Vermont Pub Serv Corp	CVPS	Y	0.0193
Western Massachusetts Elec Co	Northeast Utilities	Y	0.0187
Green Mountain Power Corp	Green Mountain Power Corp	N	0.0170
Consolidated Edison Co-NY Inc	ConEd	Y	0.0168

$$\text{SRNF} = \frac{\text{Total Non-fuel O\&M Costs from Electric Utility Steam Power Generation}}{\text{Total Steam Power Generation}} \quad (\$ \,/\, \text{Kwh})$$

Tables 3a and 3b list the IOUs with the ten lowest and highest reported average O&M costs from steam-power generation, excluding fuel costs (SRNF). We focus only on costs from steam power generation as most IPP power plants are steam-powered.[10] We also exclude fuel costs as fuel costs have a strong regional component. Without excluding fuel costs, an IOU that can operate and maintain a given power plant better than any other IOU may still exhibit a relatively high O&M cost if the IOU operates in a state (such as California) where fuel prices are high and the use of coal (the least expensive of the fossil fuels) is restricted. From the tables, there does not appear to be a discernible relationship between IOU SRNF values and the decision to participate in IPP activities during the initial period of 1996-2000 by their parent companies.[11] However, the Pearson correlation between SRNF and the IPP decision for IOUs in our data is statistically significantly negative: -0.15254 with a standard error of 0.0785.[12] While not definitive, this suggests that IOUs with higher O&M costs are less likely to expand into IPP activities.

There are two possible concerns associated with our use of SRNF as a measure of the relative cost efficiency for an IOU. First, the cost data used to construct SRNF are based on the values reported by the IOU to a regulatory commission. In so far as an IOU has an incentive to misreport its cost (and in so far as the regulatory commission cannot completely monitor the IOU), these variables may be distorted reflections of the true underlying cost of generation. However, this concern is mitigated by the fact that generation cost is, perhaps, the aspect of electric utility cost that can be best monitored; regulators can use engineering information and fuel receipts to arrive at good bounds for generation cost – this is the basic insight motivating much of the "competitive benchmark" literature, such as Wolfram (1999), BBW, and, more recently, Mansur (2003) and Bushnell, Mansur, & Saravia (2003)

The more troubling concern is the fact that these variables capture average generation cost for a given amount of generation; they provide us with a single point of observation for an IOU's generation cost function. Therefore, SRNF is only truly comparable across firms if either all firms produce similar amounts of generation or average generation cost is roughly constant over the observed range of generation. Neither assumption holds outright as IOUs are observed providing varied amounts of generation and electricity generation is usually understood to involve some fixed costs (e.g. ramping constraints). Consequently, even if more generation cost efficient utilities are more likely to be involved in IPP activities, it may not be perfectly borne out by the average cost measure of SRNF. Ideally, we would like to observe the O&M costs for IOUs for comparable levels of generation. However, such data is unavailable. We proceed with the belief that while SRNF may

[10] FERC classifies generation as steam power, nuclear, hydraulic, or other. Steam-power captures the vast majority of fossil-fuel based generation.

[11] Expanding to top 20 does not alter this impression

[12] The same Person correlation for the average O&M costs including fuel cost is similarly negative, -0.15403 with a standard error of 0.0756

be an imperfect reflection of an IOU's generation cost (dis)advantage, it is still likely correlated with the "ideal" measures and serve as good proxies. Most notably, SRNF should be a good proxy after accounting for differences in utility generation size.

O&M costs only make up one aspect of a firm's overall independent power production cost. An IPP also incurs costs associated with developing new and acquiring existing power plant projects. An important component of the cost of developing and acquiring power plants is the cost of capital. The FERC Form 1 Report does report utility capital costs. However, such reported capital cost is likely not comparable across IOUs nor the relevant capital cost for IPP power plant projects. This is because the regulated retail electricity price that an IOU can charge is largely set such that the IOU has the opportunity to earn a regulated rate of return on its reported capital investment. Depending on the diligence of the local regulators, an IOU has a weak incentive[13] to keep capital costs down. Instead of using reported capital costs, we infer an IOU's capital cost from its observed financial characteristics. With imperfect capital markets (due to asymmetric information between IPP and outside lender about the profitability of a power plant project) the outside cost of capital faced by an IPP will be greater than the opportunity cost for internal capital owned by the IPP. We use measures of an IOU's access to internal capital to capture its potential relative capital cost for IPP projects.

Table 4a: Top 10 Highest NETY

Investor-owned Utility	Parent Company	IPP	NETY
Texas Utilities Electric Co	Texas Utilities Company	N	862695
Pacific Gas & Electric Co	PG&E	Y	755210
Commonwealth Edison Co	Exelon	Y	743368
Duke Power Co	Duke Energy	Y	729966
Consolidated Edison Co-NY Inc	ConEd	Y	694085
Southern California Edison Co	Edison International	Y	655395
Georgia Power Co	The Southern Company	Y	625353
Florida Power & Light Co	FPL Group Inc	Y	614895
Public Service Electric & Gas Co	Public Serv Enterprise Group	Y	535071
PECO Energy Co	Exelon	Y	517204

NETY = Electric Utility Net Income ($1000)

[13] Possibly disincentive, as hypothesized under Averch & Johnson (1962) and subsequent literature

Table 4b: Top 10 Lowest NETY			
Investor-owned Utility	Parent Company	IPP	NETY
Connecticut Light & Power Co	Northeast Utilities	Y	-78561
Entergy Gulf States Inc	Entergy Corporation	Y	-4209
Holyoke Water Power Co	Northeast Utilities	Y	-772
Indiana-Kentucky Electric Corp	American Electric Power Co Inc	Y	0
Maine Public Service Co	Maine Public Service Co	N	2111
Ohio Valley Electric Corp	American Electric Power Co Inc	Y	2315
Western Massachusetts Elec Co	Northeast Utilities	Y	4205
South Carolina Generg Co Inc	SCANA Corp	N	4611
Cambridge Electric Light Co	NSTAR	N	5121
Commonwealth Edison Co Ind Inc	Exelon	Y	5991
NETY = Electric Utility Net Income ($1000)			

Table 4a and 4b list the top 10 major IOUs with the highest and lowest 1996 net income (NETY), respectively. An IOU parent company with an utility earning greater net income is presumably one who has access to greater internal capital in the form of retained earnings.[14] Table 4a is practically a list of who's who in U.S. independent power production. All of the parent companies represented in table 4a are significant players in the U.S. independent power market except Texas Utilities Company (TXU). And even the exclusion of TXU is an exception that proves the rule: although TXU has, as of 2000, remained inactive in the U.S. IPP market, TXU is a major player internationally, especially in the deregulated markets of Australia and United Kingdom. An expansion of table 4a to include the major IOUs with the top 20 highest net income would include the parent companies that own major IPP firms Constellation Energy, PPL Energy, and Reliant Energy. There appears to be a definite, positive relationship between the amount of net income an IOU earns and the likelihood of U.S. IPP participation by the IOU parent company.[15] But this apparent relationship, though consistent with the argument that IOU parent companies use their regulated utilities to help finance IPP power plant projects, could be explained by other factors. For example, net income may also reflect the cost efficiency of the IOU.[16] Furthermore, being an accounting measure, net income may not reflect the economic variable of interest: the

[14] Under the standard model of corporate finance, we would expect an IOU parent company's cost of capital to rise as it uses up cheaper sources of capital (retained earnings) and moves onto more expensive forms of capital (high priced corporate bonds). So greater retained earnings means that a firm can invest more at the lower capital cost.

[15] The Pearson correlation coefficient between net income and IPP participation is 0.20478 with a standard error of 0.0176.

[16] Note that higher reported net income does not necessarily indicate a better run utility. As found in Berndt, Epstein, & Doane (1996), the effective rate of return faced by a firm can be significantly affected by factors outside the control of the managers of the firm.

retained earnings of the IOU. Due to such factors as taxes, firms may have an incentive to "play with the numbers" and report a net income different from its economic value. The analysis on net income is *caveat* the usual criticisms associated with using accounting financial measures.

In addition to net income, we also examine the net revenue from the sale of electricity (NRVSE). For an IOU parent company considering making large IPP capital investments, the relevant financial information may not be so much retained earnings as it is cash flow. Moreover, revenue is a figure that may be less prone to accounting manipulation than net income as retail electricity prices are set by the regulators. Not too surprisingly, the results for revenue are similar to the results for net income, with many of the same IOUs on the top lists for both financial characteristics.[17] There is clearly a strong positive correlation between net income and revenue, based primarily on the scale of utility operation: an IOU serving a larger franchise area will face a larger revenue stream and have the opportunity to earn a greater level of net income. This raises another concern: it is difficult to tell whether the significant correlation we observe between net income / revenue and IPP participation is due to greater access to capital (as argued) or to other benefits of scale, such as more experience from operating more generation capacity. Further complicating the analysis is the idea that scale may be endogenous; IOUs with greater scale of operation may be the ones with greater (unobserved) advantages. Unfortunately, there are no simple fixes for these complications. Some of these complications are dealt with explicitly later in the paper.

Lastly, we use the reported assets-to-liabilities ratio (ATOL) to arrive at a more direct inference of an IOU's capital cost, especially with respect to outside sources of capital. The idea is that an IOU with a lower assets-to-liabilities ratio is one that faces greater borrowing constraints (less collateral, more leveraged) and greater capital costs from outside lendors. The ATOL data reveals a positive relationship as well.[18] Again, like the case for net income, this result is *caveat* the usual criticisms surrounding the use of accounting measures, with the chosen accounting definition of assets and liabilities possibly different from their relevant economic definitions. However, while the observed significant correlation between the financial variables (NETY,NRVSE,ATOL) and IPP participation may not necessarily reflect the intended capital cost argument, it is difficult to think that the correlations are purely spurious. There is most likely some economic story underlying these observed correlations.

Tables 1 through 4 provide some descriptive support for the idea that the characteristics of the IOUs bear some influence on the decision of the IOU parent companies to participate in U.S. IPP activities. Table 1 and 2 show that both the main buyers and sellers of divested utility power

[17] The Pearson correlation coefficient is similar as well, 0.23095 with a standard error of 0.0073

[18] The Pearson correlation coefficient is 0.29613 with a standard error of 0.0005

plants are IOUs owned by parent companies active in U.S. IPP. Combined with the results from tables 4a and 4b, these tables paint a suggestive story that an IOU's financial situation, especially with regards to its ability to provide cash-flow to finance other projects, may help explain the significant presence of IOU parent companies in U.S. IPP activities. At the same time, Tables 3a and 3b provide some evidence that parent companies affiliated with IOUs with lower reported O&M costs are more likely to participate in U.S. IPP. Both of these findings are consistent (though not exclusively) with the argument that the IPP participation decision of IOU parent companies is driven by relative cost considerations, with more efficient IOUs entering the newly restructured wholesale electricity markets. The descriptive information analyzed above, while not conclusive, does motivate a closer examination of the relationship between these utility characteristics and the IPP participation decision.

3 An Entry Model for IPP Generation Capacity

In the previous section, we examine how different individual IOU characteristics seem to correlate with the decision of the parent company to expand into U.S. independent power production. Here, we examine these factors jointly within the framework of an entry model. The empirical entry model allows us to exploit greater observed variation in the IPP participation decision. Instead of just focusing on whether the IOU parent company is involved in *any* IPP activity, the entry analysis also considers the *level* of IPP activity. The level of IPP activity is reflected by the number of markets the IOU parent company "enters" and the amount of generation capacity the IOU parent company decides to invest in a given market. An IOU parent company well suited for independent power production would presumably be active in many markets, owning sizable capacity in such "entered" markets. Therefore, the entry analysis helps discern the relative importance of IOU characteristics by placing more emphasis on characteristics displayed by IOU parent companies active in more wholesale generation markets and/or owning greater capacities in these markets.

The market the IOU parent companies are considering entering is defined in the following two manners. First, geographically, the market definition follows the North American Electricity Reliability Council (NERC)'s 13 U.S. major subregion definition. NERC is the industry governing body for the North American electricity transmission and distribution entities. Each of these subregions, spanning the continental U.S., is based on existing transmission and distribution capabilities and helps take into consideration the fact that a power plant located in one state may actually provide much of its generation to end consumers located in a neighboring state. Thus, NERC subregions provide the closest geographic definition based on location of actual demand.

Second, the product sold in the market is not generation services per se but rather generation capacity. The wholesale electricity market consists of two vertically related markets. The downstream "spot" market is the market where actual generation (in terms of kilowatt-hours, kWh) are traded between energy traders and retail marketers who represent end consumers. This is the market that has been the focus of much current research, including various market power studies such as BBW. However, the market that drives much of the investment decision for IPPs is the upstream market for new generation capacity (in terms of megawatts, MW). This is the market where IPPs sell options for the rights to their generation output for some time period (often 5-10 years) to an energy trader. These power purchase agreements are usually negotiated before the commercial start and sometimes even before the construction of the power plant. For many IPPs, the decision to go forward with a merchant power project hinges crucially on the price it expects to earn from its power purchase agreements.[19]

In this paper, entry in the market is signified by the parent company acquiring or building a positive amount of IPP generation capacity in the NERC subregion.[20] Unfortunately, identifying the exact timing of entry is complicated by the fact that the exact year in which an IPP capacity was built/acquired is not readily available for some IOU affiliated IPPs. What we observe for *all* IPPs is the generation portfolio of the IPP as of mid-2000. Consequently, we consider entry during a period of time. We consider 1996 to mid-2000 as the initial entry period. An IOU parent company is assumed to have entered a market if it acquired and/or successfully constructed a positive amount of IPP generation capacity between 1996 and 2000 in that NERC subregion. The main drawback to studying entry during a period of time is that market conditions may vary within that period. Of particular concern is the impact that observed effects of ongoing restructuring may have on firm expectations about the profitability of IPP activities. Some of this concern is mitigated by the choice of mid-2000 as the end of the period, which allows us to avoid investment distortions from the California Energy Crisis. Moreover, a review of the industry press does not raise any significant concern about changes in the prices for power purchase agreements negotiated between IPPs and energy traders between 1997 and 1999.[21]

The "entry" data we observe for each of the 81 IOU parent companies consist of the amount of

[19] In California, examples of these upstream "capacity" transaction include the power purchase agreements negotiated by IPPs AES and Calpine with energy traders Williams and Enron, respectively. Some firms, such as Reliant and Dynegy in California, are vertically integrated, contracting their capacity to their own internal energy trader.

[20] We exclude any transfers of generation capacity from the utility subsidiary to the IPP subsidiary of the same parent company.

[21] Most of the new capacity became commercially online between 1998 and 2000. With construction taking over a year, this implies that much of the power purchase agreements were signed between 1997 and 1999.

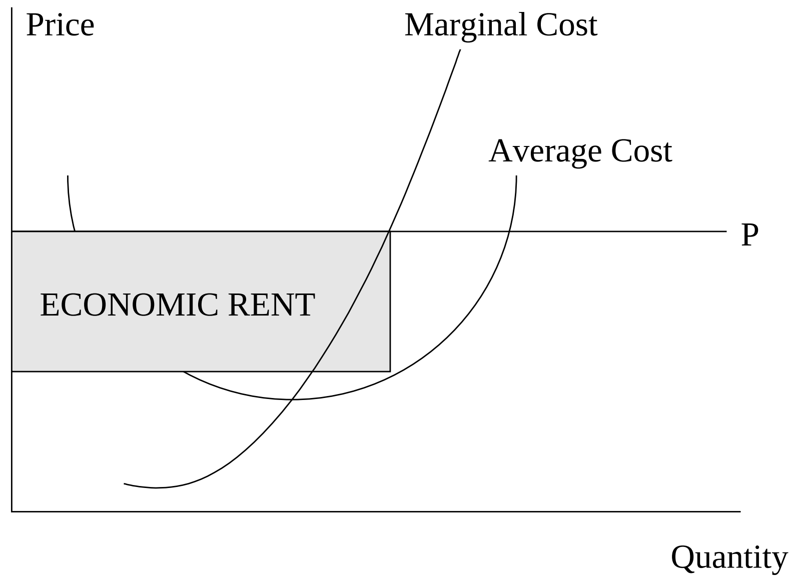

Figure 1: Case of an Entrant IOU Parent Company

generation capacity acquired by each company in each of the 13 NERC subregions between 1996 and mid-2000. An IOU parent company is considered as participating in an IPP market ("entered") if they invested in a positive amount of capacity during the study period. The degree of participation is indicated by the amount of capacity they acquired. Standard microeconomic theory provides a guideline on how each of these two aspects of the participation decision is determined. With respect to the latter, the amount of participation, profit maximization implies that the company acquires capacity until the marginal cost of capacity equals the marginal revenue. In a competitive market, price equals marginal revenue, leaving us with the standard $P = MC$ rule: the company acquires capacity until marginal cost equals the price it earns for the marginal unit of capacity. With respect to the latter, whether to participate at all, the company participates if the variable profit (economic rent from being a low cost provider) the company earns from acquiring capacity (at the level where $P = MC$) is greater than the fixed entry cost.

These two basic insights are reflected in Figure 1. The profit maximizing capacity that the company acquires in the market, conditional on having decided to participate, is indicated by the intersection between the capacity marginal cost curve and the price line. Whether the company decides to participate depends on whether the economic rent the company earns from participating – the shaded area below price but above average cost – is greater than the fixed entry cost. For IPPs with a lower cost of providing generation capacity, the marginal cost curve is further right ("flatter"), leading to an intersection with the price line at a larger capacity and a larger area of economic rent between price and average cost. Similarly, shifts in the price offered for generation capacity can alter the intersection and area of economic rent, with higher prices (weakly) leading to greater participation.[22] This leads us to our identification strategy: observed market characteristics, reflecting capacity price, should help explain why some markets attract more IPP participation than others while observed firm characteristics, reflecting capacity cost, should help explain why some IOU parent companies participate in more markets and/or invest in larger capacities than others.

In order to implement this empirical strategy, two sets of specification decisions must be made. First, the nature of competition in the market must be defined and, second, the form of the revenue and cost curves must be specified. With respect to the former, we model the market for capacity as being competitive, with each IPP acting as a price-taker. While much of the current economic literature on electricity restructuring has focused on potential market power in the downstream, spot market, there are reasons to believe that the upstream capacity market is largely competitive. First, the ability of energy traders to exercise market power in the spot market hinges on real-time fluctuations in market conditions that cannot easily be forecasted (mainly climate factors such as temperature and rainfall).[23] While spot market prices can adapt to reflect these unexpected real-time changes, the price for capacity cannot, in general, because it has been set *a priori*, with a price schedule determined and fixed for several years based on *expected* market conditions.[24]

Second, favorable changes in market conditions can lead to (short-run) market power for energy traders in the spot market because there are sizable entry barriers; it is difficult for firms outside of the spot market to take advantage of unexpected shocks because new power plants cannot be constructed quickly nor can electricity from a different market be exported economically to the desired market. But this is not necessarily true for the capacity market. Given that many of these power purchase agreements are negotiated well before the commercial start of the new plant, both IPPs inside and outside the market have time to adjust their supply capability. Consequently, shifts in expectations about current and future value of generation can elicit supply reactions from both current and potential entrants, leading to much of the benefits from anticipated market shifts being competed away. Combined with the earlier argument, this suggests that IPPs in the capacity market are price-takers, with the capacity price largely determined by the *expectations* energy traders have concerning future spot generation prices. Consequently, we model the market as being competitive with prices determined principally by observed market characteristics.

In a competitive market, the revenue that the IPP earns from participating in the capacity

[22]Strictly leading to greater participation if there is no entry cost

[23]See Borenstein & Bushnell (1999) for an analysis of factors contributing to market power in California.

[24]In theory, the agents could draw up a contingent claims contract. But this is not general industry practice.

market is simply the product of the "capacity price" and the amount of capacity being made available. The capacity price can be thought of as the net present value of the expected generation payments the energy trader contracts with the IPP, per unit of capacity.

$$\begin{aligned} P_{\text{capacity}} &= \sum_{t=1}^{T}\sum_{d=1}^{365}\sum_{h=1}^{24} \beta^t \; P_{tdh} \; u_{tdh} \qquad (1) \\ &\text{where} \\ P_{tdh} &= \text{Unit price for generation for year t, day d, hour h} \\ u_{tdh} &= \text{Expected utilization rate for year t, day d, hour h} \end{aligned}$$

We argue that this P_{capacity}, for a given market, is roughly the same across all IPPs. Although power purchase agreements are negotiated bilaterally between IPP and energy trader, there are good reasons to believe that these negotiated prices converge for a market as [1] industry press suggests that market participants are aware of the prices/quantities being negotiated among IPPs and traders and [2] the relatively small number of IPPs and traders implies a low transaction cost to "comparison shopping." Combined, these arguments suggest that price differences would not survive long for similar capacity, making the assumption of uniform price reasonable.[25] Consequently, we model P_{capacity} as varying by market (indexed by g) but not IPP characteristics: $P_g = P(X_g; \theta_p)$.

Capacity costs, on the other hand, are modelled as varying across IPPs (denoted by the index f) and capacity level – with capacity cost $C_f(q)$ increasing quadratically with capacity level q.

$$\begin{aligned} C_f(q) &= \alpha_{0f} + \alpha_{1f} \; q + \alpha_{2f} \; q^2 \qquad (2) \\ &\text{where} \\ (\alpha_{0f}, \alpha_{2f}) &\geq 0 \end{aligned}$$

The quadratic specification allows for some limited economies of scale, consistent with the generation technology available during the study period.[26] $\alpha_{1f} \; q + \alpha_{2f} \; q^2$ reflects both the capital cost necessary to acquire the capacity q and the discounted stream of operation and maintenance costs necessary to satisfy the generation requirements contracted with the energy trader. α_{0f} represents the fixed entry cost the IPP must sink in order to participate in the market. We model the parameters of $C_f(q)$, the α_f's, as functions of the observed IPP characteristics discussed earlier: $\alpha_f = \alpha(X_f; \theta_c)$. Given that some IOU parent companies own multiple IOUs, some method of

[25] A *caveat* is that not all capacity are the same. Due to transmission constraints, the location of a power plant may make it more or less valuable, especially in the ancillary services markets for generation. However, for many restructured wholesale electricity markets, such as California, the main "generation" spot market values electricity from all locations equally. For now, we ignore the location dimension of generation capacity.

[26] See Ishii (2004) for details on capital and operation costs for a large class of generation technology, gas turbines

aggregating the utility information to the level of IOU parent company needed to be adopted. We considered two aggregation methods: [1] using the characteristics of the "largest" owned IPP as defined by the amount of 1996 steam power generation and [2] using the weighted average of the characteristics of all owned major IOUs with the ratio of the utility's 1996 steam power generation over the sum of 1996 steam power generation by all owned major IOUs as weights.[27]

Table 5: IOU Parent Company Characteristics

Variable	Mean	Std Dev	Min	Max
Owned IPP U.S. Capacity (IPPUSN)	0.96185	2.50588	0.00000	13.18277
Divested Utility Capacity (DIVTOT)	1.59649	3.12699	0.00000	12.69900
"Largest Utility" Specification				
Non-fuel O&M Cost (SRNF)	0.00656	0.00549	0.00191	0.03960
Net Income (NETY)	0.19953	0.20780	-0.00421	0.86270
Revenue from Elec Sale (NRVSE)	1.63047	1.75148	0.05103	7.43300
Assets-to-Liabilities (ATOL)	0.98420	0.23265	0.16782	1.48192
"Weighted Average" Specification				
Non-fuel O&M Cost (SRNF)	0.00663	0.00544	0.00191	0.03960
Net Income (NETY)	0.18932	0.19622	0.00211	0.86270
Revenue from Elec Sale (NRVSE)	1.55860	1.67034	0.05103	7.43300
Assets-to-Liabilities (ATOL)	0.99335	0.21642	0.16782	1.46687
$N = 81$				
IPPUSN, DIVTOT in 1000 MWs; NETY, NRVSE in $ billions; SRNF in $ per kWh				

As the summary statistics reveal, the variables do not differ much between the two methods.[28] Consequently, we adopt the simpler specification of "largest utility" in determining the observed utility characteristics assigned to each IOU parent company. We make one exception: we use the total amount of utility generation capacity divested by all major IOUs owned by the parent company, instead of just the largest IOU. Divestiture is an one-time event (for each utility) whose timing is erratic. Therefore, it does not make sense to use a "representative" utility approach for the divestiture characteristic.

[27]Steam power is used as a criterion as most merchant power generation is steam powered

[28]This is primarily because most IOU parent companies own only one IOU or own one that simply dwarfs all others in scale of operation.

3.1 Empirical Framework

Given the basic specification outlined above, an estimator can be derived that measures the impact of observed market and IPP characteristics on the observed participation decisions of each IPP in each market (whether and how much capacity they invested). Conditional on IPP f "entering" market g, the adopted revenue and cost functions ensure that the "P=MC" condition inverts for a unique, profit-maximizing value of capacity (q^*_{fg}).

$$q^*_{fg} = \frac{P_g - \alpha_{1f}}{2\alpha_{2f}} \tag{3}$$

$$\Pi^*_{fg} = P_g q^*_{fg} - C(q^*_{fg}) = \frac{(P_g - \alpha_{1f})^2}{4\alpha_{2f}} - \alpha_{0f} \tag{4}$$

To capture the econometrician's ignorance, we propose that we observe the difference between market price and the linear cost term ($P_g - \alpha_{1f}$) up to some additive error term (ν_{fg}) which is distributed *i.i.d.* Normal across (firm,market) observations. This term is meant to reflect the components of the firm negotiated price and cost that are not completely captured by the model.

$$q^*_{fg} = \frac{P_g - \alpha_{1f} - \nu_{fg}}{2\alpha_{2f}} \tag{5}$$

$$\Pi^*_{fg} = \frac{(P_g - \alpha_{1f} - \nu_{fg})^2}{4\alpha_{2f}} - \alpha_{0f} \tag{6}$$

$$\nu_{fg} \overset{i.i.d.}{\sim} N(0, \sigma^2_\nu) \tag{7}$$

Accordingly, a likelihood function can be derived for the observed q_{fg}. Recall that a firm enters ($q_{fg} > 0$) only if $q^*_{fg} > 0$ and $\Pi^*_{fg} \geq 0$. This implies a range of values for ν_{fg} such that a firm with characteristics (X_{0f}, X_{1f}, X_{2f}) facing market price P_g will enter.

$$\begin{aligned} q^*_{fg} > 0 &\quad \text{implies} \quad \nu_{fg} < P_g - \alpha_{1f} \\ \Pi^*_{fg} \geq 0 &\quad \text{implies} \quad \nu_{fg} \leq P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}} \;\text{ or }\; \nu_{fg} \geq P_g - \alpha_{1f} + 2\sqrt{\alpha_{0f}\alpha_{2f}} \end{aligned}$$

Combining the two constraints, we find that an observation of $q_{fg} > 0$ is associated with $\nu_{fg} \leq P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}}$. Similarly, observations where firm f has not entered market g ($q_{fg} = 0$) are associated with $\nu_{fg} > P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}}$. This yields us the following explicit likelihood function

$$(\hat{\theta}_p, \hat{\theta}_c, \hat{\sigma}^2_\nu) \equiv \text{argmax} \sum_{f=1}^{81} \sum_{g=1}^{13} \log\ l_{fg} \tag{8}$$

where

$$l_{fg} = \left[\phi(\frac{P_g - \alpha_{1f} - 2\alpha_{2f}\ q_{fg}}{\sigma_\nu})\ \frac{2\alpha_{2f}}{\sigma_\nu} \right]^{\delta_{fg}} \left[1 - \Phi(\frac{\nu^*_{fg}}{\sigma_\nu}) \right]^{1-\delta_{fg}} \tag{9}$$

$$\alpha_{0f} \leq \alpha_{2f} \times (\ q_{fg}\ )^2 \tag{10}$$

$$\nu^*_{fg} = P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}} \tag{11}$$

$$\delta_{fg} = \begin{cases} 0 & \text{if } q_{fg} = 0 \\ 1 & \text{if } q_{fg} > 0 \end{cases} \tag{12}$$

The constraint on the relative values of $(\alpha_{0f}, \alpha_{2f})$ in equation (10) is necessary in order to ensure full parameter support for the likelihood. With the presence of arbitrary fixed costs, it is possible for the value of q_{fg} obtained from inverting the "P=MC" condition (q^*_{fg}) to imply a value $\nu_{fg} > \nu^*_{fg}$. The above constraint on $(\alpha_{0f}, \alpha_{2f})$ ensures that this does not happen.[29] Note that an alternative to this constraint is to introduce an additional error term, such as in the level of profit (perhaps an unobserved component of fixed cost). With two errors, one error would fit the observed entry decision and the second error would fit the observed amount of q_{fg}.[30]

3.2 Model Specification

We present estimates from a parsimonious model where observed utility characteristics that differ across IOU parent companies largely affect the cost function through the quadratic term α_{2f}.[31] This specification takes a stance on what we believe the data can best explain: for a quadratic cost curve and a given price, it is the linear cost term that determines whether a firm enters and the quadratic cost term that largely determines the amount by which a firm enters (q_{fg}). Putting the observed explanatory variables exclusively in the quadratic term makes the stance that what can be best explained by the data is not the (0-1) decision of whether an IOU parent company enters the generation capacity market but the level of capacity associated with an entrant IOU parent company. Therefore, the empirical estimates seek mainly to explain the observed differences in the

[29] One can think of this constraint as yet another derived from the data. Here, the minimum amount of positive investment made by an IOU parent company in a market provides information on the upper bound of the fixed cost.

[30] The model would need to be estimated using simulated maximum likelihood as evaluating the likelihood entails numerical integration

[31] Estimation of a model where utility characteristics were included in both the linear and quadratic terms yield qualitatively similar results

level of IPP activities among entrants. However, the model does not abandon the goal of using observed utility characteristics to explain the IOU parent company (0-1) entry decision: the fixed cost α_{0f} is modeled as an increasing function of α_{2f}.

$$
\begin{aligned}
C(q) &= \alpha_{0f} + \alpha_{11}\ q + \alpha_{2f}\ q^2 && (13)\\
\alpha_{2f} &= \exp\{\alpha_{20} + \alpha_{21}\ \mathrm{ATOL}_f + \alpha_{22}\ \mathrm{LNETY}_f + \alpha_{23}\ \mathrm{LNRVSE}_f \\
&\quad +\alpha_{23}\ \mathrm{DIVTOT}_f + \alpha_{24}\ \mathrm{SRNF}_f + \alpha_{25}\ \mathrm{FOSCAP}_f \\
&\quad +\alpha_{26}\ \mathrm{LFOSYR}_f + \alpha_{27}\ \mathrm{NEWCAP}_f\} && (14)\\
\alpha_{0f} &= \Phi(\alpha_{01})\ \alpha_{2f}\ \left(\ \min\{\ q_{fg} | q_{fg} > 0\ \}_{(f,g)}\ \right)^2 && (15)\\
\sigma_\nu &= \exp\{\ \mathrm{VSIGMA}\ \} && (16)\\
\mathrm{LNETY} &\equiv \log(\ 1 + \max\{\ 0, \mathrm{NETY}\ \}\ )\\
\mathrm{LNRVSE} &\equiv \log(\ \mathrm{NRVSE}\ ) \qquad \mathrm{LFOSYR} \ \equiv\ \log(\ \mathrm{FOSYR}\ )
\end{aligned}
$$

Along with the utility characteristics we examine earlier, we consider three additional variables: FOSCAP, FOSYR, and NEWCAP. One of the concerns raised while examining the correlation between observed IPP participation and the utility net income (NETY)/ net revenue (NRVSE) is that NETY and NRVSE may not be reflecting capital cost advantages as much as the utility scale of operation. A reason why scale might matter other than access to greater retained earnings / cash-flow is that IOUs with greater generation operations have more opportunities to learn / benefit from the experience of running power plants. In order to help alleviate this concern, FOSCAP is included in the specification. FOSCAP is the total (nameplate) capacity of fossil-fuel burning power plants operated by the "largest" owned utility in 1996.[32] By including FOSCAP, we hope to separate the two scale effects: larger internal sources of capital and greater operational experience. We also include the 1996 average age of the fossil-fuel burning capacity (FOSYR) and the amount of utility generation capacity developed between 1985 and 1995. Both reflect the vintage of the power plants operated and maintained by the IOU parent company. On a technical note, we point out that the specification of α_{0f} ensures that fixed cost is non-negative and bounded above appropriately.[33]

The price for capacity (P_g) is modeled around the 1996 retail electricity price (\$/Kwh) for the market (g). We hope that much of the variation in capacity price will be captured by the variation in the 1996 retail electricity price. We use differences in observed generation demand characteristics to model other variation in capacity price.

$$
P_g \ = \ P_{1996}^{\mathrm{retail}}\ \exp\{\ \gamma_1\ \mathrm{LOAD96}_g + \gamma_2\ \mathrm{RM96}_g\ + \gamma_3\ \mathrm{LDFACT96}_f + \gamma_4\ \mathrm{LOAD10}_f\ \} \quad (17)
$$

[32] Again, "largest" refers to most steam-powered generation in 1996.

[33] The specification ensures full parameter support as it guarantees that $q_{fg} \geq \sqrt{\alpha_{0f}/\alpha_{2f}}$ for all (f,g) where $q_{fg} > 0$

We include two demand characteristics (RM, LDFACT) that we believe affect the spot price an energy trader expects to earn in the downstream generation market. RM is the 1996 reserve margin for the market, calculated as the ratio between peak demand and existing generation capacity in the market. RM reflects the general tightness of supply. A market with a low reserve margin is one that is susceptible to supply shortages, whether due to unexpected demand / supply shocks or strategic withholding of capacity. Thus, energy traders may expect a larger price for generation in such markets and be willing to pay more for capacity. LDFACT is a measure of the load factor for the market and is calculated as the ratio between peak and average generation demand. LDFACT captures the tightness in supply during peak periods as a high load factor implies that a large amount of generation capacity is needed just for the peak period. To capture the overall demand level, we include LOAD96 and LOAD10. LOAD96 is the log of peak demand (MWs) for the market. LOAD10 is the 10 year expected growth in peak demand, based on 1996 forecasts. A market with a greater level of demand *ceteris paribus* will face a higher price because the market will need to resort to the greater participation of less efficient firms in order to satisfy demand ("climbing up" the system marginal cost curve).

3.3 Results

In the estimates reported below, the parameter for the fixed cost, α_{01}, was set to 0. In theory, the parameter is identified. However, in practice, it is difficult to estimate with precision. The only aspect of the model that helps pin down the units for the level of profits is the retail price. Thus, identification of α_{01} is tenuous. The estimates reported below should be interpreted as the parameters for the cost and price functions normalized by the (unobserved) level of fixed cost.

Table 6: Estimates for the Entry Model				
Parameter	ML (Base)		ML (Excl. Inc, Rev)	
	Estimate	Std Error	Estimate	Std Error
PRICE PARAMETERS				
Log Load (LOAD96)	.39460	.25381	.38599	.23583
Reserve Margin (RM96)	-.94177	1.30405	-.87537	1.26480
Load Factor (LDFACT96)	-1.67627	.78443	-1.63178	.76041
Load Growth (LOAD10)	-.02903	.03340	-.02824	.03164
LINEAR COST PARAMETERS				
Constant (α_{11})	1.26237	3.42358	1.42807	3.79771
VSIGMA	-.55644	2.67197	-.43489	2.62669
QUADRATIC COST PARAMETERS				
Constant (α_{21})	13.7037	4.37098	5.48411	2.92862
Assets-to-Liab (ATOL)	.83558	.32941	1.15694	.28797
Net Income (LNETY)	4.41288	1.71651		
Revenue (LNRVSE)	-1.05263	.40562		
Divestiture (DIVTOT)	-.16808	.03025	-.17478	.02953
Non-fuel O&M (SRNF)	233.795	49.0385	305.175	36.8136
Fossil-Fuel Cap (FOSCAP)	-.01400	.05684	-.04041	.03476
Fossil-Fuel Age (LFOSYR)	-.93574	.68983	-2.29286	.48586
New Capacity (NEWCAP)	-.24642	.10373	-.18366	.09989
Log Likelihood	-446.189		-447.970	
N = 1053				

The quadratic cost term includes utility characteristics that reflect both the parent company's skills in operating and maintaining power plants and its access to capital. The direct measure of the impact of a parent company's O&M costs, SRNF, is statistically (p-value < 0.01) and substantially positive. A one standard deviation increase in SRNF (+\$5.49 per MWh) leads to a much greater absolute change in quadratic cost than any other utility characteristic, except revenue (LNRVSE). The fact that SRNF seems to matter more in this analysis than the earlier correlation study suggests that utility non-fuel O&M costs affect the capacity size decision more than the 0-1 decision of whether to participate at all. A reasonable interpretation, then, is that IOU parent companies reporting larger non-fuel O&M costs are less likely to invest in sizable capacity in a given IPP capacity market.

The three "scale of operation" variables (FOSCAP, NEWCAP, LFOSYR) also provide indirect measures of the parent company's O&M skills. The estimated coefficients before all three measures are negative, implying that parent companies associated with utilities with greater scale and history of operating fossil-fuel power plants face lower IPP capacity costs. The fact that experience with *both* new (NEWCAP) and old (FOSCAP, LFOSYR) plants appear to lower IPP capacity costs likely reflects the two main ways an IPP can acquire capacity in a market: building a new power plant and buying an older existing power plant. Hence, familiarity with both new and old power plants can translate into lower cost for operating IPP merchant power plants. That said, a *caveat* is that only NEWCAP is estimated significantly negative under conventional significance levels (p-value < 0.05). Moreover, the impact on quadratic costs (from a 1 standard deviation increase) is modest compared to the other utility characteristics. This suggests that the data does not point to a strong impact of these indirect measures of O&M skills on capacity costs.

However, an alternative explanation is that the estimation of the impact of utility operational scale is complicated by the presence of other variables highly correlated with operational scale, namely the financial characteristics of net income (NETY) and revenue (LNRVSE). While the coefficients for both financial characteristics are statistically different from zero (p-value < 0.02), only revenue (LNRVSE) has a sign consistent with the "capital cost" story. The estimated positive coefficient before net income suggests that parent companies with utilities reporting greater income face *larger* capacity costs – a result at odds with the view that retained earnings serve as a low-cost, internal source of capital. In the case where the operational scale story is confounded with the capital cost story, individual coefficients could have "inconsistent" positive signs, with the net effect of these scale/financial variables yielding the expected negative sign. To explore this possibility, we estimate a restricted version of the model that excluded NETY and LNRVSE from the specification. As the table above shows, the major qualitative difference in the estimates are in the estimated coefficients for operation scale/history with older power plants (FOSCAP, LFOSYR). Both coefficient estimates become more "precise" and substantially negative. This suggests some confounding of the two effects.

The other two utility financial characteristics, assets-to-liabilities ratio (ATOL) and utility divestiture (DIVTOT) also provide mixed results with respect to the hypothesized capital cost story. The estimated coefficient before utility divestiture (DIVTOT) is significantly negative, consistent with the view that the cash flow from the sale of utility capacity makes it easier for the parent company to acquire IPP capacity elsewhere. But the estimated coefficient before ATOL is significantly positive, contrary to the view that less leveraged firms face lower capital costs. The joint effect of these four utility financial characteristics (NETY, LNRVSE, ATOL, DIVTOT) are negative for most utilities, especially larger utilities (with the negative revenue effect dominating the positive net income and assets-to-liabilities effects). So there is some support for the hypothesis that utility financial health encourages IPP participation, to the extent that these reported, accounting measures are indicative of their underlying economic concepts. But the support is not as strong as in the earlier correlation study, underscoring the difficulty in identifying the individual impact of these utility characteristics when considered in unison.

Interpretations of the coefficients in the price function are tenuous due to the precision with which they are estimated. The estimates are of the expected sign, with the exception of the estimated coefficient for load growth (LOAD10) which is nominally negative but both substantially and statistically indistinguishable from zero. The strongest results are for the 1996 level of peak demand (LOAD96) and load factor (LDFACT96), the two significantly differing from zero at the 0.12 and 0.04 levels, respectively. This suggests that IPPs expect higher prices for their capacity in larger (LOAD96) and less peak-ish (LDFACT96) markets. The former is consistent with the earlier argument of higher demand climbing up the system marginal cost curve. The latter suggests that IPPs may earn more from providing units that are frequently "on" than more peaker units.

A possible concern about all of these results is that the underlying model does not distinguish between entering a market and entering the IPP industry in general. There may be sizable costs to entering the industry that are separate from entering any individual market. In order to explore this concern, the model was re-estimated based on a limited sample. The full data set was pruned to include only firms that have entered at least one of the markets during the sample period and only markets where at least one state has enacted substantial restructuring legislation. The latter criterion eliminated the NERC regions FRCC (Florida), MAPP (South Dakota, Nebraska area), and WSCC-NWP (Pacific Northwest). The resulting estimates were qualitatively similar to their full sample counterparts. A more comprehensive exploration of this issue would require modeling the two entry decisions separately. We leave such a study for the future.

4 Conclusion

The recent state level experiments with electricity restructuring have opened up many new research opportunities for regulatory economists. Much of the current work has focused on the behavior of the independent power producers, abstracting away from their identity. In this paper, we examine the identity of a major subset of the IPPs: IPPs who are owned by parent companies who also own investor-owned electric utilities. By exploring the firm characteristics of these IOU-owned

IPPs, we are able to shed some light on the behavior of these firms. Specifically, we are able to ask: why do some IOUs participate in U.S. independent power production but not others? The specific conjecture raised in the paper is that IOU parent companies differ along two dimensions, their relative ability to run and maintain power plants and their relative capital access. Thus, IOU parent companies that decide to participate in the restructured wholesale electricity markets may be the ones that can leverage one or both of these competitive advantages. By combining reported utility data from FERC with IPP activity data from various trade sources, the empirical linkage between utility characteristics and IOU parent company IPP activity can be used to examine this conjecture.

The results of the empirical analysis suggest that among the observed utility characteristics, those that reflect the ability of an IOU parent company to run and maintain power plants similar to those used as merchant power plants by IPPs seem to be key. The average non-fuel O&M cost for steam power generation, the amount of fossil-fuel burning capacity, the amount of new capacity (built between 1995 and 1996), and even familiarity with aging, utility fossil-fuel burning power plants (similar to power plants sold in divestiture auctions) all figure prominently as important factors that reduce an IOU parent company's merchant power costs and increase the likelihood of significant IPP participation. On the other hand, the impact of financial characteristics such as assets-to-liabilities, net income, and revenue do not seem to be individually robust. The combined effect suggests that the capital cost story is relevant mostly for the largest IOUs.[34] Furthermore, the significant and robust estimates for an IOU parent company's divested utility capacity suggests that the "swapping" of generation assets among IOU parent company is a real phenomenon and one that has a substantial impact on the U.S. IPP industry. This potential, unintended effect of divestiture clearly merits more attention, especially as other states (and countries) design their own restructuring programs.

The analysis above provides some hope for the long-run viability of electricity restructuring. A major motivation for electricity restructuring is the belief that opening up the generation sector to competition will lead to the exit of inefficient, incumbent generators and the entry of more efficient out-of-state electricity producers. Although the estimated model does not completely explain the different levels of IPP participation chosen by the IOU parent companies, it is encouraging to see that the observed ability of these IOU parent companies to operate and maintain utility power plants do appear to play an important factor in the parent company's IPP participation decision. In this manner, we find this paper to be complimentary with other, current research that examines

[34] This is *caveat* the "unreliability" of accounting measures. Retained earnings and cash flow may matter but not reported net income and revenue.

possible efficiency gains from electricity restructuring.[35] In particular, the scope of this paper fits in well with efforts to estimate explicitly the power plant operation/maintenance efficiency gains (or losses) from observed differences in power plant performance pre- and post-regulatory restructuring. The results from this paper would suggest that any efficiency gains found from such effort may be due to differences in the firm operating the power plant (pre- and post-) as well as changes in the regulatory incentives faced by the firm.

We do not see this paper as being a comprehensive study of either the IOU parent company IPP participation decision or IPP investment behavior, in general. This paper abstracts from many interesting and relevant aspects of both issues. These aspects include the distinction between buying and building generation capacity, potential gaming between utility and regulator, balancing of investment portfolio by multi-product utilities, management based reasons for corporate expansion, the impact of regulatory uncertainty, among others. Each merits its own study as these factors require their own data and empirical model.[36] Given the relative wealth of information available for reported utility characteristics and the key roles played by utility-affiliated IPPs in U.S. restructured electricity markets, this paper, with its focus on generation cost, represents a natural starting point. We hope that this paper, along with others, helps provide a more complete view of the entry and investment behavior of non-utility independent power producers.

[35]See Wolfram (2003) for an overview

[36]Two recent works that examine some of these issues are Ishii & Yan (2003, 2004)

Bibliography

210 Independent Power Companies: Profiles of Industry Players and Projects. 2000. New York, NY: McGraw-Hill Companies

Electricity Supply & Demand. 1999. Princeton, NJ: North American Electricity Reliability Council (NERC). See http://www.nerc.com

Electric Power Annual. 1997. Washington D.C.: Energy Information Administration (U.S. Department of Energy)

Averch, H. & L. Johnson (1962). "Behavior of the Firm under Regulatory Constraint." *American Economics Review*. Vol.52 No.4

Berndt, R., Epstein, R. & M.J. Doane (1996). "System Average Rates and Management Efficiency: A Statistical Benchmark Study of U.S. Investor-owned Electric Utilities." *The Energy Journal*. Vol.17 No.3

Borenstein, S. & J.B. Bushnell (1999). "An Empirical Analysis of the Potential for Market Power in California's Electricity Market." *Journal of Industrial Economics*. Vol.47 September

Borenstein, S., Bushnell, J.B. & F.A. Wolak (2000). "Diagnosing Market Power in California's Restructured Wholesale Electricity Market." *American Economic Review*. Vol.92 No.5

Bushnell, J.B., Mansur, E.T., & C. Saravia (2003). "Market Structure and Competition: A Cross-Market Analysis of U.S. Electricity Deregulation." mimeo. University of California Energy Institute.

Bushnell, J.B. & C. Wolfram (2005). "Ownership Change, Incentives and Plant Efficiency: the Divestiture of U.S. Electric Generation Plants." University of California Energy Institute CSEM Working Paper 140.

Fabrizio, K.M., Rose, N.L., & C. Wolfram (2004). "Does Competition Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency." University of California Energy Institute CSEM Working Paper 135.

Ishii, J. & J. Yan. (2003). "The Make or Buy Decision in U.S. Electricity Generation Investment." University of California Energy Institute CSEM Working Paper 107.

Ishii, J. & J. Yan (2004). "Investment under Regulatory Uncertainty: U.S. Generation Investment Since 1996." University of California Energy Institute CSEM Working Paper 127.

Ishii, J. (2004). "Technology Adoption and Regulatory Regimes: Gas Turbine Electricity Generators from 1980 to 2001." University of California Energy Institute CSEM Working Paper 128.

Joskow, P.L. & E. Kahn (2002). "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000." *Energy Journal*. Vol.23 No.4

Mansur, E.T. (2003). "Vertical Integration in Restructured Electricity Markets: Measuring Market Efficiency and Firm Conduct." University of California Energy Institute CSEM Working Paper 117.

Puller, S.L. (2001). "Pricing and Firm Conduct in California's Deregulated Electricity Market." mimeo. University of California at Berkeley.

White, M. (1996). "Power Struggles: Explaining Deregulatory Reforms in Electric Power Markets." *Brookings Papers on Economic Activity: Microeconomics*.

Wolfram, C.D. (1999). "Measuring Duopoly Power in the British Electricity Spot Market." *American Economic Review*. Vol.89 No.4

Wolfram, C.D. (2003). "The Efficiency of Electricity Generation in the U.S. after Restructuring." University of California Energy Institute CSEM Working Paper 111.

Data Appendix

There are three main categories of data used in this analysis: electric utility characteristics, independent power production investments made by electric utility parent companies, and market characteristics. The data on utility characteristics are obtained from the Federal Energy Regulatory Commission (FERC)'s Form 1 reports for 1996. More precisely, the data was gathered from the summary tables of the 1996 FERC Form 1, tabulated by the Energy Information Administration (EIA). The summary tables are available on the Internet at

http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/fi_tabs.html

The tables list the financial characteristics of major private electric utilities, with the "major" status determined by EIA. For the purposes of the paper, the pool of utilities were further whittled down. Cooperatives were excluded as many of them are non-profit and not candidate for expansion into nation-wide IPP activity. Furthermore, utilities whose generation needs were satisfied with less than 10% of own fossil-fuel burning units were excluded as well. This excluded a few utilities that were either strictly transmission & distribution companies (imported most of their electricity) or generated most of their electricity using an existing hydro system. The remaining utilities were then classified by the parent company that owned the utility. The 1996 Major Parent Company List (also available from the same EIA source) was used as a template, though substantial updating was done via Internet sources (mostly company web sites). For some utilities, their parent company changed during the interim between 1996 and 2000.[37] In those cases, the most recent ownership status was used.[38] A total of 81 parent companies were arrived at through this process.

Information on the IPP activities of the 81 electric utility parent companies were obtained using various industry resources. The majority of the data was obtained from the annual McGraw-Hill publication "210 Independent Power Companies: Profiles of Industry Players and Projects." The publication provides data (as of first half 2000) on many of the major electric utility affiliated independent power producers. Data on the smaller electric utility affiliated IPPs as well as second half 2000 updates on the activities of the larger ones were obtained from the various industry publications and the company web sites. The collected variables of interest are whether the electric utility parent company has a subsidiary for domestic independent power production and how much domestic merchant power plant (operational) capacity they owned as of the end of 2000 in each state.

[37]This is due to mergers and acquisitions among electric utilities and their parent companies

[38]Three of the utilities were bought out by major independent power producers, AES and Enron. Those utilities were dropped from the analysis.

Lastly, information on market characteristics are obtained from the North American Electricity Reliability Council (NERC)'s *Electricity Supply & Demand* (ES&D) database. NERC is the private, industry-organized governing body for North American electricity transmission & distribution operators. The 1996 actual values for load (electricity demand), reserve margin, and load factor for 13 major NERC regions were obtained.[39] In this study, a market is defined as one of the 13 major NERC regions, most of which span across several state lines. More precisely, a market is defined as the wholly included set of states that span the NERC region. For a state at the intersection of multiple NERC regions, the state is assigned to the NERC region that captures most of the state's urban population. In most cases, the assignment of a state is very clear.

NERC Subregions and Corresponding States			
Region	States	Region	States
ECAR	IN, KY, MI, OH, WV	ERCOT	TX
FRCC	FL	MAAC	DE, MD, NJ, PA
MAIN	IL, WI	MAPP	IA, MN, ND, NE, SD
NPCC-NE	CT, MA, ME, NH, RI, VT	NPCC-NY	NY
SERC	AL, GA, MS, NC, SC, TN, VA	SPP	AR, KS, LA, MO, OK
WSCC-CNV	CA	WSCC-NWP	ID, MT, NV, OR, UT, WA
WSCC-RA	AZ, CO, NM, WY		

The NERC definition was used as it largely accounts for imports and exports of electricity across state borders: a merchant power plant in one state may actually have been built with the intent of exporting electricity to a neighboring state. Moreover, IPPs are often quoted as saying that they are building a power plant to serve a particular NERC region. Additional information on NERC regions can be found at the NERC web site (www.nerc.com)

[39]However, the 1996 retail electricity price is calculated using state-level information obtained from the Energy Information Administration's *Electric Power Annual.* The price is aggregated to the NERC region level by weighted average, where the weight is the ratio of the state's 1996 generation and the total amount of 1996 generation in the region.