

# THE ROLE OF MAINFRAME COMPUTER MODELS IN LEAST-COST UTILITY PLANNING

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## ABSTRACT

Electric utility companies are increasingly using main frame computer models as their central planning tools. Adoption of modelling represents a response to the complexities that have complicated planning over the last few years. At the same time, the concept of least-cost utility planning is gaining acceptance among regulators and, more slowly, utilities as the guiding principle of planning. The interaction between these two significant changes in industry thinking and methods is described, and two of the leading planning models are evaluated for usefulness as tools in the least-cost planning process. It is argued that for better or worse computer modelling is *de facto* the industry's chosen road to least-cost planning, and, indeed, no alternative is apparent. Further, regulators and policymakers must adopt comparable modelling capability if useful exchange is to continue in the industry.

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## 1. INTRODUCTION

"Least-cost utility planning" (LCUP) is an integrated approach to demand-side and supply-side electric utility planning. LCUP results in a least-cost plan for the company consisting of a policy set that, if adopted in its entirety, will ensure that forecast demand for electricity services within the company's service territory will be met. The least-cost principle simply requires that the policy set that incurs the *least cost* be the one adopted. The problem then reduces to evenhandedly estimating and comparing the costs of policy scenarios that are different in nature, have uncertain outcomes, and are not independent in effects. In an electric utility nowadays this problem would most likely be approached, at least initially, by use of one or more standard mainframe corporate planning model. In fact, mainframe models have emerged as *the* standard method of analysis for LCUP purposes.<sup>2</sup> The adoption of models reflects both the complexity of the analysis and the historical "accident" that the LCUP principle and the comprehensive models came into common currency at the same time, that is, over the last five years.

Developing a least-cost plan requires a sophisticated analysis of the company and the exogenous market conditions it faces. Further, the interaction between the company and its economic and regulatory environment is a simultaneous system and any analysis of it must recognize it as such. Since the LCUP principle requires that interventions of several diverse types be traded off against each other, and, since an intervention anywhere in a simultaneous system will affect everything else, large scale computer modelling promises to be the most appropriate tool. Computer models allow the analyst to keep track of the numerous details that can have significant feedback effects under different policy options, to do sensitivity cases easily, and to replicate results of other company departments or outside agencies. Regulators and policymakers are currently a step behind the industry in their appreciation of the models' value as LCUP tools, although their acceptance of LCUP principles is, arguably, ahead of the companies'.<sup>3</sup> The use of models by companies will undoubtedly expand, and regulators and policymakers should be accelerating their modelling efforts to keep pace with the historic changes in industry thinking and methods currently unfolding.

## 2. BACKGROUND

Until the mid-1970's, electric utility demand forecasting and generation planning were separate company functions. Electricity demand grew rapidly but consistently, and the role of the generation planner was perceived as one of commencing new construction in a timely manner to meet the forecast demand as cheaply as possible. Nonetheless, the inherent stability of the electricity supply industry, with consistently rising demand on one side and falling costs on the other, was an environment in which this planning method was adequate. After the mid-1970's, however, great uncertainties entered both sides of the utility supply-demand balance, making utility forecasting suddenly complicated and traditional planning methods inadequate. The unfamiliar instability of the electricity market has had double-barrelled consequences for utility planners. On the one hand, the potential for planning error has grown, and on the other, the costs of error have also grown.

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<sup>2</sup> This is not to deny that great skepticism about the value of large models exists in the industry.

<sup>3</sup> See reference 20.

Economic Forecasting

Generation Planning

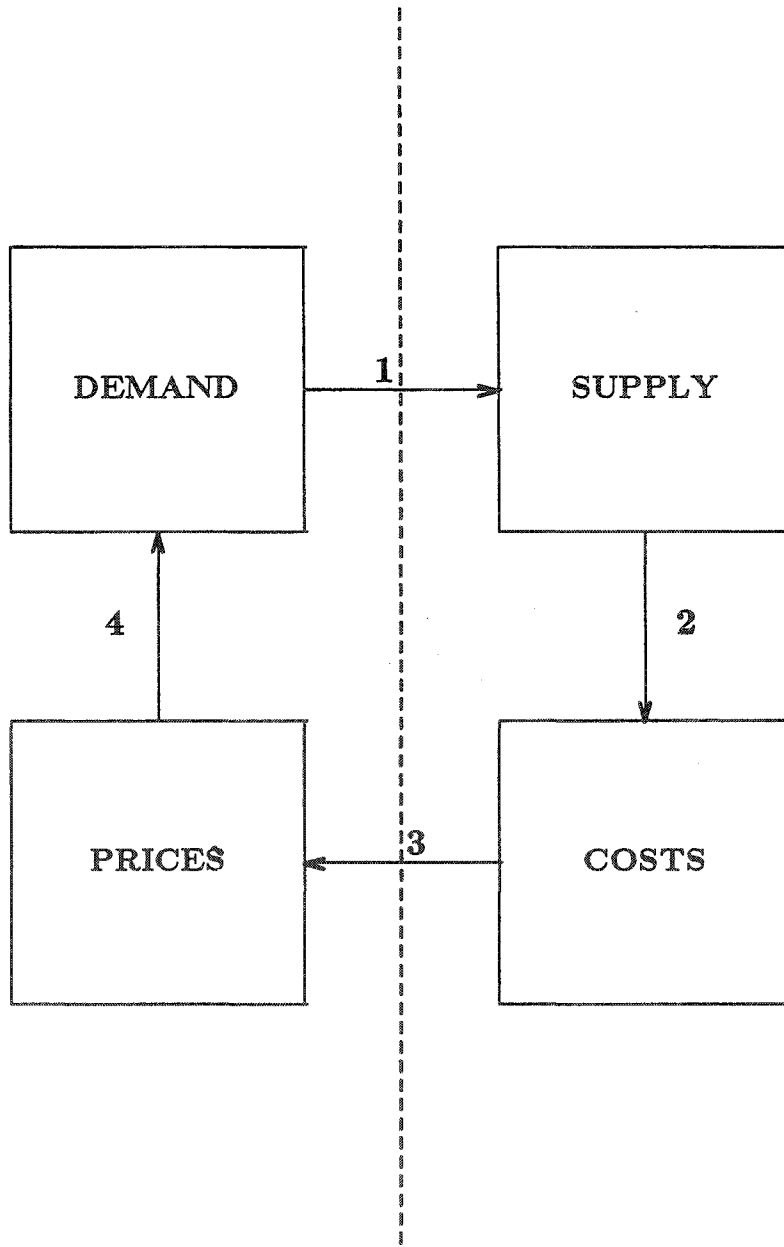


Figure 1

Two responses to this unfamiliar environment are the focus here. The first is the adoption of large scale computer models, and the second is the emergence of "demand-side" programs, that is, programs intended to limit or reshape demand so that it is more readily met by expected generating capacity.

Use of the expression "least-cost" was first popularized by Roger Sant and Amory Lovins in the late 1970's and it rapidly entered the everyday energy lexicon.<sup>4</sup> These authors claim a parallel exists between their original global terms of reference, the problem of meeting worldwide energy needs, and the point of view of an electric utility, which is usually the *only* supplier of electric power in its territory, and which is required by law to meet the demand of its customers.<sup>5</sup> Although this parallel in part contradicts Sant's earlier view that fostering greater competition in energy markets is desirable, the least-cost approach is being embraced by the industry.<sup>6</sup> To achieve the demand-supply harmony implied by LCUP, an integrated approach is necessary wherein the traditional supply-side planning methods are coordinated with the more recent methods of evaluating demand-side programs. Demand is to be no longer thought of as an exogenously determined output target but rather as a controllable parameter that utility policies should aim to set at the desirable level. This level is the one at which reducing demand by one kWh at any point in time costs exactly as much as delivering that kWh to the customer.<sup>7</sup> Clearly, the meaning of "cost" in LCUP as it is currently used is somewhat different from the "cost" originally referred to by Lovins and Sant, that is, the full cost, both direct and indirect. The current usage of "least-cost," and the one adopted here, is the limited company-level view in which "cost" refers to the company cost, with customer cost, externalities, etc., excluded. The LCUP problem, as it is addressed here, is, therefore, *given the business and regulatory environment in which an electric utility finds itself, what policy set, or least-cost plan, will ensure that it meets the forecast demand for electricity services within its service territory at minimum direct cost?*

When forecasting is conducted at a utility, the least-cost principle requires that all conceivable means and combinations of means of meeting forecast customer demand for the services electricity provides should be evenhandedly considered. This sounds both intuitively reasonable and analytically straightforward, but in practice it is a mammoth undertaking. First, adequately forming the problem requires large data sets. Second, advanced methods and considerable resources are required to adequately weigh the pros and cons of diverse policy sets, all of which involve great uncertainties. And third, the institutional difficulty of coordinating the work of formerly separate company departments is significant. And further, overcoming these problems is required of an industry whose forecasting ability was rudimentary until recent times. The challenge for computer modellers is to adequately represent this complex company problem in a comprehensible yet manageable model.

### 3. THE MODELLING PROBLEM

Figure 1 shows a simple schematic of an electricity system, or, indeed, any market. While Figure 1 appears trivial, several salient features of this industry contrive to make the modelling problem immensely complex, and the simple demand and supply diagram of economics a poor basis for modelling. The major complications are the following:

1. Since electricity cannot be stored at reasonable cost, a full characterization of demand must include an hour-by-hour load curve.
2. Being such a capital intensive industry with long lead times for new plant construction, forecasting must have at least a ten-year time horizon.
3. Regulation produces a set of prices that do not reflect true time and place dependent electricity costs but derive from a formula that aims to just meet average costs and an allowable return on investment over the long run.

<sup>4</sup> See references 19 and 25.

<sup>5</sup> See reference 21.

<sup>6</sup> See reference 24, page 40.

<sup>7</sup> Note that as always with electricity, the instant of delivery has to be specified.

4. The "obligation to serve" principle requires an electric utility to operate unprofitably at certain times and in certain places.
5. The utility is usually a monopolist within its service territory.
6. Electricity rates are non-linear, and numerous rate schedules are in effect simultaneously, so changes in costs have diverse consequences for sales and revenues depending on which specific consumers' behavior is affected.<sup>8</sup>

Among the standard corporate planning models, two groups of models can be identified. The first are ones based on the traditional methods of production costing. Treatments of demand-side policies can be added to a standard supply-side algorithm to create a LCUP tool. The second group, now in their infancy, are full system models that attempt to solve the whole of the problem portrayed in Figure 1 in one integrated process. The two models reviewed below represent the state of the art for each of these two camps.

#### 4. EGEAS

##### *Description*

The Electric Generation Expansion Analysis System (EGEAS) represents the state of the art traditional generation planning and production costing model.<sup>9</sup> It incorporates advanced optimization techniques based on load duration curve methods to obtain a cost minimizing use of plant capacity. Some of the EGEAS computer code is original and some is based on pre-existing models.

EGEAS is structured in five components. The first component is a pre-processor for user-supplied hourly loads. The second component creates a central data base used by the simulation. The third component performs the annual simulation of production costs and optimizes generation expansion. The fourth component generates output reports summarizing the results of the analysis. The fifth component creates "reduced-form" summaries of the results.

Up to thirty years of data describing hourly loads for the company system, a single additional interconnected system, and up to four non-dispatchable technologies can be processed in a single run. Similarly, if less than a whole year's worth of data is available, a single year or set of years can be built-up from typical days. The representation of information as normalized values allows the user to construct an output file of any length, for any number of years from a set of data consisting of perhaps only a few days. The output of the program exhibits substantial flexibility.

The features of EGEAS that merit special mention are the following:

1. EGEAS relies on load duration curves, although the demand input processor exhibits great flexibility.
2. Production costing is based on cumulant methods and draws heavily on proven pre-existing models. An annual load shape is reduced to weekly load duration curves which are filled up by the dispatch of generation capacity available. The dispatch can reach higher levels of detail by specification of sub-weekly periods.
3. Demand-side programs are introduced either by inputting an adjusted load shape or by proxies on the supply side. For example, conservation could appear as a diminished load duration curve, or as a power plant with exactly the operating characteristics that produce the same effects on the system as the conservation policy being modeled.

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<sup>8</sup> By "non-linear" it is meant that price varies over levels of usage, usually in an increasing or decreasing block manner, with the added effect of a fixed customer charge or minimum bill requirement.

<sup>9</sup> EGEAS was developed by the Massachusetts Institute of Technology and Stone and Webster Engineering Corp. for EPRI. See reference 6.

### *Least-Cost Capability of EGEAS*

EGEAS is not a full market model that solves the whole problem as portrayed in Figure 1. Its main focus is linkage 2, wherein the dispatch is translated into costs, although elementary financial variables are also calculated. However, linkage 3 between costs and rates is not made, so a simultaneous solution is impossible. EGEAS is, in fact, fixed on the demand side, although demand-side intervention can be modeled through supply-side proxies. The future demand is predetermined and the problem is approached as one of meeting the forecast load at minimum cost. Being an optimizing model, EGEAS is able to undertake this problem with rigor, using a full tool box of the methods available. EGEAS can develop an expansion plan for the company, consider storage technologies and other innovations, and evaluate the financial implications of its choices. A process of sensitivity analyses is built into EGEAS so a comprehensive analysis is available in one step.

For LCUP purposes, EGEAS could only be used iteratively with other models. EGEAS does not permit a direct simultaneous solution that would allow direct trade-offs between demand-side and supply-side options. One scenario has to be evaluated at a time in an iterative fashion.

Finally, it should be mentioned that running EGEAS is cumbersome. The choice of optimization algorithms, the large size, and the use of large format output files all limit the number of company staff that could use EGEAS. This problem is compounded by the lack of simultaneity requiring repeated runs and coordination with other models to achieve a least-cost plan. Also, experience with utility managers suggests that they are uncomfortable with the optimization capabilities of EGEAS. They argue that in the real world the set of expansion options is small and that choosing the optimum plan is better left to human judgment.

## 5. LMSTM

### *Description*

The Load Management Strategy Testing Model (LMSTM) starts from a view of the modelling problem very similar to the one portrayed in Figure 1.<sup>10</sup> LMSTM is a truly self-contained model that explicitly addresses the simultaneity of this system.

Several aspects of LMSTM's approach merit special mention:

1. The expansion plan of the company is predetermined, that is, the supply inputs are fixed. LMSTM does not create an optimal generation strategy, rather, policy interventions, such as load control or energy storage, are evaluated in the context of an established expansion plan. Comparing new generation to other alternatives, that is, developing a least-cost plan, requires re-runs with different input data sets. This feature of LMSTM does not undermine the simultaneous solution method, rather it means that it cannot be called upon to recommend the addition or subtraction of generating capacity.
2. The demand model is of the end-use type. It first estimates ownership of all end-use appliances and then adds up load shapes designated by the user to each end-use to achieve a forecast of loads and energy. No explicit account is taken of business cycles, weather fluctuation, or efficiency improvements.
3. The LMSTM dispatch algorithm is chronological, which is a non-traditional approach to a problem normally reduced to a compact representation, usually a load duration curve. LMSTM executes a full set of dispatch orders across the available plants for each of 16 day-types and the process is repeated to minimize costs of start-up and to ensure optimal use of storage technologies.

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<sup>10</sup> LMSTM was developed by Decision Focus Inc. for EPRI. See references 7, 9, & 14.

*Least-Cost Capability of LMSTM*

The input data burden of LMSTM is substantial but not overwhelming. While no utility or regulator should have difficulty collecting the required supply-side inputs, and the rate and financial information should all be matters of public record, the demand-side inputs would likely cause some serious difficulties. This is typical of end-use models. While popular wisdom has it that these models are more reliable for long run forecasting than econometric models, the data requirements are burdensome.<sup>11</sup> Even, as mentioned above, after accepting the consequences of excluding weather, business cycles, efficiency improvements, etc., the end-use by end-use detail is not likely to be available at any but the most sophisticated utilities. Also, typically the analyst is attempting to calibrate his/her model against only a few years of load data and often such data has little if any breakdown of loads by rate class, let alone by end-use. Often generic load shapes are substituted for local company data and this has pitfalls; notably, weather sensitive end uses exhibit load shapes other than one would expect based on temperature variation alone. As a consequence of these problems, load forecasting models are often run after limited calibration and backcasting.

The problem of replicating the load pattern of an entire system is a taxing one indeed and the appliance saturation approach of LMSTM may not be advisable for any but the residential sector. While the market share approach seems reasonable for domestic appliance purchases, it is not so convincing a method for modelling the other sectors. Nowhere in the LMSTM manual is any specification of the industrial sector suggested other than as an amorphous single end-use mass. Here more than anywhere the absence of business cycle and efficiency improvement inputs create cause for concern.

The problems involved in accurately recreating a full system load shape by end-use are daunting, and, further, getting it right once is no guarantee that the specification is correct and forecasts credible. Particularly, the exclusion of efficiency improvements from the industrial sector is worrisome. On the plus side, the breakdown of the year into 16 typical days permits sensible and manageable simplification, and LMSTM is wisely structured so the user can build his/her data sets from scanty beginnings. Also, it should be emphasized that for LCUP the horizon must necessarily be distant, given that ten years is the minimum time required to plan and build new baseload capacity, so the end-use approach is probably the most promising.

The outputs of LMSTM are extensive. For each of the 16 representative daytypes that the model uses, hour-by-hour loads, costs, and conditions of all plants are produced. The loads customer classes and end-uses are calculated and financial statistics that describe the effect of adopted policies on the utility given. The effectiveness of a individual strategies is still judged by the user, but elementary cost-benefit calculations are done by the model.

Load management through creative pricing in general should be a strategy at the top of the least-cost planner's tool box and, unfortunately, LMSTM's treatment of time-differentiated pricing is unconvincing. Neither the origin nor the application of the elasticities asked for in the input files is clear from the documentation.

Within the class of large planning models, LMSTM is relatively easy to use. It appears to be stable and error messages are comprehensible. It could be run by staff at many levels of a company, adding greatly to its value as a filtering tool whose purpose is to select candidates from a large class of potential strategies. It also means that the user will become familiar with the general character of outcomes, and establishing credibility bounds is easier.

Finally, it should be restated that LMSTM is rigid on the supply side. Certainly its authors have ingeniously written so it permits the adoption of numerous possible interventions such as direct load control, energy storage, time-differentiated pricing, etc., but any one strategy has to be evaluated one run at a time. That is, LMSTM does not derive an optimal strategy for a utility; it merely, as its name suggests, tests policy options input by the user. As such, it does not answer the real modelling challenge of least-cost planning and depends on the creativity of the user to develop potential strategies.

<sup>11</sup> See reference [17]

*Other Models*

EGEAS and LMSTM are the state of the art models used in the industry, but it would be a mistake to think that the choice of LCUP tools must be limited to these two. Numerous other models have been built by various modelers over recent years, including many developed by companies for their own use. Many of these models can and will be used to provide primary and intermediate level inputs.

**6. CONCLUSION**

Returning to Figure 1, the complexity of developing a least-cost plan should now be apparent. A true least-cost plan would include a set of policy initiatives that might intervene at any of the corners. Consider, for example, the importance of being able to forecast the effect of a simultaneous innovative pricing policy and new plant construction. The optimal size of the new plant cannot be known until the effect on demand of the new pricing policy is known. Vice-versa, the level of the new prices cannot be known until the size of the plant and its consequent costs are known. Given the complexity of this problem and the importance of solving it simultaneously, large scale computer modelling presents the only promising rigorous approach. However, the heavy requirements for accurate data of large models inhibits their rapid worthwhile application, the intra-company barriers to cooperation pose a difficult obstacle, and since no ideal model exists, either current models must undergo improvement or groups of models must be run in shaky hard-to-handle tandems.

Utility companies clearly recognize the importance of expanding their modelling capability and they are using large scale models increasingly. The models are *de facto* the currency of the industry. Policymakers and regulators must recognize the same currency if beneficial exchange is to continue. Fortunately, however, the models establish a stable and convenient standard for cooperation.

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