The "Make or Buy" Decision in U.S. Electricity Generation Investments

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Abstract

The paper presents an empirical model of the "make or buy" decision by independent power producers (IPPs) in restructured U.S. wholesale electricity markets. The model is based on observing whether an IPP buys a divested utility power plant ("buy"), builds a new power plant ("make"), or chooses not to invest at all. The model is applied to plant-level data that track the investment decisions of major IPPs from 1996 to 2000, leading to estimates of the investment cost and expected profit functions that characterize how IPPs evaluate different power plant investment opportunities. The main purpose of the empirical exercise is to evaluate the effectiveness of divestiture programs (which sold utility power plants to IPPs) in encouraging greater IPP participation in restructured wholesale markets. The estimates suggest that the main factor influencing an IPP's willingness to pay for a divested power plant is the investment cost the IPP must incur in order to build a new power plant in the market. Moreover, the estimated model finds that IPPs which are affiliated with electric utilities are observed buying most of the divested plants precisely because they face a relative disadvantage in building large power plants, *vis a vis* their unaffiliated counterparts. Consistent with these findings are the simulation results that examine IPP investment behavior in the absence of divestiture. The simulations provide strong evidence indicating that a minimal amount of new power plant investment was "crowded out" by the presence of divestiture. Moreover, the simulations indicate that divestiture encouraged entry and participation by a greater number of IPPs, most particularly those affiliated with investor-owned electric utilities.

Introduction

Beginning with California in 1996, many state governments in the United States have enacted restructuring legislation aimed at transforming the electricity supply industry away from the traditional regulated structure toward a more competition-based marketplace. Historically, the industry has been dominated by vertically integrated investor-owned utilities (IOUs) whose regulated geographic monopolies controlled all three main sectors of the industry: generation, transmission and distribution (T&D), and retail services. One of the main goals of the restructuring process is to introduce competition into the electricity generation sector and allow non-utility, independent power producers to invest and compete for market-based returns.[1] In order to facilitate the introduction of competition, many state policymakers have argued for and implemented a plan under which IOUs were enticed to sell their existing generation assets to non-utility, independent power producers (IPPs). From 1997 through 1999, "over 15% of the IOU generating capacity has been sold or is for sale" (Joskow (2000)).

Policymakers felt that the divestiture of IOU generation assets would serve three purposes. First, it would help prevent the incumbent utilities from using their existing generation capacity and ownership of transmission and distribution facilities to exert market power in the "deregulated" electricity generation sector. Second, divestiture would provide a market-based method of evaluating the "stranded cost" that IOUs would incur due to restructuring.[2] In fact, stranded cost recovery was the primary reason many IOUs agreed to divestiture: many of the state restructuring programs required divestiture as a condition for regulatory assistance in recovering stranded cost. Third, many policymakers believed that divestiture sales would help encourage greater entry and new generation investment by IPPs. IPPs buying these divested assets would be able to participate immediately in these restructured markets, without having to undergo the costly and time consuming process of permitting and building new power plants. Moreover, divestiture could help encourage greater IPP participation by signalling a greater commitment to restructuring by the state, which reduces the regulatory risk faced by IPPs; a state that has transferred a greater amount of its existing generation supply out of the hands of regulated IOUs and into the hands of unregulated IPPs would be harder pressed trying to put the "genie back in the bottle."

The empirical evidence from the past five years of electricity restructuring in the United States

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[1] As of October 1, 2001, 24 states have enacted electricity restructuring legislation or implemented comprehensive regulatory orders on restructuring, with many other states considering following suit. (Energy Information Agency, "Status of State Electric Industry Restructuring Activity," http://www.eia.doe.gov)

[2] Stranded cost can be thought of as the difference in revenue the IOU expects to earn from existing generation assets between the non-restructured (regulated) and restructured industry.

has provided mixed evidence on the effectiveness of divestiture sales in achieving these goals. Divestiture sales have been very successful in resolving the stranded cost issue: for many utilities, the proceeds they received from their divestiture sales have largely covered their negotiated stranded cost figure. This has mitigated the degree to which state governments have had to provide stranded cost assistance, either through the issuance of government-backed bonds or the imposition of price supports in the form of "competition transition charges" (CTC).[3] Moreover, early divestiture sales signalled what has become clear during recent times: earlier discussions on the magnitude of "stranded cost" have been overstated.

However, at the same time, the evidence on the effectiveness of divestiture in facilitating lower wholesale electricity prices has been less encouraging. While IOUs may not have been able to exert market power in the restructured generation sector, the recent academic literature suggests that IPPs who bought the divested IOU power plants have, instead, been able to exercise sizable market power. Borenstein, Bushnell, & Wolak (2000) and Puller (2001) both find empirical evidence that demonstrate the ability of IPPs to earn wholesale electricity prices much greater than marginal cost during periods of tight supply in California. Consequently, it is not obvious that divesting generation assets to IPPs has, in the immediate short-run, mitigated the market power concern in a restructured, wholesale electricity market. In fact, such a transfer of generation assets may have exacerbated the situation; given that many of the IOUs are the major buyers of electricity in the wholesale electricity market, IOUs may have been more tempered in their electricity bidding (with much of the proceeds from high electricity prices coming from their own pockets) than their non-buying IPP counterparts.

Although current empirical research suggest that divestiture may have driven up wholesale electricity prices in the short-run, there is little in the developing literature that evaluates the effectiveness of divestiture in achieving the more long-run, competitive goal of encouraging greater IPP entry and investment. This distinction between the short-run and long-run consequences of divestiture is important, especially given the understanding that some amount of high wholesale prices is unavoidable during the initial transition period of electricity restructuring.[4] Despite pos-

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[3] San Diego Gas & Electric (SDGE), one of California's three major IOUs, was able to recover its entire stranded cost through sale of its generation assets. As a result, SDGE customers no longer pay the CTC.

[4] During this initial period, the physical electricity system is still very much the same as the system built by the IOUs under the principle of minimizing *total* cost of electricity supply; IOUs built a system, consisting of a few large power plants and a correspondingly limited transmission network, that reduced transmission costs while taking advantage of scale economies in electricity generation. Such a system is not conducive to wholesale competition, conferring each large power plant some degree of local market power. It is more acceptable in the vertically integrated, regulated monopoly regime as state commissions are able to regulate explicitly the price charged by IOUs

sible complications from divestiture in the short-run, divestiture may still be overall desirable if it helps foster beneficial long-run competition through the encouragement of greater IPP participation. Nominally, divestiture has increased IPP participation in wholesale electricity markets in the United States; much of the current major IPP participants, such as the California "Big Five," participate through their ownership of divested IOU assets.[5] However, whether divestiture led to greater IPP participation in *real* terms is unclear as many of these IPPs may have chosen to participate even in the absence of divestiture by building new power plants. Divestiture may have just "crowded out" new power plant investments without necessarily encouraging any new IPP participation. Therefore, the relevant comparison is not the actual comparison between IPP participation before and after divestiture but rather the counterfactual comparison between IPP participation in a market *with* divestiture and IPP participation in the same market but *without* divestiture. The main focus of this paper is the calculation of such a counterfactual.

In order to calculate this real difference in IPP investment, a structural model of an IPP's power plant investment decision is proposed and estimated. A structural model is necessary in order to estimate the optimal investment decision of an IPP in the counterfactual world without divestiture. Trying to deduce such a decision by means of cross-sectional regression on IPP investment data in markets with and without divestiture is problematic as the presence of divestiture no doubt induces structural change in the IPP (reduced form) investment function. Divestiture not only changes the investment opportunity for an IPP but also the relationship between one IPP's investment decision and the investment decisions of its potential competitors: in order for an IPP to buy a divested power plant, the IPP must be willing to pay more for the divested asset than any of its competitors. As a consequence, there is a need to model explicitly how IPPs evaluate both the "making" of new power plants and the "buying" of existing, divested utility power plants.

The model adopted in this paper specifies the expected profit stream associated with a power plant, both new and old, and the investment cost that needs to be incurred in order to build a new power plant as functions of exogenous plant, firm, market, and regulatory variables. In a market without divestiture, an IPP invests when the expected profit stream from a new power plant is greater than the investment cost associated with the plant.[6] However, in a market with divestiture, an IPP must not only choose whether to invest but also how. This "make or buy" decision creates a link between an IPP's valuation of a new power plant and the maximum amount an IPP is willing to pay for a divested power plant: an IPP is willing to buy a power plant as long as the value of

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[5] The "Big Five" are AES, Duke, Dynegy, Reliant, and Southern

[6] The model is based on the standard net present value (NPV) approach to investment. Ishii (2001a) presents a model of IPP capacity investment based on a real options approach.

the acquired power plant (expected profit stream minus transaction price) is no less than either the value earned from building a new power plant or the value from making no investment. Assuming that divestiture sales are efficient, whether an IPP ends up buying a divested power plant depends on whether the IPP has the highest willingness to pay among competitors. Similarly, whether an IPP builds a new power plant depends on whether the IPP faces both a competitor with a greater willingness to pay and an expected profit stream from building a new power plant that exceeds its investment cost. These revealed preference type arguments provide the constraints on the data which identify the parameters in the IPP's expected profit stream and investment cost functions.

The empirical model is applied to data on the investment decisions of 20 major IPPs during the period 1996 to 2000 for all 48 contiguous U.S. states. Although the primary motivation underlying the estimation is the calculation of counterfactual investment decisions, the estimated expected profit stream and investment cost functions, in of themselves, provide some insights into observed IPP investment behavior. First, the estimates indicate a clear difference in the evaluation of power plants between IPPs affiliated and unaffiliated with electric utilities. More specifically, IPPs affiliated with electric utilities face a much greater investment cost associated with building a new power plant and a modest profit advantage in running older power plants. The result is intuitive and helps explain why the majority of divested power plants have been bought by IOU affiliated IPPs. Second, the estimates argue that the main incentive underlying the buying of power plants is the avoidance of the investment cost associated with the "making" of new power plants, rather than the value associated with the (possibly desirable) location of old power plants. Last, the estimates echo some of the market power and scarcity rent concerns found in the recent literature on IPP bidding behavior: market characteristics reflecting the tightness of supply are found to have a significant, positive impact on expected profits in markets further along in restructuring. However, the estimates also find that for markets with suitably adequate supply, further restructuring lowers expected profits.

In order to evaluate the real difference in IPP participation introduced by divestiture, the estimated expected profit stream and investment cost functions are used to calculate the counterfactual investment decisions of IPPs in the absence of divestiture. The results show that among the 32 (firm, market, year) observations in the sample associated with an IPP buying a divested power plant, on average only *one* would have been associated with the construction of a new power plant in the absence of divestiture. Furthermore, the simulations find that the amount of new generation capacity "crowded out" by divestiture is very small, on average 387.6 megawatts (MW). This indicates that while divestiture has not "crowded out" a large amount of new generation capacity, it has encouraged substantial new IPP participation in the restructured market. A *caveat* to this result is that divestiture has been biased toward encouraging participation by IPPs affiliated with investor-owned electric utilities.

The remainder of the paper is organized as follows. Section 1 provides the theoretical model for the "make or buy" decision. Section 2 describes in detail the empirical analog to the theoretical framework. Section 3 discusses the data used to estimate the model. Section 4 presents and analyzes the parameter estimates of the model as well as the policy simulations based on the estimates. The paper then concludes with some final thoughts.

1 Theoretical Model

We assume that in the same year and market, an IPP only considers carrying out at most one type of positive investment: either acquisition of divested utility assets or the construction of new power plants. The idea is supported by the data on IPP investment decisions: no firm is observed buying a divested asset and sinking a large amount of investment costs toward a new power plant in the same market and year. One economic rationale behind this assumption is that there may be some kind of resource constraint that prevents the firm from exploring both "make" and "buy" options. However, this constraint is neither modeled nor directly observed; rather, it is simply imposed.

Given this basic assumption, we make the following specification concerning the elements in a firm's choice set and the timing of its decision. First, in a year when there is no divestiture sale in the market, the firm chooses between investing through building a new plant and not investing at all. Second, in a year when an IOU in the market is selling some of its generation assets, the firm always participates in the divestiture sale first.[7] If the firm succeeds in buying the divested asset, it does not build new power plants in that market during that same year. The firm only (explicitly) considers building a new power plant if it fails to buy any divested asset from all the divestiture sales available in the year in the market. The assumptions lead us to the following decision tree for a firm:

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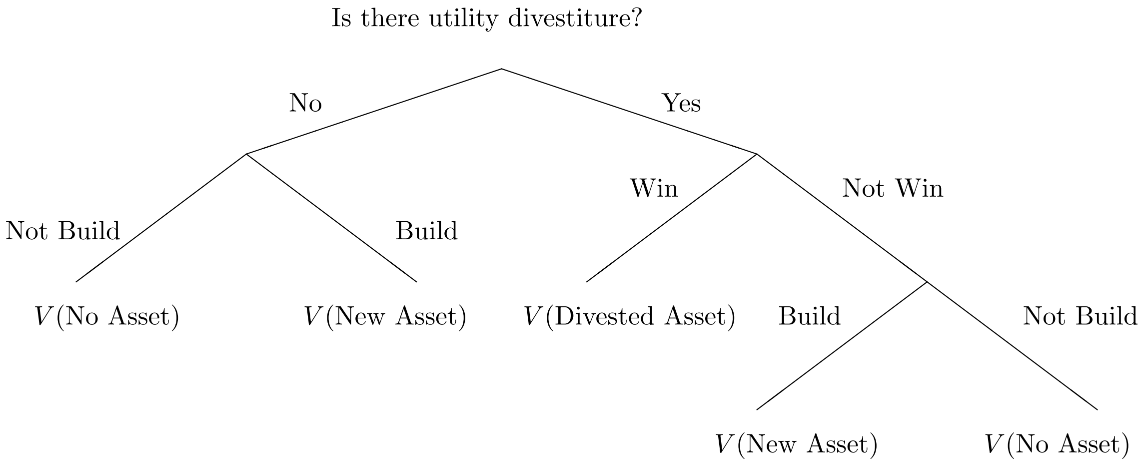
[7] For the case of multiple divestiture sales in the same market and year, the model assumes that the sales occur concurrently and the firm takes part in all of them. However, a firm evaluates the assets independently across the sales. In other words, the firm's willingness to pay for a divested asset is neither related to the asset involved in another sale nor contingent on the outcome of that sale.



The idea underlying the timing assumption is that when a firm participates in a divestiture sale, it takes into consideration its option to build a new power plant, an option which is forsaken if the firm is successful in buying a divested asset. Therefore, the value the firm places on acquiring the rights to the divested power plant, net the sales price, must not only be greater than the value of not investing; it must also be greater than the value the IPP places on the option of building a new power plant. Otherwise an IPP would prefer redirecting the resources it spent on acquiring the divested power plant toward the construction of a new power plant. Let V denote the expected return from an asset (old or new). In a divestiture sale, a firm's willingness to pay for the divested asset can be derived from the following inequalities:

$$\begin{aligned}
\underbrace{\Pi(\text{divested asset}) - \text{Pay}}_{V(\text{divested asset})} \quad &> \quad \max\ \{\ 0\ ,\ \underbrace{\Pi(\text{new asset}) - C(\text{new asset})}_{V(\text{new asset})}\ \} \\
\text{Pay} \quad &< \quad \underbrace{\Pi(\text{divested asset}) - \max\ \{\ 0,\ \Pi(\text{new asset}) - C(\text{new asset})\ \}}_{W^*}
\end{aligned}$$

where

Π = Expected discounted profit stream from asset

C = Investment cost associated with the new asset

W^* = Maximum willingness to pay

where the return to not investing is normalized to be zero. Also, V(new asset) is the highest return the firm expects to receive from building new plants. The expression above takes advantage of the fact that, to a profit maximizing firm, the value of a power plant is based on the expected profit stream from the asset (Π). Furthermore, the expression makes clear a fundamental feature of the model: the maximum amount that an IPP is willing to pay for a divested asset is weakly increasing with the cost of building a new power plant (C).[8] Therefore, willingness to pay is more likely to be higher in markets where the cost of building a new power plant is higher and for firms who have a relative disadvantage in building new power plants, *ceteris paribus*.

We assume that every firm participates in all available divestiture sales; so all firms in our sample are potential buyers of a divested asset. Therefore, the winner of a divestiture sale is determined from the comparison of the maximum willingness to pay (W^*) across all firms. We assume that the divestiture sales are efficient: the firms with the highest W^*'s are always the firms that succeed in buying the assets.[9] So, if firm i succeeds in buying a particular divested asset, we know from the observation that firm i must have had the highest maximum willingness to pay for the asset among all firms

$$W^*(i) > W^*(j) \quad \forall\, j \neq i\ , \qquad j \in \{\text{Other potential IPP buyers}\}$$

Following the same logic, if a firm is observed building a new power plant, two things can be inferred. First, it cannot have had the highest maximum willingness to pay for any of the available divested assets. And second, the value that the IPP placed on building the new power plant must be greater than the value of making no investment. Thus we have the following inequalities :

$$\begin{gathered} W^*(i) < W^*(j) \quad \text{for some } j \neq i \\ \Pi(\text{new asset}) - C(\text{new asset}) > 0 \end{gathered}$$

Analogously, observing an IPP make no investment translates into the following set of inequalities

$$\begin{gathered} W^*(i) < W^*(j) \quad \text{for some } j \neq i \\ \Pi(\text{new asset}) - C(\text{new asset}) < 0 \end{gathered}$$

These sets of constraints together capture the information contained in observing a firm's "make or buy" decision in a given market and year. For the case where there are multiple divestiture sales, the only modification is that an additional constraint is derived from the observed outcome of each additional sale. For example, in the case where a market has two sales and IPP i is observed buying asset 1 but not asset 2, the implied set of constraints for IPP i would be

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[8] In the case of "make" being profitable, $\Pi(\text{new asset}) - C(\text{New Asset}) > 0$, we have

$$W^* = \{\Pi(\text{divested asset}) - \Pi(\text{new asset})\} + C(\text{new asset})$$

The value for the divested asset is determined by the difference in expected profit stream between the divested and new assets, as well as the cost of building the new asset

[9] Assuming there are no ties.

$$\begin{aligned} W_1^*(i) &> W_1^*(j) \quad \forall\, j \neq i \\ W_2^*(i) &< W_2^*(j) \quad \text{for some} \;\; j \neq i \end{aligned}$$

The model continues to assume that an IPP, once it buys a divested asset, will no longer consider building a new power plant. However, an IPP can win multiple divestiture sales in the same market and year. Moreover, an IPP will only consider building a power plant if it fails to acquire any of the divested assets (or no divested assets were available) in the market for the given year. What remain to be specified are the characteristics a firm chooses for the new power plant built under a "make" investment. In the model, a firm only decides on the capacity of the new plant. The capacity is chosen to maximize the return on the new asset (the $(\Pi - C)$ of the asset). We make this assumption because new power plants built by IPPs during the sample period are very similar to one another in other dimensions. For example, many of the new IPP plants use the same natural gas based combined-cycle (CCGT) technology. If a firm is observed building more than one plant in the same market and year, we treat the plants as one asset whose capacity is equal to the sum of the capacity of each plant in the portfolio.

Overall, the key point of the theoretical model is to establish the inter-connection between the "make" and "buy" options. On one hand, the value of the "make" option is explicitly modeled as one of two key factors that determine the value of the "buy" option. By imposing the sequential timing for the two options ("buy" first), the model is able to disentangle the channels through which different plant, firm, market, and regulatory variables affect the evaluation of the divested assets and the new assets (Π(divested asset), Π(new asset) and C(new asset)). On the other hand, the model attributes the outcome of the divestiture sales to the comparison of willingness to pay across firms. Thus, the investment decision a firm makes under a certain scenario not only depends on its own evaluation of the available options but also on how other firms evaluate these options and the relative order of these valuations. Consequently, the model is able to address how the evaluation of generation asset is affected by firm heterogeneities.[10]

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[10] Note, the model does not explicitly consider the impact of possible future divestment or resale of the asset on a firm's decision to invest in the asset. Thus far, there have only been one resale of divested utility assets: Sithe resold the power plants it acquired from Pennsylvania utility GPU Inc. to Reliant a year after the original purchase. Sithe is excluded from our sample of major IPPs.

2 Empirical Model

An observation in our data is an IPP's investment decision in a state/year. For this paper, we use the same set of data as in Ishii (2001a) and Yan (2001) except for the plant-level data for divested assets.[11] Given the theoretical model described in the last section, we map exogenous plant, firm, market and regulatory variables to observed firm investment decisions ("make", "buy", or not investing) by specifying the function of the expected profit stream (Π) associated with an asset (old or new) and the function of the investment cost (C) incurred for building a new asset a by firm i in state g during year t. In addition, we distinguish between the information set that is observed by a firm from that observed by the econometrician; based on this distinction, we formulate the stochastic structure of the empirical model, solve the model, and derive the associated likelihood function.

2.1 Expected Profit and Investment Cost Functions

The basic form of the expected profit function and the investment cost function are similar to those in Yan (2001). The per-unit profit a firm expects to receive from a generation asset in a year (denoted as r) is modeled as a hedonic function of the exogenous characteristics of the asset, of the market in which the asset operates and of the firm itself. Under this formulation, the difference of the expected profit between divested and new assets in the same market and year for the same firm is due to differences in plant characteristics between the two assets. The expected profit stream (Π) is modeled as the sum of the expected per-year profit over a finite horizon:

$$\begin{aligned} \Pi_{igta} &= \overline{\Pi}_{igta}\; K_{igta} \\ &= \left(\sum_{\tau=1}^{10} \beta^{\tau} E_t\; r(X^r_{ig(t+\tau)a}\;;\; \theta^r) \right) \cdot K_{igta} \end{aligned}$$

where

$$\begin{aligned} (i, g, t, a) &= \text{(firm,market,year,asset)} \\ E_t\; r(X^r_{ig(t+\tau)a}\;;\; \theta^r) &= X^r_{ig(t+\tau)a|t}\theta^r \\ X^r_{ig(t+\tau)a|t} &= \text{Forecasts for variables related to profit per unit of capacity} \\ K &= \text{Generation capacity of the asset} \\ \overline{\Pi} &= \text{Expected revenue stream per unit of capacity} \end{aligned}$$

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[11] For a detailed description of the data, please refer to the Appendix

Note, the specification does not distinguish between the lead times for the "make" and "buy" options. In both cases, a firm incurs the investment cost (for a new asset or for a divested asset) in year t and begins to earn revenue from the asset in year $t+1$. The reason is that while new power plant projects may be announced as early as three years before commercial start, the construction and installation of the new plants usually begins 12–18 months before commercial start. The period just prior to construction, associated with the earning of various regulatory approval, is considered the time during which the significant portion of the investment cost is sunk. On the other hand, a divestiture sale usually takes 6–12 months to close. Therefore, we set the time lag in both cases to be one year. Basically, the time lag captures the fact that a firm has to sink substantial investment cost up front before it can get a plant ready for commercial operation. In addition to the time lag, the specification also assumes that an IPP focuses on the profit stream from the first ten years of the asset's operation after its acquisition/construction ($\tau \leq 10$). This assumption follows industry practice as the dispatch models used by IPPs only predict key economic variables (such as production levels, annual revenues, and fuel costs) up to ten years in the future.[12] This is also consistent with the observation that under a more competition-based environment, firms tend to focus on earning their return over a shorter horizon.

As for the investment cost, we assume that it consists of two parts: the fixed component (C^f) and the variable component (C^v). The former is meant to capture costs related to matters like obtaining regulatory approval and finding a suitable site while the latter represents capital costs that are directly related to the size of a project, such as the cost of purchasing generation equipment and the cost of construction. Furthermore, we assume that a firm incurs positive investment cost only if it invests $K > 0$. In other words, $C = 0$ for $K = 0$. Also, we do not allow divestment or resale ($K < 0$).[13] For $K > 0$, we have

$$\begin{aligned}
C_{igt} &= C^f_{igt} + C^v_{igta}(K_{igta}) \\
&= X^c_{igt}\,\theta^c + \alpha_1\,K_{igta} + \alpha_2\,K^2_{igta} \\
&\quad \text{with } \alpha_2 = \exp\{X_i^{\alpha 2}\theta^{\alpha 2}\} > 0 \\
C &= \text{Investment cost for building a new asset} \\
C^f &= \text{Fixed cost } (X^c\theta^c) \\
C^v &= \text{Capital cost } (\alpha_1 K + \alpha_2 K^2)
\end{aligned}$$

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[12] See Vallen & Bullinger (1999)

[13] As mentioned earlier, there are very few observed divestment/resale by IPPs in the data. By excluding this action from the choice set, we abstract away from the task of modeling the value a firm expects to receive from its divestment/resale, which is a very complicated problem

The quadratic form of the capital cost reflects the assumption that it becomes more costly to build per unit of capacity as the total capacity increases, thus helping to bind the maximum size of a new power plant project. We account for firm heterogeneity in capital cost by parameterizing α_2 as a function of firm characteristics. The presence of a fixed cost corresponds to a barrier to investment.[14] The profit from a new power plant (before subtracting the fixed cost) must be large enough before a firm is willing to invest through "make." The higher the fixed cost, the less likely a firm is to build a new plant. In addition, the existence of fixed cost helps bind the minimum size of a new power plant and eliminate the trivial case where capacity is tiny ($K \to 0$).

Details on the variables that are included in the investment cost and per-unit expected profit functions are discussed later in the Data section. However, it is important at this point to highlight one key difference in plant characteristic between a divested asset and a new asset. For a new asset, the firm can choose the capacity size (K) of the asset. But, for a divested asset, K is fixed. Therefore, when comparing the values between the two types of assets, the comparison is between the value of the divested asset with a fixed K, which is generally not optimal for the firm, and the value of the new asset with optimal K ($K^* \geq 0$). The optimal K of a new project is the solution to the following problem:

$$\max_{K \geq 0} \; \{ \; \underbrace{-C(K) \; + \; \Pi(K)}_{V(\text{new asset}, K)} \; , \; 0 \; \}$$

First order condition on $V(\text{new asset}, K)$ yields

$$\begin{aligned} 0 \;\; &= \;\; \frac{\partial}{\partial K} \left(\overline{\Pi} \; K - X_t^c \; \theta^c - \alpha_1 K - \alpha_2 K^2 \right) \\ &= \;\; \overline{\Pi} - \alpha_1 - 2\alpha_2 K \end{aligned}$$

If $K_0^* = \frac{1}{2\alpha_2}(\overline{\Pi} - \alpha_1) > 0$ and $V(\text{new asset}, K_0^*) > 0$ then we have an interior solution $K^* = \frac{1}{2\alpha_2}(\overline{\Pi} - \alpha_1)$.[15] Otherwise, we have a corner solution ($K^* = 0$), which is possible under two scenarios. First, even without any fixed cost of investment ($C^f = 0$), building a new plant may not be profitable ($-C^v(K) + \Pi(K) < 0$). This corresponds to $K_0^* = \frac{1}{2\alpha_2}(\overline{\Pi} - \alpha_1) < 0$. Second, it may seem profitable to build before considering the fixed cost but unprofitable after accounting for the fixed cost. This corresponds to $V(\text{new asset}, K_0^*) < 0$ for $K_0^* > 0$. Given the optimal value a firm can get from the "make" option, we can infer the firm's maximum willingness to pay for a divested asset a as

$$W_{igta}^* = \overline{\Pi}_{igta} \; K_{igta} - \max \; \{ \; 0 \; , \; V(\text{new asset} \; , \; K^*) \; \}$$

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[14] Such as from local environmental and economic regulation.

[15] Because $\alpha_2 > 0$, the objective function is concave for $K > 0$ and the second order condition for the interior solution is satisfied.

Thus far, the discussion has assumed that the econometrician observes all aspect of the information set characterizing a firm's investment decision. Next, we describe the stochastic structure of the empirical model. We assume that there are three sets of information that are known to the firm but unknown to the econometrician. The first error, ξ, captures the unobserved component in the capital cost per unit of capacity for a new asset. The second error, η, captures the unobserved component in the fixed cost associated with building a new asset. And lastly, the third error, ϵ, captures the unobserved component of an IPP's valuation of the divested asset a. The three random terms account for the corresponding variations that cannot be fully explained by the observed variables for a given set of parameters: ξ for the variation in the capacity of new plants, η for the variation in the level of the investment barrier a firm faces in a market and ϵ for the variation in the order of the willingness to pay for a divested asset.

Furthermore, we impose a timing rule concerning the realization of these three errors to the firm. If there are divestiture sales, a firm observes ϵ when it participates in the sales but does not observe the errors related to the new asset (ξ and η) until after the conclusion of the divestiture sales. Therefore, when evaluating the divested assets, the firm's information about ξ and η depends on its expectation based on the distribution of the two errors, just like the econometrician. If the firm does not buy any divested asset or there is no divestiture sale, the firm gets to observe the values of ξ and η when deciding whether to build a new plant. So, the errors are introduced into the empirical model in the following manner:

$$\begin{aligned}
V_{igt}(\text{new asset}, K^*) &= \overline{\Pi}_{igt(new)} \cdot \ K^* - \left(C^f_{igt} + \eta_{igt} + (\alpha_1 - \xi_{igt}) \cdot K^* + \alpha_2 \cdot (K^*)^2 \right) \\
W^*_{igta} &= \overline{\Pi}_{igta} \ K_{igta} + \epsilon_{igta} - E_t \max \{ \ 0, \ V_{igt}(\text{new asset}, K^*) \ \} \\
&= \overline{W}_{igta} + \epsilon_{igta}
\end{aligned}$$

By separating the time of realization for ϵ and (ξ, η), the model simplifies the derivation of the likelihood because the "make" and "buy" observation are stochastically separated. Moreover, we assume that if a firm succeeds in acquiring a divested asset, the IPP does not receive draws of ξ and η because "make" is not an option for the period anymore. To complete the specification, we make the following distributional assumptions for the three errors :

$$\begin{aligned}
\xi_{igt} &\overset{i.i.d.}{\sim} N(0, \sigma^2_\xi) \\
\eta_{igt} &\overset{i.i.d.}{\sim} N(0, \sigma^2_\eta) \\
\epsilon_{igta} &\overset{i.i.d.}{\sim} \text{Type I Extreme}
\end{aligned}$$

To keep the model computationally tractable, the three errors are further assumed to be independent of each other.[16] The Type I Extreme distribution is adopted for ϵ as it allows the probability of a firm having the greatest willingness to pay (and hence be the buyer of the divested plant) be represented analytically by the standard logit form.[17]

2.2 Likelihood

Given the stochastic structure of the model, if there is no divestiture sale in a market/year, the investment decisions of all firms are independent from one another.[18] However, if there is a divestiture sale, the observed "buy" decisions of all firms are correlated with each other; in order for one firm to win in a divestiture sale, its willingness to pay, which has an unobserved term (ϵ), must be greater than that of any other firm. The investment decision of a firm i in market g for year t is fully characterized by the following variables: [19]

$$\begin{aligned}
\delta_{igta} &= \begin{cases} 1 & \text{if IPP } i \text{ buys asset } a \\ 0 & \text{otherwise} \end{cases} \\
\psi_{igt} &= \begin{cases} 1 & \text{if IPP } i \text{ builds a new plant} \\ 0 & \text{otherwise} \end{cases} \\
K^*_{igt(new)} &= \begin{cases} K_{igt(new)} & \text{if IPP } i \text{ builds a new plant} \\ 0 & \text{otherwise} \end{cases}
\end{aligned}$$

Consider first the case where there is no divestiture sale in market g and year t. With no divestiture, δ does not enter into a firm's decision under this scenario. So the likelihood for the observed investment decision of firm i takes the form $l_{igt}(\psi_{igt}, K^*_{igt(new)})$. Furthermore, under the adopted stochastic structure, each firm's "make" decision is independent of each other. Therefore, the likelihood for the observed investments in market g year t can be expressed as:

$$l_{gt} = \prod_{i=1}^{N} l_{igt}(\psi_{igt}, K^*_{igt(new)})$$

Next, consider the case where there are A divestiture sales ($A \geq 1$). Firm i's investment decision in the market g year t takes the form $\left(\delta_{igt1}, \cdots, \delta_{igtA}, \psi_{igt}, K^*_{igt(new)}\right)$. According to the model, $(\psi_{igt}, K^*_{igt(new)}) = (0,0)$ with probability 1 if $\delta_{igta} = 1$ for any $\delta_{igta} \in (\delta_{igt1}, \cdots, \delta_{igtA})$. Moreover,

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[16] This simplification is further justified by the fact that we have no natural prior as to how they should be correlated.

[17] We have also considered the model where ϵ is assumed to be distributed *i.i.d.* standard normal, with the variance set to 1 for normalization. The results are qualitatively similar to the results using the logit specification

[18] In this case, the decision is between "make" or "do not invest"

[19] Note, the capacity of a divested plant is fixed, not a choice of the firm.

because there is only one winner in a divestiture sale, the conditional probability of $\delta_{jgta} = 0$ given that $\delta_{igta} = 1$ is 1 for all $j \neq i$. Therefore, keeping in mind that divestiture sales are assumed to be independent of each other, the likelihood of the observed investments in market g year t is:

$$\begin{aligned}
l_{gt} &= \texttt{Prob}\left\{(\delta_{1gt1}, \cdots, \delta_{1gtA}, \psi_{1gt}, K^*_{1gt(new)}), \cdots, (\delta_{Ngt1}, \cdots, \delta_{NgtA}, \psi_{Ngt}, K^*_{Ngt(new)})\right\} \\
&= \left\{\prod_{a=1}^{A} \texttt{Prob}(\delta_{1gta}, \cdots, \delta_{Ngta})\right\} \times \left\{\prod_{i=1}^{N} \texttt{Prob}(\psi_{igt}, K^*_{igt(new)} \mid \delta_{igta}, \cdots, \delta_{igta})\right\} \\
&= \left\{\prod_{a=1}^{A} \texttt{Prob}(\text{firm } i^a \text{ wins } a)\right\} \times \left\{\prod_{i \in \{j:\ \delta_{jgta}=0,\ \forall a \leq A\}} l_{igt}(\psi_{igt}, K^*_{igt(new)})\right\}
\end{aligned}$$

As will be explicitly shown below, both $\texttt{Prob}(\text{firm } i^a \text{ wins } a)$ and $l_{igt}(\psi_{igt}, K^*_{igt(new)})$ can be derived based on the three sets of constraints raised in the theoretical model. Given $\{l_{gt}\}$, the parameter estimates are obtained by maximizing the joint log-likelihood:

$$L = \sum_{g=1}^{G} \sum_{t=1996}^{2000} \log[\ l_{gt}\ ]$$

2.2.1 Deriving `Prob`(firm i^a wins a)

According to the model, firm i^a's willingness to pay for asset a ($W^*_{i^a gta}$) must be the highest among all firms. Given that ϵ_{igta} is distributed i.i.d. Type I Extreme across firms, we have

$$\begin{aligned}
\texttt{Prob}(\text{firm } i^a \text{ wins } a) &= Pr\left\{W^*_{i^a gta} > W^*_{jgta}\ ,\quad \forall j \neq i^a\right\} = \frac{\exp\{\overline{W}_{i^a gta}\}}{\sum_{j=1}^{N} \exp\{\overline{W}_{jgta}\}} \\
&\text{where} \\
\overline{W}_{jgta} &= \overline{\Pi}_{jgta}\ K_{jgta} - \\
&\quad E_t \max\left\{\ 0,\ \left(\overline{\Pi}_{jgt(new)} \cdot K^*_{jgt(new)} - (C_{jgt}(K^*_{jgt(new)}, \xi_{jgt}) + \eta_{jgt})\right)\right\}
\end{aligned}$$

Due to the truncation at 0, it is infeasible to calculate the value of $E_t \max\{\cdot\}$ analytically. Instead, simulation methods are used.

$$\begin{aligned}
E_t \max\{\cdot\} &\approx \frac{1}{S}\sum_{s=1}^{S} \max\ \left\{\ 0, \left(\overline{\Pi}_{igt(new)} \cdot K^*_{igt(new)}(\xi^s_{igt}) - (\ C_{igt}(K^*_{igt(new)}, \xi^s_{igt}) + \eta^s_{igt})\right)\ \right\} \\
\xi^s_{igt} &\overset{i.i.d.}{\sim} N(0, \sigma^2_\xi) \qquad \eta^s_{igt} \overset{i.i.d.}{\sim} N(0, \sigma^2_\eta)
\end{aligned}$$

2.2.2 Deriving $l_{igt}(\psi_{igt}, K^*_{igt(new)})$

There are two types of investment decisions that must be considered. In the first type of investment decision, firm i is observed buying no divested asset but building a new power plant ($\psi_{igt} = 1$) of size $K_{igt(new)}$. This investment decision implies the following set of constraints:

$$\begin{aligned} \overline{\Pi}_{igta} \cdot \ K_{igt(new)} &- \Big((\alpha_1 - \xi_{igt}) \cdot K_{igt(new)} + \alpha_2 \cdot K^2_{igt(new)} + C^f_{igt} + \eta_{igt}\Big) > 0 \\ K_{igt(new)} &= \frac{1}{2\alpha_2}(\overline{\Pi}_{igt(new)} + \xi_{igt} - \alpha_1) > 0 \end{aligned}$$

The first constraint ensures that the expected profit stream from a new plant with observed capacity must exceed the investment cost of building the plant ($V(\text{new asset}, K) > 0$). The second constraint sets the observed capacity equal to the optimal capacity (satisfying the first order condition). Rearranging the first inequality, we get the range of η that is consistent with the observed investment given ξ. The idea here is that for a firm to build a new plant, the investment cost should not be too high relative to the profit stream the firm expects to receive.

$$\underbrace{\overline{\Pi}_{igta} \cdot K_{igt(new)} - C_{igt}(K_{igt(new)}\ ,\ \xi_{igt})}_{\eta^*_{igt}} \quad > \quad \eta_{igt}$$

The second constraint can be inverted to obtain the implicit value of ξ_{igt}.

$$\xi^*_{igt} \quad = \quad 2\alpha_2\ K_{igt(new)} + \alpha_1 - \overline{\Pi}_{igt(new)}$$

The likelihood for this case can be expressed as follows, keeping in mind that η^*_{igt} is a function evaluated at $\xi_{igt} = \xi^*_{igt}$

$$l_{igt} \quad = \quad \frac{2\alpha_2}{\sigma_\xi}\phi\left(\frac{\xi^*_{igt}}{\sigma_\xi}\right) \ \int_{-\infty}^{\eta^*_{igt}/\sigma_\eta} \phi(u)\ du = \frac{2\alpha_2}{\sigma_\xi}\phi\left(\frac{\xi^*_{igt}}{\sigma_\xi}\right)\ \Phi\left(\frac{\eta^*_{igt}}{\sigma_\eta}\right)$$

where the term $\frac{2\alpha_2}{\sigma_\xi}\phi\left(\frac{\xi^*_{igt}}{\sigma_\xi}\right)$ captures the second constraint: we observe the size of the new power plant that was built by the firm i.[20]

In the second type of investment decisions, firm i is observed making no investment, "buy" or "make" ($\psi_{igt} = 0$). The main difference between the derivation of the likelihood for this case and the first case is that the value of ξ_{igt} cannot be inverted from the constraints in this case. There are two possible reasons why $K^*_{fgt(new)} = 0$. First, the value of K^*_0 that maximizes $V(\text{new asset}, K^*_0)$ may be negative and the constraint $K^*_0 \geq 0$ may be binding (corner solution). Second, the value of

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[20] $\frac{2\alpha_2}{\sigma_\xi}$ is the Jacobian from the transformation of variables from $K^*_{igt(new)}$ to the standard normal $\frac{\xi^*_{igt}}{\sigma_\xi}$

K_0^* that maximizes $V(\text{new asset}, K_0^*)$ may be positive but $V(\text{new asset}, K_0^*) < 0$ (interior solution, but IPP better off not investing at all). Taking these two possibilities into consideration, the constraints that characterize this investment decision are

$$\begin{array}{rcl} \overline{\Pi}_{igta}\cdot\ K_{igt(new)} & - & \Big((\alpha_1-\xi_{igt})\cdot K_{igt(new)} + \alpha_2\cdot K^2_{igt(new)} + C^f_{igt} + \eta_{igt}\Big) < 0 \\ & & \text{for } K_{igt(new)} > 0 \\ \text{or}\ \ K_{igt(new)} & = & \dfrac{1}{2\alpha_2}(\overline{\Pi}_{igt(new)} + \xi_{igt} - \alpha_1) < 0 \end{array}$$

So the likelihood can be derived as

$$l_{igt} \;=\; \underbrace{\int_{\xi^0_{igt}/\sigma_\xi}^{+\infty}\left(1-\Phi\left(\frac{\eta^*_{igt}}{\sigma_\eta}\right)\right)\ \phi(u)\ du}_{K_0^*>0 \text{ but } V(\text{new},K_0^*)<0} + \underbrace{\int_{-\infty}^{\xi^0_{igt}/\sigma_\xi}\phi(u)\ du}_{K_0^*<0}$$

The value of ξ^0_{igt} is obtained simply from inverting $0 = \frac{1}{2\alpha_2}(\overline{\Pi}_{igt(new)} - \xi^0_{igt} - \alpha_1)$. It represents the threshold value that needs to be surpassed in order for $\max\limits_K\ V(\text{new asset}, K)$ to have an interior solution.

3 Data and Model Specifications

To estimate the parameters in the empirical model, we collect four sets of data in addition to the data on firm investment decision: plant characteristics, firm characteristics, market conditions and regulatory conditions. The source of the data is described in the Appendix. The data are then categorized into groups that are related to investment cost and per-unit return of a project. To capture differences in firms' evaluation of a project due to observed firm heterogeneity, we also utilize selected interaction terms between (plant, market, regulatory) variables and firm characteristics. We first describe the variables used to control for plant characteristics and then discuss briefly the specifications for the expected profit and investment cost functions.

3.1 Plant Characteristics

Plant characteristics are meant to capture the differences between divested plants and the newly built plants as well as the differences across divested plants. In the estimation, we use information on two characteristics of a plant: the age of a plant and the location of a plant. Both of these potentially affect the return a firm expect to receive on a plant and hence are included in the group of variables characterizing per-unit return (X^r).

The age of a plant is used as a proxy for the general competitiveness and implied profitability of the plant in the market. Older plants tend to be less efficient than new plants. Moreover, the effect of age is most likely to be discrete. An one year old plant may not be that different from a plant that is two years old but may be quite different from a plant that is 15 years old. So we discretize the age of a plant in the following way:

$$\mathsf{AGE} = \begin{cases} 0 & \text{if plant is less or equal to 10 years old} \\ 1 & \text{if 10 to 20 years old} \\ 2 & \text{if 20 to 30 years old} \\ 3 & \text{if more than 30 years old} \end{cases}$$

By definition, all new plants have an age value equal to zero.[21] Therefore, the effect of age can only be identified by the variation across divested plants. Furthermore, as described in the model section, this identification depends on the comparison of the willingness to pay among firms. As a result, any effect of age that is common to all firms will be cancelled out in the comparison and hence cannot be identified by the observed data.[22] So only the effect of age that vary across firms can be estimated.

Additionally, the location of an existing plant can affect how an IPP evaluates the divested power plant. The plant may be located in an area with growing, high demand (e.g. urban population center) where it is both difficult to build new plants due to the lack of appropriate sites and to import electricity due to transmission constraint, conferring some local market power to the plant. As a result, firms that are experienced in "playing" the market may put higher value on these plants. We use the relative population density (RELPOP) at the location of the plant to capture this effect. RELPOP is the ratio of the population density at the plant site to the average population density of the state. For new plants, we assume their site has the average population density of the state (RELPOP=1).

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[21] Recall that in the model firms only consider the annual returns from a project for up to ten years

[22] To see this, recall that the logit probability that firm i has the highest willingness to pay ($W_i > W_j, \ \forall j$) is determined by differences ($W_i - W_j$). So any additive common part in W_i and W_j will cancel each other out. One way to get around this is to introduce some kind of functional form separation. We plan to explore this in a future draft

3.2 Model Specifications

3.2.1 Expected Profit Function

The expected profit function takes the following linear form:

$$\begin{aligned}
E_t r_{igt+h} \;=\; & \theta_0^r \;+\; \theta_1^r\mathsf{P96}_g + \;\theta_2^r\mathsf{LOGLOAD}_{gt+h|t} + \;\theta_3^r\mathsf{SHARE96}_g + \;\theta_4^r\mathsf{INT96}_i \,+ \\
& \theta_5^r\mathsf{US96}_i + \;\theta_6^r\mathsf{USIOU}_i + \;\mathsf{LOGYRLEG}_{gt+h|t} \times (1 \;+\; \theta_7^r\mathsf{DIVFLAG}_{gt+h|t}) \times \\
& [\;\theta_8^r + \;\theta_9^r\mathsf{LOGLOAD}_{gt+h|t} + \;\theta_{10}^r\mathsf{RM}_{gt+h|t} + \;\theta_{11}^r\mathsf{LDFACT}_{gt+h|t} \,+ \\
& \theta_{12}^r\mathsf{INT96}_i + \;\theta_{13}^r\mathsf{US96}_i + \;\theta_{14}^r\mathsf{USIOU}_i\;] \;+ \\
& \mathsf{AGE}_a \times (\theta_{15}^r\mathsf{INT96}_i + \theta_{16}^r\mathsf{US96}_i \;+\; \theta_{17}^r\mathsf{USIOU}_i) \;+ \\
& \mathsf{RELPOP}_a \times (\theta_{18}^r\mathsf{INT96}_i + \theta_{19}^r\mathsf{US96}_i \;+\; \theta_{20}^r\mathsf{USIOU}_i)
\end{aligned}$$

$\mathsf{P96}_g$: Average retail electricity price in state g in 1996

$\mathsf{LOGLOAD}_{gt+h|t}$: Log of the forecasted demand (load) in the NERC subregion for state g

$\mathsf{SHARE96}_g$: Capacity share of nuclear and hydro generation in state g in 1996

$\mathsf{INT96}_i$: Generation capacity owned by firm i outside the U.S. in 1996

$\mathsf{US96}_i$: Generation capacity owned by firm i inside the U.S. in 1996

USIOU_i : Dummy for whether firm i is affiliated with some major utilities

$\mathsf{LOGYRLEG}_{gt+h|t}$: Log of 1 + number of years since enactment of restructuring legislation

$\mathsf{DIVFLAG}_{gt+h|t}$: Dummy for whether major divestitures have occurred in state g by $t+h$

$\mathsf{RM}_{gt+h|t}$: Forecasted reserve margin in the NERC subregion where state g is located

$\mathsf{LDFACT}_{gt+h|t}$: Forecasted load factor in the NERC subregion for state g

AGE_a : Age of divested asset a

RELPOP_a : Ratio of the population density at the location of a and that in the state.

The chosen expected profit function includes elements from all four sets of data: plant characteristics, firm characteristics, market conditions and measures of restructuring progress. AGE and RELPOP are plant characteristics. $\mathsf{INT96}$ and $\mathsf{US96}$ reflect a firm's merchant power experience overseas and within the US.[23] USIOU is a dummy variable used to control for possible differences in the skill set available to IOU affiliated IPPs compared to unaffiliated, "truly" independent power producers. The interaction between AGE, RELPOP and these three firm characteristics reflect how

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[23] The two variables are meant to be the proxies for experience. It is reasonable to think that the difference in experience gained from operating power plants vary coarsely with the size of capacity. Consequently, based on the

merchant power experiences and affiliate status help an IPP gain advantage in operating a divested asset of a certain type.

As for market variables, P96 is a proxy for the profitability of a state before restructuring, LOGLOAD a measure of the relevant market size, SHARE96 a reflection of the technological composition of the existing utility generation portfolio, and (RM,LDFACT) indices of the supply/demand situation in the state. Considering that the economic fundamentals in a market usually exhibit strong time-persistence, a high P96 may indicate, *ceteris paribus*, a high likelihood of having high prices in the market after 1996. LOGLOAD is used to capture possible scale effects from demand; IPPs may prefer to participate in a state where the "pie" is larger.[24] SHARE96 is the 1996 utility capacity share of hydro and nuclear generation. Due to the low marginal cost of these two technologies, a high SHARE96 may imply a diminished profit prospect for IPPs. RM is the ratio of total available generation supply over expected peak hourly demand and LDFACT the ratio of peak hourly demand over average hourly demand. The former reflects the tightness of supply and the latter the degree of fluctuation in demand over a year. A market with a low RM and a high LDFACT is more likely to be hit by price spikes due to low demand elasticity and significant short-run capacity constraint in the electricity market.

The main "regulatory progress" variable is a measure of the time since enactment of restructuring legislation $(\mathsf{LOGYRLEG} \times (1+\theta_7^r\ \mathsf{DIVFLAG}))$. The variable is used to capture "market maturity": the degree to which market fundamentals are reflected in the wholesale electricity price. Intuitively, a market that has just started restructuring for one year and where much of generation supply is still under the control of electric utilities may be less "mature" than a market that has been under restructuring for several years with much of the generation supply either built or acquired by IPPs. This may be due to several factors, including firms "learning" about new market rules and regulators gradually implementing various policies outlined in the state restructuring program. Therefore, it is reasonable to think that the impact of restructuring may vary in magnitude as restructuring

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capacity distribution in the data, we choose to discretize the two variables in the following manner:

$$\mathsf{INT96} = \begin{cases} 0 & \text{if no intn'l projects in 1996} \\ 1 & \text{if less than 500 MW} \\ 2 & \text{if less than 1500 MW} \\ 3 & \text{if at least 1500 MW} \end{cases} \qquad \mathsf{US96} = \begin{cases} 0 & \text{if no US projects in 1996} \\ 1 & \text{if less than 500 MW} \\ 2 & \text{if less than 1000 MW} \\ 3 & \text{if at least 1000 MW} \end{cases}$$

For details of the discretization, please check Yan (2001).

[24] Note, we use the load data (including the forecasts) for the North America Electricity Reliability Council (NERC) subregion in which the state is located rather than those for the state itself. Given the interconnection between electricity grids, oftentimes spanning across state borders, these NERC subregions capture the potential demand that can be satisfied by a power plant better than the pure geography of a state.

progresses in a state. Note, we have chosen not to interact plant characteristics (AGE and RELPOP) with $\mathsf{LOGYRLEG}$. This is mainly due to identification reasons. With AGE and RELPOP taking non-constant values only for divested assets and divestiture usually occurring within the first two years of restructuring, there is not enough variation to pin down the interaction terms. Consequently, we exclude them from our model specification.

3.2.2 Investment Cost Function

For the two functions related to the investment cost, consider first the capacity cost function. Because the linear term in the capacity cost function is not identified separately from the constant in the expected profit function, we specify only the coefficient for the quadratic term:

$$\alpha_{igt} = \exp\left(\theta_0^{\alpha} + \ \theta_1^{\alpha}\mathsf{INT96}_i + \ \theta_2^{\alpha}\mathsf{US96}_i + \ \theta_3^{\alpha}\mathsf{USIOU}_i\right)$$

All the variables are defined as in the last section. We include in the capacity cost function firm characteristic variables in order to allow for heterogeneity in the ability of an IPP to control its capacity cost. We allow both an IPP's experience with merchant power ($\mathsf{INT96}$ and/or $\mathsf{US96}$) and its possible affiliation with an IOU to affect capacity cost.

Fixed investment cost function takes the following form:

$$C_{igt}^{f} = \theta_0^{f} \ + \ \theta_1^{f}\mathsf{AGE30}_g + \ \theta_2^{f}\mathsf{STNOX}_g + \ \theta_3^{f}\mathsf{DMLEG}_{gt} + \ \theta_4^{f}\mathsf{DIVFLAG}_{gt}$$

where $\mathsf{P96}$ and $\mathsf{DIVFLAG}$ are as previously defined; $\mathsf{AGE30}$ is the percentage of the utility generation portfolio that is more than 30 years old in the state in 1996; STNOX is the average level of NO_x emission stemming from electricity generation in a state; DMLEG is a dummy indicating whether restructuring legislation has been enacted in the state. $\mathsf{P96}$ and $\mathsf{AGE30}$ are included in the fixed investment cost to act as proxies for the magnitude of the investment barrier for the state. Presumably, a high $\mathsf{P96}$ and a high $\mathsf{AGE30}$ imply that the market is hard to enter/invest; otherwise new investments would have occurred, leading to a lower price and a "younger" generation portfolio than what is observed.[25] STNOX is another variable that is related to the investment barrier. It is a proxy for the toughness of the state environmental requirements. It is something of an ambiguous proxy as both a higher and lower value can possibly imply tougher state environmental requirements, depending on whether the emission levels are "pre" or "post" the adoption

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[25] Alternatively, it is possible for a high $\mathsf{P96}$ and a high $\mathsf{AGE30}$ to imply lower future investment barriers, as regulators try to attract new generation investment to replace older, less efficient existing generation capacity.

of more restrictive environmental measures.[26] DMLEG is included to capture the direct effect of the restructuring process on the investment barrier. In theory, restructuring eliminates some of the regulatory hurdles to investment, such as the need to prove the economic merit of a new power plant project. The estimated coefficient before DMLEG can be used to examine the degree to which this reduction in "economic" regulation is actualized. Lastly, DIVFLAG is included as a direct measure of the effectiveness of divestiture in attracting new power plant investments. As argued earlier, divestiture may be viewed as a commitment device for the state. Thus, a negative coefficient before DIVFLAG may be interpreted, in part, as a reduction in the "regulatory risk premium."

4 Results

4.1 Estimates

The parameters in the model are estimated using the Maximum Likelihood (ML) method. Table 2a shows the parameter estimates for the expected profit function. Following the empirical specification, the results are divided into three groups: the coefficients for the base variables, for the interaction terms with the "market maturity" index, and for the interaction terms with plant characteristics (AGE and RELPOP)

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[26] Different measures of state environmental restrictions are being considered, such as the voting record of state Congressmen on national environmental legislation.

Table 2a: Estimates for the Expected Profit Function

Parameter	Estimate	Std. Error	P-value
Non-interacted			
θ^r_0 : CONS	-1.041	0.033	0.00
θ^r_1 : P96	-0.008	0.001	0.00
θ^r_2 : SHARE96	-0.047	0.010	0.00
θ^r_3 : LOGLOAD	0.037	0.003	0.00
θ^r_4 : INT96	0.001	0.004	0.87
θ^r_5 : US96	-0.051	0.007	0.00
θ^r_6 : USIOU	0.056	0.011	0.00
θ^r_7 : DIVFLAG	-0.029	0.154	0.85
Interacted with LOGYRLEG × (1 + θ^r_7DIVFLAG)			
θ^r_8 : CONS	-1.483	0.065	0.00
θ^r_9 : LOGLOAD	-0.072	0.006	0.00
θ^r_{10} : RM	-0.732	0.031	0.00
θ^r_{11} : LDFACT	1.730	0.045	0.00
θ^r_{12} : INT96	-0.002	0.006	0.80
θ^r_{13} : US96	-0.002	0.005	0.77
θ^r_{14} : USIOU	-0.080	0.014	0.00
Interacted with AGE			
θ^r_{15} : INT96	0.001	0.003	0.65
θ^r_{16} : US96	0.019	0.004	0.00
θ^r_{17} : USIOU	0.039	0.007	0.01
Interacted with RELPOP			
θ^r_{18} : INT96	0.000	0.000	0.26
θ^r_{19} : US96	-0.001	0.000	0.00
θ^r_{20} : USIOU	-0.003	0.002	0.00

Prior to restructuring, an IPP's expected profit appears largely determined by the overall market size (LOGLOAD), with a larger market size leading to a higher expected profit. Moreover, the estimates suggest that the IPP with the best profit prospect in a regulated market is an IPP affiliated with an IOU but with limited U.S. merchant power experience. The advantage of IOU affiliation is intuitive as we would expect such affiliated IPPs to be able to draw upon valuable experiences and skills concerned with operating in a explicitly regulated wholesale market. However, the disadvantage of domestic merchant power experience is unexpected and difficult to rationalize.

The coefficients for the variables interacted with the "market maturity" index reflect the difference in expected profits between a more and less restructured market. A strong result among these estimated coefficients is the positive impact of a "tight supply" on expected profits in markets further along in restructuring. This result is reflected by the significant coefficients for RM and LDFACT. A market with a high RM is one where existing generation supply more than adequately covers demand. Therefore, a possible interpretation of the negative coefficient before RM is the presence of significant scarcity rents in restructured markets with an overall tight supply. Along the same lines, a high LDFACT indicates a high level of demand volatility; the positive LDFACT coefficient may be reflecting scarcity rents during peak demand, as a market is unlikely to support too many "peak units" that remain idle much of the year. These results echo the current empirical literature on electricity restructuring in suggesting that there may be opportunity to earn sizable scarcity rents in restructured markets.

With respect to the firm characteristics interacted with the market maturity index, only IOU affiliation seems to matter. The negative coefficient for the market maturity interacted USIOU coefficient is most likely a reflection of the relative disadvantage (in restructured markets) of affiliated IPPs compared to the non-affiliated IPPs in the sample. The non-affiliated IPPs in the sample include AES and Calpine, both of which are recognized leaders in merchant power production. Furthermore, USIOU affiliated IPPs appear to have a modest advantage in operating older (high AGE) power plants. These two results, coupled together, are consistent with the idea that IOU affiliated and unaffiliated IPPs draw upon different skill sets. An affiliated IPP has more knowledge concerning older, coal-based power plants while an unaffiliated IPP is more familiar with the modern, natural gas based power plants. However, the estimates for the firm characteristics interacted with RELPOP seem to indicate that the value of a power plant's location does not vary across firms. The coefficients, while significant, are insubstantial and account for only a very small fraction of the difference in expected profit faced by different IPPs. Consequently, plant characteristics do not seem to help much in explaining why a given firm is observed buying the divested power plant.[27]

Lastly, it should be noted that the coefficient before DIVFLAG is largely insignificant and insubstantial. This seems to indicate that divestiture may not matter much in terms of accelerating "market maturity." However, an alternative explanation may be that there is not enough variation in

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[27] Note that the coefficient estimates do not imply that plant characteristics do not contribute to the overall value of the power plant - just the differential value.

the incidence of divestiture to identify this coefficient; for most restructuring programs, divestiture occurs 2 years after the enactment of restructuring legislation. As a response, we are considering using other, more variable measures of divestiture, such as the share of utility generation capacity that has been divested. Estimates based on such variables, used in *lieu* of DIVFLAG, are under way.

Next, Table 2b shows the estimates for the parameters in the investment cost function.

Table 2b: Estimates for the Investment Cost Function

Parameter	Estimate	Std. Error	P-value
Fixed Cost			
θ_0^f : CONS	-1.234	4.334	0.78
θ_1^f : AGE30	5.811	8.813	0.51
θ_2^f : STNOX	1.521	0.754	0.04
θ_3^f : DMLEG	-0.946	2.596	0.72
θ_4^f : DIVFLAG	-4.151	3.156	0.19
σ_η	9.245	3.782	0.01
Capacity Cost (α)			
θ_0^α : CONS	-0.324	0.314	0.30
θ_1^α : INT96	-0.269	0.127	0.03
θ_2^α : US96	-0.190	0.076	0.01
θ_3^α : USIOU	-0.099	0.147	0.50
σ_ξ	4.007	0.189	0.00

Among the coefficients in the fixed cost function, only the coefficients for STNOX and DIVFLAG appear to be estimated with any degree of precision. The positive STNOX coefficient indicates that new power plants are tougher to build in more polluted states, perhaps reflecting the adoption of tougher environmental standards. The negative DIVFLAG coefficient, on the other hand, indicates that divestiture facilitates investment in new power plants. As discussed earlier, a possible explanation of this result is that divestiture, acting as a commitment device, lowers the the regulatory risk faced by an IPP considering building a new power plant in the market. Given that restructuring is much more difficult to undo once power plants are taken from regulated utilities and given to unregulated IPPs, the negative DIVFLAG coefficient may be representing a reduction in the "regulatory risk premium" - the amount of expected profits that needs to be earned above the standard investment cost in order to compensate the IPP for assuming the risk associated with regulatory uncertainty. [28]

While precision is a problem in the estimation of the fixed cost, the coefficients in the capacity cost appear to be estimated much more precisely. Firms with substantial merchant power experience are found to be more capable of controlling the costs of large size projects. For an IPP with more than 1500MW of generation capacity overseas in 1996 ($\mathsf{INT96} = 3$), its capital cost[29] is less than 50% of that of a firm without any international generation capacity, *ceteris paribus*. Similar results also hold when comparing capital costs between IPPs with more than 1000MW of domestic merchant power capacity and those with none. This is strong evidence supporting the existence of cost advantages for experienced generators. While the impact of merchant power experience on expected profits seem largely non-existent, the sizable impact on investment cost suggest that merchant power experience significantly raises the return from building new power plants, especially those with large capacity. This result helps explain a major feature of observed divestiture sales thus far: most divested power plants have been bought by IOU affiliated IPPs.

Table 3: Divestiture 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%)

Divestiture data from various issues, EIA “Electric Power Monthly”
Excludes transfers between IOU and affiliated IPP
IPP classification from various industry resources

In our sample, there is a strong negative correlation between IOU affiliation and merchant power experience: almost all of the unaffiliated IPPs have considerable merchant power experience (high

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[28] Concepts such as risk premium for regulatory uncertainty should ideally be examined within the context of a dynamic model. Implicit in the regulatory risk premium story is the idea that some aspect of investment cost is irreversible, creating an option value to delaying investment until the arrival of suitably favorable market conditions. However, such a dynamic model would be computationally taxing given the dimension of the state-space associated with modelling investment at the power plant level. For elaboration see Ishii (2001a)

[29] Ignoring the linear part of the cost, which is not identified

INT96 and/or high US96). Furthermore, among the 31 divestiture sales won by affiliated IPPs (in our data), 11 were won by affiliates who had INT96 and US96 less than or equal to 1. Consequently, an explanation for the preponderance of divested assets bought by affiliated IPPs that is supported by the estimated model is that IOU affiliated IPPs have a higher willingness to pay due to the larger premium they place on being able to avoid the investment cost associated with a "make" investment. Note that the opportunity cost of buying a divested power plant is different between an affiliated IPP with low merchant power experience and an unaffiliated IPP with high merchant power experience. The unaffiliated IPP can build a new power plant much cheaper, due to its substantial capital cost advantage, and, thus, places a higher value on the "make" option.

Overall, we draw four main conclusions from the parameter estimates. First, we find that the an IPP's evaluation of the expected return from generation investment evolves with the progress of restructuring. Market fundamentals, such as the reserve margin RM and the load volatility LDFACT, seem to play a more important role the longer a market has been under restructuring. This alludes to the growing importance of market-based signals (as opposed to regulator-based signals) in IPP generation investment. Second, we find that firm characteristics do help explain the difference in the investment choices adopted by different IPPs. IPPs with greater merchant power experience (larger values of INT96 and US96) face a substantial discount in the capital costs incurred from developing a large, new power plant while IOU affiliated IPPs face a modestly larger expected profit from operating older, divested power plants. Combined with the fact that many of the IPPs with substantial merchant power experience are unaffiliated with IOUs (e.g. AES and Calpine), these results help explain why IOU affiliated IPPs are observed to be the major buyers in divestiture sales. Third, we find no substantial impact of plant characteristics on relative valuation of divested power plants. This suggests that the main motivation underlying the "buy" investment is the avoidance of the investment cost associated with the "make" investment. Last, we find weak empirical evidence supporting the idea that divestiture encourages IPP generation investment by lowering the fixed investment cost. This is presumably due to the role of divestiture as a commitment device that reduces regulatory risk.

4.2 Simulation

Given the parameter estimates, we can use the model to run policy simulations that examine IPP investment behavior under different scenarios. The estimated model has two general sources of uncertainty: the uncertainty surrounding the parameter estimates $(\theta^r, \theta^\alpha, \theta^f)$ and the uncertainty stemming from the unobserved components of the IPP investment decision, as characterized by

$(\xi_{igt}, \eta_{igt}, \epsilon_{igta})$.[30] Consequently, simulations are run based on 500 joint draws from the estimated asymptotic distribution of $(\theta^r, \theta^\alpha, \theta^f)$ and $\{\xi_{igt}, \eta_{igt}, \epsilon_{igta}\}_{i=1,\ g=1,\ t=1996,\ a=1}^{N\quad 48\quad 2000\quad A}$

One important policy simulation related to the "make or buy" decision is whether and how much divestiture have "squeezed" out investment in new generation capacity. In other words, would those IPPs that are observed "buying" divested power plants have chosen to "make" instead if the "buy" option was not available? The answer to this question gets at the heart of evaluating whether divestiture has truly succeeded in achieving the long-run goal of encouraging greater IPP participation. The question is of particular policy interest in states like California where a low reserve margin combined with low price elasticity in demand has allowed owners of existing generation capacity to earn significant scarcity rents.[31] Consider the case where there are no divestitures is any market during any year in our sample. Under this scenario, "buy" is not an option anymore and cannot squeeze out "make" investments. Nor does divestiture explicitly alter the expected profit or investment cost functions for an IPP as the variable DIVFLAG is set to be 0 for all observations.[32] Table 3a shows the new capacity investments ("make") in the simulation by those IPPs who chose to "buy" in reality. Note, multiple "buys" by the same firm in the same year and market are aggregated into one observation. Thus, there are 32 instead of 38 "buy" observations. The reported values for "Make" (except for min and max total investment at the end) are the values of the sample mean across the 500 draws.

Table 4a: "Make" to "Buy"

Case	# of Inv.	Total Inv.	Avg. Inv.	Min Total Inv.	Max Total Inv.
"Buy" (Data)	32	69248	2164		
"Make" (Sim.)	0.94 (0.96)	387.6 (595.2)	234.9 (310.2)	0	4356.7

1. Results are based on 500 draws 2. All Inv. numbers are in MW
3. Standard deviation in parentheses

The simulation exercise finds that the divestiture crowds out very little new generation investments, 387.6 MW in total on average. This corresponds roughly to the generation output of a single gas-fired combustion turbine. On the other hand, the simulation finds that most of the IPPs who

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[30] We are, for now, ignoring the uncertainty surrounding model specification.

[31] Note that the estimated expected profit function is consistent with this California experience.

[32] A simulation where divestiture sales existed as in reality but none of the 20 major IPPs were allowed to buy resulted in qualitatively similar results.

chose to enter and participate in these newly restructured markets would have chosen not to do so if the option to buy existing generation assets was not available. On average, only one of the 32 divestiture investments (and no more than 3 with any sizable probability) would have lead to a new generation investment project in the absence of divestiture. This suggests that divestiture has greatly encouraged the number of IPPs active in the restructured market. This result is not surprising given the earlier discovery that the main factor contributing to a high willingness to pay for a divested asset is the desire to avoid incurring a high investment cost — implying that IPPs who buy divested assets place a low valuation on the "make" option.

To demonstrate this point, consider the simulation exercise where all IPPs are assumed to have the same "make" valuation. In this situation, the difference among firm valuations of the "buy" option stems solely from the difference in the profit stream each firm expects to earn from the divested asset. Table 4b compares the characteristics of the actual winner of a divestiture with the average characteristics of simulated winner, under the assumption that all firms value "make" equally, for 13 divestiture sales.

Table 4b: "Buy" with Identical "Make" Valuation

State	Year	AGE	POP	CAP (MW)	Change	Actual Winner			Average of Sim Winner		
						INT96	US96	IOU	INT96 (+)	US96 (+)	IOU
CA	1997	21	69	294	48%	2	1	1	2.1 (26%)	1.2 (20%)	65%
CA	1997	31	4	2406	74%	1	0	1	2.2 (64%)	1.1 (70%)	91%
CA	1997	35	69	500	82%	0	3	0	2.0 (78%)	1.7 (0%)	37%
CA	1997	14	8	78	47%	0	3	0	1.1 (44%)	2.3 (0%)	10%
CA	1997	26	29	2881	50%	1	1	1	1.9 (47%)	1.1 (10%)	93 %
CA	1997	25	11	1613	51%	1	0	1	1.5 (31%)	0.6 (46%)	70%
CA	1998	19	8	1354	90%	0	3	0	2.1 (88%)	1.5 (0%)	30%
CA	1998	29	19	674	82%	0	3	0	2.0 (79%)	1.9 (0%)	49%
MD	1999	28	92	3755	99%	1	1	1	2.8 (96%)	1.5 (50%)	42%
NY	1998	32	94	2232	99%	1	1	1	2.4 (70%)	0.8 (0%)	100%
NY	1998	20	0.5	1806	40%	2	1	1	1.7 (0%)	1.0 (1%)	69%
PA	1999	30	2	1002	53%	1	1	1	1.9 (47%)	1.4 (39%)	53%
PA	1999	40	0.4	5774	93%	1	0	1	2.5 (77%)	1.5 (86%)	40%

1. Results are based on 500 draws.
2. Change (column 6) is the share of simulations where the non-actual IPP wins the divestiture
3. The categories for INT96 and US96 are defined in the Data section.
4. The numbers in the brackets next to INT96 and US96 (+) are the percentage of sims where the INT96 and US96 of sim winner are greater than actual winner.

As the table demonstrates, when the difference in "make" valuation is eliminated, more divested assets are bought by IPPs with greater merchant power experience. Consider the first divestiture sale in Table 4b. The asset has an age of 21 years and a capacity of 294 MW. The population density at the location of the asset is 69 times that of the California state average. In the data, the asset was bought by an IOU affiliate (IOU=1) who, in 1996, had an international generation capacity in the range of 500 MW to 1500 MW and a domestic generation capacity less than 500 MW. If all firms valued "make" equally, the simulations indicate that there is a 48% probability that some other IPP than the actual winner would have had a higher willingness to pay for the asset. On average, 26% of those possible winners would have an 1996 international capacity greater than 1500 MW and 20% of them a 1996 domestic capacity greater than 500 MW. Only 65% of the new winners are likely to be affiliated with utilities. Similar large changes are also exhibited in the other 12 divestiture sales. Clearly the simulation demonstrates that it is the difference in the evaluation of the "make" option that drives much of the difference in the evaluation of the "buy" option.

Simulations indicate that concerns about divestiture "crowding out" new generation investment are unfounded. The IPPs who buy divested power plants generally face investment costs that are so high that they are discouraged from building new power plants. However, divestiture does appear to encourage the participation of a greater number of IPPs in the market. By giving IPPs the option to buy existing power plants, divestiture provides some IPPs with limited "make" abilities the opportunity to enter profitably in the market. As raised in earlier discussion, these IPPs consist mostly of affiliates of U.S. investor-owned utilities. Such IOU-affiliated IPPs are willing to pay more for divested power plants than unaffiliated IPPs because [1] the opportunity cost (the "make valuation") is less and [2] they have an advantage in operating the older power plants (presumably from the familiarity gained from utility operations).

This raises the policy question: do we want to encourage greater participation by IOU-affiliated IPPs? One of the main factors driving restructuring is the hope that competition would lead to the replacement of existing IOU generation by more efficient generation from IPPs. If these IOU-affiliated IPPs are among the more efficient generators, then divestiture may be helping to foster healthy competition in the market.[33] However, if these affiliated IPPs only have an advantage in buying and running existing power plants based on older technology, then divestiture may be hurting the more long-run prospects for a competitive market. Although not explicitly explored in this paper, there may be strategic consequences of investment: affiliated IPPs, by buying and

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[33] Preliminary results from Ishii (2001b) suggests that the IOUs that have branched out into IPP are among the more efficient utility generators.

controlling the lion's share of the initial generation capacity in the restructured market, may be able to curtail the participation of unaffiliated IPPs who may be more competitive in the long-run when new power plants become necessary.[34] Thus, an important concern may be that divestiture is subsidizing the participation of the wrong types of IPPs. Divestiture, while not "crowding out" much current new generation investment, may be "crowding out" future new generation investments by more efficient unaffiliated IPPs.

Conclusion

In this paper, we present an empirical model of the "make or buy" decision faced by independent power producers in many restructured wholesale electricity markets. The model is based on observing whether an IPP buys a divested power plant, builds a new power plant, or chooses not to invest at all. This is in contrast to existing research in the literature that has attempted to deduce how IPPs value divested assets by examining the transaction prices associated with these divestiture sales.[35] We believe that the empirical model introduced in this paper is a contribution precisely because the model avoids using transaction prices. As has been well noted in the industry press, the transaction price quoted for many divestiture sales include more assets and liabilities than just the power plant.[36] Consequently, a straight comparison of transaction prices may lead to a comparison of apples and oranges. Moreover, reliable financial data on divestiture sales are difficult to obtain. Therefore, the "make or buy" model developed in this paper provides a feasible method of estimating how IPPs evaluate their investment options relying only on the most basic level of data.

Applying this empirical model to plant-level data that track the investment decisions of major IPPs from 1996 to the present, we estimate the investment cost an IPP must pay to build a new power plant and the profit stream an IPP expects to earn from a power plant (new or old), given plant characteristics and the characteristics of the market served by the power plant. These estimates are then used to evaluate an important aspect of most state-level electricity restructuring programs: the divestiture sales of electric utility power plants. In particular, the estimates are calculated in hopes of evaluating the effectiveness of divestiture in achieving the long-run competitive goal of encouraging greater IPP participation. Although there are many reasons why an IPP

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[34] This would correspond to some kind of first-mover advantage in the market.

[35] See Kahn (1999) for an overview

[36] For example, in some divestiture sales, IPPs are also "required" to take over the fuel procurement and labor contracts associated with the power plant.

might prefer to buy a divested power plant rather than build its own, the estimates provide strong evidence corroborating one particular intuitive explanation: IPPs buy divested power plants to bypass the high investment cost they otherwise would have had to incur in order to participate in the restructured market. Furthermore, extending this line of reasoning, the estimates provide an explanation why it is the IPPs affiliated with U.S. investor-owned electric utilities who seem to buy most of the divested power plants: affiliated IPPs are relatively less experienced in merchant power production and hence face a larger investment cost that they wish to circumvent.

Consistent with these findings are the simulation results used to demonstrate IPP investment behavior in the absence of divestiture. The simulations find that the amount of new generation investment "crowded out" by divestiture is minimal; this is expected as the absence of divestiture forces IPP to incur the high investment cost if it wishes to participate in the market. The main impact of divestiture on IPP generation investment appears to be the encouragement of greater IPP participation, particularly among IPPs affiliated with investor-owned utilities. Whether this translates into greater long-run competition is contingent on the degree to which participation by affiliated IPPs are desirable. Such participation, while generally promoting competition in the short-run, may hurt long-run competition if it curtails future new power plant investments by more efficient unaffiliated IPPs.

Given these preliminary result, it is difficult to say whether divestiture is, overall, desirable. There are some evidence in the developing literature that link divestiture to greater wholesale price volatility during the initial transition period of restructuring. However, there are mitigating factors, one of which is the understanding that some level of price volatility is unavoidable given the way the electricity system was developed under the vertically integrated, regulated regime. Another is the fact that there is no evidence that speaks against the potential of beneficial competition in the long-run, once various IPPs enter and build new power plants. In fact, the expected profit function estimated in the paper suggest that expected profits (and presumably wholesale electricity prices) fall as a market both advances further into restructuring and develops adequate new electricity supply. Therefore, it may behoove a state to "bite the bullet" during the initial years, divest utility power plants, and accelerate toward full restructuring as quickly as possible. In the minimum, the analysis in this paper demonstrate that divestiture will not crowd out any desirable new power plant investment and initially increases the number of IPP entrants. Finally, the results suggest one productive avenue of encouraging both IPP investment and beneficial participation: reduce investment costs. State policy-makers might achieve such a goal by stream-lining the permitting process and providing siting assistance that helps avoid some of the "not in my backyard" (NIMBY) opposition.

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Appendix

Variable List

AGE_a : Age of divested asset a

$\mathsf{AGE30}_g$: Percentage of generation capacities more than 30 years old in a state in 1996

$\mathsf{DIVFLAG}_{gt+h|t}$: Dummy for whether major divestitures have occurred in state g by $t + h$

DIVID_{gt} : Dummy for whether there was some major divestiture in state g in year t

$\mathsf{DMLEG}_{gt+h|t}$: Dummy for whether the restructuring legislation has been enacted in state g by $t + h$

$\mathsf{INT96}_i$: Generation capacity owned by firm i outside the U.S. in 1996

$\mathsf{LDFACT}_{gt+h|t}$: Forecasted load factor in the NERC subregion where state g is located

$\mathsf{LOGLOAD}_{gt+h|t}$: Log of the forecasted demand (load) in the NERC subregion where state g in located

$\mathsf{LOGYRLEG}_{gt+h|t}$: Log of one plus the years since the restructuring legislation was passed in state g

$\mathsf{P96}_g$: Average electricity price in state g in 1996

RELPOP_a : Ratio of the population density at the location of a and that in the state.

$\mathsf{RM}_{gt+h|t}$: Forecasted reserve margin in the NERC subregion where state g is located

$\mathsf{SHARE96}_g$: Capacity share of nuclear and hydro generation in state g in 1996

STNOX_g : Average level of NO_x emission related to electricity generation in a state in 1996

$\mathsf{TRADE96}_g$: Dummy for whether firm i had an energy trading operation in 1996

USIOU_i : Dummy for whether firm i is affiliated with some major utilities

$\mathsf{US96}_i$: Generation capacity owned by firm i inside the U.S. in 1996

IPP Sample

Data on 42 IPPs were collected. All of them satisfy the following qualifications: [1] the firm must be listed in either *UDI Who's Who at Electric Power Plants (Ninth Edition)* published by the Utility Data Institute or *205 Independent Power Producers (1999 Edition)* published by the Global Energy Report, McGraw-Hill Companies [2] the firm must have at least 750 Megawatts (MW) of net equity in merchant power plants as of January 1, 2001. These two conditions help ensure that fairly comprehensive data will be available for the firms and that the firms will be non-utility generators whose main line of business is serving the general wholesale electricity market. The sample includes almost all of the major IPPs affiliated with large investor-owned electric utilities (e.g. Duke Energy North America), all of the large U.S. based players in the international wholesale electricity markets (e.g. AES), and several of the major U.S. energy traders (e.g. Enron). Following (Table A2.1) is the full list of the IPPs for which data was collected.

Table A2.1: The 42 Independent Power Producers in the Data

AES Corp	American National Power	Aquila Energy / UtilCo
Caithness Energy	CalEnergy	Calpine
CMS Generation	Coastal Power Corp	Cogentrix Energy
Columbia Electric	Constellation Power	Continental Energy Services
CSW Energy	Dominion Energy	Duke Energy North America
Dynegy	Edison Mission Energy	El Paso Energy
Enron International	EPG (Entergy Power Group)	FPL Energy
GE Global O&M Service	GPU International Inc	Illinova Generating
Indeck Energy Services	LG&E Energy Corp	LS Power
NRG Energy	Ogden Energy	Panda Energy International
PP&L Global	PSEG Global	Reliant Energy
Sempra Energy Resources	Sithe Energies	Southern Energy
Tenaska	Texaco Global Gas & Power	Tomen Power
Tractebel Power	U.S. (PG&E) Generating	Wheelabrator Technologies

The analysis in this paper focuses on major IPPs which have the capability of entering generation markets nationwide. To determine whether an IPP is "major," we employ the following criteria: [1] the firm must own at least 500 MW of capacity internationally or domestically or at least 100 MW both internationally and domestically before the first year of our sample period (1996); [2] if a firm does not satisfy [1] it can still be selected if it is affiliated with large investor-owned electric utilities and owned some capacity internationally or domestically before 1996; [3] there is no information in *205 Independent Power Producers (1999 Edition)* that indicates that the firm is not a national player. [1] and [2] are meant to ensure that the firm has the experience and financial strength to enter generation markets nationwide during our sample period. [3] is an additional selection criterion that relies on more specific information about an individual firm. Using [1] and [2], we exclude the following firms: Aquila Energy, Caithness Energy, Columbia Electric, Continental Energy, Indeck Energy Services, LS Power, Panda Energy International Inc, Sempra Energy Resources and Tenaska. Using [3], we further eliminate the following firms:

Table A2.2: IPPs Eliminated by Criterion [3]

Firm	Reason
CalEnergy	its core business is geothermal generation
CSW Energy	it has targeted Texas and southeastern U.S. markets[37]
Dominion Energy	its business focus is on Midwest and Northeastern markets
GE Global O&M Services and Texaco Global Gas & Power	both are affiliates of firms that own significant generating technologies and use their plants as "displays"
GPU International	its business focus is on Australia and UK
Illinova Generating	merged with Dynegy during the sample period
Ogden Energy	its business focus is on overseas markets. [38]
PSEG Global	its business focus is on overseas markets, e.g., Latin America
Sithe Energies	bought some capacity but plan to exit industry [39]
Tomen Power	most of its activities are outside U.S. [40]
Tractebel	its focus is on the Northeastern market
Wheelabrator Technologies	its core business is waste-to-energy facilities[41]

After these steps, we are left with 20 major IPPs. Table A3 shows some summary statistics for these IPPs.

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[37] *205 Independent Power Producers (1999 Edition)*, p. 90. Another factor for our exclusion of CSW Energy is that the firm had been in the process of being taken over by American Electric Power (AEP) during our sample period. AEP was an active player internationally but had no domestic IPP activities and hence is not in our sample.

[38] "the company's first efforts were mostly mass-burn waste-to-energy plants, but more recently, it has focused on fossil-fueled projects in overseas markets" (*205 Independent Power Producers (1999 Edition)*, p. 227.). Ogden has also been acquiring renewable energy project in the U.S. But none of these is the focus on "major" IPPs, whose plant are mostly gas-based.

[39] Sithe has sold or are in the process of selling most of their merchant power capacity

[40] Tomen Power is owned by a Japanese company, Tomen Corp. of Tokyo.

[41] "It no longer develops non-waste-to-energy projects in the U.S.", *205 Independent Power Producers (1999 Edition)*, p. 340.

Table A3: The 20 "major" Independent Power Producers in the Sample

Firm	IOU Aff.	TRADE	INT96 (MW)	US96 (MW)
AES Corp	0[a]	0	3	2
American National Power	0	0	3	2
CMS Generation	1	1	2	2
Calpine	0	0	0	2
Coastal Power	0	1	1	1
Cogentrix Energy	0	1	0	2
Constellation Energy Services	1	1	1	1
Duke Energy North America	1	1	1	1
Dynegy	0	1	0	3
EPG	1	1	1	0
Edison Mission	1	1	3	3
El Paso Energy	0	1	1	1
Enron International	0[b]	1	2	1
FPL Energy	1	1	1	2
LG&E Energy	1	1	1	1
NRG Energy	1	1	2	1
PP&L Global	1	1	1	0
Reliant Energy	1	1	1	0
Southern Energy	1	1	3	1
U.S. Generating	1	1	0	3

a. AES bought CILCORP, an U.S. utility in late 1998.

b. Enron bought the utility Portland General Electric in 1997 but have since sold it

Data Source

The investment and firm characteristic data for each of the independent power producers in the sample were collected over several years (1996-present).[42] The actual data set contains 42 IPPs. The sample used for estimation was whittled down to 20, as described in the last section.

The main foundation of the IPP data comes from the firms themselves, either through postings on their web sites or through personal communication. Data was also augmented with information from popular trade presses. Many of the trade presses, such as the weekly *Global Report* published by the McGraw-Hill Companies, have a section that lists power plant transactions. Also of particular help was the online

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[42] This section is based on an early version written by Jun Ishii, with modifications by the author.

newsletter e-published by *Energyonline*.[43] The newsletter provides notification and summaries of the relevant press releases associated with the electricity industry. Lastly, data was also acquired from various releases of the McGraw-Hill publication *205 Independent Power Producers*. This data source was very useful in detailing the international operations of the IPPs. As much as possible, data acquired from third-party sources were later confirmed with sources closer to the firm.

Information on utility divestiture sales were gathered from various issues of the *Electric Power Monthly* published by the Energy Information Agency, the primary agency within the U.S. Department of Energy that collects and publishes data on energy industries. Each issue contains a list of the utility power plants that were transferred to non-utility power producers. Information about the divested power plants themselves were obtained from the EIA annual publication *Inventory of Power Plants*. All EIA publications mentioned in this appendix are available in electronic format at the EIA web site (http://www.eia.doe.gov).

The market forecast data used in this analysis were obtained from the EIA. The forecasts are from the supplemental tables of the Annual Energy Outlook (AEO) forecast publication. Releases of the forecast from 1996 to 2000 were obtained. Although our copy came from correspondence with the very capable and helpful staff at the EIA, an archive of the forecasts have since been posted on the EIA website.[44] Market forecast data was also obtained from the North American Electric Reliability Council (NERC), the private governing association of electric transmission and distribution utilities in North America. Most of the data is similar to the AEO data as AEO bases much of their forecast on this NERC information. The NERC information can be found in their annual “Electricity Supply and Demand” (ES&D) publication. The AEO data is used for all market forecasts except LDFACT which is based on NERC data. The regulatory information is obtained from the EIA as well. The EIA, on their web site, maintains a monthly update of the status of electricity restructuring.[45] The information on independent system operators (ISOs) mostly came from ISO press releases and trade press reports.

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[43] http://www.energyonline.com

[44] Previously, they only posted the current forecasts. URL is http://www.eia.doe.gov/oiaf/aeo/index.html

[45] http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html