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EVALUATION OF TOOLS FOR RENEWABLE ENERGY POLICY ANALYSIS: THE TEN FEDERAL REGION MODEL

Panel on
Evaluation of
Renewable Energy Models

Prepared by:
Analysis and Evaluation Programs
Science/Engineering Education Division
Oak Ridge Institute for Science and Education

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PANEL ON
EVALUATION OF RENEWABLE ENERGY MODELS

Panel Chairman

James Gruhl
Gruhl Associates

Panel Members

Samuel Baldwin
Energy and Materials Program
Office of Technology Assessment
United States Congress

James Davidson
Director of Applied Analytic Methods
Electric Resources Planning Department
Pacific Gas and Electric Company

Edward P. Kahn
University-Wide Energy Research Group
University of California, Berkeley

Chris Marnay
Center for Energy Studies
University of Texas

Staff

Joe G. Baker, Project Director
Gary Gordon, Research Associate
Analysis and Evaluation Programs
Science/Engineering Education Division
Oak Ridge Institute for Science and Education

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FOREWORD

It is a very difficult task to assess the extensive amount of work that is represented by the Sandia National Laboratory's Ten Federal Region Model (TFRM). It is even more difficult to evaluate how the results of that model will simulate future scenarios. To accomplish these tasks, the panelists studied all available documents and presentations, and had comprehensive discussions with the modelers, at meetings and via telephone. In addition, the modelers made special sets of sensitivity runs which were of interest to the assessment panel. These runs included changes in inputs, parameters and model components, as well as the addition of new model output categories.

Based upon their areas of expertise and interests, the panelists then chose primary and secondary responsibilities for the assessment of various TFRM modules and capabilities: Demand & Load, Capacity Expansion, Dispatch/Production Costing, Storage, Renewables, Transmission, Reliability, Finance & Regulatory, Environmental Effects, Policy Controls, Scenario Costing, and Structure/Feedback/Tradeoffs. The assessment of each of these modules and capabilities was discussed individually and with regard to the implications for the other sections of the model, and with regard to the overall results of the model. Various areas were combined as a result of these discussions.

The individual assessment sections include discussions of quality of information, alternative methodologies, endogenous/exogenous treatments, different levels of detail, test results and other model runs, evidence of performance, treatment of risk, possible biases of data and methodology, appropriate and inappropriate applications, quality of documentation, usability of model, future enhancements and improvements that would be suggested, and the best guess on payoffs in terms of increased applicability, accuracy, and so on.

The assessment panel did an excellent and thorough job of assimilating all the information and discussing the ramifications. They deserve great thanks for their efforts, as do the following people. The time and information of Joe Galdo and other Department of Energy people was extremely helpful. Gary Gordon and Joe Baker provided outstanding support, and Joe Baker, in particular, was the perfect leader and facilitator for this difficult project.

Jim Gruhl
Evaluation Panel Chairman

Chapter 1
INTRODUCTION AND SUMMARY OF FINDINGS

PROJECT DESCRIPTION

The Energy Policy Act of 1992 establishes a program to support development of renewable energy technologies including a production incentive to public power utilities.[1] Because there is a wide range of possible policy actions that could be taken to increase electric market share for renewables, modeling tools are needed to help make informed decisions regarding future policy.

Previous energy modeling tools did not contain the regional or infrastructure focus necessary to examine renewable technologies. As a result, the Department of Energy Office of Utility Technologies (OUT) supported the development of tools for renewable energy policy analysis. Three models were developed: The Renewable Energy Penetration (REP) model, which is a spreadsheet model for determining first-order estimates of policy effects for each of the ten federal regions; the Ten Federal Region Model (TFRM), which employs utility capacity expansion and dispatching decisions; and the Regional Electric Policy Analysis Model (REPAM), which was constructed to allow detailed insight into interactions between policy and technology within an individual region.[2] Sandia National Laboratories Strategic Technologies developed the TFRM and REPAM; Princeton Economic Research Inc. (PERI) developed the REP model. These models were developed to provide a suite of fast, personal-computer based policy analysis tools; as one moves from the REP model to the TFRM to the REPAM the level of detail (and complexity) increases. Thus, an analyst could use the REP model to define several likely policy actions from a large group of candidate policies; the TFRM and REPAM could then be used to further explore these likely policies.

In 1993, the Office of Utility Technologies supported the Oak Ridge Institute for Science and Education (ORISE) to form an expert panel to provide an independent review of the REP model and TFRM. This panel was to identify model strengths, weaknesses (including any potential biases) in the models and to suggest potential improvements in the models. This report contains the panel's evaluation of the TFRM; the REP model is evaluated in a companion report. The panel did not review the REPAM.

In November of 1993, the panel was briefed on the TFRM and the REP model by modelers from Sandia National Laboratories and Princeton Economic Research Inc. The panel then developed a set of simulations for the models to assist in the evaluation (see Appendix B). The panel met for a second time in January 1994 to discuss model simulations and to deliberate regarding evaluation outcomes. This report is largely a result of this second meeting.

The report is organized as follows. The remainder of this chapter provides a description of the TFRM and summarizes the panel's findings. This chapter is followed by individual chapters that examine various aspects of the model: demand and load, capacity expansion, dispatching and production costing, reliability, renewables, storage, financial and regulatory concerns, and environmental effects.

TFRM DESCRIPTION[3]

The heart of the TFRM is the Sandia Capacity Expansion and Energy Production and Costing module (CEPC). The TFRM is a simple shell that drives the CEPC. For each of the ten federal regions for a given year, the TFRM provides inputs regarding load, technology base, operating costs and other characteristics. These input data are then fed to the CEPC, which returns the energy production by technology for that year. The TFRM shell also provides input to the CEPC regarding future costs, technology characteristics, and load; the CEPC then determines a capacity expansion plan. The model keeps track of construction schedules and retirements of existing capacity and thus updates existing technology mix and capacity. This sequence is then repeated for the next year. Each of the ten federal regions is examined separately with no crosstalk between regions.

Technologies are divided into dispatchable technologies and intermittent renewable technologies. Dispatchable technologies include fossil technologies, hydro, nuclear, geothermal, and biomass. Intermittent renewable technologies include wind, photovoltaic, solar thermal, and pumped storage. Policy effects on the amount of electricity dispatched or capacity constructed for each of these technologies can be simulated by the TFRM. Any policy that changes capital or operating costs of any of these technologies (including increasing the cost of conventional technology) can be tested. TFRM is a supply side model; demand is exogenously determined.

The CEPC uses the same concepts as existing utility capacity expansion models (e.g., EGEAS and PROVIEW) including dispatching intermittent sources when they are available, meeting loads using the lowest operating-cost technologies, and minimizing total system life-cycle costs.[4] The CEPC applied these concepts to a regional level. The CEPC contains two basic components, an energy production module and a capacity expansion module.

The energy production module operates in three steps: (1) it dispatches all intermittent source power by treating intermittent sources as negative loads; (2) it optimizes system operating costs and dispatches storage by treating discharge power as a negative load and charge power as a positive load; and (3) it dispatches dispatchable source power using merit order. Thus, a load profile is presented to the energy production module; from this intermittent source power available is subtracted to generate net load. If storage use is economic, this net load is further reduced. The remaining load is then divided among the dispatchable sources in merit order to reduce total system life-cycle costs.

The capacity expansion module analyzes utility generation asset, future load, and future technology costs to determine the combination of new capacity by technology that will minimize the electric generation cost for the utility system. The capacity expansion module uses iteration with trial sets of capacity additions to search for this optimal mix.

SUMMARY OF FINDINGS

The TFRM is an appropriate and valuable tool for conducting energy policy analyses of renewable energy scenarios. In its current form, the model requires a user who has invested considerable time in learning about model operation. The panel feels that with moderate effort, the model could be made substantially more user-friendly. This effort includes both streamlining and developing menus of the input procedures, as well as providing more comprehensive displays and post-processor interpretation of the outputs.

Intended Applications

TFRM was built to provide relatively quick turnaround results for an analyst who wants to conduct a somewhat detailed study of the impacts of renewables on a specific set of federal regions.

The evaluation panel feels that the TFRM provides a new kind of model that is intended to deal with renewable energy technologies in the context of regional electric systems. Some of the renewable energy issues that can be investigated include the effects of capital cost and operating cost improvements, renewable tax incentives, fossil tax disincentives, efficiency improvements, regional variations in performances and site availability, competition between renewables and between fossil technologies and renewables, changes in risks associated with renewables, and other policies and issues.

The panel feels that the greatest value for this model is in the mid- to far-term. It will require some costs to develop, refine, test, maintain and make it into a user-friendly tool that will be accessible to a wide community of analysts. The TFRM is dependent upon the quality of input data, support analysis from overview models (such as the PERI REP model), and the familiarity of the user with the constraints and requirements of the model. The panel feels the limitations of TFRM will lessen in time, if additional work is conducted to improve the elements and usability of the model.

Structure

The structure of the TFRM was somewhat dictated by the initial assumption that a relatively quick turnaround regional model was needed to investigate the impacts of renewable energy technologies on the electric supply sectors. Feedbacks of cost of energy to change the level of demand, and other feedback relations, must be accomplished by the user in out-of-model feasibility checks, output-to-input calculations, and additional scenarios. Occasionally, some model results are dictated by constraints and ratios, such as with renewable growth rates of 20 percent per year for attractive technologies. For the most part, however, the nonlinear optimal search of the TFRM leaves most variables in the active basis and is much less directed by constraints than linear programming or other dynamically solved models.

Several features of the model (e.g., the capacity expansion, dispatching, and especially the renewables areas) employ methods that differ from previous modeling approaches and are very creative and innovative in nature. The major advantage to having a different methodology is that it may offer new insights. The disadvantage is a public relations problem in educating analysts about the uses and applicability of the new methodology.

One major concern of the panel was the way in which the renewable space was searched to find an optimum allocation of available renewables. The concern is that the whole economic and policy space be searched. Although it is a little hard to determine from the documentation, it appears as if the search is beginning at the origin, or the zero use of renewables point. If the model then settles in any local optimum, it will probably be in the vicinity of the start of the search, and this would bias against the use of renewables.

Demand

Demand modeling requires close attention from the user; it is entirely exogenous. Conservation, independent producers, and demand-side management effects must all be backed out of the load seen by the electric system. Without this attention, the model will obviously bias in favor of supply-side solutions, including renewables. A helpful addition here might be to use a post-processor to generate the demands that would be consistent with costs of electricity in various years. The user could then immediately see if changes in demand inputs were necessary. There is also some concern about the accuracy with which demand seasonality is modeled and the way that correlations are missed with seasonal fuel cost variations and seasonal renewable performance variations.

Capacity Expansion

The capacity expansion offers a very creative, alternative approach to other methodologies. It incorporates renewable resource depletion. It is well documented and has been validated against the Electric Generation Expansion Analysis System (EGEAS), a widely used electric industry expansion tool.[5]

Regional models are, however, difficult to validate against reality. The gap method, in particular, needs additional documentation, especially with regard to its problems: occasionally choosing uneconomic technologies, periods of disequilibrium, and biases. Repowering, especially repowering with combined cycles, also needs to be offered as an alternative to retirement.

Reliability

The conceptual approach to reliability in TFRM is an important improvement over the full-capacity/no-capacity credit approaches that some other models use for intermittent renewable energy technologies. There are, however, some issues and weaknesses that require investigation. The use of intermittent renewables as negative loads makes some reliability and reserve issues more difficult to study. This treatment also does not account for forced outages as a function of unit size or correlation of renewable energy productions.

The biases are difficult to sort out. Not accounting for some renewable technology reliability problems would tend to overestimate the use of renewables. However, biases toward lower reserve margins and lack of unit-size outage considerations would bias against renewables.

Dispatch

The dispatch logic of the TFRM is a traditional, deterministic, merit order dispatch. It seems to fit the renewables' needs impressively and reacts properly to many different sensitivity tests.

It seems clear that with the national screening objective, the TFRM has to operate on regions (10 versus 13 regions is a debatable issue). And with regional modeling, it seems appropriate to use a deterministic technique, rather than a laborious probabilistic method.

The modelers are to be commended for testing their dispatching model against a Booth-Baleriaux probabilistic method and against a Lilienthal probabilistic method.[6] The method used in the TFRM consistently underestimates energy displacement from gas turbines.[7] Based upon a November 15, 1993 briefing by Sandia staff, the TFRM method underestimates these peaking energies displaced by wind and photovoltaics by a factor of 4 to 6. The approximation used probably is a little crude at the peak upswings. The quantities and costs are small (about 2 percent), but still worth concern if storage or peaking renewables are being modeled, or if there is a significant quantity of renewables. The bias here is toward the use of more gas turbines, and less attractive renewables.

It is clear that with a substantial amount of intermittent renewable capacity, such as wind and solar, that a system or region might need more than the usual 7 percent spinning reserve. The right value may even be as high as 15 to 20 percent. In order that the spinning reserve be tied to the renewable capacity decision, it might be necessary to construct renewable turbine hybrids or renewable storage hybrids.

The TFRM results are often tightly constrained by operating and capacity assumptions. The operator must be aware of pressures and strains within the model. For this reason, it seems very important that the model output routinely print capacity factors (or percentage operating levels), cost of electricity, and other outputs that will make it easier for the user to make exogenous feedbacks.

Storage

In the comparison of the TFRM with EGEAS, the TFRM builds about 80 percent more pumped storage in the year 2006 but is about 10 percent lower by the year 2012.[8] This should be considered to be a bias in favor of building storage in the near term.

Storage may not be an important issue to correct if the questions revolve around renewables. However, there are two indications from the storage model run that storage may not be handled properly in the model. With the use of storage, the decrease in the use of baseload coal is counterintuitive, as is the increase, especially, of the peaking gas turbines. The modelers have looked at this and determined that this behavior is appropriate since, given the numbers in the trial run, coal is competitive with combined cycle at capacity factors as low as 25 percent. Hydro- storage is added in the storage scenario that was run, but the cumulative capital costs and the cumulative operating costs are higher, leading to some question about why it was built. The explanation for this problem seems to come from the fact that, although not optimal in the current year, storage is economic in the long-term average. It is impressive that the model can capture such subtle concepts.

Transmission

TFRM has no real transmission modeling capability. It is recommended that this model incorporate a technique similar to that used by the REP model.[9] Its simulations look reasonable and appear to be consistent with areas where there are good data, such as California.

Finances

The model incorporates technological and financial risks in a rudimentary way. Models that do not include these risks at all are likely to miss the main issue involved in the selection of renewables. Riskless models will overestimate the use of renewables, and so TFRM has much greater accuracy in this area.

However, the model does not take into account the varying cost of capital by utility type, private or public. Some of the financial risks of new technologies are not accounted for, as they are in the REP model. A better study of the value of gamma (the cost diversity parameter γ) would be helpful. It appears that the TFRM results are in nominal dollars, but this requires further checking into the dollars and the accounting.

Environmental Concerns

The TFRM does an excellent job in modeling the effects of the various carbon tax possibilities. On other environmental issues, however, the model may have some difficulties. One such area is that the total sulfur ceilings of the Clean Air Act can be exceeded in the model. These would probably have to be modeled with surrogate sulfur taxes, which would have to be adjusted until the sulfur caps were met.

Another untreated issue is the total life-cycle carbon implicit in the construction of facilities, although the carbon implicit in the production of fuels was accounted for in the trial runs. National carbon-limiting scenarios would have to take account of these implicit carbon emissions. The costs of materials and fuels would also go up with carbon taxes. This is a data problem rather than a methodological problem.

Additional untreated issues include land use, aesthetics, habitat destruction, and many other issues which are not amenable to a national modeling methodology. Values or proxy values must be generated before such externalities could be analyzed.

It is difficult to approximate the bias involved in not treating these environmental issues. Not including regional or national sulfur caps would bias against renewables. Life-cycle carbon accounting would probably bias slightly in favor of existing units. Land use, aesthetics, and habitat concerns might bias against renewables.

Usability

The temptation seems to be to make the TFRM act like an exact utility planning model, such as EGEAS. There are several reasons why this would not be the ideal model. First, EGEAS has none of the mechanisms necessary to properly treat renewables. Second, EGEAS, and other more detailed utility capacity planning models, were developed to suggest the *next optimal unit to add to a system*. Putting together a whole string of such next optimal units and adding the other utilities in a region would not provide a good predictor of the future of that region. It would be knife-edge in its selection of generation types, that is, all of one kind. It would not capture the risks, financial or technical, or the fuel diversity which is another important risk hedge used by utility planners. In short, a more statistical approach will do a far better job of forecasting regional capacity planning. TFRM incorporates those more statistical techniques. Not only would the addition of individual utilities and individual units be the wrong direction for TFRM to take, but it would make the model unusable for simulations of regions or the United States.

SUGGESTED MODEL IMPROVEMENTS AND ENHANCEMENTS

With the operating levels so tightly constrained, small movements ought to be watched as signs of needed changes in operating and capacity assumptions. It is necessary that the operator be aware of pressures and strains within the model. For this reason, it seems *very important that the model output routinely print capacity factors (or percentage operating levels), cost of electricity, and other outputs that will make it easier for the user to make exogenous feedbacks* (such as yearly reporting of peak load, energy demand, all costs, installed resources, reserve margin, carbon, sulfur, nitrogen oxides, particulates, technology mixes, and perhaps some jobs forecast, which is of major interest to much of the policy community). Perhaps *some of the hard constraints could be made softer* with the addition of penalties for exceeding various constraints. Other kinds of back-end diagnostics would also be very helpful in guiding the user into comfortable areas. One possibility is to have *the model flag the constraints that are limiting.*

In addition to back-end improvements, an area of moderate cost and high potential payoff would be the addition of a front end to the model that would *make it more user-friendly as well as increase the user understanding of the model workings.* It is almost always worthwhile to have a new programmer or systems analyst, specializing in foolproofing and user aids, spend the startup time to make the model more usable. Transparent, easily understood, and easily changed inputs, formats, menus, defaults, and other helpful devices would help make this model more accessible to analysts. A more complete and succinct disclosure of assumptions, inputs, valid application areas, limitations and concerns should be part of a user's guide or part of the automated front end information.

Another low-cost/high-payoff project would be *the investigation of the gamma mechanism* (γ). The gamma could be used to cover variations in decision-making between investor-owned and municipal utilities, variations in market allocations, and fuel diversity issues. It would be a good project to try to sort out the issues, and perhaps do some statistical fits to determine empirical values and sensitivities of gamma. The user deserves more verification of the value of gamma than "no one has ever used anything different."

TFRM needs input information from an overview model, such as the PERI REP model, that can direct the policies and operating space around which the TFRM will operate. The exception to this would be if the TFRM user is knowledgeable enough to define this policy space without an overview model. Some discussion of the use of these models in tandem is given in the documentation, but the PERI REP model is not user-friendly enough at present to offer a viable partner to the TFRM model.[10] The panel knows of no other potential overview screening model that has the renewables capabilities of the REP model. Thus, a REP type model would be helpful for screening policy options so that the TFRM could take a more detailed look at a smaller policy set. Even though the TFRM presently runs 10 regions in 10 minutes, there was talk among panel members of possibly *creating a fast switch, (or adding the capability to skip years)* which could be used to simplify the model and allow hundreds of runs to be made for certain searching problems.

The TFRM model is missing several important feedback mechanisms, which, if incorporated, would destroy the necessarily quick-and-simple nature of the model. One of these important feedbacks is the effect of the cost of electricity on the demand. A helpful addition here might be to use *a post-processor to generate the demands that would be consistent with costs of electricity in various years*. The user could then immediately see if changes in demand inputs were necessary, especially if input demands and cost-consistent demands were printed side by side.

The reliability treatment in the model could use some improvement and standardization. This would be a medium cost, high value activity. Perhaps some price tag could be associated with different levels of reliability. Reliability measures must also be responsive to the amount of intermittent renewable capacity in a region, otherwise there will be concern about the accuracy of its treatment. If REP and TFRM are to complement one another, then standardization in the approach each model takes for assessing reliability is important because each model produced significantly different resource capacity expansion plans during the simulation runs.

In the capacity expansion section of the TFRM, *the gap method, in particular, needs additional documentation*, especially with regard to its problems: occasionally choosing uneconomic technologies, periods of disequilibrium, and biases. Repowering also needs to be offered as an alternative to retirement. There was some concern in the panel that the model should try to *improve its performance and accuracy in the short run*. This might involve changes in the gap method, or more variation in the time step sizes. The fact that the capacity expansion model has no look-ahead capabilities, puts more responsibility on the model to get the short term correctly simulated. These types of enhancements would probably be of high cost and uncertain improvement.

TFRM has no real transmission modeling capability. *It is recommended that this model incorporate a technique similar to that used by the REP model.*[11] Transmission might well be the limiting factor in the siting and proliferation of renewables.

The model apparently runs with about 12 supply technologies. This would have to be increased to *20 or more supply technology slots to allow for adequate coverage of the conventional and renewable technologies*. Repowering, especially repowering with combined cycles, also needs to be offered as an alternative to retirement.

When compared to a Monte Carlo Sherali technique, the TFRM method shows about the correct capacity expansion for baseload and peaking, but *is about 10 percent low on the intermediate capacities.*[12] This might be a fault of the production costing *and should be investigated.*

There are some substantial biases in favor of building storage in the near term. *If storage becomes an important option, by itself or in concert with renewables, then the model should be checked to see if it is handling the storage option properly.*

Several seasonality concerns were expressed by the panel. Without any look-ahead capability, it would be counterproductive to put the model on a seasonal roller coaster, as opposed to the smooth annual ride. The real world has seasonality in loads, fuel costs, hydro availability, and other information. Working on incorporating such seasonalities into the model is an area which would probably be high cost and with uncertain payoff. The concern here is more one of credibility than accuracy. The industry has spent time disaggregating their models to account for seasonality, and they have had important payoffs. *Without seasonality, TFRM may be judged to be too simplistic by industry norms.* It might be possible to use the comparative studies done in California to prepare some evidence for the sufficient accuracy of the annual time steps.

Chapter 2
DEMAND AND LOAD

Chris Marnay
Center for Energy Studies
University of Texas

GLOBAL PERSPECTIVE

Forecasting customer load is the first of the three analysis steps in utility planning described in the capacity expansion section (see Chapter 3). This first step appears straightforward, but has many complexities that can trip up the analyst. Because the inability to store electricity requires that the power system meet both energy and capacity requirements, it has been traditional in the industry that both components of future loads be forecasted. Both forecasts are typically made on a ground-up approach: predicted numbers of customers, sizes of various component demands, etc., are inflated to the system level and converted into bus bar loads that the utility's assets must meet.

However, any sort of detailed production costing requires simulation of actual operations through time, usually on an hourly basis. The peak and energy forecast is, therefore, usually converted to an hour-by-hour load forecast by the adjustment of loads from an historic year that is considered in some sense typical, especially weatherwise. The peak and energy forecast defines the load factor of the system but provides no more detail on how hourly load shapes should be adjusted through time, which means most models use various heuristics to shape future loads into compliance with the forecast. One of the problems with this approach is that assumptions used in the formation of the load forecast are the least likely of all modeling assumptions to be questioned later by sensitivity analyses. Therefore, some quite questionable assumptions about future load shapes are often buried deep in data bases and never revisited. Since capacity expansion results can be quite sensitive to unit capacity factors, which directly depend on load shapes, results can be affected.

Once the customer load has been defined, the system has to be operated to meet that demand. For all but the short time-horizon-simulation, that is, less than one year, a full simulation of system operations for every hour of the year is neither feasible nor desirable. Rather, information in the load curve must be condensed into a reduced and more manageable form. Herein lies one of the great schisms in the industry between those models that reorder the loads into a load duration curve (LDC) representation and those that represent the year with short representative periods of sequential data. The later models are usually called chronological. The LDC approach permits the use of computationally efficient algorithms that approximate system operations, as are described by Sandia in the TFRM manual, while the chronological models can claim to better represent real world operational problems.[13] The magnitude of the problem at hand here precludes any load characterization beyond the simplest level. Therefore, a load duration curve approach is the most detailed analysis possible.

DEMAND AND LOAD IN TFRM

Sandia's load forecasting and load characterization are conducted in the TFRM shell and the data fed to CEPC. The origin of the data sets is Electric Power Research Institute (EPRI) profiles for six National Energy Regulatory Commission (NERC) regions, which was converted to federal region data using population ratios. The original data includes one representative week in each month, which Sandia reduced to three typical days per month, or an 864-hour representation of the year. Load forecasts are developed using a simple growth rate. The manual provides no information on how the LDC is adjusted to meet the demand forecast.

Results

Simulation Results. Sandia Laboratories did a number of simulations with varying assumptions regarding growth in demand. The results of the test case where demand growth is reduced are reasonable, with installed capacity of most assets falling dramatically. Sandia also conducted test cases in which the load was leveled and load curve variability was accentuated. Again, the simulation results seem reasonable.

Usability. The panel has not used the model and cannot comment on usability.

Recommendations. Given the questionable origin of the original load curves as adjusted NERC shapes and the sensitivity of capacity expansion results to load and capacity factors, more attention should be paid to the basic load shape. The model user, for example, should be able to change the load factor as an input.

Some capability for endogenous load forecasting should be considered. Given the usefulness of policy models for simulating extreme cases, such as the $200/ton carbon tax case, a price elasticity effect to simulate customer response would be valuable.

The flattened (or levelized) load case was motivated in part by interest in possible future load management and demand side management (DSM) implementation. To represent the current industry, these effects need to be directly represented in the model in some fashion.

Chapter 3
CAPACITY EXPANSION

James Davidson
Pacific Gas and Electric Company

Chris Marnay
Center for Energy Studies
University of Texas

GLOBAL PERSPECTIVE

At the simplest level, the problem of electric utility planning can be reduced to three steps: (1) forecasting customer demand, (2) operating existing assets to meet current load through time, and (3) constructing or contracting for new capacity additions to meet future needs. Historically, the first and third steps have been linked; however, the process of deciding what type and how much new generating resources to buy or construct, and when and where to add them within a given electric utility system, was somewhat divorced from step (2), current company operations. Capacity expansion plans were developed using crude linearized approximation tools and intuition that overlooked the fact that the value of new additions is determined in part by the nature of the preexisting capacity in place, that the interaction between new and old capacity is complex, and that upgrading the preexisting capacity is a common approach to system improvement. That the simplicity of the planning did not tie the hands of future operators was more or less a fortuitous result of the predictable demand growth, the homogeneity of the mostly thermal generation being constructed, and persistent economies of scale that mitigated the burden of overbuilding.

The nuclear difficulties of the 1970s, the exhaustion of economies of scale in thermal generation, and the recognized need to better account for the special characteristics of non-thermal resources, such as renewables, prompted the development of improved planning methods that could integrate the three steps above into one unified process. The problem immediately encountered, namely the high computing cost of planning models, still dominates work in this area today. That problem, simply stated, is that enormous computing power is needed to repeatedly simulate system operations for the long planning periods necessary in an industry in which investments can be in place for decades. The large computing requirement arises for the most part from the difficulty of storing electricity, which unlike other products cannot be produced in a smooth flow and kept on hand until demand clears the shelves. Rather, enough generating capacity must be available at all times to instantaneously serve the varying load. A conflict has, therefore, emerged between the desire to carry out the most accurate simulation possible of the system in question taking all of the effects of timing correctly into account and the need to develop many plans with long time horizons.

The EGEAS model developed by EPRI and later commercialized by Stone and Webster and the commercial product of Energy Management Associates, PROSCREEN II®, are two commonly used models in the industry that solve the planning problem in some detail using dynamic programming expansion algorithms linked to a simplified Booth-Baleriaux equivalent load duration curve production costing. This combination represents more or less the limit of current computing capability at reasonable cost, and such a combination would certainly be impossible at the regional level.

Dynamic programming solves future additions in a stepwise annual progression that finds the optimal expansion path in terms of minimum net present cost of revenue requirements. Most importantly, dynamic programming provides a mixed integer solution, which in this application simply means that units added to the system are whole practical sized units and not idealized fractions. This distinction is important because the trade-off between the ability to absorb large, lumpy capacity additions and economies of scale was a recurring problem to the industry.

The models currently under review here, then, add to a long and rich history of research and practice of electric utility capacity expansion planning. The models' authors encounter the same conflict between computing requirements and accuracy, and with a particular vengeance, because the systems under review extend to the regional level and because particular attention is focused on the renewables that have been dealt with poorly in the past.

The extension of capacity expansion planning to the regional level represents a major departure from industry traditions. The only precedents for regional level capacity expansion planning are reliability planning done for the NERC regions and planning at the power pool level. The additional problems involved in planning regionally are as follows:

(1) Industry structure is heterogeneous. It is somewhat inaccurate to assume that a regional investor-owned utility exists and that planning for the region can be based on the same principles as might be used by a single company. In areas where locally controlled municipal utilities or larger government entities are major generators, inaccuracies would be the most severe. Notably, the lower costs of debt of these institutions is likely to skew technology selection in favor of higher capital cost options.[14]

(2) In addition to industry heterogeneity, creeping deregulation is leading to a growing share of generation going to independent generators whose decision making is based on project finance and differs significantly from investor-owned equity financing.

(3) Localized constraints within service territories can be quite important in determining utility decisions, and yet these concerns are lost at the local level. A key example is availability of sites.

(4) Utility dispatch is usually solved as a company-level problem. To the extent that the sum of individual utility dispatches differs from a hypothetical regional dispatch, modeling regionally can introduce substantial differences in results.

CEPC DESCRIPTION

The objective of TFRM is straightforward but challenging, namely to develop a capacity expansion methodology that can provide reasonable results for an entire federal region to a long (30-40 years) time horizon and yet gives fair and equitable treatment to renewables. This objective must be obtained with data requirements far below those typical of single utility system models, and, like the production-costing algorithms discussed in Chapter 4, the approach must be detailed enough to appear credible to industry planners and engineers, who are a key audience for the policy pronouncements to be based on the model results.

Capacity additions are determined annually through time by a capacity expansion module. Results cannot be claimed to be globally optimal because they result from a stepwise process involving only an annual 6-year look ahead. The cost minimization is straightforward, with the sum of all levelized capital and energy costs minimized subject to the power constraint.

A key feature of the overall TFRM approach of particular importance to the capacity expansion is the separation of technologies into two categories, intermittent renewables plus storage (IRETs) and dispatchables (DTs). The procedure begins with the trial specification of a renewable storage combination. Estimated net outputs from the IRETs are subtracted from load to account for the existence of these assets. The mix of dispatchable asset additions that minimizes total cost is then found. A search of possible IRET additions is made to find the minimum.

Selection of the dispatchable mix is achieved by a heuristic process. The LDC is broken into sections in order of increasing cost. The net capacity shortfall for the year is then inserted into each break in turn. Each gap is then filled by new dispatchable capacity based on levelized cost minimization, subject to a logit function that ensures the adoption of a range of cost diverse technologies at each gap. The logit parameter γ currently used is -10. The full package of additions at the lowest cost break is adopted. Clearly, the package adopted is suboptimal in any year, but because similar packages are unlikely to be adopted in sequential years, over time the regional system approximates an optimal mix.

Results

As a general comment, the expansion planning algorithm has undergone considerable expert review prior to this panel, so further critical review can add relatively little in this area.[15] Not only has the CEPC approach been critiqued, but it has been extensively tested and compared to other methods and results, notably with the EGEAS model.[16] The extent of this prior validation is in keeping with the standards of the profession, although more comparison between models is always better than less. And, in general, the results of past validation efforts are reassuring.

Usability. The panel has not used the model.

Recommendations. There are some areas where clarification of the method is desirable.

(1) Storage Selection. Both in the initial trial IRET contribution and in the subsequent trials used in the search routine it is unclear how the split between IRETs and storage is established. The operation of storage is explained in detail in the documentation but not how the installed storage capacity is established Clearly, this represents a key analysis step, if we accept that the existence of storage in a system makes it more amenable to intermittent resources. The importance of this detail is magnified by the EGEAS validation test, in which storage was the only IRET selected in a significant amount. Given that the production costing in EGEAS is based on a simple LDC approach, its storage algorithms must be viewed with skepticism and replicating them is not necessarily an achievement worthy of merit.

(2) Search Algorithm Work.[17] The authors need to show in more detail that the search procedure used to find the minimum cost solution is accurate.

(3) Possible Biases in the Gap Method. An obvious concern of the gap method is the adoption of a full package of DT capacity additions at a certain break in the LDC. While the authors have shown that over the long term, in comparison tests with other models, the mix is comparable, the short run remains a concern. It seems that major additions at one end of the LDC could leave the regional system imbalanced for a number of years. The natural constraint on the imbalance, of course, is the limited size of the annual capacity addition. The refinement described in a March 16, 1992 memo, in which the cost of adding all new capacity at one break is compared to an alternative of adding it equally between all technology pairs, appears to be a reasonable enhancement.[18] Other alternatives along these lines should be considered. If the computing burden of more fragmented additions is too high, a more precise selection could be done for the early years only.

(4) The Golden Rule (Cost Diversity Parameter $\gamma = -10$). There needs to be more sensitivity analysis on this value, perhaps a more explicit invitation to the user to change it.

(5) Retirement Rate. CEPC uses a retirement rate for existing capacity. This is not unreasonable given the scope of the model, but forecasting retirements can often be quite tricky, and repowering should be used as an expansion alternative to mitigate the errors that would result from accelerated retirements.

(6) Decaying Site Quality. The documentation of how the model takes care of declining site quality for renewables is in the TFRM documentation.[19] That document covers wind, geothermal, and biomass resources. There is currently no modeling of the depletions of the two types of solar energy, based on the assumption that solar is widespread. With the advent of better transmission and distribution modeling, better data and modeling capabilities may be necessary on decaying site quality.

Chapter 4
DISPATCH AND PRODUCTION COSTING

James Gruhl
Gruhl Associates

MODEL DESCRIPTION

The TFRM uses a deterministic, merit-order dispatch technique on a net-load duration curve from which the intermittent renewable technologies have been removed. It is assumed that these renewables are of such low operating cost that they operate whenever possible. This is a standard technique and seems consistent with the level of detail of the input data (regional), and of the output specificity that is required of the model (regional totals, as opposed to specific unit additions).

The most complete description of the dispatching technique used is contained in volume IV of the Sandia documentation.[20] An approximate hourly load profile is compared to the intermittent sources to determine a net-load duration curve to be met by the dispatchables. Storage is accounted for after the load has been reordered from highest to lowest hourly levels. Twelve lowest-highest load pairs are created for each typical day collapsed over time and these are used to test the storage's economic viability. The loads are then collapsed over time into a load duration curve, power versus fraction of year. The technologies are then used to fill in this load duration curve in cost-merit order. After this, algorithms are used to compute energy generation and the effects of maintenance outages.

SENSITIVITY RUNS

Table 4.1 contains some of the results of sensitivity testing that the panel asked be performed by the Sandia modelers. Additional information on these model runs can be found in the Appendixes. Part of the problem with interpreting these numbers is that these are annual results. Some of the results are accumulated and shown in Table 4.2.

Table 4.1 Carbon Tax Case Studies for Years 2015 and 2030

	Costs in Billions of Dollars					Carbon Emissions in Metric Tons C	
	Capital		Operating		Total Carbon Tax		
	Total	Net	Total	Net	Tax	Total	Net
$25/Ton Carbon Tax							
Surprise							
2015	10.6	-0.6	12.4	2.0	1.2	128	-13
2030	5.4	-0.3	13.9	0.8	0.9	178	-8
No Surprise							
2015	10.6	-0.6	12.4	2.1	1.2	128	-13
2030	5.5	-0.3	13.9	0.8	0.9	178	-8
$200/Ton Carbon Tax							
Surprise							
2015	9.8	-1.4	17.0	6.6	4.0	102	-39
2030	5.1	-0.7	16.4	3.3	3.5	161	-25
No Surprise							
2015	9.7	-1.5	17.0	6.6	3.9	100	-41
2030	5.1	-0.7	16.4	3.3	3.5	161	-25

Note: "Surprise" implies that the tax was implemented without a lead time; "No Surprise" implies that the utilities were aware in 1993 of a carbon tax taking effect in 2005.

Table 4.2 Cumulative Difference Between Base Case and Various Carbon Tax Cases, 1992 to 2030

	Costs in Billions of Dollars		
	Capital	Operating	Carbon Tax
$25/Ton Carbon Tax			
Surprise	2.6	37.0	28.4
No Surprise	2.5	37.1	28.3
$200/Ton Carbon Tax			
Surprise	8.0	133.6	97.4
No Surprise	7.7	133.7	96.1

Note: "Surprise" implies that the tax was implemented without a lead time; "No Surprise" implies that the utilities were aware in 1993 of a carbon tax taking effect in 2005.

The lack of large differences between the "surprise" and "no surprise" cases are due to the fact that there is excess coal capacity in the base case. This excess capacity means that there is very little capacity decision making before the year 2005, which was the year the tax was initiated. The "surprise" cases have slightly higher capital costs and slightly higher carbon emissions, as one would expect. The fact that the cumulative operating cost is slightly smaller in the "surprise" cases, but not enough to offset higher capital costs, is plausible and thought provoking.

The TFRM results show, appropriately, that the total net cost of capital and operation with the tax is about 50 percent higher than the cost of the tax alone. This is very plausible, and shows that the model is probably reacting properly to this important input.

In some of the other sensitivity runs, there was a major difference between the REP results and the TFRM in the wind capacity. The REP model had 13 gigawatts (GW) of wind in 2030 while the TFRM had 87 GW. This was apparently caused by a miscommunication in the setup of the build constraints between the two models. The difference was caused by a 20 percent annual growth rate limit taking effect at different threshholds in the two models. This underscores the need for good input data, the need for sensitivity studies, and the need for flagging the important constraints.

As can be seen in Table 4.3, the cut in natural gas prices hit coal very hard, and raised the gas combined cycle and gas turbine capacities significantly. Wind was substantially cut, showing that the model is correctly accounting for part of the wind in the intermediate and peaking markets. Biomass goes down significantly, as also would be expected from the competition with gas combined cycles.

With the increase in the cost of capital, the coal and gas combined cycles increase capacity and usage, at the expense of the more costly wind technologies. This seems to be a very appropriate response by the model. The wind gets harder hit in the near term, 2015, than the far term, 2030, also as one might expect.

All of the dispatching and expansion seems to be appropriate in the reductions and increases in demand, except perhaps the photovoltaic and the solar thermal operating levels. These numbers are, however, very small and possibly are due to the corner effects of the dispatch approximation scheme.

The carbon tax operating levels are also very appropriate. It is even possible to see some gains that are possible in the "no surprise" case versus the "surprise" case, which is more expensive. In the \$200-per-ton carbon tax case, the coal is reduced greatly, and the combined cycle and biomass increase to make up the difference. All of these changes seem to be entirely appropriate activities in the model.

Table 4.3 Dispatch Results for Region 6 Sensitivity Runs: 2015 and 2030 (all Figures in 1000 Gigawatt hours)

Sensitivity Run	Year	Coal	Gas Combined Cycle	Gas Turbine	Wind	Photo-voltaic	Solar Thermal	Bio-mass	Geo-thermal
Baseline	2015	440	119	0.3	62	0.0	0.1	1.0	0.0
	2030	624	53	6.0	234	0.3	1.0	18.0	0.0
Gas Price 3% to 1%	2015	69	500	16.0	21	0.0	0.0	0.0	0.0
	2030	1	672	50.0	213	0.0	0.3	0.1	0.0
Capital $ 6.1% to 10%	2015	410	151	0.2	60	0.0	0.0	1.0	0.0
	2030	642	70	8.0	195	0.0	1.0	22.0	0.0
Demand Growth 2.5% to 1%	2015	273	70	0.3	60	0.0	0.1	1.0	0.0
	2030	285	36	4.0	153	0.3	2.0	9.0	0.0
Demand Growth 2.5% to 4%	2015	721	144	0.1	62	0.0	0.3	0.7	0.0
	2030	1326	95	8.0	268	0.1	4.0	33.0	0.0
$25 C tax Surprise	2015	359	199	0.2	63	0.0	0.3	1.0	0.0
	2030	595	58	5.0	253	0.0	5.0	23.0	0.0
$25 C tax No Surprise	2015	356	201	0.2	63	0.0	0.3	1.0	0.0
	2030	594	58	5.0	253	0.3	5.0	23.0	0.0
$200 C tax Surprise	2015	196	346	1.0	63	0.0	1.0	13.0	0.0
	2030	533	66	2.0	284	0.3	16.0	43.0	0.0
$200 C tax No Surprise	2015	189	351	1.0	63	0.0	1.0	15.0	0.0
	2030	531	65	2.0	284	0.2	16.0	43.0	0.0
Solar Cost Reduction	2015	439	118	0.3	62	0.3	1.0	1.0	0.0
	2030	610	54	8.0	225	6.0	18.0	16.0	0.0
Storage Option	2015	440	119	0.3	62	0.0	0.1	1.0	0.0
	2030	612	63	8.0	234	0.3	2.0	18.0	0.0
30% Less Load Variation	2015	486	74	0.0	62	0.0	0.1	1.0	0.0
	2030	647	41	3.0	226	0.2	2.0	17.0	0.0
30 % More Load Variation	2015	422	135	1.0	61	0.0	0.1	1.0	0.0
	2030	614	66	10.0	230	0.2	2.0	17.0	0.0

Note: See Appendix B for a description of sensitivity runs.

In the case of the reduction in the cost of solar thermal, the 2030 solar thermal energy increases substantially, at the expense mostly of the coal. Also, there appears to be a problem with the storage scenario. This is discussed in the storage section (Chapter 7).

The action that resulted from the change of the load shape ("load variation" in Table 4.3) occurred almost entirely within the coal and combined cycle sectors. As the load became flatter, the amount of baseload coal increased and the amount of intermediate combined cycle decreased.

CONCLUSIONS

The dispatch logic of the TFRM is a traditional, deterministic, merit-order dispatch. It seems to fit the renewables' needs impressively and reacts properly to many different sensitivity tests. The model apparently runs with about 12 supply technologies. This would have to be increased to 20 or more to allow for adequate coverage of the conventional and renewable technologies.

It seems clear that with the national screening objective, the TFRM has to operate on regions (10 versus 13 regions is a debatable issue). And with regional modeling, it seems appropriate to use a deterministic technique, rather than a laborious probabilistic method. There are some biases, which then will have to be kept in mind, and these are discussed below.

The modelers are to be commended for testing their dispatching model against a Booth-Baleriaux probabilistic method and against a Lilienthal probabilistic method.[21] The method used in the TFRM consistently "underestimates energy displacement from gas turbines."[22] Based upon a November 15, 1993 briefing, the TFRM method underestimates these peaking energies displaced by wind and photovoltaics by a factor of 4 to 6. The approximation used is probably a little crude at the peak upswings. The quantities and costs are small (about 2 percent), but still worth concern if storage or peaking renewables are being modeled, or if there is a significant quantity of renewables. The bias here is toward the use of more gas turbines and less attractive renewables.

When compared to a Monte Carlo Sherali technique, the TFRM method shows about the correct capacity expansion for baseload and peaking, but is about 10 percent low on the intermediate capacities.[23] This might be a fault of the production costing, and should be investigated.

It is clear that with a substantial amount of intermittent renewable capacity, such as wind and solar, that a system or region might need more than the usual 7 percent spinning reserve. The right value may even be as high as 15 to 20 percent. In order that the spinning reserve be tied to the renewable capacity decision, it might be necessary to construct renewable/turbine hybrids or renewable/storage hybrids.

Movements in operating levels ought to be watched as signs of needed changes in operating and capacity assumptions. It is, therefore, necessary that the operator be aware of pressures and strains within the model. For this reason, it seems very important that the model routinely output capacity factors (or percentage operating levels), cost of electricity, and other outputs that will make it easier for the user to make exogenous feedbacks.

Transmission

TFRM has no real transmission modeling capability. It is recommended that this model incorporate a technique similar to that used by the REP model.[24] TFRM simulations look reasonable and appear to be consistent with areas where there is good data, such as California.

Chapter 5
RELIABILITY

James Davidson
Pacific Gas and Electric

RELIABILITY PLANNING PRACTICES AT ELECTRIC UTILITIES

Historically, reliability planning criteria were based on engineering judgment, with the earliest criteria being deterministically based. For example, the percent reserve margin approach is the earliest and most easily computed criterion.[25] This criterion is calculated by comparing the total installed capacity at the peak load period to the peak load. Electric resource planners have used figures ranging from approximately 12 percent to 25 percent as acceptable reserve margins for planning. These rule of thumb based percentages varied from system to system depending on the characteristics of the system and the planner's and operator's experience with the dependability of the system. The disadvantage of such an approach is that it is insensitive to unit size considerations, unit forced outage rates, and factors such as load shape. A variation of this approach was also used to capture the unit size impact on reliability. This approach, referred to as "loss-of-the-largest-generating-unit method," captured the effect in the reserve margin calculation of the impact of a single unit (or sometimes 2-units combined) outage contingency by adding reserves on top of the baseline reserve target, calculated as a percent of the largest contingency compared to the peak load. This approach, while an improvement, still did not address the issues of multiple unit outages, load shapes, and forced outage rates.

Probabilistic reserve criteria were subsequently developed based on the evaluation of the "loss-of-load-probability" (LOLP) index and expected unserved energy (EUE). A commonly used yardstick in the industry today is the 1 day in 10 years LOLP. LOLP is defined as the probability that the system reserve random variable (system capacity minus load) is less than zero. EUE is basically the expected energy demand that the system capacity is unable to serve due to loss of load events. LOLP, the more commonly used measure, considers forced outage rate characteristics and size of units, multiple unit outages, and load shapes. Thus, it has substantial improvements over the more traditional deterministic methods cited above. Although often cited as a way of standardizing or comparing the reliability of power systems, LOLP can be calculated using hourly loads or daily peaks and will give different equivalent reserve margin results using each method. Another characteristic of LOLP is that the particular index used (e.g., 1 day in 10 years, 1 day in 2 years, 1 day in 50 years, etc.) still is based on the planner's and operator's judgment. Thus, the planners for systems with the same characteristics and same reliability may employ different LOLP criteria based on their judgment as to the level needed for reliable service.

Most recently, the concept of value of service based reliability is increasingly being employed at utilities. This methodology is an extension of LOLP and EUE methodologies that integrates the costs of providing a particular level of service reliability with the determination of reliability worth from the customer's point of view. This approach is critical for determining an optimal reserve margin that minimizes total costs. As a methodology, it embodies all of the attributes of the probabilistic methods and has the added advantage of capturing the worth of reliability from the perspective of the customer.[26]

RELIABILITY PLANNING METHODOLOGY EMPLOYED IN TFRM

A key issue in the expansion planning component of the modeling process is maintaining a given level of system reliability as units of various technology types and operating characteristics are added to the system. This issue is complicated by the addition of intermittent generating resources such as wind and solar. In the past, treatment of such resources in reliability planning has ranged from assuming full capacity credit for such resources to assuming zero capacity credit. Although these assumptions clearly bound the range of possibilities, neither is satisfactory.

An improvement to such extremes is employed by the TFRM. The TFRM employs an approximate reserve margin calculation based on fitting results from a probabilistic LOLP analysis for a variety of load duration curve shapes. This was done to avoid the calculation time and complexity of performing actual LOLP analyses during the resource plan expansion process.

Specifically, an exponential equation defining a load duration curve and the relationship of the peak to minimum load and slope was assumed. The utility used in the LOLP analysis consisted of a conventional generation capacity mix representative of the United States mix of generation. The generation mix consisted of 6000 megawatts (MW) of coal (24 units, each 250 MW, 0.963 availability), 2550 MW of nuclear (3 units, each 850 MW, 0.908 availability), 3600 MW of combined cycle (24 units, each 150 MW, 0.945 availability), and 1350 MW of combustion turbine (27 units, each 50 MW, 0.965 availability).[27] In this instance, the mix (in percent of installed capacity) was approximately the following:

Coal	44 %
Nuclear	19 %
Combined cycle	27 %
Combustion turbine	10 %

A parametric analysis for LOLP was done with various peak to minimum load relationships (from 0.4 to 1.0) and slopes of the load duration curve (to capture needle-peak effects). The peak load was then adjusted, as needed, to determine the amount of capacity needed to satisfy a

0.0002 LOLP. From these data, a correlation of reserve margin to load factor was calculated. Specifically, the relationship used to represent the required value of modified reserve margin is:

$$r = 1 + .25\,(\Lambda_a/\Lambda)^{2.7}$$

where Λ_a is the utility's average load and Λ is the utility's peak load in kW.[28] This algorithm is intended to substitute for and approximate an LOLP analysis. The correlation is not strong, but was deemed adequate by Sandia because "For all of the load curve shapes we tried, when Λ_a approached Λ, modified reserve margin, r, always approached 1.25, which was used as an upper bound."[29] As applied in the expansion algorithm, the net peak load (e.g., after netting out the intermittent resources such as wind by treating them as a negative load) is multiplied by the modified reserve margin.

COMMENTS

As stated above, Sandia's approach to reliability for intermittent resources is an improvement over approaches that either assume full capacity credit or no capacity credit for intermittent resources such as wind. There are, however, some areas of concern in Sandia's approach (several of which they have already noted in their description of the modeling process).

The first area of concern is the treatment of intermittent resources as negative loads. An earlier review of the CEPC model, as noted by Sandia in Appendix B of volume IV, identified the treatment of intermittent resources as negative loads as a possible concern due to the fact that such treatment may overvalue intermittent capacity. Sandia performed some analysis that verified this concern and demonstrated that over valuation is not an issue at up to 5 percent penetration, but becomes significant at greater than 10 percent penetration. Although this concern was addressed, and a possible fix suggested (page B-8), the issue still remains unresolved in this model. It is all the more important to fully determine the cumulative error of this type of approach on reliability and capacity expansion since the resource expansion plan developed by this model incorporates almost 29 percent wind (by capacity) and 23 percent wind (by energy). The resource plans developed using such an approach may underrepresent the amount of combustion turbine capacity that needs to be added to the system, and thus underrepresent the costs of a resource plan that incorporates a substantial amount of intermittent resources.

A second area of concern is the assumption of the conventional generation capacity mix. Although Sandia applied their results to a Pacific Gas and Electric (PG&E) load profile and found the results fitted the curve, the whole calibration of the curve may be off from region to region. This is because the conventional generation mix assumed is not representative of any particular region, especially regions with substantial hydroelectric resources or conventional oil/ gas steam generation resources. The availability factors assumed for the representative utility are rather high (for a system as a whole), and the number of generating units is large. This could tend to result in a bias toward lower reserve margins than appropriate for some regions. Further, the resource mix does not contain any hydroelectric facilities that are energy limited, which could also result in an understatement of needed reserve margins.

Finally, the reliability approach taken by Sandia does not capture unit size and forced outage rate characteristics of units added to the base generation mix. The unit size impacts would generally tend to favor wind and some other intermittent resources that improve LOLP because of their small unit size. Outage rate characteristics would generally tend to favor more conventional resources than intermittent resources.

CONCLUSION AND RECOMMENDATION

Sandia's approach to reliability planning is creative and is an improvement over approaches that either give no capacity credit or full capacity credit to intermittent resources such as wind. However, there are weaknesses in the model that have been identified such as the treatment of intermittent renewable energy as negative load, the use of one conventional generating resource mix to represent all regions, and the failure to capture unit size and outage characteristics. Some of these weaknesses may offset others, but to what extent is unknown. Clearly, the model's base-case runs show a significant penetration of intermittent technologies (principally wind) that borders on implausibility for an operational electric supply system. Therefore, it is recommended that the following study be undertaken: test the built out resource plans from this model against a detailed production simulation model and a detailed LOLP model. This will help ascertain whether Sandia's model captures the operational and reserve margin costs of high penetrations of renewable resources.

Chapter 6
TREATMENT OF RENEWABLES AND POLICY ISSUES

Samuel Baldwin
Office of Technology Assessment
U.S. Congress

GLOBAL PERSPECTIVE

Incorporating renewable energy technologies (RETs) into utility planning and operations raises a variety of issues, including: (1) the availability of the renewable resource; (2) the cost and performance of the RET and the potential to reduce its cost over time; (3) the dispatchability of the RET; (4) the transmission and distribution impacts of the RET; and (5) the impact of various policy instruments on market penetration by RETs.

Resources

Renewable energy resources vary widely across the United States. Overall, wind resources are greatest in the belt from North Dakota to Texas and scattered mountain or coastal areas in the West and East; biomass resources are greatest across the eastern half of the United States and parts of the West; geothermal resources are primarily limited to particular locations in the West; hydro resources are largely in the West, but face increasing environmental constraints; and solar resources are widely available but best across the Southwest. Some of these resources are highly site dependent and variable.

Cost and Performance

The cost of several RETs dropped sharply and performance improved during the past 10-15 years. Wind electricity costs, for example, dropped by more than ten times. Continuing technological advances for these and other RETs (such as biomass) will further reduce costs. At least as important for future cost reductions is realizing manufacturing economies of scale and learning.

Dispatchability

Geothermal is operated as baseload, biomass and hydro are dispatchable, and wind and solar are intermittent. Use of intermittent resources can offset fuel use by conventional generating technologies; intermittent renewable energy may also offset capacity, depending on: (1) the match between the renewable resource and the local utility loads — such as solar matching summer air conditioning demands; (2) the level of intermittent renewable energy technology (IRET) penetration into the grid — high levels of penetration tend to saturate their potential capacity credit; (3) geographic diversity — gathering renewable energy over a large area may moderate local fluctuations (but may increase transmission and distribution [T&D] requirements); (4) the correlation between different renewable energy resources — wind and solar, for example, may complement each other in some areas and help provide capacity value.

Transmission and Distribution

Renewables have mixed impacts on T&D requirements. Renewables such as geothermal, biomass, solar thermal, and wind are generally relatively large installations (typically 10 to 100 MW or so) and are often located at a distance from populated areas. Consequently, these systems will often require long, high power T&D extensions to carry power to the utility grid. In contrast, small scale renewables such as PVs or dish-stirling can potentially be widely dispersed within the utility service area and may then be able to reduce peak loading within the T&D system.

POLICY TOOLS

A variety of policy instruments are in use or are being considered or discussed as means of encouraging market penetration by RETs. These include the following:

- Tax policy
  - Accelerated depreciation
  - Investment tax credits
  - Energy production tax credits
  - Property taxes
  - Externality taxes
- Green policies
  - Green pricing
  - Green competitive set-asides
  - Green rates-of-return to utility investors
- Miscellaneous policies

It would be useful to understand the impact of these and other policies on: RET capacity expansion, electricity generation, emissions, ratepayer costs, tax revenues, and other factors.

TFRM DESCRIPTION AND RECOMMENDATIONS

The TFRM addresses each of the above considerations at varying levels. Dispatch and capacity expansion are discussed in Chapters 3 and 4 of this report.

Resources

The TFRM does an excellent job of characterizing (and documenting) various renewable resources, parameterizing them, and recognizing their limitations. The parameters may need some revision, however. Biomass resources, for example, may be somewhat larger than those estimated here. The reference capacity for biomass is 56 GW or about 4 exa joule (EJ).[30] Modeling currently underway at the University of Tennessee to develop regional biomass supply curves for energy crops suggests a potential of perhaps 15 EJ at costs under $2.50/giga joule (GJ). Crop productivity will likely increase significantly over time, which will increase the resource base and lower these costs. Such changes appear to be easily incorporated in the model as new resource data becomes available.

Cost and Performance

Cost and performance projections seem reasonable overall but may also need some revision in particular cases. Wind capital costs, for example, are now well below the value generated by the parameters listed in Table 9 of Volume III. Technology costs also appear to have been set independently of market growth. This ignores the potential for capturing economies of scale and learning. Future implementations might modify the current time driven cost and performance improvements with consideration of the cumulative production volume through a learning curve.

T&D

TFRM does not really address T&D. Future implementations may want to consider T&D issues generally, as well as the T&D-specific nature of various renewable energy technologies, varying from long distance T&D for large biomass or wind power plants to the distributed utility concept.

Policy

The TFRM can address a variety of policy issues, including depreciation schedules, investment tax credits, production tax credits, property taxes, externality taxes, green policies, and others. Incorporating the impact of changes in these policies on tax revenues would also be helpful.

Chapter 7
STORAGE

James Gruhl
Gruhl Associates

MODEL DESCRIPTION

As stated in the documentation:

> The use of storage is optimized to minimize the utility's operating cost. The general rule is that the operating cost of the source displaced must be greater than the operating cost, divided by storage efficiency, of the source used for recharge. To optimize storage use, the module arranges the net hourly loads for a single day from largest to smallest.[31] The load pairs are checked in order, using assumed marginal costs of energy in the two pairs. If storage makes economic sense, given the inefficiency, then it is performed. This process is nearly, but not entirely, optimum.[32]

It is not optimum because it requires integer hours of pumping and discharge.

SENSITIVITY RUNS

Unfortunately, in the comparative model runs between the TFRM and the REP model, the storage was set to zero because the REP does not handle storage. Table 7.1 shows the results of a sensitivity run that was conducted to see the effect of allowing for storage competition in the model.

Table 7.1 Dispatch Results for Region VI (Southwest) Storage Runs: 2015 and 2030 (all Figures in KGWhr)

Sensitivity Run	Year	Coal	Gas Combined Cycle	Gas Turbine	Wind	Photo-voltaic	Solar Thermal	Bio-mass	Geo-thermal
Baseline	2015	440	119	0.3	62	0.0	0.1	1.0	0.0
	2030	624	53	6.0	234	0.3	1.0	18.0	0.0
Storage	2015	440	119	0.3	62	0.0	0.1	1.0	0.0
Option	2030	612	63	8.0	234	0.3	2.0	18.0	0.0

Note: See Appendix B for a description of sensitivity runs.

The decrease in the use of baseload coal is counterintuitive, as is the increase, especially, of the peaking gas turbines. The cumulative capital costs and the cumulative operating costs are higher in this storage scenario, leading to some question about why it was built.

CONCLUSIONS

In the comparison of the TFRM with EGEAS, the TFRM builds about 80 percent more pumped storage in the year 2006 but is about 10 percent lower by the year 2012.[33] This should be considered to be a bias in favor of building storage in the near term.

Storage may not be an important issue to get correct if the questions revolve around renewables. However, there are two indications from the storage model run that storage may not be handled properly in the model. With the use of storage, the decrease in the use of baseload coal is counterintuitive, as is the increase, especially, of the peaking gas turbines. The modelers have looked at this and determined that this behavior is appropriate since, given the numbers in the trial run, coal is competitive with combined cycle at capacity factors as low as 25 percent. Hydro-storage is added in the storage scenario that was run, but the cumulative capital costs and the cumulative operating costs are higher, leading to some question about why it was built. The explanation for this problem seems to come from the fact that, although not optimal in the current year, storage is economic in the long-term average. It is impressive that the model can capture such subtle concepts.

Chapter 8
Financial and Regulatory Issues

Edward Kahn
University-Wide Energy Research Group
University of California, Berkeley

MODEL DESCRIPTION

The TFRM uses levelized constant dollar costs based on rate base regulation economics for investor-owned utilities to characterize the institutional setting in which costs are incurred, and to track scenario costs. Levelized costs include both capital-related costs and operating costs. This approach incorporates taxes (and tax credits), financing, depreciation and inflation into the analysis. The utility is treated as a business firm that pays taxes on profits and can deduct interest expenses, depreciation, and operating costs from taxable income.

The mechanical procedures for performing these calculations are well known and reasonably standardized. The TFRM documentation references the Electric Power Research Institute's Technical Assessment Guide (1991).[34] Regional and corporate variation in depreciation and tax accounting procedures are to be expected, but they are probably small effects.

There are two larger effects. One is the difference between investor-owned utilities (IOU) under ratebase regulation and publicly owned utilities (POU). The second is the difference between utility ownership and private power finance, or non-utility generator (NUG) ownership.

IOUs have a substantially higher cost of capital than POUs. This is due to the availability of tax-exempt financing for POUs and their all debt capital structure, compared to the IOU requirement of common equity capital subject to income taxes and higher cost corporate debt. The difference in cost of capital can easily be 50 percent.[35] By modeling the capital cost component of levelized cost in the IOU framework, these models create an upward bias industry-wide. Approximately 75 percent of the electricity industry is represented by IOUs, so this is not a very large effect.

The difference between NUG and utility finance is probably more significant. NUGs use project finance structure in most cases. This means that there is no financial recourse to any corporate entity, and the projects must have positive cash flow when they begin to operate. There is probably not a large difference in the capital charges between a NUG project finance structure and the corporate framework. The NUGs probably have a slightly lower cost of capital than IOUs, but typically face larger amortization burdens. The cash flow implications of these differences result in approximately equal capital charges. There may be, however, a bigger difference in risk-bearing potential. The viability of project finance structures are very sensitive to revenue uncertainty. Because the amount of debt that projects can bear is limited by the fixed debt service obligations, uncertainty in revenue may mean that such financing will not be available.

The principle uncertainty for renewable energy technologies at the financing stage is technology performance. This is not accounted for in the TFRM.

Chapter 9
ENVIRONMENTAL EFFECTS

Chris Marnay
Center for Energy Studies
University of Texas

GLOBAL PERSPECTIVE

The inclusion of environmental effects in various production costing and utility planning models reaches one of three levels.

At the first level of implementation, the model does no more than keep track of estimated environmental insults. Emissions are usually based on simple emissions factors but a functional representation is often used for pollutants whose creation varies nonlinearly with output, such as NOX. Since production costing can be considered a simple accounting exercise in which the primary function of the model is to keep track of the numerous details of power system operations that must be taken into account in planning, environmental accounting readily fits into this general framework. The environmental consequences of utility operations are tracked along with the other effects. Most production-cost models today can at least estimate air emissions of SO_2, NOX, and VOC's, and often CO_2. Tracking of other environmental effects, such as land use, is less common.

At the second level, emissions are not only tracked, but are recognized as constraints on generation. The constraints have two common forms. The first is the capability to tax pollution, usually through the inclusion of a simple adder to generation costs. The second form attempts to replicate actual emissions regulations. For example, certain pollutants are subject to emissions ceilings, either within a geographical boundary or over a time period. These are real limits that change the way utilities operate and should be represented in models.

At the third level, models can be built that simulate operations under environmental as well as economic objectives, or under a combination of the two. Dispatch can be simulated as SO_2 emissions minimizing, for example. While such simulation may sound unrealistic, a total environmental dispatch capability is often a useful tool in policy analysis where the question often being asked is of the form, what is the maximum possible effect of this proposed policy instrument. The most commonly used production-cost model in the industry, PROMOD III®, a product of Energy Management Associates, incorporates such an environmental dispatch capability for the major air pollutants.

CEPC AND ENVIRONMENTAL EFFECTS

The CEPC module does not appear to track environmental effects in any consistent or comprehensive fashion. Normal consideration of environmental effects is only at the first level above, although Sandia did conduct the carbon tax case (see Appendix B), which would be at the second level.

Results

Simulations. The CEPC was used in the 4 carbon tax policy cases requested by the panel. The results reported are reasonable and consistent.

Recommendations. The scant implementation of environmental effects is clearly an area of major deficiency in the model. Not only are environmental objectives increasingly important in making policies, but given the renewables focus of the models, environmental considerations should have major prominence. More specifically:

(1) The documentation contains virtually no mention of environmental effects. The documentation should be expanded to discuss environmental issues and offer the user guidance on model use.

(2) The model should report emissions of at least the criteria air pollutants and permit the use of adders or taxes on emissions of all those pollutants. Given the importance of land use concerns for some renewables, these effects also should be tracked.

(3) The model should be enhanced to ensure that the SO_2 emissions ceilings of the Clean Air Act restrictions cannot be exceeded. This may at first be possible only region by region, but the ceilings cannot be ignored.

APPENDIX A

Appendix A
COMMENTS ON MODEL TEST RESULTS AND COMPARATIVE RESULTS

Following is a commentary on the results from the specified scenarios and cases that were run with Sandia's TFRM and PERI's REP model.

SCENARIOS

Based on a quick examination of the results, each model by itself appears to be performing reasonably relative to the base case. For lower gas price forecasts, the amount of combined cycle and combined turbine (CT) installed generation increases, while coal and wind decrease in the Sandia model. In PERI's model, the changes in installed generation were rather muted. Installed coal resources decreased and combined cycle capacity increased, as expected. However, CT capacity remained essentially the same, and wind capacity increased slightly. I would have expected greater changes in installed capacity in PERI's model in response to the change in gas prices. For higher cost of capital, both models illustrate the impact on the higher capital cost plants by showing a reduction in coal, wind and solar, and slight increases in the installed capacity of combined cycle and CT generation.

A comparison of the results between models, however, raises some significant issues that need to be resolved before REP, for example, can work as a screening model for TFRM. The most significant issue is that each model builds out resource plans that differ by 30 percent or more in installed capacity. And, within a given case or scenario, the installed capacities of the technologies differ substantially. For energy generation, the differences are less than 5 percent, although the technologies vary substantially between the models.

Conclusion

The output of the Sandia TFRM appears responsive to changes in the key parameters of fuel price and capital cost. However, the response, as measured by changes in the resource mix, appears exaggerated. The output of PERI's REP model is also responsive but appears muted in its response. While time does not permit a detailed diagnostic to be run on the inter-model results, the results suggest that more development on the reliability/capacity expansion algorithms is warranted before these models can be relied upon to support policy development for renewable energy technologies. Unless the reliability and expansion algorithms are standardized for each model, the models are unlikely to complement each other.

POLICY RUNS

Both models responded reasonably to the specified policy runs for load growth sensitivity. It is unfortunate that cross model comparisons are not possible for these cases, since Sandia used

Region VI (Southwest) data and PERI appears to have used data that aggregated all 10 regions. For the high growth case, such a comparison might have further highlighted the need for a more standardized reliability and expansion algorithm to be used by each model.

With respect to policy runs on carbon taxes, Sandia's model appears to respond reasonably as measured by changes in the resource mix. Of continuing concern, however, is the absolute amount of intermittent resources (e.g., wind) included in the resource mix. The amount appears excessive when considered from a system operation and reliability perspective. PERI's model behaves similarly but does not have excessive amounts of intermittent resources in the mix. PERI also appears not to have constrained nuclear development, which increases in the high carbon tax scenario as expected.

MODEL-SPECIFIC RUNS

Sandia's model-specific runs were: (1) a solar accelerated-cost reduction case; (2) a storage competition case; (3) a 30 percent reduction in load variability case; and (4) a 30 percent increase in load variability case. Performance of the model appears reasonable for all cases with the continued exception of wind. The percentage of wind in the resource mix remains unreasonably high from a system operation perspective. However, this is not a criticism of the performance of the models under these model-specific runs.

PERI's model-specific runs were: (1) EAR/FAR tests;[36] (2) Risk Premium tests; (3) Grid Limit tests; (4) Transmission and Distribution Costs tests; (5) Manufacturing Capability tests; and (6) manufacturing scale economies for renewable energy technology equipment tests.

REP performed sensitivity runs on the FAR parameter. The tests consisted of changes in the shape of the curve from the hyperbolic function in the base case to two extreme linear cases. In test case one, market acceptance is zero whenever the renewable energy cost is equal or greater than the conventional alternative and becomes 100 percent when renewable energy is less expensive. In test case two, by contrast, the linear relationship is stretched out so that 50/50 market share is achieved when costs are equal, zero occurs when renewable costs are twice those of conventional, and 100 percent when renewable costs are half those of conventional.

The results of these tests are more significant in the intermediate years than in the final years of the simulations; that is, changes in the FAR representation affect the timing of additions more than ultimate market share. Test case one shows substantially lower market penetration for wind turbines in the years 2000 and 2005 than either the base case or the test case two. By 2010, however, a large increase occurs, followed by an even larger one in 2015. PERI argues that part of the large delayed effect in test case one results from the interaction of technology progress over the time period with the retarded early penetration; there are more attractive resources left for new efficient technology in this case than in the other two.[37] Test case two shows much slower and more even market penetration than either case one or the base case. The base case also has something of the bang bang technology adoption logic illustrated in the extreme by test case one.

APPENDIX B

Appendix B
TASK DESCRIPTION FOR RENEWABLE ENERGY MODEL REVIEW

The following describes the support work to be completed by Sandia National Laboratories (SNL) and Princeton Economic Research Inc. (PERI). These tasks fall into three basic areas:

(1) Standardized model runs to compare model compatibility

(2) Policy model runs to gauge model sensitivity to various policy variables

(3) Model specific runs to capture unique model attributes

Base case: unless otherwise stated, the base case is defined as 3 percent annual increase in the real price of oil and gas, 0 percent annual increase in the real price of coal, 6.1 percent cost of borrowing, 2.5 percent annual growth in demand, and the same efficiency improvements for RETs and conventionals.

STANDARDIZED MODEL RUNS

The standardized model runs are for the purpose of comparing the model output of the PERI and SNL models with each other. To the extent possible, the PERI and SNL runs must use identical assumptions, data, time periods, discount rate, and model features. Unless otherwise stated, this standardization will occur through discussions between SNL and PERI, and this standardization will be documented.

The model will compare three scenarios:

(1) Base case

(2) Reduction in oil and gas real price increase to 1 percent per annum (0 percent for coal)

(3) Increase in the cost of capital (cost of borrowing assumptions 6.1 percent from base case to 10 percent for scenario)

These three scenarios will be examined under the following restrictions:

(1) Simulation of Region VI data only (Southwest)

(2) Technologies limited to wind, solar thermal, biomass, photovoltaic (PV), coal, combined cycle, and gas turbine (assume nuclear capacity unchanged throughout scenario)

(3) Assume same efficiency improvements in conventionals and RETs during period of analysis

These results will be reported in the following format:

(1) Capacity and generation will be reported by technology by cumulative megawatts and gigawatt hours.

(2) Time period of analysis will be 1992 to 2030.

(3) To the extent possible, graphics will be used to report results (with data tab backups).

(4) If possible, report the constant dollar cost of capacity expansion and operation by technology.

The results of these model runs will be delivered to ORISE no later than December 8, 1993. ORISE will distribute the results to the panelists and DOE.

POLICY RUNS

The policy runs will not require the PERI and SNL models to standardize assumptions, parameters, etc., limit technologies, regions or other variables. These runs are to test the model sensitivity to various policy variables using the full power of the models.

The following two policy issues will be examined and compared to a base case (base case assumes zero carbon tax):

(1) Carbon tax: The carbon tax analysis will consist of four scenarios.[38] The key variables to be evaluated are ratepayer cost, cost to the Federal Government, and annual carbon emissions (in short tons). The four scenarios are:

   A. Carbon tax $25 per ton carbon (C) in 2005 (no surprise)

   B. Carbon tax $25 per ton C in 2005 (surprise)

   C. Carbon tax $200 per ton C in 2005 (no surprise)

   D. Carbon tax $200 per ton C in 2005 (surprise)

(2) Comparison to base case of assumptions that demand growth is A) 1 percent per annum, B) 4 percent per annum.

The reporting format will be the same as for the standardized model runs. Results are to be delivered to ORISE no later than December 15, 1993 for distribution to DOE and panelists.

MODEL-SPECIFIC RUNS: PERI

Using their judgement regarding data values and assumptions, PERI will examine the sensitivity of their model to the following variables:

EAR/FAR

risk premium

grid limit

transmission and distribution costs

manufacturing capacity for RET equipment (quantity)

manufacturing scale economies for RET equipment (cost)

In addition, PERI is invited to provide the panel with information regarding their model's "best trick," i.e., counterintuitive results that can be explained by model logic; innovative approaches to problems, etc.

There is no standard format for reporting the results of these runs; however, the results of the sensitivity analysis should be summarized for the panel (graphics with backup tabs preferred). Results are to be delivered to ORISE no later than December 15, 1993 for distribution to DOE and panelists.

MODEL-SPECIFIC RUNS: SANDIA

Using their judgment regarding data values and assumptions, Sandia will examine the sensitivity of their model to the following scenarios:

(1) Comparison runs with and without storage

(2) Comparison of changes in load duration curve:

   A. Leveling of load duration curve

   B. Accentuation of load duration curve variability

(3) Model sensitivity to changes in the capital costs of renewable energy technology

In addition, Sandia is invited to provide the panel with information regarding their model's "best trick," i.e., counterintuitive results that can be explained by model logic; innovative approaches to problems, etc.

There is no standard format for reporting the results of these runs; however the results of the above analysis should be summarized for the Panel (graphics with backup tabs preferred). Results are to be delivered to ORISE no later than December 15, 1993 for distribution to DOE and panelists.

APPENDIX C

Appendix C
Comments on the Panel's Review

From Mike Edenburn, Sandia National Laboratories
February 14, 1994

The panel has done an excellent job of understanding and communicating the TFRM model's strengths and weaknesses. In general, the panel's findings and recommendations are very constructive and valuable. In this appendix we will comment on some of the review's findings and recommendations. These comments are intended to provide clarification on the model's present or future capabilities.

GENERAL

Input to TFRM is not user friendly. We would like very much to make the model much more user friendly, and this will not be difficult. Ultimately, it is possible that input to the model can be menu driven.

The review suggests that a different region definition may be better than ten federal regions. The model has no inherent preference for using a particular regional breakdown. A new breakdown would require developing new data and finding a new name for the model.

The review indicates that it will be helpful to have more information from the model such as operating costs, consumer prices, peak demands, energy demand, limiting constraints, etc. We can add the capability for some of these parameters directly to the model and others can be generated by a post processor. For the trial runs, we developed a post processor which listed annual carbon emissions, carbon tax revenue, capital cost, operating cost, and changes from the baseline case. Doing the same for other parameters is relatively easy.

DEMAND AND LOAD

The review recommends that the model develop a capability to endogenously alter the load curve to account for price elasticity or other factors. This would be relatively easy to do. We can add the capability to adjust loads annually based on time or any parameter computed in the model such as electricity cost. If electricity price (instead of cost) is desired, algorithms can be developed to calculate price from costs.

CAPACITY EXPANSION

Our method of selecting a new storage capacity to install was apparently not clear. Storage is treated the same as an intermittent renewable. We guess an initial capacity and use a search procedure to find the capacity, which results in a minimum-cost system. If we have wind, photovoltaic, solar thermal, and storage, the search is four-dimensional. Storage is one of the four dimensions.

The review suggested that the model should include repowering. We believe that adding repowering, which keys off of retiring plants, will be tricky but possible.

The model does not currently consider transmission and distribution. The cost of transmission and distribution can be easily added if it is a fixed value for each generation technology. If it varies from location to location, we may be able treat it through the logit apportionment, which allows for price diversity.

Our optimization search for new intermittent source capacity is not immune to local minimums. We may be able to make it less immune at the expense of added computation time. Local minimums are theoretically possible, but we do not know if they are a significant problem in TFRM.

DISPATCH AND PRODUCTION COSTING

There was some misunderstanding about grid limits. The model does not use grid limits. For the case runs, we used a 20 percent growth limit for renewables. Added new capacity was allowed to increase by 20 percent every year over the previous largest capacity addition. This was done to represent limits to manufacturing expansion. Except for renewable growth rate limits, economics and generation characteristics determined capacity expansion results, not constraints or ratios. TFRM's optimization method is not inherently constrained by limits, as are many methods that depend on searching boundaries.

The review suggests that seasonal fuel costs be investigated. We can investigate the importance of seasonal fuel costs with tools developed to evaluate our dispatch algorithms. Adding a seasonal capability to the model would require performing four dispatches where we presently perform one. It would require significant computation time, and consequently, reduce the model's effectiveness as a policy analysis tool.

RELIABILITY

We do not capture unit size related to reliability, but we do try to capture outage characteristics. All dispatchable plants have a forced outage rate which enters into our reserve margin calculation. We do this by basing our reserve margin for net peak load on derated capacity (not the standard definition of reserve margin). If we calculate a reserve margin of 10 percent, the real reserve margin will be higher (maybe 20 percent) depending on the forced outage rates for the dispatchable sources. We based our reserve margin on a standard utility. If the dispatchable capacity composition in a region is much different than the standard, our reserve margin may be in error.

The TFRM model computes capacity value inside the model, not outside. It is not a specific calculation but is an inherent result of treating intermittent generation as a negative load and meeting the net load with dispatchable capacity.

Reviewer comments imply that treating intermittent generation as a negative load overstates the capacity value of an intermittent source. If the load data and intermittent generation data both contain a statistically representative sample of long-term data, treating intermittent generation as a negative load will not overstate capacity value. Capacity value is overstated when we try to reduce the data to a smaller set which is too small to be statistically representative. The problem is using too small a data set, not treating intermittent generation as a negative load. Of course, using a small data set reduces computation time.

We use a single meteorological site (except for region IX wind) to get a time dependent intermittent source generation profile for the whole region. This will overestimate capacity value if the site has a better-than-average correlation with the load, and it will underestimate capacity value if the site has a less-than-average correlation. In our data, there are many near peak load points. The intermittent generation values associated with each load point are somewhat random because they were derived from meteorological data which is somewhat random. We believe that our data selection process incorporates sufficient randomness to avoid greatly overestimating capacity values. Modest overestimates or underestimates, however, are likely.

Our data selection process uses some averaging, which will give a systematic overestimate of capacity value for an intermittent source. We have attempted to quantify this overestimate in Appendix B of the CEPC report (Volume IV). We estimate, based on a test case, that limiting data to 3 days per month results in overestimating capacity value by 15 percent when rated power for the intermittent source is 25 percent of peak load (this is a large penetration). We believe that a 15 percent overestimate at high penetration is acceptable and much better than for previous policy analysis tools, which assume capacity value is either 0 percent or 100 percent. If 15 percent is not acceptable, for the application being considered, our data selection process can be modified to reduce the error at the expense of increasing computation time.

TREATMENT OF RENEWABLES

The review points out the importance of using production volume feedback to determine cost and performance improvements for renewables. We agree. We believe that tying renewable cost to a production level is important and relatively easy to do.

The review apparently missed our documentation for decay of site quality (resource depletion), which is described in our TFRM document (Volume III). In that document, we cover wind, geothermal, and biomass. We do not model resource depletion for photovoltaics or solar thermal because the solar resource is wide spread. This may change if transmission and distribution concerns cause us to look for sites near loads.

STORAGE

The review stated that the decrease in base capacity, when storage is added, is counterintuitive, and indeed it is. This was explained in the notes accompanying the storage-case results. For the cost parameters we used, coal is competitive with combined cycle at capacity factors as low as 25 percent (we do not normally expect coal to compete at such low capacity factors). Storage levels the load duration curve and reduces the total capacity associated with a capacity factor above 25 percent. Hence, when storage is added, coal capacity decreases. This is consistent with the circumstances found in the trial run.

The storage case appears to have higher cumulative costs than the base case, which evokes the question of why the model elected to install storage. The costs printed out are current costs. The decision to add storage (or any other capacity) is based on future levelized capital and operating costs. It is quite possible that adding storage increases current costs in the near term but will decrease future costs. Since storage is added in the last 15 years of the trial case, cost savings may not show up. It is not clear that the model is in error; nor is it clear that it is correct. Checking it more thoroughly is a reasonable thing to do.

FINANCIAL AND REGULATORY ISSUES

The review points out the differences among IOUs, POUs, and NUGs. The test runs of TFRM did not specifically account for their differences. We believe that most of the differences between IOUs and NUGs can be accommodated in the economic processor by assigning different economic parameters to the same technology. For example, the model may consider an IOU combined cycle plant with one set of economic parameters to compete with a NUG combined cycle plant with another set of economic parameters. The two types of plants are considered to be separate technologies. Since these differences can be handled by increasing the number of competing technologies, computation time will increase. The model does not specifically handle POUs and IOUs at the same time because regions are not divided into a POU part and a IOU part. If we conclude that POUs must be treated separately, regions can be divided into IOU and POU subregions at the expense of greater computation time.

ENVIRONMENTAL EFFECTS

The review implies that TFRM can handle carbon emissions and taxes but not other emissions. The model can handle any quantifiable emissions or taxes on emissions. Carbon was the example used to demonstrate the model's capabilities. The model does not presently consider emission ceilings. The idea of using surrogate taxes to approximate a ceiling may work. The model does a minimum cost dispatch, not an environmental dispatch; however, if operation taxes or costs are added for emissions, the model will adjust the merit order to disfavor emitters.

The carbon generation numbers we used for the test cases do include fuel production. We did not include construction carbon, but can if it is important.

ENDNOTES

1. Energy Information Administration, U.S. Department of Energy, *Annual Energy Outlook 1993 With Projections to 2010*, DOE/EIA-0383(93) (Washington, DC: U.S. Department of Energy, 1993), p. 4.

2. See Sandia National Laboratories Strategic Technologies, "Tools for Renewable Energy Policy Analysis" Draft Report SAND92-2558, 5 volumes, (Albuquerque, New Mexico: Sandia National Laboratories, 1993).

3. For detailed documentation, see Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volumes III and IV.

4. EGEAS is the Electric Generation Expansion Analysis System, a product of Stone and Webster, Inc.; PROVIEW® is a proprietary product of Energy Management Associates.

5. See Electric Power Research Institute, *Electric Generation Expansion Analysis* EPRI EL-2561 (Palo Alto, CA: Electric Power Research Institute, 1982).

6. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume IV, Appendix B.

7. *Ibid*, p. B-10.

8. *Ibid*, Appendix D.

9. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis", volume V, p. 39.

10. See Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume I, Overview.

11. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V, p. 39.

12. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume IV, Appendix B.

13. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume III, pp. 3-4.

14. Please see Chapter 8 for discussion of this point.

15. See Sandia Laboratories, "Tools for Renewable Energy Policy Analysis," volume IV, Appendix B.

16. The capacity expansion module has also been validated with the Sherali method in Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis, volume IV, Appendix C. See also H.D. Sherali, "A Feasible Direction Algorithm for a Capacity Expansion Problem", *European Journal of Operational Research*, volume 19 (1985), pp. 345-61.

17. The documentation references a "pattern search" procedure. See K.A. Haskell and R.E. Jones, *Brief Instructions for Using the Sandia Mathematical Subroutine Library (Version 7.2)* (Sandia National Laboratories, 1978).

18. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume IV, page B-2.

19. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume III.

20. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume IV, pp. 5-10, and Appendixes.

21. *Ibid*, Appendix B.

22. *Ibid*, Appendix B, p. B-10.

23. *Ibid*, Appendix B.

24. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V, p. 39.

25. See Harry G. Stoll, *Least-Cost Electric Utility Planning* (New York: John Wiley and Sons, 1989), p. 322.

26. See Sandra Burns and George Gross, "Value of Service Reliability," in *IEEE Transactions on Power Systems*, volume 5, number 3, August 1990.

27. Personal communication with Michael W. Edenburn of Sandia National Laboratories, December 1993.

28. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume IV, p. 12.

29. Personal communication with Edenburn.

30. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume III, Table 7.

31. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume IV, p. 6.

32. *Ibid.*

33. *Ibid*, Appendix D.

34. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume III, p. 14.

35. Suppose the IOU had 50 percent equity and 50 percent debt in its capital structure, and that the cost of equity capital were 11 percent and the cost of debt were 8 percent. This would give a weighted cost of capital of 9.5 percent. The income taxes on common equity, both state and federal might be 40 percent, which would add 2.2 percent, for a total cost of 11.7 percent. By contrast tax-exempt bonds sold by POUs might cost 7 percent. If the IOU had less equity and more debt, the difference would be smaller.

36. EAR (economic attractiveness ratio) summarizes the relationship of costs of renewable to conventional technology; FAR (Financial Acceptance Relationships) is a parameter to incorporate financial risk.

37. Memorandum from Frank Brock and Tom Schweizer of Princeton Economic Research Inc., December 21, 1993 p. 6.

38. "Surprise" implies that the tax was implemented without a lead time; "No Surprise" implies that the utilities were aware in 1993 of a carbon tax taking effect in 2005.

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