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REGULATION BY SIMULATION: THE ROLE OF PRODUCTION COST MODELS IN ELECTRICITY PLANNING AND PRICING

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Regulation by Simulation: The Role of Production Cost Models in Electricity Planning and Pricing

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1 Introduction

This paper is a case study in the role of complex computer simulation models in the regulation of the electricity industry. Regulated industries frequently base prices on explicit cost calculations. Cost based pricing represents a traditional approach to assuring customers that regulated monopolies are not charging excessively for the services they provide. Where production processes are complex, as in electricity, cost tracking requires simulation modeling. The same models that are used by managers to plan and optimize production are also being used in the price setting function as well. This dual role can create tensions since the level of sophistication and the needs of the two user communities are often different.

The electricity industry is increasingly subject to competitive forces, particularly in its wholesale generation segment. Managing this competition places new stresses on the regulatory process. Generically, the regulatory problem in such a setting involves a much finer examination of the cost structure of firms than had typically been the case before competition became a significant factor. Other regulated industries under competitive pressure have experienced a similar intensification of cost analysis (Bailey, 1986). In electricity, the focus for this scrutiny of the production process has been simulation models. The interaction of the policy process with the community of expert modelers raises the potential for misunderstanding, strategic gaming, and substantial wasted effort. Such issues have been a generic concern since computer modeling began to be a widely used analytical procedure (Greenberger et al., 1976). Their emergence in electricity regulation is a growing concern (Pechman, 1993).

This discussion focuses on electricity production cost simulation models. These models are a standard planning tool used by utility management. Over the last decade, they have found their way into the regulatory planning and pricing process. These simulation models vary widely in their level of resolution and the precision of the representation. They are potentially subject to strategic manipulation by the use of tunable parameters. This paper examines the uses and abuses of these models in one particular setting. This application, the pricing of short run non-utility generation in California, is particularly important because it represents an early part of the trend toward "markets" for electric power, and away from pure monopoly supply. The tensions created by the introduction of even limited competition illustrate conditions both favoring and hindering the reliability of cost estimates, and demonstrates the sensitivity of results to problem specification and model implementation.

The landmark transition in California from private managerial use of these models, to public adjudication is represented by the Computer Model Uniformity Act (AB475) passed by the California Legislature in 1985. This law authorized the California Public Utilities Commission (CPUC) to establish rules governing access to these models, to establish procedures for their verification and evidentiary use, to conduct studies of and improve the capabilities of these models. Finally, the law required the CPUC to make annual written reports on its activities under the act. This paper examines the implementation of AB475 in one particular dimension.

The basic themes raised here involve managing the strategic use of models. Industries experiencing the transition from regulation to competition are vulnerable to the abuse of modeling techniques for competitive advantage. Highly structured processes for using models in such situations offer some constraints on manipulation of the process by competing parties. Otherwise, experts are apt to overwhelm regulators and reduce modeling to the numerical equivalent of rhetoric. This paper illustrates how a structured process was able to work in one important setting even with changes in modeling techniques over time.

The discussion is structured in the following fashion. Section 2 gives an overview of the pre-history and implementation history of AB475, emphasizing the non-utility generation pricing problem. In Section 3, the particular form of this pricing problem is characterized. Section 4 examines one of the most litigated of the technical issues, the representation of the unit commitment problem in power system operation. Section 5 discusses verification issues. Section 6 offers some conclusions and generalizations.

2 Implementation History of AB475

2.1 The Pre-History

The California legislature did not get interested in computer modeling out of the blue. A number of issues led up to the legislation and shaped its nature and implementation. Utilities has used computer simulations of the electricity production process in various uncontentious regulatory settings for a number of years. When marginal production costs began to be estimated, conflicts emerged. Marginal costs were being estimated in rate cases as a guide to the design of tariffs. Their actual role in this regard was quite limited (Friedman, 1991). But the estimates were conceptually similar to the pricing rules that would be used for non-utility power producers. This similarity heightened the attention given to the simulation process. Representatives of the non-utility generators complained that they did not have adequate access to the utility's models, nor was the use of the models understandable or transparent. Pricing by such methods, they claimed, amounted to "black box" regulation.

Computer simulation also appeared in California's Energy Cost Adjustment Clause (ECAC) hearings, where fuel and purchased power costs were reviewed. A critical component to estimating the total cost of fuel is the average thermal efficiency (or "heat rate") of the utility oil and gas steam plants, which can vary widely. The traditional methods for estimating the average heat rate began to break down as major new baseload nuclear generation stations came into service. A number of ECACs involving Pacific Gas and Electric (PG&E) resulted in disputes over the simple historical correlations that has been used for the estimate (CPUC, 1983,1984). By the 1985 PG&E ECAC, it was agreed that the effect of changes in the resource mix and their implications for the average heat rate ought best be examined using an appropriate computer model (CPUC, 1985). This last decision was roughly contemporaneous with the Legislature's enactment of AB475. Computer simulation, it seemed, was "in the air" and ripe for public policy attention.

2.2 The Battle of the Models

As initial activities at the CPUC began, conflicting claims of model vendors about their commercial products dominated discussion. The utilities tended to support models with great detail of representation and which had relatively high costs of acquisition and use. One prominent product of this kind is PROMOD III, sold by Energy Management Associates (EMA, 1986). The CPUC staff and certain private power producers tended to support a simpler, easier to use and less expensive program, the Elfin model developed and distributed by the Environmental Defense Fund (EDF).

The Elfin model evolved substantially over many years of use in different regulatory settings in California. Initially, in the late 1970s and early 1980s, it was used in adjudication involving major power plant investment decisions. This history is described by a leading member of the EDF staff (Roe, 1985). In the mid-1980s, supported by funding from state agencies in California, its representation of electric operations was improved (Kahn, 1985). In subsequent developments, the level of detail was progressively increased, using a fundamentally similar approach to

PROMOD III (EDF,1987; EDF,1992; Kirshner,1993). Nonetheless, it has always been less detailed than PROMOD III. These differences tended to create disputes about comparative validity that came to be known as "The Battle of the Models."

In 1988, the CPUC shifted from simply studying the different models, integrating its analysis with on-going regulatory tasks. This shift, described in the CPUC's third report to the legislature (CPUC, 1989b), defines the term "rolling review" to describe the process of simultaneously exploring the models and their features and using them for particular purposes. The forum for these "rolling reviews" was the Energy Cost Adjustment Clause (ECAC) hearings, and in particular, the calculation of short term energy prices for a certain class of private power producers. In Section 3 and 4 below, the technical details involved in the rolling review will be examined. First, we consider procedural questions. These involve how the CPUC approached the standardization problem, i.e. the conflict between the desirability of using a common model for pricing purposes with diversity of opinion regarding the appropriate model.

2.3 Standardization, Technical Innovation and Learning

The "Battle of the Models" presented the CPUC with a dilemma. If participants in the pricing dispute are using different models, how can the Commission distinguish between differences due to input data disputes or model features? As a first approximation, the CPUC initiated a process of requiring that parties meet in an informal workshop early in the litigation to identify all areas where there was agreement over data issues, and to identify and narrow the range of disputed issues. These workshops still could not resolve disputes over appropriate model features.

The CPUC experimented with two approaches to this problem. In the first approach, initiated in the Southern California Edison (SCE) 1988 ECAC, the CPUC required all participants to use Elfin. Any party that wanted to use another model as well, was free to enter its results as evidence, but this would be in addition to the filing of an Elfin simulation using the common data set (CPUC, 1988a). The common model approach ran into difficulties almost as soon as it was introduced. In the 1988 Pacific Gas and Electric (PG&E) ECAC, the common data set was negotiated assuming that Elfin Version 1.57 would be the common model. Subsequently, EDF released Version 1.60, which had been in beta test versions. Elfin users all switched to the new version. There were sufficiently many changes from Version 1.57 that it became impossible to stick with the common framework that had been negotiated in workshops. The CPUC was left with a de facto battle of the models in which three competing programs were presented as testimony[1]. Given the range of issues litigated in this case, the CPUC concluded that model differences were less important than issues associated with input assumptions (CPUC, 1988b).

The implication of the 1988 PG&E ECAC was that standardization of modeling was inappropriate. Therefore, in the 1989 PG&E ECAC, the CPUC gave up the notion of a common

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[1] In addition to PROMOD III and Elfin, testimony was presented using PROSYM, a model using chronological load shapes instead of the load duration curve representation used in PROMOD III and Elfin. The load duration curve is introduced in Section 3.2.

model, and allowed participants to file testimony using whatever model they preferred. There still was an attempt to develop a common data set using the workshop framework. Despite the efforts toward commonality developed in workshops, the outcome in this case was not particularly satisfying. The CPUC staff was not capable of translating PG&E's PROMOD III simulation into the Elfin format that they preferred. As a result, the staff was not able to file their own testimony in a timely fashion. The CPUC concluded that standardization was inevitable. They required that in subsequent cases an Elfin file had to be provided by any party using a different model (CPUC, 1989a).

3 Short Run Pricing to Private Power Producers

The decision to focus on short run pricing to private power producers lent a sharper focus to CPUC efforts than was possible through studies alone. The problem of pricing such power in the long run is considerably more complex than the short run problem, because it involves issues of optimal capacity expansion (Hagen and Vincent, 1989; Kwun and Baughman, 1991). In the short run, the issues largely involve only existing assets and their operating characteristics (Jabbour, 1986).

The particular form of the short-run avoided cost price calculated by the CPUC was determined by the nature of the private production technology in use. The large majority of private power capacity and energy production in California arises from natural gas-fired cogenerators. The utility avoided energy costs are based primarily, but not exclusively, on natural gas-fired generation. Since gas costs can be expected to fluctuate on a seasonal basis, it is useful to separate the fuel price variation from what is essentially an efficiency factor reflecting the supply/demand balance. Updates in the efficiency factor would be made less frequently, on an approximately annual cycle in the ECAC proceeding. For gas-fired cogenerators being paid the short term avoided energy price, the following formula was adopted

Avoided Energy Cost = $IER*UEG_t$,

where UEG_t is the price of natural gas sold to the utility electric generation market in period t, and IER is an efficiency factor.

3.1 The Incremental Energy Rate (IER): Definition

The efficiency factor, called the Incremental Energy Rate (IER), can be defined formally as follows:

$$IER = \left[\sum_{i=1}^{j} AG_i \cdot TM_i\right] / \ UEG_f$$

where AG_i = unit cost ($/kWh) of avoided generation of type i,

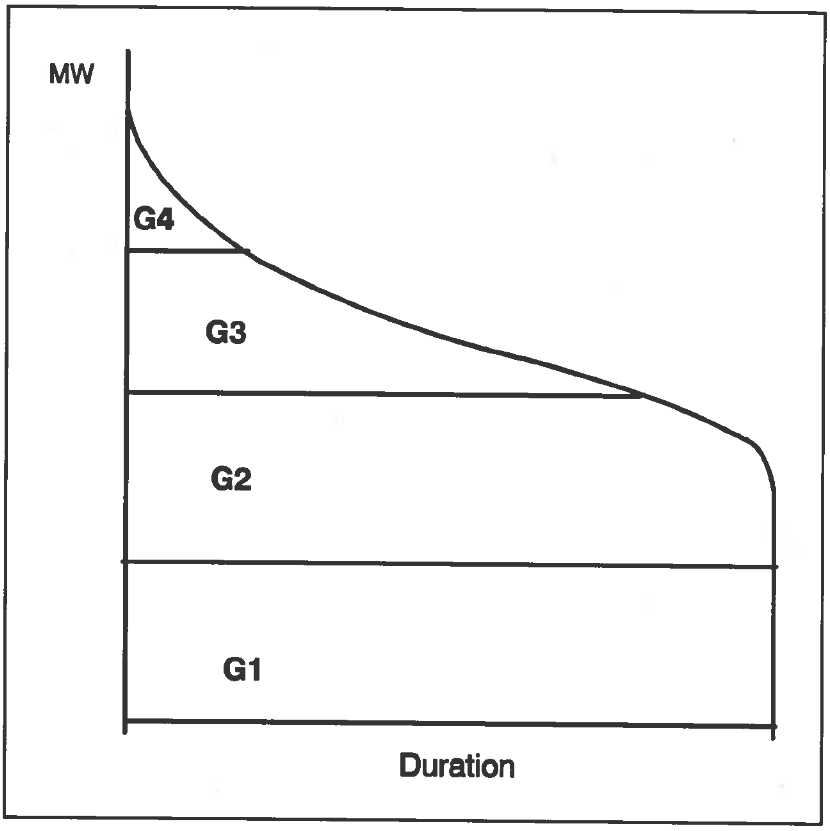
TM_i = fraction of time generation type i is the avoided resource,
UEG_f = forecasted UEG price.

The IER has units of Btu/kWh, but is strictly speaking not a "heat rate" in the engineering sense of that term. The reason for this is that not all generation included in the formula will be based on natural gas. Therefore dividing those non-gas generation types by the UEG price results in a factor that is a "gas equivalent" heat rate. For example, suppose AG_i is 21 mills/kWh, for i representing a purchase of coal fired power, and UEG_f is \$3/MMBtu, then AG_i/UEG_f is 7000 Btu/kWh.

The subtle part of the IER is the set of weights called the TM_i's. These are determined by production simulation[2].

3.2 Production Cost Simulation and the Definition of Avoided Cost

Figure 1. Load-duration Curve

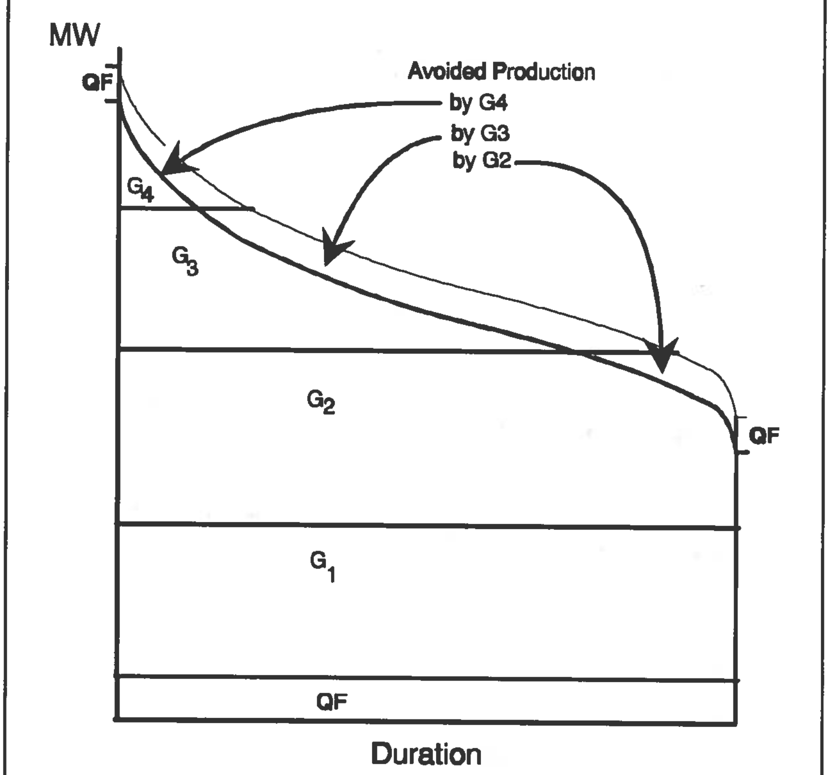


At its simplest level the typical production cost simulation looks like the situation illustrated in Figure 1. This shows the load duration curve representation of demand, in which the chronological fluctuations are suppressed, and the hourly loads are simply sorted in monotonically declining order from their highest to their lowest level. The merit-order dispatch is illustrated in this figure by stacking generators G1 to G4 in order of increasing variable cost, starting with the least cost unit G1 at the bottom of the load curve (or at the top of the merit order). This achieves a least cost solution because the most expensive unit G4 serves the smallest fraction of energy demand, the next most expensive unit G3 serves the next smallest fraction of energy demand, and so on.

[2] This definition of the IER is notationally equivalent to the procedures used in the ECAC. The approach adopted here makes for a more convenient and intuitive exposition.

The modern period of production simulation starts with the formulation of Balerieux et al (1967) and Booth (1972), who introduced the treatment of random generator outages into the framework illustrated by Figure 1. Subsequent refinements included further attention to operating constraints such as spinning reserve, or hydro generation. As computational costs declined, the load duration curve was used to represent shorter and shorter time periods. PROMOD III uses a typical week to represent each month of the year, and then subdivides each week into three sub-period load duration curves, one for weekdays, one for week nights and one for the weekend (EMA, 1986).

Figure 2. Calculating Avoided Cost



$$\text{AVOIDED COST } (\$) = AVC(G_2) + AVC(G_3) + AVC(G_4)$$

$$\text{Avoided Cost Price (cents/kWh)} = \frac{\text{Avoided Cost}}{\text{QF MW} * t}$$

The basic notion of avoided energy cost is easily illustrated with a simple variation on Figure 1. The term avoided cost was originally used in the legislation creating the first class of unregulated private producers known as Qualifying Facilities (QFs). Among the guarantees accorded to QFs under the law was the right to have their power purchased by franchised utilities at all times. This obligation to purchase imposed on utilities can be conveniently linked to the avoided cost price concept as shown in Figure 2.

The obligation to purchase is represented in Figure 2 as an "out of merit order" dispatch which places QF production at the top of the loading order (i.e. as the first resource dispatched). The effect of this is to shift the dispatch of all other resources up by the amount of the QF capacity. As a result, a certain amount of production by units G2, G3 and G4 is "pushed out" the top of the load duration curve. This is indicated in Figure 2 by the area between the solid and the dashed curves.

The geometry of Figure 2 gives some intuition about the TM_i's used in the definition of the IER. The fraction of the total area between the solid and the dashed curves corresponding to each generating unit G2-G4 is the corresponding weight TM_i. As the magnitude of QF production increases, the weight associated with G2 will increase and that associated with G4 will decrease, and vice versa as QF production decreases. Shifts for intermediate resources such as G3 depend upon the curvature of the load duration curve.

The characterization of avoided energy cost given here resembles the notion of marginal energy cost. There are several computational formulations of marginal energy cost in the production simulation framework (Bloom, 1984; EDF, 1992). In the terminology adopted here these are equivalent to measuring the TM_i's at the intersection of the solid curve. It has been argued that marginal cost, estimated with QF production included, is a more economically efficient interpretation of the avoided energy cost concept (Woo, 1988). These arguments have not generally been accepted, and have been explicitly rejected by the CPUC, which has adopted a definition of avoided cost that is equivalent to the representation in Figure 2 (CPUC, 1986).

4 Unit Commitment Issues

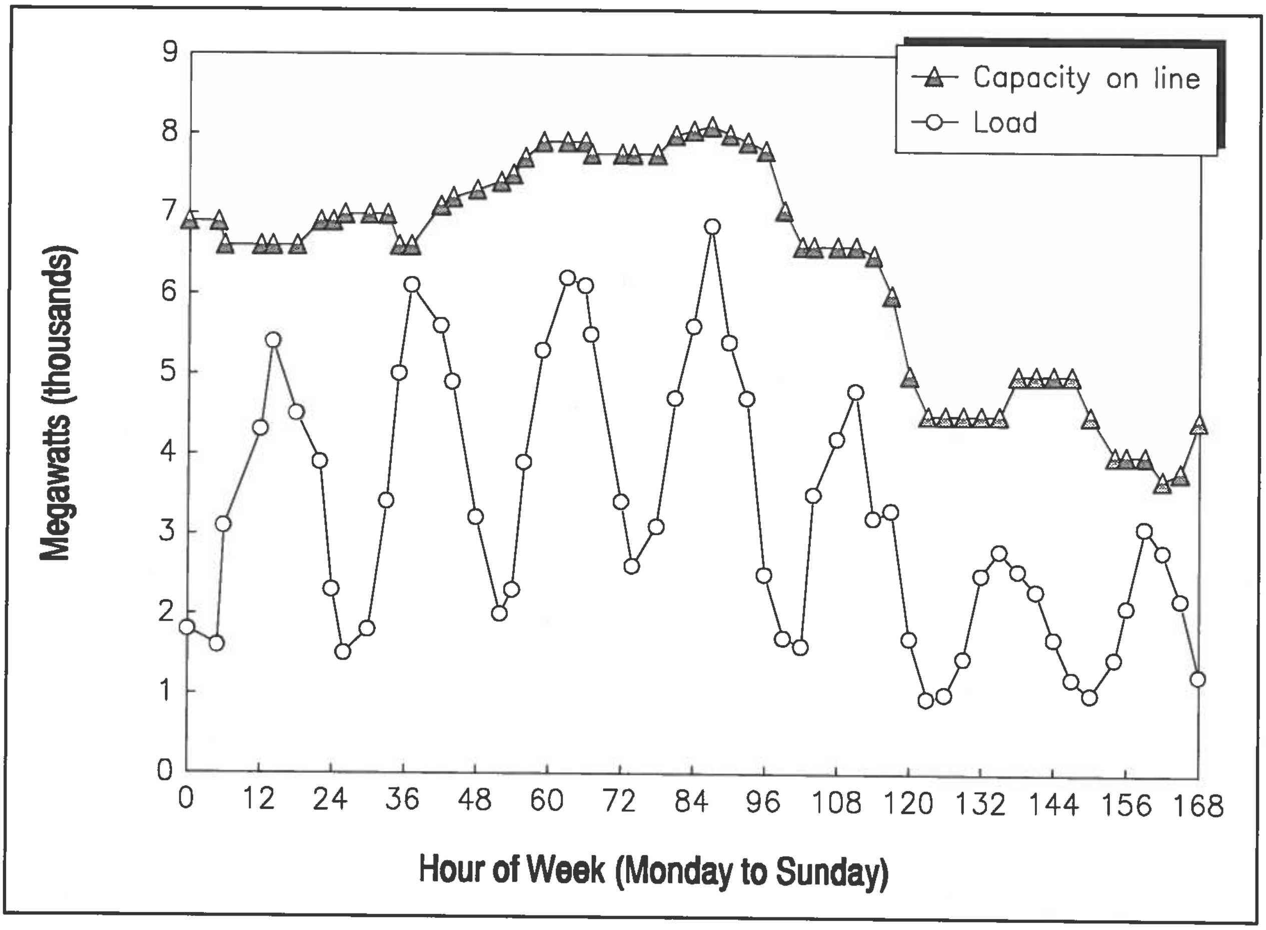
4.1 The Basic Phenomenon

Thermal power plants require significant periods of time to warm up for operation and to cool down before re-starting. The optimal running time for such plants in the face of large load fluctuations must account for such constraints. It is frequently the case that the thermal lags coupled to cyclic demand requires that the plants be kept in operation during low load periods, even though their efficiency is quite low, so that they will be ready to serve subsequent high demands. Figure 3 shows data characterizing this phenomenon. This figure represents the operation of Southern California Edison's oil and gas generation system during a summer week in 1984 (Kahn, 1991). These units are operating in addition to large baseload coal and nuclear generation. The oil and gas units are serving the fluctuating demand commonly referred to as intermediate and peaking load.

The top line in Figure 3 represents the total nameplate capacity of oil and gas generation that is running and capable of serving load over this week. The line indicated by the open circles shows the actual generation from these units. Actual generation ranges over approximately 6000 MW from its highest to its lowest level. The amount of capacity capable of operating (i.e. that is committed) fluctuates much less and much less frequently. During the weekdays (hours 1-108) the amount of capacity committed varies by about 1500 MW. On the weekends, much more capacity is shut down.

Figure 3 shows that substantial amounts of thermal capacity is committed but will operate at low output levels during low load periods. The efficiency of oil and gas-fired steam units at low output levels is poor. Nonetheless it is more economic to incur this efficiency penalty than to start and stop units frequently. These effects are typically embodied in minimum downtime constraints. Stoll (1989) presents simple examples illustrating how these constraints end up producing a pattern of commitment qualitatively similar to that shown in Figure 3.

Figure 3. Capacity/Load Graph



4.2 Representation in Production Simulation

Basic Features

There is a large literature on the unit commitment problem (Sheble and Fahd, 1994). For operational purposes, where the time horizon is short (one day to one week), and the value of precision is great, sophisticated and detailed optimization algorithms are appropriate (Bard, 1988; Jackups et al., 1988). In long range planning models or for intermediate term applications, where many uncertainties are present, simple approximations are both more convenient and more acceptable. Within the load duration curve framework, we can show the basic approach to the representation of unit commitment by modifying Figure 2. This will simultaneously show the qualitative effect of including this feature on the estimated value of avoided energy cost.

Figure 4 modifies Figure 2 by adding a further block of capacity in the "out of merit order" dispatch. This block corresponds to that region in Figure 3 which is the minimum output of the oil and gas units. Strictly speaking, the capacity of the committed units in Figure 4 should be reduced by the size of the block labelled "Commit" in that figure. This reduction would apply to units G3 and G4. The minimum capacity of units G1 and G2 is already represented.

Neglecting this small effect, the figure illustrates the basic change in avoided cost resulting from representing the unit commitment process. The result is to increase TM_2 and to decrease TM_4. TM_3 decreases in this case, because the increase in TM_2 is much greater than the decrease in TM_4. Regardless of the general balance of the shift in the weights of the contributors to avoided cost, the "typical" effect under California conditions will be a lower IER with commitment than without it.

Figure 4. Avoided Cost with Commitment

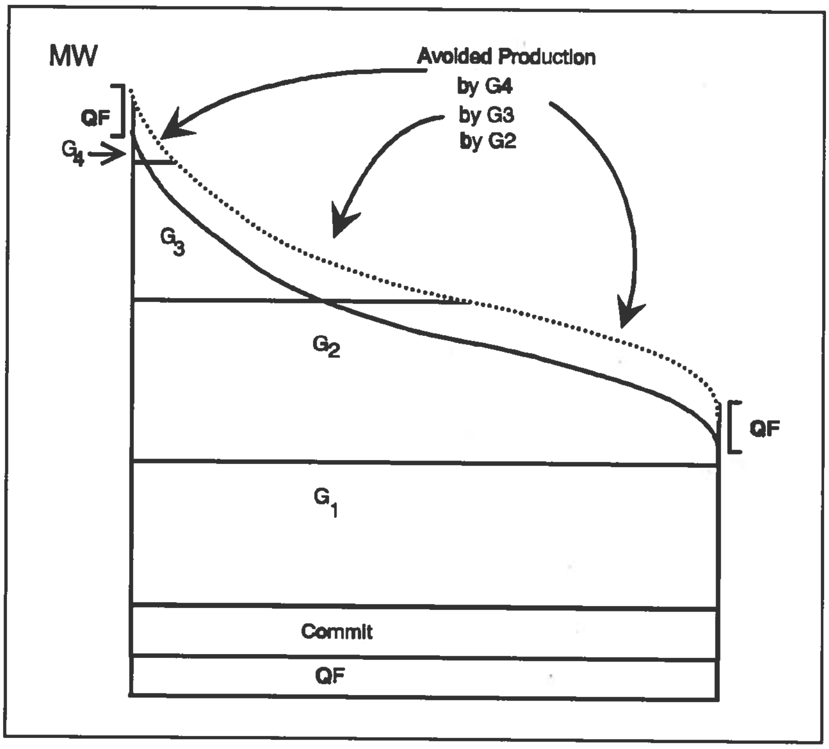


Table 1 gives a numerical illustration of this effect. The TM_i's in this table correspond roughly to those in Figures 2 and 4. The values for AG_i/UEG_f correspond to typical expectations for coal power (G2), efficient gas-fired steam plants (G3), and inefficient gas-fired steam (G4). The "typical" reduction in IER resulting from adding unit commitment is due both to the shifts in the TM_i's and the large difference between AG_2/UEG_f and AG_3/UEG_f.

Table 1. Effect of Commitment on IER

Unit	*TM_i*	*AG_i /UEG_f*	*IER*	*Avoided Cost @ \$3/MMBtu*
		No Commit		
G2	0.20	7000		
G3	0.65	9500		
G4	0.15	11000	9225	2.76¢/kWh
		Commit		
G2	0.50	7000		
G3	0.40	9500		
G4	0.10	11000	8400	2.52¢/kWh

Implementation Details

There are a number of details involved in implementing even simplified versions of a unit commitment representation into production simulation. These include: (1) determining a "commitment target," i.e. how much capacity should be operating, (2) whether all units and resources count equally toward that target, (3) whether the target is a deterministic or an expected value, and (4) how to rank order units for commitment purposes[3].

In many cases these questions could be resolved by reference to actual utility operating procedures. Even in these cases, however, there is frequently some ambiguity. Therefore, a number of these details have been litigated in the ECAC proceedings to determine appropriate ways to implement in simulation models, the operating procedures used by utilities.

4.3 Litigation History

The litigation history shows several consistent themes. First, the QFs and the utilities always argue disputed technical issues from a position that is consistent with their economic and competitive interest. This means that QF representatives will maintain that system constraints are less than those articulated by the utilities, because more constraints mean lower IERs. This is just a generalization of the argument illustrated by Table 1. Second, the CPUC staff typically ended up playing the role of referee. Sometimes they offered "split the difference" solutions, but as QF payments grew increasingly large in aggregate they tended to side with the utilities.

Southern California Edison

The first case in which the technical details of unit commitment became a litigated issue was the 1988 SCE ECAC. The Elfin version in use for this case had a very simplified commitment feature which failed to make any distinction between firm resources that meet commitment goals and non-firm ones which do not (Kirshner, 1993). Since SCE has monthly variation in the amount of non-firm power available, the Elfin users had to adjust the commitment target monthly to reflect these changes. Separately, there were differences of opinion about whether the expected value of capacity should be counted toward the commitment target (i.e. rated capacity reduced to account for maintenance and forced outages), or simply rated capacity should be counted.

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[3] The issue here involves the varying efficiency of thermal units over their output range. If several units have a similar, but not identical range of efficiency variation, then should they be ranked by their most efficient output level, their expected efficiency at full output or their expected efficiency at expected output? This is a different problem from the merit order for dispatch. In that case, once units are committed, there is an unambiguous merit order.

The result of these model limitations and modelling disagreements was substantial variance in the position of the parties on the appropriate specification of the commitment target. Table 2, reproduced from the CPUC decision in this case (CPUC, 1988a), reflects the different positions.

Table 2. Comparison of Elfin Commit Target Values for Version 1.58

Month	*QFs*	*CPUC Staff*	*SCE*
June 1988	*1.12*	*1.14*	*1.16*
July	*1.11*	*1.13*	*1.15*
August	*1.11*	*1.13*	*1.16*
September	*1.11*	*1.18*	*1.21*
October	*1.12*	*1.18*	*1.22*
November	*1.13*	*1.23*	*1.26*
December	*1.12*	*1.22*	*1.24*
January 1989	*1.22*	*1.24*	*1.26*
February	*1.24*	*1.28*	*1.29*
March	*1.24*	*1.26*	*1.29*
April	*1.22*	*1.25*	*1.27*
May	*1.19*	*1.21*	*1.23*

The pattern illustrated in Table 2 reveals a consistent positions. The QF parties argue for modeling conventions that impose fewer constraints on operation, and consequently higher avoided costs. The utilities typically invoke system constraints, in this case high values for the commitment target, which result in correspondingly lower avoided costs. Positions favoring high avoided cost are also adopted by QF representatives in the disputes over data assumptions, and correspondingly, the utilities adopt positions favoring low avoided cost (these data disputes will not be reviewed here). The CPUC staff typically finds itself playing the role of referee. In this case, they adopted a position intermediate between the two sides. Because the CPUC itself could not make the appropriate judgments conclusively in this case, they endorsed the staff position.

There is a further dimension to the commitment issue, involving the average oil and gas heat rate. Broadly speaking, the higher the commitment level, the higher the average oil and gas heat rate. The reason for this correlation is that the capacity running at minimum levels is very inefficient compared to average performance. Higher levels of commitment mean that the balance between the efficient and inefficient range of operation will be shifted somewhat toward the latter. This effect has incentive implications because the utilities had been at some risk for these fuel costs under CPUC procedures. The recovery of fuel and purchased power costs had not been fully guaranteed. Therefore, the utilities would desire a higher estimate of total costs as a hedge against under-recovery. This would provide an additional incentive to seek high unit commitment levels, since these would raise the total revenue requirement, even as it lowered QF prices.

The issues litigated in the 1988 ECAC appeared again in the 1991 SCE ECAC. Between the 1988 decision and the 1991 ECAC, SCE settled the IER issues without litigation. The parties were able to agree on an estimate without having to file testimony and adjudicate differences. By 1991, when QF production had grown much larger, and the IER was expected to decline, such settlement was no longer achievable. By this time Elfin incorporated the firm vs. non-firm distinction, so the monthly adjustments to the commitment target were no longer necessary. The dispute over expected values versus nominal rated capacity, however, continued[4]. If the commitment target were specified neglecting forced outages, the result is less capacity committed, and therefore a smaller commitment block in the base load. By the previous discussion of Figure 4, this would result in a higher IER than the case where forced outages were used to derate the capacity being counted toward the commitment target. It should be no surprise that the QFs argued for neglecting forced outages and the utilities argued for including them.

The QFs also raised a related issue involving the specification of minimum capacity for committed oil and gas units. SCE has a number of units whose minimum capacity varies depending upon how they operate. The higher minimum is the capacity at which the automatic generation control (AGC) equipment operates. AGC provides the capability to respond to minute to minute fluctuations in demand while maintaining system frequency. These units can be operated below their AGC limits when necessary. This is may occur at times of high minimum loads[5]. The QFs argued that for the IER calculation, the lower minimum level (known as the DO-5 minimum) should be used, rather than the higher AGC minimum. SCE argued the opposite. These positions are consistent with the overall objectives of the two parties. By the same logic as argued previously, higher capacity in the commitment block (see Figure 4) typically means a lower IER, and vice versa. Thus the AGC vs. DO-5 minimum capacity issue is conceptually identical to the issue of derating versus no derating with respect to the commitment target.

In this case, the CPUC staff supported SCE's position on both the commitment and AGC minimum issues. The Commission itself endorsed the joint utility/staff view (CPUC, 1992).

Pacific Gas and Electric

The PG&E ECACs exhibited more variation in the litigation over unit commitment than the two SCE cases. In addition to the issue involving de-rating for forced outages in meeting the commitment target, there were related issues raised surrounding operating constraints in general and those that are peculiar to the PG&E system.

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[4] By this time, Elfin offered users an option to meet the commitment target without de-rating capacity for forced outages (EDF, 1992; Kirshner, 1993).

[5] Minimum load conditions can create operating problems for utilities when the baseload generation is high compared to demand (Le et al., 1990). QF output purchased under the PURPA obligation exacerbates minimum load problems when it is large. This has frequently been the case in California.

In the 1988 PG&E ECAC, PG&E asserted that oil and gas generation could never fall below 600-700 gWh per month, reflecting a variety of transmission, reactive power and local area constraints. Modelling techniques adopted by PG&E to reflect these constraints include the specification of some units as "must-run" and the use of PROMOD's fuel limit feature to insure that the minimum oil and gas generation was realized. QF representatives objected to these assertions, pointing out that "excessive" constraints on the dispatch lower the IER, and that the nature of the claimed constraints were not documented. In its decision, the CPUC adopted the PG&E position for the 1988 calculation, and directed PG&E to report on the justification for such constraints in its next ECAC (CPUC, 1988b). PG&E filed such a study as required, specifying the minimum oil and gas production as 565 gWh/month (PG&E, 1989). There was no discussion of this issue in the 1989 ECAC, but the 1990 ECAC decision included the 565 gWh/month minimum as one of the uncontested modelling assumptions (CPUC, 1990a).

The 1989 ECAC raised two related issues which were similarly framed, and similarly resolved. PG&E used two PROMOD features to represent operating constraints, the minimum downtime and Dispatcher's Risk Aversion (DRA) features. In both cases, the effect of these constraints is the same as commitment broadly speaking, and as the area-related constraints litigated in the 1988 ECAC, they lower the IER compared to the no-constraint, or less constrained cases. The QFs challenged the PG&E representation. In the case of the minimum down time, they cited evidence purporting to suggest that actual operating practice was more flexible. For the purposes of the case at hand, the CPUC ordered that PG&E's use of these features be accepted, but that the utility should file supporting studies in the subsequent ECAC (CPUC, 1989a). The PG&E reports were filed with the 1990 ECAC application (PG&E, 1990a, 1990b). In the case of the DRA feature, PG&E modified its position slightly. By the 1990 ECAC decision, all parties agreed on both the DRA feature and the minimum downtime assumptions (CPUC, 1990a).

5 Verification

Although the AB475 language treats verification as an activity of equal importance with access to models and improving them, in reality verification has received relatively little attention. It has been argued that this result is due in large part to the probabilistic nature of production simulation models. The models compute expected values, reality turns out to be one draw from the underlying distributions. Comparing model to reality, therefore, requires something of "an apples to oranges" comparison. While the ECAC record does show several cases where verification came into play, it is still surprising the extent to which empirical support for various modeling approaches was not brought to bear. This leaves an impression that disputes were fundamentally settled by negotiation rather than fact.

Pacific Gas and Electric

The minimum oil and gas generation issue discussed above appears to have been resolved by the detailed discussion of historical experience. In its report on this issue (PG&E, 1989), the discussion included extensive excerpts from the dispatch records indicating when non-economic requirements forced the operation of particular units. The study ended up recommending a minimum generation constraint that was somewhat lower than what had originally recommended, but the evidence offered was sufficiently compelling that the subject was no longer litigated.

Southern California Edison

There has not been any verification activity of significance in the SCE ECACs. Historical data is frequently used to argue positions regarding resource availability and cost (as is also the case in PG&E ECACs), but none of the modeling controversies associated with unit commitment have been addressed using historical data.

6 Conclusions

The ECAC experience with production simulation models has to be declared a limited success. During the period 1986-1992, a large range of technical issues associated with using these models for determining IERs and the associated short term QF energy payments have been resolved. This process was not without cost. Making a monetary estimate of the costs and benefits is speculative, but instructive.

The California Legislature appropriated $600,000 for the CPUC to implement the requirements of the law in 1986. The same amount was appropriated in subsequent years. The private costs of the utilities and the QF participants were small before the "rolling review." During the ECAC period, however, their costs would have to be many times greater than the CPUC costs.

The benefit of explicit computer simulation as a model for the struggle over QF pricing is the limitations on gaming by both sides. The cases reviewed here show that both the utilities and the QFs have used their modelling to pursue their conflicting objectives. This kind of behavior has to be expected (Jurewitz, 1990; Pechman, 1993). The effect of explicit modelling has been to narrow radically the range of dispute. There are two aspects to this effect. First, modelling has forced a very explicit articulation of assumptions about resource availability and cost. We have not emphasized this aspect of the process in our discussion, but it was observed by the CPUC itself early in the rolling review process (CPUC, 1988b). The technical modelling issues discussed here may have had a smaller impact numerically, but their more problematic nature raises the potential for manipulation and subversion of the pricing process. For this reason, their role has been emphasized in this discussion.

Before the rolling review procedure was adopted, differences is IER estimates of 2000 Btu/kWh were not uncommon. As a result of the ECAC procedure, the maximum dispute is now closer to 500 Btu/kWh, and frequently less. If we assume a "split the difference" model of CPUC decision-making, then the result of the modelling would be half the reduced IER spread (i.e. half of the reduction from 2000 to 500 Btu/kWh), or about 750 Btu/kWh. Moreover, the trend in IERs over time has been downward. As more QF production has come into operation, this could be expected.

The larger policy environment in California has been extremely favorable to the QF industry. California regulators have taken credit for creating this class of suppliers (Hulett, 1989). Since the IER is essentially a transfer price, it has the potential to overpay QFs. Given the promotional attitude of California regulators, this potential could well have been realized in the IER process as some argue it was in other California QF pricing arrangements. The rolling review, therefore, may well have provided a restraint on overpayments, and reduced their magnitude. Under this assumption, the reduced spread in IER estimates is probably an absolute reduction in the transfer. This makes it a benefit to ratepayers. We estimate the magnitude of this benefit and compare it to costs.

Since some of the IER reduction might have occurred in the absence of AB475, we use 500 Btu/kWh as an estimate of benefits. At $3/MMBtu as an average price of natural gas during this period, 500 Btu/kWh is equivalent to 1.5 mills/kWh. While this is small on a unit price basis, the volume of QF production is very large. The 1988 SCE ECAC involved 4861 million kWh priced using the IER. By 1990, the PG&E ECAC involved a volume of 8971 million kWh priced using the IER; the SCE volume in that year was around 10,000 million kWh. At 10,000 million kWh, 500 Btu/kWh and $3/MMBtu gas amounts to $15 million.

Using these estimates of value, the benefits of modelling IERs would exceed costs by roughly five times even if private costs of modelling were ten times greater than the CPUC budget (roughly $30 million in benefits for 1990, counting both SCE and PG&E, compared to roughly $6 million in costs). The benefits were smaller in the early years than the 1990 estimate largely because the amount of QF production priced with the IER was less.

This cost/benefit exercise does not tell the whole story of AB475. Indeed, it puts the best face on this experience. There are a number of costs that have not been counted, and that belong in a reasonable assessment. First, the CPUC use of the AB475 funding may not have been optimal. CPUC personnel policy is based on a rotation system. Staff assigned to ECACs would frequently have a different assignment shortly after they had acquired the modelling skills necessary for dealing with IER issues. While some continuity has been maintained with more senior staff, turnover has been high. Further, CPUC staff familiar with IER issues have gradually left state service and often end up working for representatives of the QFs. Thus, the institutionalization of modelling capability at the CPUC has been limited.

Another significant cost of the AB475 process is the increasing ubiquity of production simulation in all areas of electricity planning and regulation in California. As familiarity with these techniques have grown, their use has become more common. Typically the settings in which these other applications occur do not involve the checks and balances of the ECAC proceeding. There are no referees; standards of proof are lower; opportunities for gaming, manipulation or mindless computation are abundant. Some critics of the California electricity resource planning process see the modelling procedures as a field for strategic manipulation, where policy and financial conflicts get disguised as technical issues (Stern, 1993).

The California experience with production simulation in the regulation of electricity is therefore quite mixed. Under tightly controlled conditions with precisely defined objectives, the modelling has assisted the goal of equitable and efficient pricing for QFs. Other regulatory settings lack such precision and controls. Here the record is less manageable and the benefits of added analytic capability are less clear. There may well be settings in which the net benefits are negative. It is probably inevitable, however, for modelling to remain a feature of the regulatory landscape. Similar QF pricing and system operation issues have arisen in New York (NYPSC, 1991; Slater, 1993; Pechman, 1993). Certainly the increasing competitive pressure in the industry suggests that more cost unbundling will occur. Similar problems will emerge as the transmission network is opened up to third part access (Kahn, 1994). The lesson of this discussion is that there are substantial returns to a methodological emphasis in this process and a structure of usage that emphasizes checks upon strategic behavior.

A final word on the model review/evaluation process is also in order. There is an extensive, if somewhat fragmented literature on evaluation processes for models of the energy system. An early review (Labys, 1982) distinguishes between the rigorous statistical tests that can be applied to econometric models and the substantial uncertainty involved where estimated engineering parameters play a large role. Since production simulation falls into this latter category, the methodological ground can be shaky.

There have been two main centers of model assessment activity in the U.S. that have been concerned with energy issues. The MIT Energy Laboratory has conducted "one at a time" assessments thay are primarily intended to deal with models whose functional value is not so well established as was the case for production simulation. The traditional goal of the Energy Modeling Forum (EMF) at Stanford University has been to use model comparisons to illuminate policy issues. This goal is too imprecise for the IER issues. The real problem in IER modeling was the comparative novelty of the application. The rolling review adopted by the CPUC was, in fact, recommended by EMF (EMF, 1988).

The EMF recommendation was based on the notion that the combination of high economic stakes and limited CPUC capability meant that attempting to select a preferred model would not be an efficient choice. The structured comparison that evolved in implementing the rolling review served both to facilitate learning and limit (but not eliminate) the strategic manipulation of models for competitive gain. The rolling review was thought to offer the best combination of opportunity for learning along with valuable use for real decisions, compared to a process that picked a preferred model. In retrospect this recommendation proved to be sound.

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