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ORCED: A Model To Simulate the Operations and Costs of Bulk-Power Markets

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MANAGED AND OPERATED BY
LOCKHEED MARTIN ENERGY RESEARCH CORPORATION
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

ORNL-27 (3-96)

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June 1998

Sponsored by
Office of Policy, Planning, and Evaluation
U.S. Environmental Protection Agency

OAK RIDGE NATIONAL LABORATORY
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managed by
LOCKHEED MARTIN ENERGY RESEARCH CORPORATION
for the
U.S. DEPARTMENT OF ENERGY
under contract No. DE-AC05-96OR22464

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SUMMARY

Dramatic changes in the structure and operation of U.S. bulk-power markets require new analytical tools. We developed the Oak Ridge Competitive Electricity Dispatch (ORCED) model to analyze a variety of public-policy issues related to the many changes underway in the U.S. electricity industry. Such issues include:

- policy and technology options to reduce carbon emissions from electricity production;
- the effects of electricity trading between high- and low-cost regions on consumers and producers in both regions;
- the ability of the owners of certain generating units to exercise market power as functions of the transmission link between two regions and the characteristics of the generating units and loads in each region; and
- the market penetration of new energy-production and energy-use technologies and the effects of their adoption on fuel use, electricity use and costs, and carbon emissions.

ORCED treats two electrical systems connected by a single transmission link (Fig. S-1). ORCED uses two load-duration curves to represent the time-varying electricity consumption in each region. The two curves represent peak and offpeak seasons. User specification of demand elasticities permits ORCED to estimate the effects of changes in electricity price, both overall and hour by hour, on overall electricity use and load shapes.

ORCED represents the electricity supply in each region with 26 generating units. The first 25 units are characterized in terms of capacity (MW), forced- and planned-outage rates (% of year), fuel type, heat rate (Btu/kWh), variable operations and maintenance costs (¢/kWh), fixed operations and maintenance costs ($/kW-year), and annual capital costs (based on initial construction cost, year of completion, capitalization structure, and tax rates, all expressed in $/kW-year). The 26^{th} unit is considered energy-limited (e.g., a hydroelectric unit).

The two regions are connected by a single transmission link. This link is characterized by its capacity (MW), cost (¢/kWh), and losses (%).

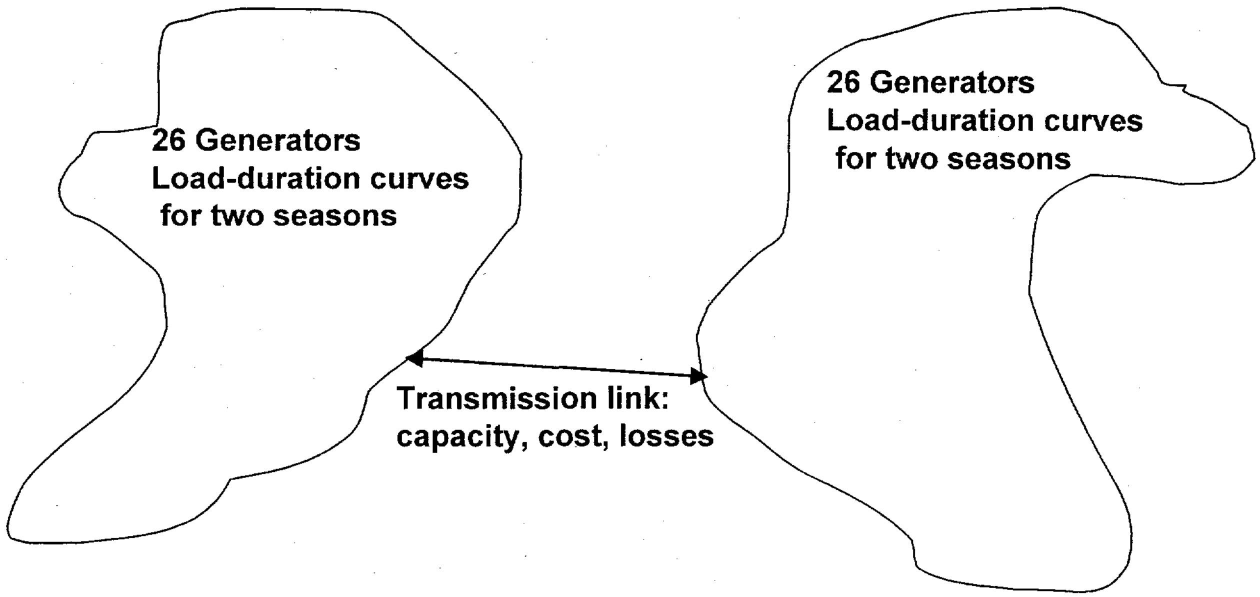

Fig. S-1. The Oak Ridge Competitive Electricity Dispatch (ORCED) model analyzes bulk-power markets for two regions connected by a single transmission link.

This report explains the inputs to, outputs from, and operation of ORCED. It also presents four examples showing applications of the model to various public-policy issues related to restructuring of the U.S. electricity industry.

LIST OF ACRONYMS

AEO97	Annual Energy Outlook 1997
A&G	Administrative and general
ECAR	East Central Area Reliability Agreement
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
LDC	Load-duration curve
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
ORCED	Oak Ridge Competitive Electricity Dispatch model
ORFIN	Oak Ridge Financial model
O&M	Operations and maintenance
PUC	Public utility commission
RTP	Real-time prices
TC	Transition cost

INTRODUCTION

Congressional passage of the Energy Policy Act of 1992 and the subsequent Orders 888 and 889 issued by the Federal Energy Regulatory Commission (FERC) signaled major changes in U.S. bulk-power structures, regulation, markets, and operations. These changes include

- much greater competition among generators;
- functional separation or deintegration of formerly vertically integrated electric utilities into separate generation, system control, and transmission entities;
- creation of independent system operators to direct the real-time operation of electrical grids to ensure nondiscriminatory access to transmission systems and to maintain reliability; and
- creation of a variety of bulk-power trading systems.

We developed a simple strategic planning model to simulate the operations of, and the resultant prices and producer profits from, competitive bulk-power systems. This Oak Ridge Competitive Electricity Dispatch (ORCED) model is intended to serve primarily as a strategic planning and analysis tool. This model is at the other end of the spectrum from the large, detailed, complicated models described below.

Many groups have developed computer models to simulate the operation (dispatch) of generating units within a larger electrical system. Other models develop optimal capacity-expansion plans, which integrate decisions on retirements of existing capacity, construction of new capacity, and operation of the stock of generating capacity. Most of the computer models in use today were designed to analyze the operations of regulated, vertically integrated utilities. In some cases, these models cannot readily analyze alternative market structures and rules. For example, the Energy Information Administration (EIA) uses a large, sophisticated model called the National Energy Modeling System (NEMS) to analyze a variety of energy issues. EIA's (1996) *Annual Energy Outlook 1997* noted that its NEMS analysis "... reflects the evolving trend of competition [an assumption of lower operations and maintenance costs] within electricity markets but does not include the full impacts of restructuring and deregulation."*

*EIA's (1997b) *Annual Energy Outlook 1998* results "reflect a greater shift in electricity market restructuring." EIA included a shorter capital recovery period and a higher cost of capital for new generating units, lower operations and maintenance (O&M) and administrative and general (A&G) costs, and early retirement of expensive nuclear units. However, the basic structure of EIA's capacity-expansion and production-costing models was largely unchanged.

EIA's (1997a) subsequent analysis of competitive electricity prices involved several assumptions that continue to reflect a traditional cost-of-service outlook. Specifically, EIA included taxes and A&G costs in its definition of the variable cost of generation. Most analysts would include only the direct fuel plus variable O&M costs in this category. Second, EIA's analysis assumed that generator retirements and new construction would proceed as in its *Annual Energy Outlook*. In other words, the analysis of competitive markets did not allow for premature (i.e., economic) retirement of generating units nor for the construction of new units in response to a change from regulated to competitive bulk-power markets.

Other models, which are able to analyze competitive markets, are extremely complicated and data intensive. For example, the GE-MAPS (Multi-Area Production Simulator) model can handle multiple control areas; more than 2000 generating units; and up to 9500 buses, 100 phase-angle regulators, 19,000 transmission lines, and 25 multiterminal high-voltage DC lines (Clayton and Mukerji 1996). The Policy Office Electricity Modeling System (POEMS), being developed for the Policy Office (1997) of the U.S. Department of Energy, is similarly complicated. POEMS consists of EIA's NEMS plus a network model of electricity capacity expansion, trade, dispatch, and pricing. POEMS represents about 110 control areas. (There are approximately 150 control areas in North America. POEMS aggregates some of the smaller ones.) Because of the complexity of these models, it is generally not feasible to use them for much sensitivity analysis. That is, the costs (primarily consisting of the time spent by analysts) of preparing inputs to these models, running them, and interpreting results from each case are sufficiently great that only a few cases can be run for any given study.

These large, sophisticated models differ in how they analyze generation (both capacity expansion and retirement as well as dispatch) and transmission. Some models focus on generation dispatch and unit commitment and largely ignore transmission, others treat transmission systems very simply as transportation networks, load-flow models ignore information on generation costs, and a few incorporate details of both the load-flow models and capacity-expansion/unit-commitment/dispatch models (Frankena and Morris 1997).

We developed ORCED to supplement, not replace, the existing detail-rich models. ORCED's appeal is its simplicity, which makes it easy and fast to run. As such, it could be used in concert with one of the detailed models mentioned above. ORCED could be used to explore "regions" of interest, and the large model could then be used to hone in on the specific details of interest.

ORCED treats two electrical systems connected by a single transmission link. It is an expanded version of part of an earlier model developed at Oak Ridge National Laboratory, ORFIN (Oak Ridge Financial Model). See Hadley (1996) for details on ORFIN. Whereas ORFIN is a comprehensive electric-utility planning model, ORCED deals only with generation.* We developed ORCED to aid in the analysis of the operation of competitive (as

*ORCED is silent on the costs and operations of transmission, distribution, and customer services. It does, however, explicitly model the single transmission link between the two regions shown in Fig. S-1.

opposed to traditional regulated) bulk-power markets. We are using the model to examine issues related to:

- CO_2 emissions from the U.S. electricity sector;
- the effects of competition on producers and retail customers in low-cost regions;
- the ability of different transition-cost-recovery and trueup mechanisms to meet particular public-policy objectives;
- horizontal market power (concentration of generation assets among a few owners);
- generator profitability [which units will be shut down because their expected revenues will not cover the sum of their fuel costs, variable O&M costs, and (avoidable) fixed O&M costs]; and
- optimal mix of new and existing generators, including the effects of new generating and end-use energy-efficiency technologies.

The model is structured to allow simulation of different bulk-power market structures. In particular, the user can specify one of three pricing schemes:

- An energy-only spot price in ¢/kWh, as used by the California independent system operator and power exchange (Pacific Gas & Electric et al. 1997). When unconstrained demand exceeds available supply, what would otherwise be unserved energy is "curtailed" because spot prices rise sufficiently to suppress demand to match the level of available generating capacity. The user simulates this situation by specifying a value for the price elasticity during these time periods. ORCED uses the amount of demand to be curtailed and the price elasticity to calculate the value of unserved energy in ¢/kWh.
- An energy-only spot price plus the loss-of-load probability (capacity) component, as used in the United Kingdom (Wolak and Patrick 1997). In ORCED, the user specifies a value for unserved energy (e.g., 200¢/kWh), which the model then adds to the energy-only spot price during hours with unserved energy. This process is equivalent to multiplying this assumed value for unserved energy by the loss-of-load probability and adding this product to all prices during the period.
- An energy-only spot price plus a capacity-reservation price (in $/kW-year), as used by the PJM Interconnection (Atlantic City Electric et al. 1997). In ORCED, customers pay and generators receive a price that is equal to the sum of the hourly energy spot price plus the annual capacity payment. The payment to generators is adjusted on the basis of their availability factors; that is, the higher the planned- and forced-outage rates, the lower the capacity payment.

We are using ORCED to examine the issues listed above as functions of the following factors (in addition to the pricing schemes noted above):

- generating-unit characteristics: type of unit (baseload, intermediate, or peaking), differences in capital and other fixed costs ($/kW-year) vs fuel and variable O&M costs (¢/kWh), dispatchability (e.g., fully dispatchable coal unit, must-run nuclear unit, energy-limited hydro unit, or stochastic wind plant), and forced- and planned-outage rates (%);

- customer and load characteristics: peak demand, shape of load curve, price elasticities of demand, and value of unserved energy;

- generating-resource portfolio: mix of generating units and relationship between generating capacity available and unconstrained peak demand; and

- transmission characteristics: capacity, cost, and losses in the transmission link between the two regions.

ORCED is an Excel workbook that can run on either Macintosh or Windows computers. The workbook consists of several worksheets to separate the input files for the two regions from the dispatch calculations and outputs. A full simulation takes about 30 seconds on a Pentium-133 computer. A full optimization can take several hours to complete.

Chapter 2 explains ORCED's representation of system loads, including customer responses to changes in overall and real-time prices (RTP). Chapter 3 describes ORCED's representation of the 26 generators it simulates in each region. Chapter 4 covers ORCED's optimization and dispatch algorithms, the heart of the model. Chapter 5 presents the types of results that ORCED produces for each analysis. Chapters 6 through 9 provide examples of the kinds of analyses that can be conducted with this model. Finally, Chapter 10 summarizes the key features and limitations of ORCED.

REPRESENTATION OF SYSTEM LOADS

Electricity consumption varies from hour to hour. Over the course of a typical day, the peak hourly load might be double the minimum load. In addition to the diurnal cycle, loads vary with the day of the week (higher during weekdays than on weekend days) and season.

Sophisticated production-costing models retain the chronological pattern of hourly demands and dispatch generation to meet the changes in load from hour to hour. ORCED, on the other hand, uses load-duration curves (LDCs) to represent system load. An LDC is created by ordering hourly system demand (in MW) from highest to lowest. The resultant curve shows the fraction of time (for the specified time period) that demand exceeds a particular value, ranging from the one-hour peak down to the minimum demand.

Use of load-duration curves is computationally much simpler and faster than the hour-by-hour analysis of chronological-dispatch models. This simplification, however, has a price: because it obscures the timing of system loads, production-cost analysis (discussed in Chapter 4) on the basis of LDCs cannot capture the details of generator operations and costs, especially those associated with minimum and maximum loading points, incremental heat rates, startup times and costs, and minimum shutdown times.

To partially remedy these problems, ORCED analyzes two user-specified seasons each year for each of the two regions. The user specifies the time periods for each season. Typically, the peak season includes either the summer months or the winter months, depending on whether the system being analyzed is summer or winter peaking. User inputs include the peak demand and load factor for each season and the fraction of the year assigned to the peak season. ORCED then calculates the three-segment LDCs shown in Fig. 1 for each season.

Because "consumer responses to marginal cost pricing could have a significant impact on capacity needs and planning" (EIA 1997a), ORCED can adjust system demands to changes in overall electricity prices and to RTP. The user inputs two price elasticities, one for overall demand and the other for responses to RTP.* Consumers and utilities have had very little experience with RTP to date. Therefore, considerable uncertainty surrounds estimates of consumer response to such time-varying prices (Faruqui et al. 1991; EIA 1997a).

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*In addition, unconstrained demand would exceed capacity for a small part of each season (typically less than 1%, depending on the reserve margin). During these times, ORCED uses a third input elasticity (which we set to −0.05) to calculate the market price at which supply and demand equilibrate.

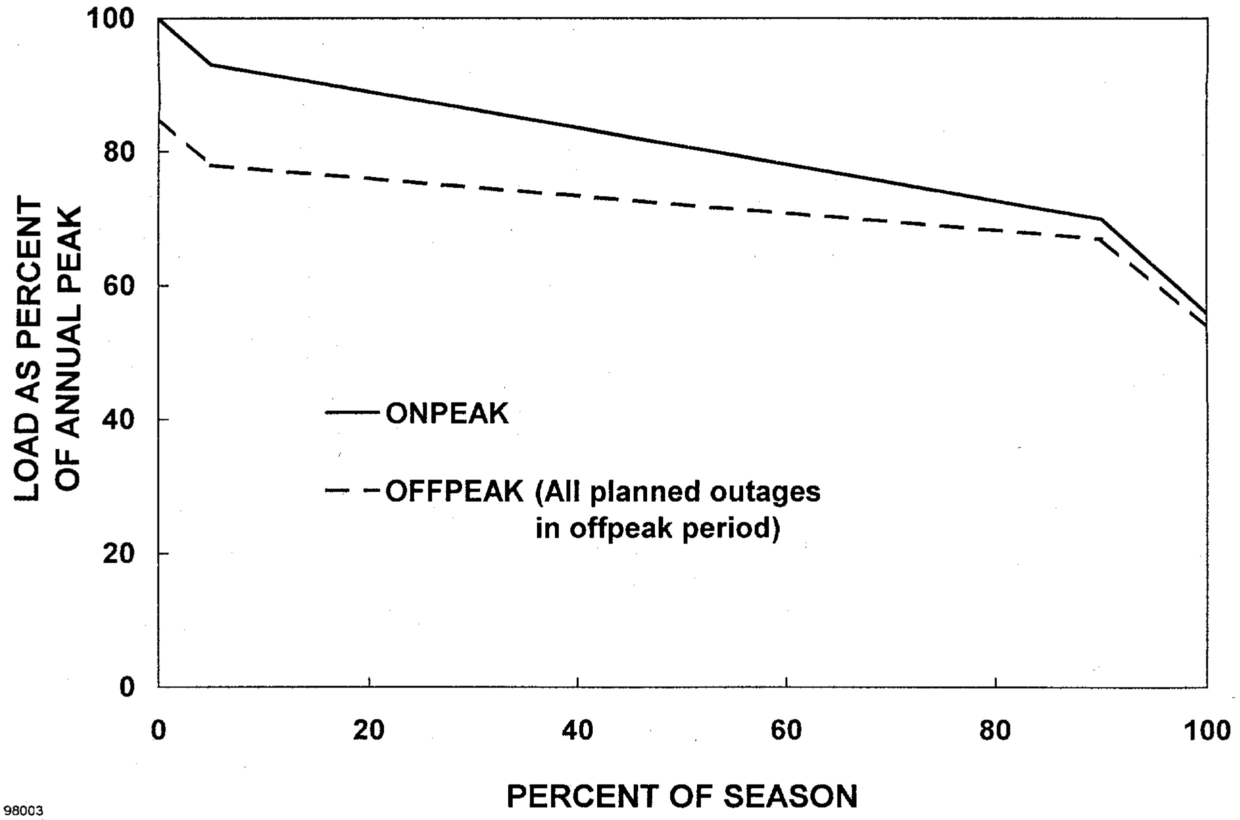

Fig. 1. **ORCED analyzes customer loads on the basis of load-duration curves for two user-specified seasons.**

ORCED has a separate workbook that calculates changes in system demand (relative to a reference LDC and a reference price) in response to changes in overall price, time-of-use prices, or both. This workbook accepts as inputs the original on- and off-peak LDCs and the associated prices that produced these original curves, as well as the RTP curves for the two seasons generated by ORCED. (In general, we assume that the original LDCs are based on time-invariant electricity prices.) The LDC workbook uses these inputs, along with user estimates for the two price elasticities to produce revised LDCs for the two seasons. The revised LDCs reflect changes in overall prices:

$$E_{ave}/E_{original} = (Price_{ave}/Price_{original})^{elasticity\text{-}ave} ,$$

where E is the total energy for the season, $Price_{original}$ is the time-invariant price of electricity associated with the original LDC, $Price_{ave}$ is the average market-based price, and elasticity-ave is the overall price elasticity (which we usually set to -0.5).

Next, the LDC workbook calculates changes in real-time demands for each season using the ORCED-calculated values of RTP:

$$E_{t\text{-new}} = E_{t\text{-original}} \times (E_{ave}/E_{original}) \times (Price_{t\text{-new}}/Price_{ave})^{elasticity\text{-}RTP},$$

where elasticity-RTP is the elasticity with respect to RTP (which we usually set to −0.1) and t refers to a particular price/electricity-use time period.

These calculations yield a new series of electricity demands and associated times that define the new LDC. The LDC workbook then uses the Solver routine in Excel to define the points on the three-segment LDC to be used in a subsequent run in ORCED. Figure 2 shows the effects of a switch from time-invariant, embedded-cost prices to time-varying market prices. Because the overall price is lower by 4%, overall electricity consumption is up by 2%. Perhaps more important, the load factor increases in response to RTP, from 70 to 77%.

ORCED, because of its focus on generation, treats electricity use at the system level. That is, the model does not treat customer usage for the residential, commercial, and industrial sectors separately. Thus, differences among customer classes in load shapes and in transmission and distribution losses are subsumed in the system aggregation. (We prepared a separate workbook that develops class-specific loads, load shapes, prices, and responses to RTP. The results from ORCED can be transferred to this workbook to perform these disaggregations, which then reaggregates results for use within ORCED.)

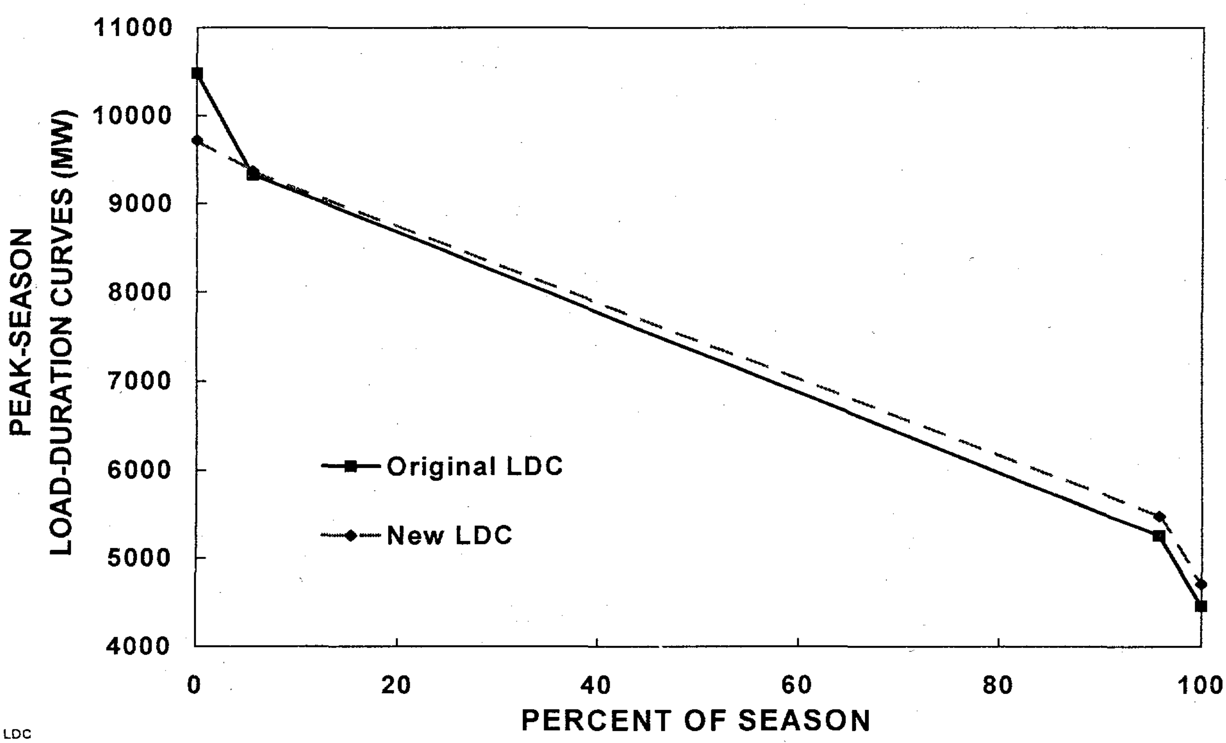

Fig. 2. Sample ORCED peak-season load duration curves based on (1) a time-invariant price and (2) real-time pricing.

REPRESENTATION OF GENERATION

A 10,000-MW power pool might, at any given time, have 75 to 100 generating units that it can dispatch to meet the time-varying customer demands. ORCED can handle 26 generating units in each region (Fig. 3). The first 25 units are characterized in terms of capacity (MW), forced- and planned-outage rates (% of season), fuel type, heat rate (Btu/kWh), variable O&M costs (¢/kWh), fixed O&M costs ($/kW-year), and annual capital costs (based on initial construction cost, year of completion, and capitalization structure, all expressed in $/kW-year).

The last (26th) unit is considered energy-limited (e.g., a hydroelectric unit). The inputs for this unit are similar to those noted above. Instead of using forced- and planned-outage rates, however, ORCED uses the unit's onpeak and offpeak capacity factors (equivalent to its maximum energy output for each season). This treatment of hydro as energy-limited ensures that hydro displaces the most expensive energy (i.e., that at the top of the load-duration curves).

Data on individual generating units are available from government sources, especially the utility submissions of FERC Form-1. Aggregate data are available from EIA's Internet site, the North American Electric Reliability Council (NERC), and several private sources.

We calculated estimates of forced and planned outage rates for generic generating units on the basis of information available in NERC's *Generating Availability Data Systems* (NERC 1996); see Table 1.[*] As examples, average equivalent forced-outage rates for the period from 1991 through 1995 were 7% for coal units, 12% for oil units, 10% for gas units, 7% for combined-cycle units, 3% for combustion turbines, 13% for nuclear units, and 4% for hydro units.

Utilities report data on O&M costs but do not split these costs into their variable and fixed components. At the conceptual level, these costs fall along a spectrum from those that are directly proportional to kilowatt-hour output to those that can be modified only rarely, perhaps no more frequently than on an annual basis.

[*]EIA also provides estimates of these outage rates for use in its National Energy Modeling System.

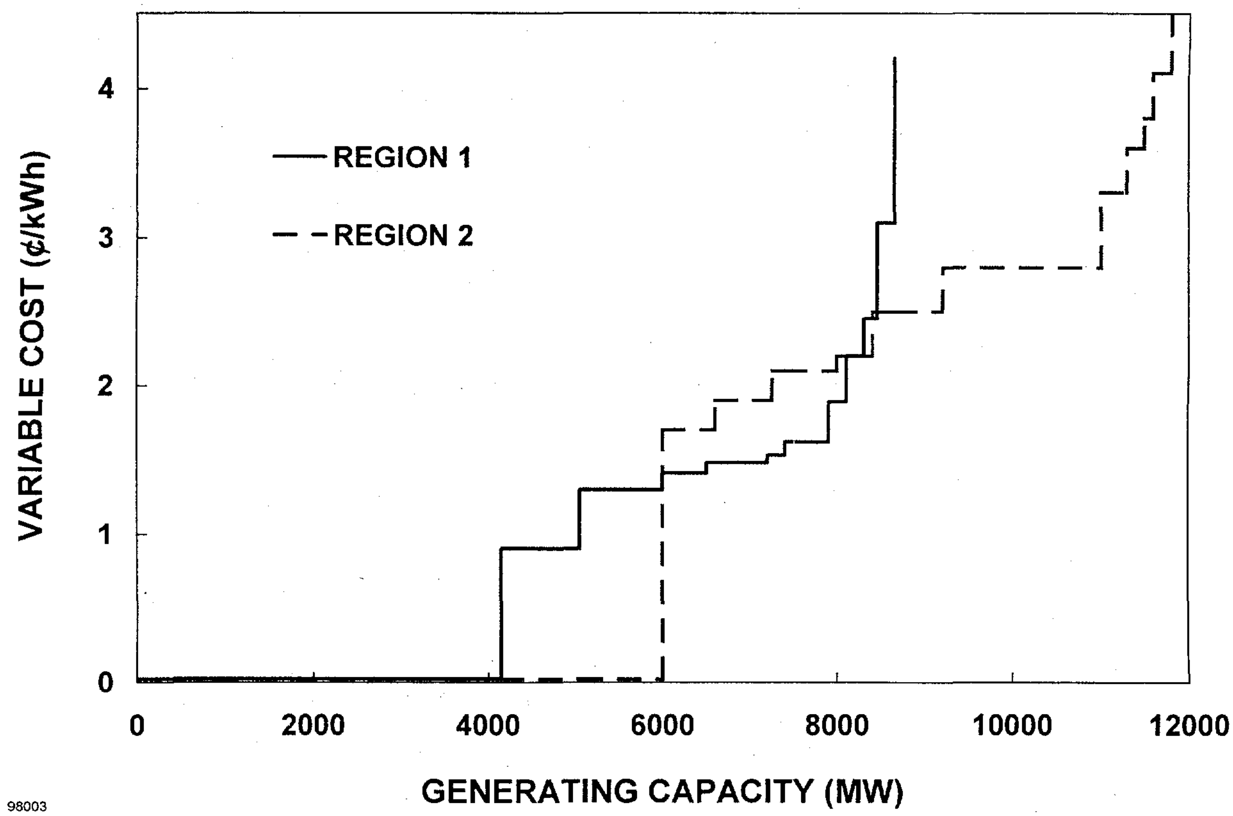

Fig. 3. User inputs specify generating-unit characteristics for 26 units in each region. ORCED then dispatches these units on the basis of either bid price or variable cost.

Our regression analysis of FERC Form-1 data as well as a comparison of results among different groups show considerable uncertainty about the appropriate allocation of O&M costs between fixed and variable costs. In many, but not all, cases, O&M costs are lower for newer units and lower per kilowatt-hour for larger units. One private supplier of generator data allocated generation O&M costs according to fixed ratios (e.g., 50:50 split of O&M costs between fixed and variable for fossil-steam and combustion-turbine units and 80:20 split for nuclear and hydro units).* However, the company offers no justification for these cost assignments. This uncertainty about how to split O&M costs into fixed and variable components is important because the prices bid into power exchanges by individual generators should reflect variable, but not fixed, O&M costs. We plan to use ORCED to test the effects of different splits on generator profitability and market prices.

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*The Northwest Power Planning Council suggests, for combined-cycle units, a variable O&M cost of 0.08¢/kWh plus a fixed O&M cost of $18.40/kW-year (Morlan 1998). At a 60% capacity factor, the fixed cost is equivalent to 0.35¢/kWh, leading to a 0.81:0.19 split between fixed and variable costs.

Table 1. Key performance characteristics of U.S. generating units, 1991–1995

Type	Capacity (GW)	Capacity factor (%)[a]	Equivalent forced-outage rate (%)[b]	Scheduled-outage factor (%)[c]
Coal	286	61	7	11
Oil	62	24	12	11
Gas	101	30	10	11
Combined cycle	7	33	7	10
Combustion turbine[d]	26	2	3	7
Nuclear	111	71	13	15
Hydro	46	48	4	7
Total	639	50	9	11

[a]Capacity factor is the ratio of a generating unit's actual energy output during a given time period to the energy the unit could have produced if it had been operating at its maximum rated capacity during that period.

[b]Equivalent forced-outage rate is the sum of the forced-outage hours plus equivalent forced-outage hours divided by the total outage hours plus the in-service hours. The equivalent forced-outage rate is a refinement of the forced-outage rate because it accounts for partial as well as full outages.

[c]Scheduled-outage factor is the sum of planned and maintenance outage hours divided by the number of hours the unit was in the active state (usually the full 8760 hours in a year).

[d]NERC's data on forced-outage rates for combustion turbines are misleadingly high because of the very low capacity factors for these units. Wood and Wollenberg (1996) calculate a 3.4% equivalent forced-outage rate, which is the default value we use in ORCED.

In ORCED, the user can select from among several choices for the capitalization structure for each unit. This selection (e.g., traditional utility or independent power producer) determines how the initial construction cost is converted into an annualized capital cost (from $/kW to $/kW-year). The capitalization module accepts as inputs the economic and tax lifetimes of the generator, income and property tax rates, equity:debt ratio, interest on debt (long-term bonds), and return on common and preferred equity. The user can also specify whether the annualization is for a particular year (e.g., the year 2000 for a generator constructed in 1989) or levelized over the book life of the unit. ORCED then calculates the annual cost for depreciation, interest payments on bonds, return on equity, property taxes, and income taxes.

For example, the annual cost of a $1000 generator built by a regulated utility might be $210 in year 1, $140 in year 10, and $40 in year 30 (the end of the unit's book life). Levelizing the capital costs yields a constant annual payment of $150. The comparable costs for an unregulated company, with a much higher equity:debt ratio and higher returns on equity and debt, might be 25% greater than the costs for a regulated utility.

As noted earlier, ORCED's use of load-duration curves and the simple nature of its production-costing algorithm ignore many of the details of generator operations and constraints. In an effort to approximate the effects of some of these costs and constraints, we obtained data on generator startup costs from three utilities, one each in the Southeast, Midwest, and Southwest. The primary cost of startup is the fuel used to heat the boilers and create steam at the appropriate pressure. There may also be O&M costs required to start up a unit that are not associated with the normal operation of the unit. The fuel-cost estimates varied with the type and size of unit and ranged from about \$4 to \$40/MW-capacity. As explained in the following chapter, we used a single input value (the default for which is \$40/MW for fuel plus O&M startup costs) as an adder for units that operate with a capacity factor below 10%. ORCED converts this adder into a ¢/kWh increase in unit operating cost and bid price by calculating the number of startups based on the unit's capacity factor.

CAPACITY EXPANSION AND GENERATOR DISPATCH

The heart of ORCED is its Dispatch worksheet. This sheet can optimize the mix of generating units, dispatch the existing generating units to meet system demand, or both. This section first describes ORCED's dispatch and production-costing calculations and then describes the capacity-expansion optimization.

DISPATCH AND PRODUCTION COSTING

ORCED dispatches generating units to meet demands for each season separately. It begins by dispatching the generators within each of the two regions to meet the intraregional demands only. Then, it redispatches generation between the two regions when doing so reduces costs. Finally, ORCED calculates market prices in each region and the consequent revenues for each generator.

The plants are first dispatched against the LDC on the basis of bid price, the default for which is variable (fuel plus variable O&M) costs.* If the unit bids a zero price for its output, that generator is treated as a must-run unit and is dispatched first by the model. The model user can specify any bid price, perhaps to test the effects of different attempts to increase generator profits. Although the dispatch process is identical for the two seasons, the results differ because of differences in the LDCs and because all the planned maintenance is assumed to occur in the off-peak season for each region (Fig. 1).

Because generators are not available 100% of the time (Table 1), ORCED also models forced outages. The user specifies whether a generator is to be derated or treated on a probabilistic basis. Derating a unit lowers its capacity rating by the forced-outage rate; the unit is then available at that lower capacity level 100% of the time. Treating units probabilistically is more accurate but also requires more computing time.# See Vardi and Avi-Ithak (1981) for additional details on the probabilistic treatment of forced outages. Figure 4 shows the model's treatment of a 100-MW generator in the two seasons with the derating and probabilistic approaches discussed here.

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*ORCED treats all fuel costs as variable and ignores the fact that many long-term fuel contracts have substantial fixed costs (e.g., minimum annual payments).

#The amount of computer time required for a full simulation depends strongly on the number of generators treated probabilistically. We found a reasonable tradeoff between computing time and accuracy when about 10 plants are modeled probabilistically and the other 16 are derated.

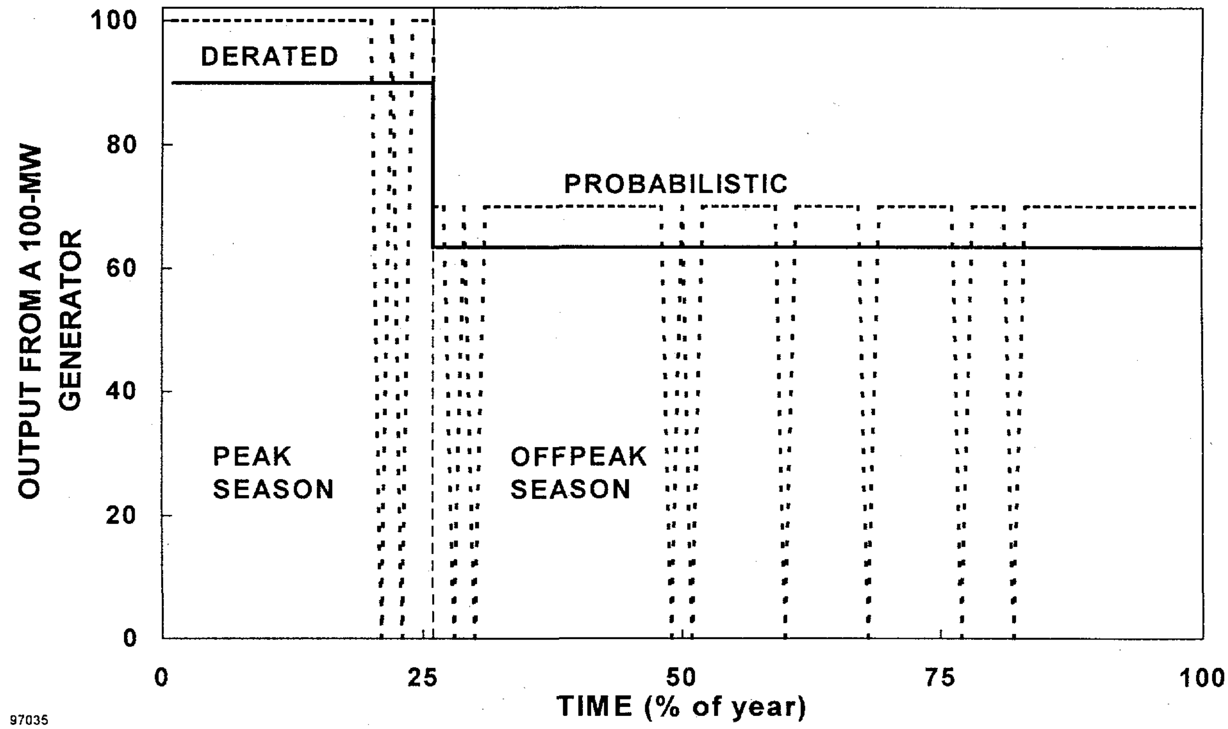

Fig. 4. **The energy output from a hypothetical 100-MW generator with a 10% forced-outage rate and a 20% planned-outage rate (i.e., the unit's maximum output for the year is 70 MW-year). The solid line is the output for a derated unit, and the dotted line is the output for a unit treated probabilistically.**

Because of the forced outages associated with probabilistic units, the higher-cost generators will see demands not only from customers, but also "equivalent demands" based on the probability that plants lower in the dispatch order (i.e., less expensive) will be undergoing a forced outage. ORCED creates an equivalent LDC for each plant, which extends the amount of time the plant runs based on the forced-outage rates of the plants lower in the dispatch order.

Before dispatching the first 25 generators, ORCED adjusts the LDCs on the basis of the energy and capacity of the 26th generator (energy-limited unit). Because of this unit's typically low variable cost and energy (rather than capacity) limitation, it is not placed in the loading order with the other 25 units. Rather, its output is used to displace what would otherwise be the most expensive energy, that associated with the highest demands (i.e., at the left hand side of Fig. 1). ORCED first lowers the system peak by the lesser of the 26th unit capacity or an amount such that the area between the new left-most line segment in Fig. 1 and the original line segment equals the maximum energy that this unit can produce. If the 26th unit has additional energy, the process is repeated for the middle line segment of Fig. 1 and, if needed, the third segment.

ORCED calculates market prices (based on the bids from individual generators) for each time during the two seasons and then permits trades between the two regions. At any given time, trading between the two regions is a function of the bid prices of the marginal units in both regions as well as the costs and losses of the transmission link between the two regions. The market-clearing price at any time is based on the bid price of the marginal generator (the last one called upon in the dispatch order) after all cost-reducing trades are completed.

Figure 5 illustrates the trading process between the two regions. For the situation shown, the pretrade prices are 0.8¢/kWh in region 1 and 2.8¢/kWh in region 2. The trading begins with the least-cost surplus capacity in the low-cost region (Region 1) displacing the highest-cost operating plant in the high-cost region. This process continues until it is no longer possible to lower costs by increasing trades, shown by the numbers 1, 2, ..., n in Fig. 5. At this point, the market-clearing price is defined as the bid price of the most expensive plant operating in both regions (2.5¢/kWh as shown in Fig. 6). The example presented here assumed that there are no transmission losses, costs, or limits between the two regions. If costs, losses, and/or limits are greater than zero, the amount of trading will be reduced, and the posttrading prices in the two regions will be different.

The prices that customers see also incorporate any externally imposed uplift charge, capacity charge, or emission taxes. The prices during high-demand hours also reflect generator startup costs and the costs of any unserved energy for those hours when unconstrained demand exceeds supply.

ORCED can use the time-of-use elasticity to calculate the value of unserved energy (in ¢/kWh) that equilibrates supply and demand when unconstrained demand would otherwise exceed the amount of generating capacity then online. Alternatively, the user can specify a value for unserved energy. A third option entails user specification of a minimum reserve margin and the associated annual capacity payment (in $/kW-year) to pay for this "extra" capacity.

ORCED can be run iteratively to estimate customer response to changes in overall electricity-price levels and to RTP. User inputs include an overall price elasticity of demand and a time-of-use elasticity. The former elasticity is used to adjust the entire load-duration curve up (or down) in response to decreases (or increases) in the overall price of electricity. The latter elasticity is used to adjust each point on the load-duration curve up (or down) based on decreases (or increases) in the price of electricity during that time period.

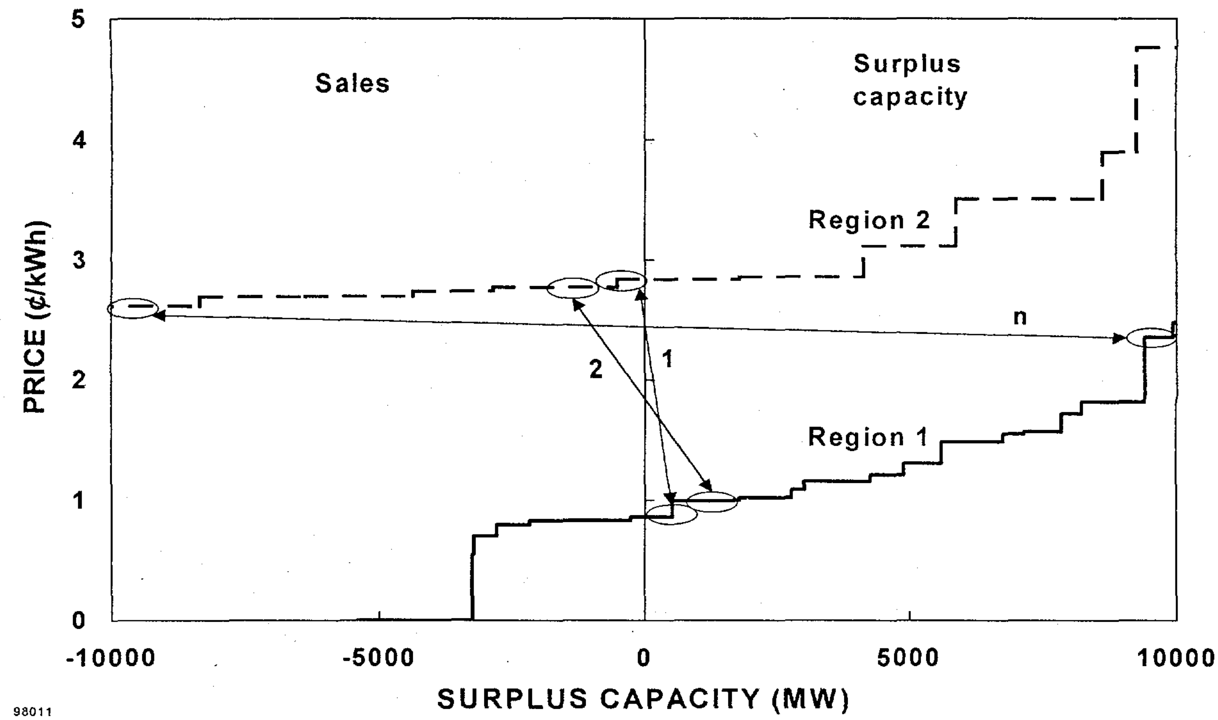

Fig. 5. Pretrade differences in price and unused capacity in two regions. The numbered arrows refer to the sequence of trades.

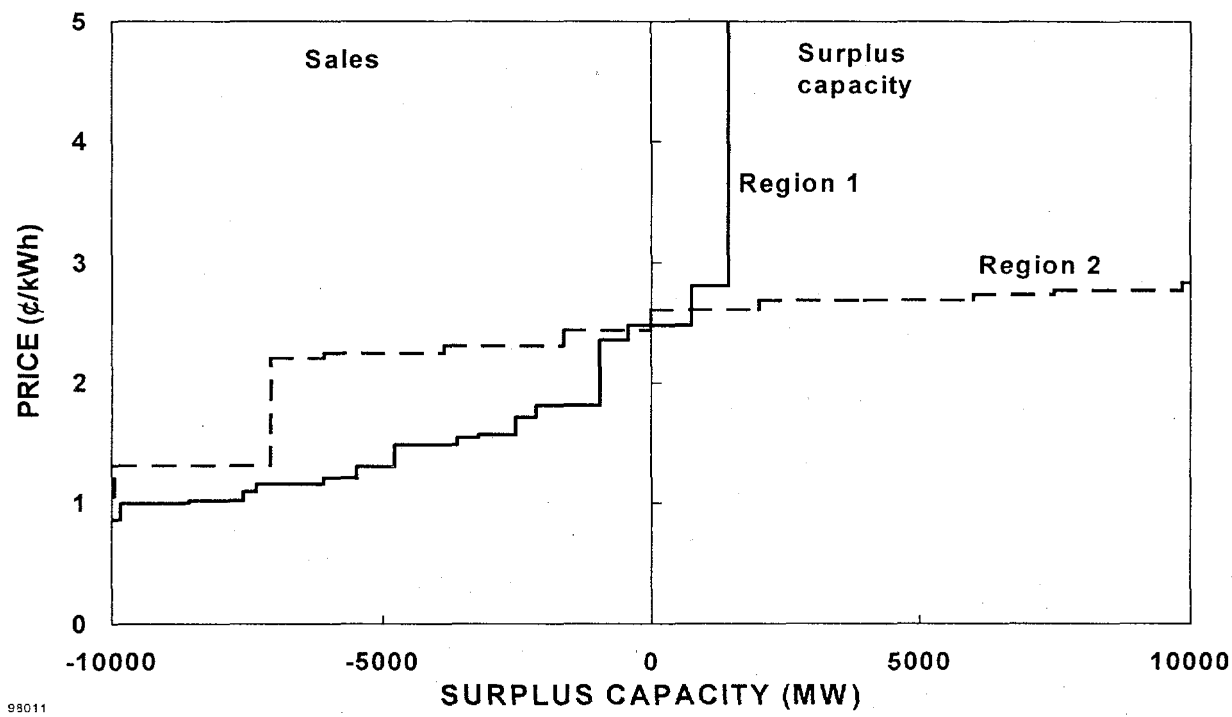

Fig. 6. Posttrade price and unused capacity in the two regions.

OPTIMIZATION

ORCED can be run in either a simulation mode or an optimization mode. In the simulation mode, the model runs as a production-costing model to determine the costs of meeting customer electricity demands given a fixed set of generating units in the two regions. In the optimization mode, ORCED runs as a combined capacity-optimization and production-costing model to determine the "optimal" mix of generating units available that year as well as the least-cost use of those generators to meet customer demands.

The user can specify different objective functions in the optimization routine,* including minimization of the total cost of producing electricity, minimization of the sum of variable plus avoidable fixed costs, minimization of electricity price, or maximization of producer profits. To study issues related to market power, profit maximization for a certain group of generators could be used as the optimization variable. Typically, we set the objective function to minimize the avoidable cost of electricity for the year in question. For plants already in existence, the avoidable cost includes fuel plus O&M. For plants not yet constructed, all costs (including fuel, O&M, and capital) are avoidable.

The user can also impose constraints on the optimization. Because ORCED analyzes only one year at a time, these constraints are very important to achieving a reasonable solution. These constraints can apply to individual generating units or to the system as a whole. For example, maximum-capacity constraints are imposed on existing generating units (i.e., those units constructed before the year of the simulation) to be sure that their capacity does not increase and that some of this capacity could be prematurely retired. Similarly, maximum-capacity constraints are imposed on new generation to reflect real-world construction limits and to prevent any single technology from capturing too high a market share.

Other constraints could require that the net revenues for each plant be nonnegative (to shut down plants for which revenues do not exceed avoidable costs), specify a minimum amount of renewable generating capacity, specify a maximum level of carbon emissions, or set a minimum reserve margin.

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*Excel includes a Solver routine, which performs the optimization calculations. Unfortunately, the method may find a locally optimal solution, rather than the desired global optimization solution. Therefore, the user should conduct some sensitivity analysis with the Solver solution to see if the objective function can be improved by varying the capacity levels of some of the generating units. Third-party software that uses genetic algorithms or other mathematical techniques are available that may yield better, faster, and easier-to-obtain solutions.

ORCED RESULTS

ORCED produces two sets of results, one at the system level and one that covers each generating unit in each region.

SYSTEM RESULTS

System results include information on the generating capacity and production, customer peak demand and energy consumption, and two measures of reliability (reserve margin and amount of unserved energy) in each region. In addition, ORCED shows the bulk-power flows between the two regions and the transmission losses and costs of these flows. Finally, ORCED calculates several annual costs and prices for each region.

ORCED produces several sets of numbers on the prices and costs of generation services, reflecting the perspectives of power producers and consumers, under both traditional regulation (full-cost recovery) and competitive-market conditions. These variables (all expressed in ¢/kWh) include:

Market Price: The annual average price (weighted by consumption) that customers would face if they purchased all their energy from the hourly spot market (Fig. 7). As trading between the two regions increases (e.g., as transmission capacity increases or changes in customer load shapes free up generating and transmission capacity), the market prices in the two regions approach each other. At the limit, where trading is completely unrestricted and cost free, the hourly market prices are identical. The market prices, averaged over the course of a year, will differ to the extent that load shapes differ between the two regions.

Market Price Adjusted for Transition Costs (TCs): The sum of market price plus TCs.* TCs are calculated for each generator as the minimum of (a) the generator's unavoidable fixed costs or (b) the difference between revenue and total cost (both expressed in millions of dollars per year). Thus, if revenues exceed the sum of fuel costs, variable O&M costs, and avoidable fixed costs, the "excess" is used to offset some of the unavoidable fixed cost in computing TCs. On the other hand, if revenues do not exceed the sum of fuel, variable, and fixed O&M costs, the unit should probably be shut down, and TC is capped at the unit's unavoidable fixed (capital)

*Roughly speaking, TCs reflect the differences between the regulated prices for electricity generation and the prices that might occur in fully competitive power markets. These costs can include generating assets, long-term power-purchase contracts, and regulatory assets (Baxter, Hirst, and Hadley 1997). TCs can be positive or negative. The present analysis does not consider regulatory assets.

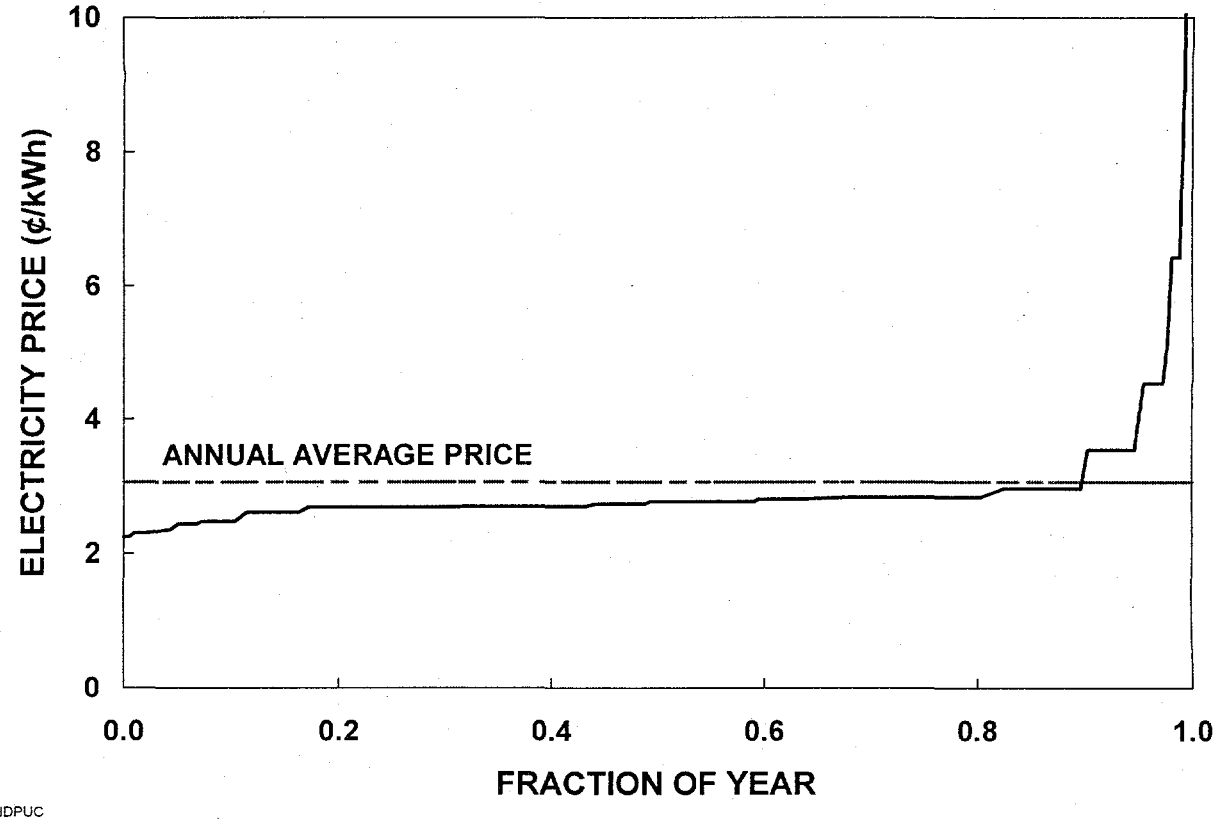

Fig. 7. ORCED simulation of bulk-power market prices. Prices exceed 8¢/kWh for 1% of the hours and exceed 20¢/kWh for 0.5% of the hours.

cost. If revenues exceed total costs, this "excess" is considered negative TC and is credited to retail customers. The TC adjustment is equal to the total dollar value of TCs for the year in question, normalized by total retail electricity sales (¢/kWh), and is added to the market price for every hour of the year.

Full-Cost-Based Price: The price calculated from the ratio of total revenue requirement (which includes variable and startup costs, net power-purchase costs, avoidable fixed O&M costs, plus unavoidable capital costs) to total retail sales. This number is the price that customers would pay if the state public utility commission (PUC) continues to regulate utilities as it has in the past. Any excess revenues from wholesale sales relative to wholesale purchases are treated as a revenue credit and used to reduce the price charged to retail customers.

Producer Price: The annual average price (weighted by production) that producers would receive if they sold all their energy into the hourly spot market. When there is no trading between the two regions, the market and producer prices are identical.

Producer Costs: The production expenses, which include three components (all expressed in millions of dollars per year and ¢/kWh):

- Variable plus startup costs are the fully avoidable variable costs associated with running generators, including fuel plus the variable portion of O&M costs. As trading between the two regions increases, variable costs per kilowatt-hour increase in the low-cost region (because it is producing additional electricity from units with higher variable costs for export to the high-cost region) and decrease in the high-cost region.

- Avoidable fixed costs include the remainder of O&M costs. As trading between the two regions increases, the per-kilowatt-hour value of these costs decreases in the low-cost region (because these fixed costs are spread among more kilowatt-hours of electricity production) and increases in the high-cost region.

- Unavoidable fixed costs are those associated with the plant's capital costs, including depreciation, taxes, interest payment on bonds, and allowed return on equity. As trading between the two regions increases, the per-kilowatt-hour value of these costs decreases in the low-cost region (for the same reason that avoidable fixed costs decrease) and increases in the high-cost region.

The sum of these three components equals total producer costs, and the ratio of this total cost to total sales is the producer price noted above. (With trade, producer sales in one region do not necessarily equal consumer purchases in that region.)

Other system-wide results are calculated and can be added to the output. Examples include total fuel use by fuel type, carbon emissions by fuel type, marginal costs of carbon reductions, and total transition costs for the region.

UNIT-SPECIFIC RESULTS

The system results discussed above are based on the ORCED determinations of the operation of each generating unit in both regions. Model outputs include, for each unit, its total production, production for export to the other region, capacity factor, percentage of time the unit is on the margin (and therefore sets the spot price), and economic results (in millions of dollars per year). These economic results show the unit's annual revenues from the sale of electricity and its variable plus startup costs, avoidable fixed costs, and unavoidable fixed costs. Those units for which the sum of variable plus startup costs and avoidable fixed costs exceed revenues are candidates for early retirement (Fig. 8). The owners of these units would lose less money if they shut down such units because they would no longer have to pay avoidable fixed O&M costs. Those units for which revenues exceed the sum of variable, startup, and avoidable fixed costs but do not exceed total costs should probably remain in operation. Even though these units do not produce enough revenues to cover all fixed costs, they do make some contribution to recovery of unavoidable fixed costs.

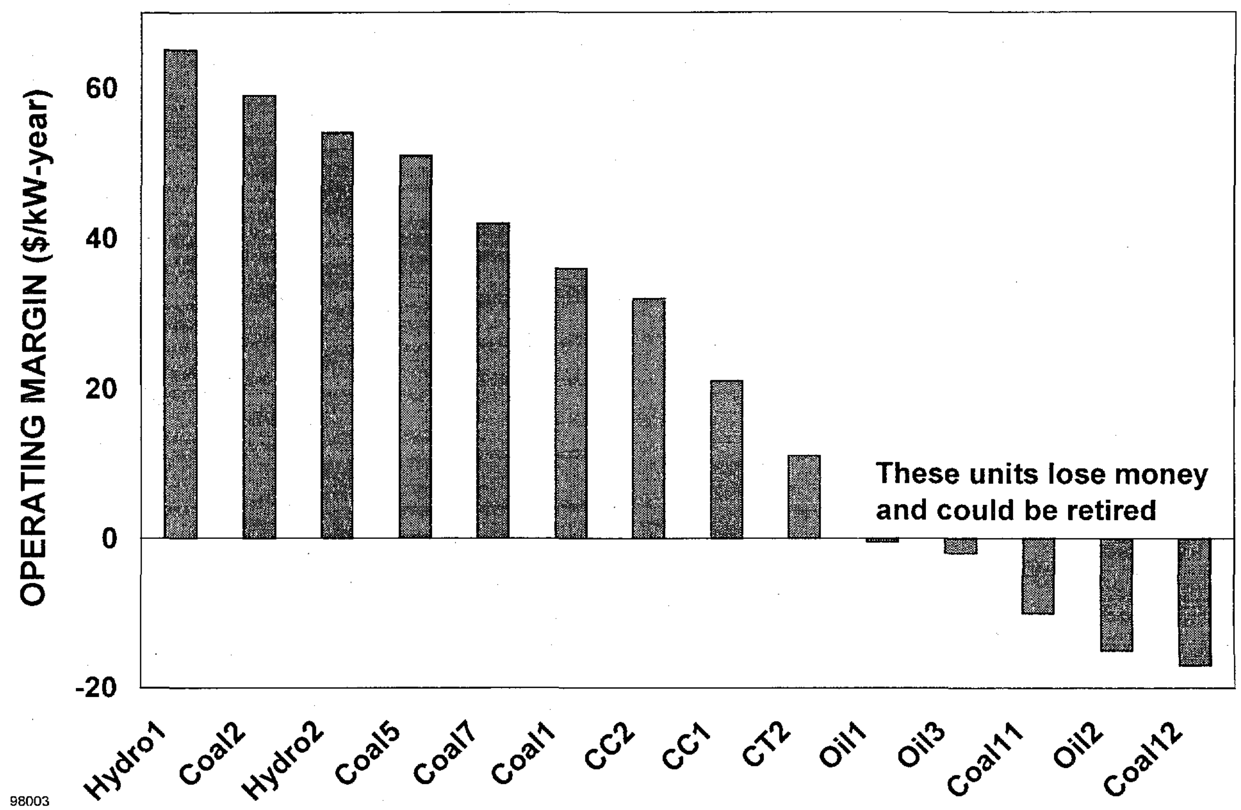

Fig. 8. **Sample ORCED results showing the contribution to margin for some of the 26 generating units in one of the two regions.**

APPLICATION: END-USE ENERGY EFFICIENCY

The U.S. Department of Energy commissioned a study involving five national laboratories to quantify the potential for energy-efficient and low-carbon technologies to reduce U.S. carbon emissions in the year 2010. Electricity consumption accounts for about 36% of both total primary-energy consumption and carbon emissions in the United States. As a consequence, converting efficiency-induced electricity savings in the residential, commercial, and industrial sectors into carbon reductions is a critical part of this study (Hadley and Hirst 1997).

This task is complicated by several factors. First, the U.S. electricity industry is in the midst of a major restructuring. Because this transformation is far from complete, predicting the structure and operation of electricity markets for the year 2010 is difficult. Second, electricity production in 2010 will depend on the generating units that are retired, repowered, and constructed between now and then, as well as on how those units are operated that year. The decisions made by the profit-maximizing owners of individual generating units are likely to be different than the cost-minimizing decisions made in the past by regulated electric utilities. These changing dynamics of capacity expansion and system operation mean that one cannot assume that the average and marginal carbon intensities of electricity use (tons of carbon/GWh)* will be the same in 2010 as they are today. Indeed, they are likely to be quite different. Third, electricity prices in 2010 are likely to vary from hour to hour based on current spot-market prices; consumer response to such time-varying prices is likely to be substantial but is largely unknown.

CALIBRATION TO EIA AEO97

Before analyzing the two end-use-efficiency scenarios developed for this study, we calibrated the single-region version of ORCED results to those produced by NEMS for 1995 and 2010 in its *Annual Energy Outlook 1997* (AEO97). Unfortunately, reconciling the two sets of results to each other is difficult because of differences in the ways that the two modeling systems classify various costs, such as fuel, variable O&M, fixed O&M, and capital costs associated with generation as well as EIA's inclusion of A&G and customer-service costs in the basic categories of generation, transmission, and distribution costs. Because of these difficulties, our numbers do not always match the EIA numbers exactly.

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*All carbon values are presented in metric tons; 1 metric ton equals 2205 pounds or 1.1025 tons.

This calibration ensures that the assumptions concerning the mix of generating units, fuel prices, customer demand, environmental regulations, and so on are consistent between ORCED and those developed by EIA. For example, both sets of results assume the continuation of current economic and environmental policies affecting the U.S. electricity industry.

We developed a year 2010 base case that includes the same mix of generating units (in both capacity and energy) as that produced by EIA, with the same reserve margin (11%). In addition to data from the AEO97, we used other data from EIA as well as data from NERC, the Electric Power Research Institute, and Resource Data International, Inc. The net result is very close agreement between the ORCED and EIA scenarios for 2010. EIA's estimate of the total cost of generation (3.26¢/kWh) is 7% higher than the ORCED result (3.04¢/kWh). The ORCED cost is lower because the single-region version of ORCED dispatches fewer expensive oil-fired resources than does the EIA model. These differences in dispatch and variable costs occur because ORCED dispatches generation nationwide and ignores transmission constraints. The close agreement between EIA and ORCED results, in spite of all the adjustments required to produce a set of internally consistent and comparably defined terms, is reassuring. It lends confidence to our development of alternative cases intended to reflect more fully than EIA did the effects of competition in bulk-power markets.

BASE CASE FOR A COMPETITIVE MARKET

Beginning with the AEO97 case, we developed a case intended to reflect the workings of a fully competitive bulk-power market in 2010. (AEO97 assumes a continuation of current economic regulation and therefore does not account for the possible effects of a restructured and largely competitive U.S. electricity industry.) To reflect these changes, we let the model select the amounts of each of 20 (of 26) generating units that minimize the sum of variable plus avoidable costs. Instead of specifying the amount of generating capacity that must be online in 2010 (to yield a 10.7% reserve margin in the AEO97 case), we allowed the model to select the amount of capacity that minimized the cost of the power-supply system plus the cost of unserved energy. We used a demand elasticity of -0.05 for those time periods when capacity is insufficient to meet unconstrained demand. The resultant optimization yielded a reserve margin of 6.8%.

Beginning with the ORCED run that matches EIA's AEO97 values for 2010, we first reran the model allowing it to select the "optimal" amounts of generating capacity from among all the plants that, according to EIA, are scheduled to come online after 1998. (The optimization was based on a minimization of avoidable costs.) We also allowed the model to select plants for retirement. For each of the new plants, we use the levelized-fixed-charges rate to calculate the annual capital cost of the plant and treated all fixed costs (both capital and O&M) as avoidable.

Next, we adjusted the LDCs for the two seasons simulated by the model (peak and offpeak). We set prices equal to their real-time (hourly) values based on the variable (fuel plus variable O&M) cost of the unit on the margin each hour of the year, adjusted overall electricity demand to reflect lower prices using an assumed overall elasticity of -0.5, and adjusted the load shape to reflect the response to RTP with a value of -0.1 for the price elasticity within each time period.

Customer responses to RTP produced a new system peak demand 3.4% below the AEO97 case and a total demand 1.2% higher. We then reran ORCED using the new load shapes. Table 2 compares the two sets of results. Although demand is higher in the restructuring case than in the AEO97 base case, carbon emissions are lower. This situation is a consequence of the reduction in coal use and the increase in natural gas use in the restructuring case.

Table 2. Comparison of year 2010 projections from EIA AEO97 and the ORCED base case

	EIA AEO97	Competitive industry
Peak demand, GW	734	709
Total energy, TWh	4058	4090
Load factor, %	62.8	65.7
Reserve margin, %	10.7	6.8
Generation shares, %		
Coal	50.8	47.4
Gas	24.4	29.2
Other	24.8	23.4
Generation prices and costs (¢/kWh)		
Retail (market) price	3.04	3.02
Variable cost	1.43	1.45
Total cost (regulated price)	2.81	2.51
Carbon emissions (million tons)	631	625

Under restructuring, the total generating cost is 0.3¢/kWh lower, but the system average price increases slightly. In a deregulated market, market prices will be based on the variable cost (or bid price) of the most expensive plant operating at that time. Thus, the link between total costs and prices is broken. Whereas current electric utility regulation sets prices to recover total costs, future prices may, or may not, be sufficient to recover all costs.

EFFICIENCY AND HIGH-EFFICIENCY CASES

We next applied the two sets of electricity-savings estimates developed for the residential, commercial, and industrial sectors to adjust the aggregate load shape for the United States as a whole. We then reran ORCED using the new load shapes. We also included an additional cost of $50/ton of carbon in the second case. Table 3 presents the results for the two scenarios along with those for the competitive-industry base case. The efficiency case yielded an 8.5% reduction in electricity use and the high-efficiency/low-carbon case cut electricity use by 16.3% relative to the restructuring case summarized in Table 2.

Table 3. Comparison of year 2010 projections: efficiency and high-efficiency/low-carbon scenarios

	Competitive industry	Efficiency	High-efficiency/low-carbon
Peak demand, GW	709	651	596
Total energy, TWh	4090	3740	3420
Load factor, %	65.7	65.5	65.5
Reserve margin, %	6.8	7.9	12.9
Generation shares, %			
Coal	47.4	52.1	46.2
Gas	29.2	22.2	26.0
Other	23.4	25.7	27.8
Generation prices and costs (¢/kWh)			
Retail price	3.02	3.03	3.66
Variable cost	1.45	1.43	2.07
Total cost	2.51	2.46	3.21
Carbon emissions (million tons)	625	596	492

The efficiency scenario yields a lower percentage reduction in carbon (4.6%) than in electricity use (8.5%). The difference occurs because the lower electricity consumption requires less construction and operation of high-efficiency gas-fired combustion turbines and combined-cycle units. In contrast, the high-efficiency/low-carbon case has a higher percentage reduction in carbon (21.2%) than in electricity use (16.3%). This reversal occurs in part because the $50/ton carbon fee changes the mix of technologies used to produce electricity. In this case, more than 16% of the coal-fired generation is retired, and the remaining, more efficient coal plants operate at lower capacity factors.

APPLICATION: COMPETITION AND LOW-COST REGIONS

In response to a request from the Idaho PUC, we analyzed the effects of competition on customers and producers in the Pacific Northwest and California (Hadley and Hirst 1998). The PUC, like those in other low-cost states, expressed concern that consumers in their state would face higher prices if low-cost power was sold to customers in high-cost states.

California's generating costs are roughly double those of the Northwest, primarily because of the dominance of hydroelectricity in the Northwest. We analyzed four cases: a pre-competition base case intended to represent conditions as they might exist under current regulation in the year 2000, a postcompetition case in which customer loads and load shapes respond to RTP, a sensitivity case in which natural gas prices are 20% higher than in the base case, and a sensitivity case in which the hydroelectric output in the Northwest is 20% less than in the base case.

BASE CASE

In this precompetition (i.e., current state regulation) case, electricity consumption is slightly lower in the Northwest than in California (243 vs 250 thousand GWh for the year 2000). Demand in the Northwest peaks in the winter at almost 40,000 MW, while demand in California peaks in the summer at 48,000 MW (Table 4). (The California peak is actually higher, but is lowered in ORCED to account for imports from the desert Southwest and other regions besides the Pacific Northwest.)

Variable production costs are almost 1.2¢/kWh lower in the Pacific Northwest than in California. Total production costs are 2.1¢/kWh lower. The hourly spot prices of electricity in the two regions are the same because of our assumption that there are no transmission costs or losses between the two regions. The annual market prices differ solely because the load shapes are different in the two regions, with the Pacific Northwest having a higher load factor than California (69% vs 59%). The regulated price of electricity is about 2¢/kWh lower in the Northwest than in California.

The Pacific Northwest generators have a negative transition cost of $2.7 billion a year. In other words, the aggregate market value of these generators substantially exceeds the aggregate book value. The California generators, on the other hand, have an annual transition cost of $2.1 billion.

As expected, producers in the Pacific Northwest sell substantial electricity to customers in California. The sales from the Northwest to California amount to 7.1% of the electricity consumption in the Northwest. Because the California units are higher in cost, they generally set the market price of electricity.

Table 4. Year-2000 base-case conditions in the Pacific Northwest and California

Factor	Pacific Northwest	California
Consumption and production		
Peak demand (MW)	40,000 (winter)	48,400 (summer)
Consumption (GWh)	242,800	250,100
Generating capacity (MW)	52,100	56,800
Production (GWh)	259,800	233,100
Reserve margin (%)	30	17
Generation costs and prices (¢/kWh)		
Variable cost	0.75	1.92
Total production cost	1.98	4.03
Market price	3.02	3.11
Market price + transition cost[a]	1.91	3.93
Regulated price	1.91	3.96

[a]Transition costs do not apply to the base case. The numbers shown here are the TCs that would occur if all retail customers paid only market prices for their generation services.

POSTCOMPETITION CASE

The postcompetition case differs from the base case in two ways. First, customers are assumed to face RTP and to adjust their time-of-use demands accordingly. That is, customers cut demands during high-price periods and increase consumption during low-price periods, which leads to a higher load factor. Also, if overall prices go up or down, overall demand will go down or up. Second, suppliers, no longer operating under an embedded-cost-recovery regime, retire those generating units that are unable to produce sufficient revenues to cover both variable and avoidable fixed costs. We simulate this latter condition by retiring enough of these uneconomical units to bring the reserve margin down to its precompetition level.

We assume for the current simulation that state regulators in the Northwest would impose a cap on retail prices to ensure that they do not increase above regulated prices. The Montana legislature passed a law to cap electricity prices from July 1998 through June 2000 at their July 1, 1998, levels. The California legislature and PUC imposed a 10% price cut, which translates into a roughly 15% cut in the price of generation. We assumed that TCs would be refunded to customers in the Northwest and collected from customers in California through the energy charge (i.e., in ¢/kWh).

As shown in Table 5, the combination of RTP and a price cap leads to essentially no change in total electricity consumption in the Pacific Northwest. On the other hand, RTP combined with a 15% cut in the price of generation leads to a 4.6% increase in both consumption and load factor in California. The California load-shape changes free up transmission capacity so that electricity flows from the Northwest to California increase by 4% from the base case.

Table 5. Pre- and postcompetition electricity use, with postcompetition customer response to real-time pricing

	Pacific Northwest	California	Total[a]
Electricity use (GWh)			
Precompetition	242,800	250,100	493,000
Postcompetition	242,800	261,500	504,300
Load factor (%)			
Precompetition	69.4	59.0	68.9
Postcompetition	68.6	61.7	71.5

[a]The totals are the electricity-consumption-weighted sums of the values for the two regions. The postcompetition load factor is higher than the load factor in either region because the Northwest is winter peaking and California is summer peaking.

Because peak demands in the two regions are virtually unchanged between the base case and the postcompetition case, no uneconomical generating units are retired (the second factor discussed at the beginning of this section).

Market prices in both the Northwest and California increase slightly (by 6%, as shown in Table 6) in spite of the 4% increase in electricity sales from the Northwest to California. These price increases occur because demand is higher in California, leading to the use of more-expensive generating units.

Table 6. Pre- and postcompetition electricity prices (¢/kWh and percentage change from the base case)

	Pacific Northwest	California
Market price	3.02 to 3.19 (+6%)	3.11 to 3.31 (+6%)
Market price + transition costs[a]	1.91 to 1.89 (-1%)	3.96 to 3.37 (-15%)
Regulated price	1.91 to 1.90 (0%)	3.96 to 3.92 (-1%)

[a]For this case, the PUCs are assumed to cap retail electricity prices in the Northwest at the precompetition regulated price and in California at 85% of the precompetition level.

As the retail price of electricity changes from market price to market price plus TCs to regulated price (Table 6), producer profits also change. (Profits are defined here as revenue minus avoidable costs.) If prices in the Northwest are allowed to increase from their regulated values to market levels, producer profits will increase dramatically from the authorized recovery of unavoidable fixed costs of $1.89 billion to $5.05 billion. Most of this $3.16 billion increment can be assigned to shareholders; none of it is needed for depreciation or interest payments on bonds, but some is needed for taxes. In California, a shift from regulated to market prices would reduce utility recovery of unavoidable fixed costs from $3.68 billion to $2.12 billion.

The ORCED analyses suggest that, absent regulatory intervention, retail competition would increase profits for producers in the Northwest and lower prices for consumers in California at the expense of consumers in the Northwest and producers in California. However, state regulators may be able to capture some or all of the increased profits and use them to lower electricity prices in the low-cost region. Perhaps the most straightforward way to allocate the costs and benefits to retail customers is through development of transition-cost charges or credits. With this option, the consumers in both regions can benefit from competition.

The bottom line from this analysis is that increased competition *can* benefit retail customers in high-cost regions without harming customers in low-cost regions. Such a desirable outcome, however, is not automatic. State regulators may have to intervene to be sure that what would otherwise be additional profits for the producers in the low-cost region are used to lower prices to retail customers.

APPLICATION: TRANSITION-COST TRUEUP MECHANISMS

The design and implementation of workable cost-recovery and trueup mechanisms that meet key policy goals are critical unresolved problems (Hirst and Hadley 1998). To quantify the ability of different mechanisms to meet such goals, we used ORCED to simulate the operations of a hypothetical utility within a larger system of interconnected generating and transmission facilities.

We ran several cases with ORCED to simulate the effects of exogenous and endogenous changes on the market price of electricity and the utility's TCs. By exogenous, we mean factors that are outside the direct control of the utility for which we calculate TCs. Exogenous factors include changes in regional loads, fuel prices, and generating capacity. By endogenous, we mean factors that are primarily within the control of the utility. Such factors include generating-unit heat rates, retirement of generating units whose revenues do not cover avoidable fixed O&M costs, and renegotiation of nonutility-generator contracts.

SCENARIOS

We began by creating a utility that faces a substantial TC problem. The utility has 7,200 MW of generating resources, including two nuclear units with very high fixed costs and three nonutility-generator contracts with costs well above market prices. This utility is embedded in a larger region that contains an additional 56,600 MW of generation. The region's peak demand is 54,000 MW, of which 6,000 MW are accounted for by the retail customers of our utility. We assume that there are no transmission losses, costs, or constraints between our utility and the rest of this region.

Under these base-case conditions, the utility's generation revenues for the analysis year total $1,096 million, its variable costs are $832 million, its (avoidable) fixed O&M costs are $246 million, and its capital costs are $359 million. (Capital costs, equivalent to unavoidable fixed costs, include depreciation, income and other taxes, interest payments on bonds, and allowed return on equity.) Thus, the utility loses $342 million, of which $147 million represents the utility's authorized return on equity and $195 million is the actual net-income loss. This utility's TC problem is reflected in the substantial difference between the total cost of its generation (3.85¢/kWh) and the market price of power (2.94¢/kWh).

In addition to this base case, we ran 32 simulations testing different combinations of exogenous and endogenous changes (Table 7). Key ORCED results include the TC that the utility experiences in each case and the market price of electricity (the annual average of the time-varying competitive price in the regional bulk-power market). ORCED computes the savings achieved by the utility's generation-cost-cutting activities, and it calculates the allowed transition charge and the price of generation to retail customers. The transition charge is the per-kilowatt-hour payment that customers make to the utility for allowable TCs. ORCED results (Fig. 9) suggest that it is difficult to design a mechanism that meets both customer and utility objectives: as market prices decline (benefitting customers), TCs increase (hurting shareholders).

Table 7. Scenarios used to analyze alternative cost-recovery and trueup mechanisms

1.	Base case
	Vary exogenous factors only
2.	Increase regional load 5%; regional load shape unchanged
3.	Decrease regional load 5%; regional load shape unchanged
4.	Increase regional heat rates 5%
5.	Decrease regional heat rates 5%
6.	Increase regional forced-outage rates 3%
7.	Decrease regional forced-outage rates 3%
8.	Decrease regional generating capacity 2300 MW by retiring uneconomical units
9.	Increase regional generating capacity 2300 MW with new combined-cycle units
	Vary endogenous factors only
10.	Make nonutility generators 2 and 3 dispatchable; guarantee earnings to the nonutility-generator owners
11.	Decrease utility heat rates 5%
12.	Retire 625 MW of utility generating units with high O&M costs
13.	Cut utility fixed O&M costs by 10%
	Vary exogenous and endogenous factors
14-17.	Decrease regional heat rates 5%; vary four endogenous factors
18-21.	Increase regional heat rates 5%; vary four endogenous factors
22-27.	Utility retires 625 MW of uneconomical units; vary six exogenous factors
28-33.	Cut utility heat rates 5%; vary six exogenous factors

MECHANISMS AND RESULTS

We analyzed seven specific mechanisms:

1. Fixed TC recovery: The utility receives 100% of the predetermined, PUC-approved TC. Here, this amount is equal to the base-case (expected) calculation of TCs.

2. Full TC recovery: The utility receives 100% of the allowed TC for the situation that actually occurs. This mechanism adjusts the TC amount based on changes in both exogenous and endogenous factors. Thus, utility shareholders receive no credit for any generation-cost reductions that the utility achieves.

3. Full TC recovery for exogenous factors only: The utility receives 100% of the allowed TC for the exogenous situation that actually occurs. Because this mechanism ignores endogenous factors, utility shareholders receive full credit for any generation-cost reductions that the utility achieves.

4. Fixed retail price: The amount of money the utility receives is determined by the requirement that the sum of the market price of power plus the transition charge is equal to a predetermined retail price for bulk-power generation services. In this analysis, that price is the expected (base-case) value of market price plus allowed transition charge.

5. Retail-price reduction: The amount of money the utility receives is determined by the requirement that the sum of the market price of power plus the transition charge is equal to some percentage, between 0 and 100, of the base-case value.

6. Cost sharing: The utility receives less than 100% of the TC for the exogenous situation that actually occurs (Mechanism 3) plus all of the cost-reduction it achieves.

7. Performance-based rate: The utility receives 100% of the allowed TC, based on the exogenous situation that actually occurs (Mechanism 3) minus an adjustment based on a predetermined reduction in utility generation costs.

Table 8 summarizes results across all 33 scenarios on the performance of the seven mechanisms relative to key policy objectives; see Hirst and Hadley (1998) for details. All the mechanisms, except for Mechanism 2 should be simple to administer. (It is no accident that so many of these mechanisms can be implemented without undue controversy because we eliminated many mechanisms that failed this all-important test.) All the mechanisms prevent retail generation prices from increasing. However, retail prices often move in the opposite direction of market prices for mechanisms 2, 4, and 5.

The first four mechanisms do well in ensuring that the utility faces the same market forces that its competitors do. All the mechanisms except for the second do well in encouraging the utility to adopt cost-cutting actions by allowing it to keep most or all of these savings.

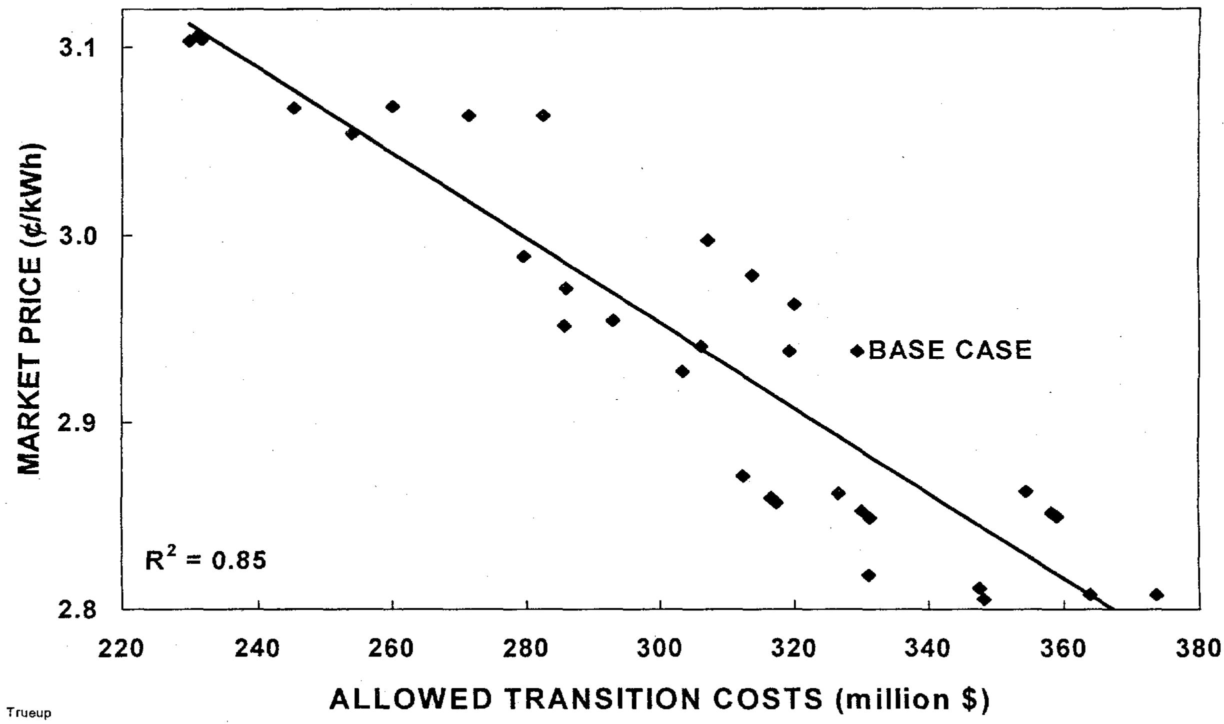

Fig. 9. **Bulk-power market prices as a function of allowed transition costs for 33 cases in which various exogenous and endogenous factors are varied.**

Table 8. Performance of mechanisms in meeting key public-policy objectives[a]

Objective/mechanism	Fixed recovery (expected value)	100% recovery for exogenous and endogenous factors	100% recovery for exogenous factors only	Fixed retail price (expected value)	5% price cut	Utility gets 100% of its cost reductions	
						+97% of recovery for exogenous factors	-$10 million
Simple to administer	Y	N	Y	Y	Y	Y	Y
Retail prices							
- Do not increase from base case	Y	Y	y	y	Y	Y	Y
- Move with market prices	Y	n	y	N	N	y	y
Utility earnings							
- Respond to market forces	Y	Y	y	y	-	-	-
- Respond to utility cost reductions	Y	N	Y	Y	Y	Y	Y
Little risk of over- or under-recovery	n	n	Y	Y	N	y	y

[a]A "Y" means that the mechanism consistently performs well on this objective, a "y" means that the mechanism generally performs well, a "-" means that the mechanism's performance is neutral or mixed, an "n" means that the mechanism generally performs poorly, and an "N" means that the mechanism consistently performs poorly.

APPLICATION: CARBON REDUCTIONS IN ECAR

In response to a request from the Ohio PUC, we analyzed the carbon emissions from the electricity sector in the East Central Area Reliability (ECAR) Agreement area, focusing on Ohio (Hadley 1998). ECAR is the regional reliability council that includes Ohio and Indiana as well as parts of Kentucky, Illinois, Maryland, Michigan, Pennsylvania, Virginia, and West Virginia.

Analyzing the costs of alternative carbon-reduction policies is particularly pertinent to the ECAR region because of its heavy reliance on coal. While coal accounts for just over half (51%) of total U.S. electricity production, its share is 82% for ECAR as a whole and 86% for Ohio. In this study, we focused on carbon taxes as the policy mechanism to reduce electricity-related carbon emissions. (In chapter 6, we focused on the effects of improved end-use energy-efficiency technologies on carbon reductions.) From an analytical perspective, a carbon tax and a cap on carbon emissions with trading (cap and trade) are equivalent. Consider a tax of $X/ton of carbon that limits carbon emissions to Y tons a year. A cap set equal to Y tons would result in a price of emissions allowances of $X/ton.

Using data and projections from EIA, the Ohio PUC, and other sources, we constructed an ECAR base case for 2010. We set the transmission limit between Ohio and the rest of ECAR at 6000 MW, which was more than enough to permit unconstrained trading between the two regions. (Because transmission was unconstrained, we were able to use the much faster single-region version of ORCED for this analysis.) We structured ORCED to optimize the ECAR generation mix for 2010 to minimize avoidable costs. Table 9 shows two base cases. The first shows results if demands are kept at their original values. The second case allows demands to vary in response to changes in overall electricity prices and in response to RTP. The second case also limited generating capacity to those units that recover essentially all of their avoidable costs through electricity sales; plants requiring a capacity payment were retired or not built.

Incorporating customer response to price changes lowers the peak demand by almost 10% with almost no change in total energy use. The amount of gas-fired combustion-turbine capacity online in 2010 is cut by more than 9000 MW because of this substantial reduction in peak demand.

Table 9. ORCED base-case results for ECAR in 2010

	Supply-only adjustments	Supply and demand adjustments
Market price, ¢/kWh	2.41	2.99
Capacity price, $/kW-year	53.0	1.2
Total price, ¢/kWh	3.27	3.01
Production cost, ¢/kWh	2.37	2.29
Peak demand, MW	104,800	92,220
Energy use, GWh	583,000	581,760
Carbon emissions, million tons	136.9	137.2
Generating capacity by type (MW)		
Nuclear	6,730	6,730
Coal	83,350	82,540
Oil	2,430	2,430
Gas	17,790	8,480
Hydro	760	760
Total	111,060	100,930

Having established a base case intended to represent the supply and demand responses to competitive bulk-power markets in 2010, we next analyzed the responses to increasing levels of a carbon tax. Here, too, we examined the supply responses and the demand responses separately and together.

With a tax of $25/ton, electricity price is up 4%, electricity demand is cut by 3%, and carbon emissions are cut by almost 4%. With a tax of $50, electricity price is up 21%, demand is down 8%, and carbon emissions are cut by 9%. Finally, at $75, price is up 28%, demand is down almost 12%, and carbon is cut 33% (Fig. 10).

Carbon reductions increase nonlinearly with an increase in the carbon tax. At levels of a carbon tax below about $20, the carbon reductions are driven primarily by demand reductions. At levels of a carbon tax above $50, on the other hand, carbon reductions are driven primarily by supply reductions. Figure 10 shows that between $20 and $50, the supply-only response to a carbon tax is greater than the combined (supply plus demand) response. This behavior occurs because the carbon tax reduces demand enough to render unprofitable the combined-cycle units that would otherwise be built.

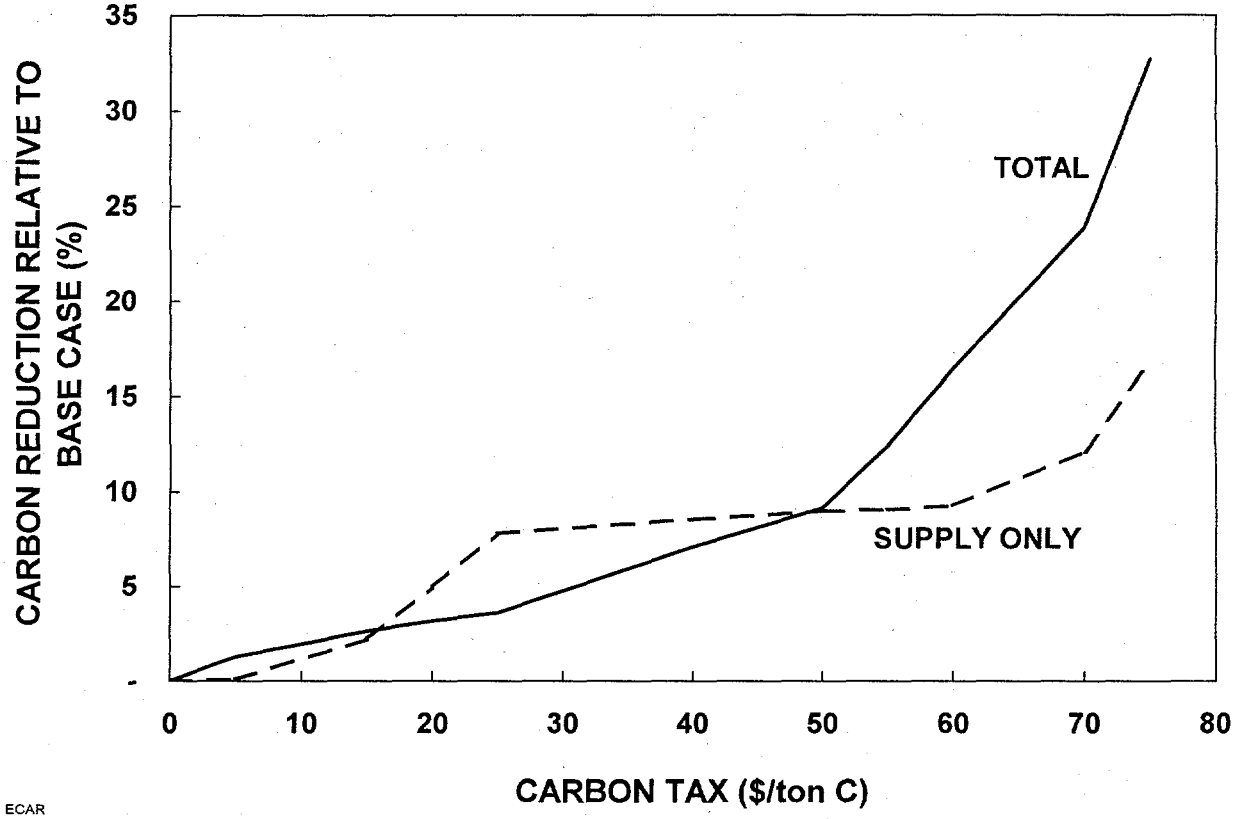

Fig. 10. **The effects of a carbon tax on carbon emissions from the ECAR electricity sector holding demand constant (supply-only curve) and allowing both demand and supply to respond to the tax.**

CONCLUSIONS

The Oak Ridge Competitive Electricity Dispatch (ORCED) model is a simple strategic computer model useful for analysis of various bulk-power issues. The focus of this spreadsheet model is competitive generation markets and the associated transmission grid that "transports" electricity from generating units to distribution centers.

We developed the model to examine a variety of issues, including:

- the environmental effects of electricity production in a competitive industry (with a focus on carbon emissions) and policies that affect emissions;
- the profitability (and therefore the market acceptance) of different types of generators, including those that might become available because of more research and development;
- the effects of competition at the bulk-power and retail levels on consumers and producers in high- and low-cost regions; and
- the effects of different generating-asset ownership patterns and transmission configurations on horizontal market power.

Because ORCED is a relatively simple model, analysts can use it to model a variety of situations. It is sufficiently flexible to permit modification or expansion with little difficulty. Compared to the more accurate, but much more complicated models, ORCED's simplicity reduces the amount of time and effort required to prepare inputs for the model, run the model, and review and interpret outputs from the model.

As is true of any mathematical representation of complicated physical and economic systems, ORCED contains many assumptions and limitations.

- It treats only one year at a time. (Although it is feasible to run ORCED for several years, linking the results from one year to the next is not simple.)
- It treats generation only (i.e., it treats transmission in a very simple fashion and ignores distribution and customer-service costs).

- Its use of load-duration curves to model system demand subsumes the details of hour-to-hour load variations (which eliminates some opportunities for cost-effective trading between regions).

- It ignores the detailed operating characteristics of generating units, such as minimum startup and shutdown times and the variation in heat rates as a unit goes from minimum to maximum output.

- It treats only two regions, which ignores the opportunities for trading electricity with other regions.

- Its use of "derating" factors for many power plants, rather than probabilistic treatment of forced outages, may lead to an underestimation of market prices.

Although useful as is (as demonstrated by the examples discussed in Chapters 6 through 9), the model could be enhanced in several ways. First, we could improve the treatment of electricity trading between regions. In reality, the times of system peaks are not necessarily coincident in adjacent regions. Modifying ORCED's load-duration curves might allow us to capture more of the potential trading opportunities than the present version of ORCED does.

Second, we could increase the number of regions modeled beyond the current two. One possibility would be to create a third region (representing the rest of the interconnection in which the first two regions are located) that is modeled very simply (e.g., with a surplus-capacity curve, as shown in Fig. 5).

Third, the present version of ORCED includes only two seasons for a given year with bid prices required to be the same in both seasons. To study horizontal-market-power issues, we could increase the number of seasons (using one season to represent, for example, the 100 highest-priced hours) and allow different price bids for different amounts of capacity (i.e., to test the effects of withholding capacity) for each season.

Fourth, we could expand the amount of detail on the financial performance of each generating unit. Additional information on the capital structure, earnings, depreciation, taxes, and interest payments would be useful for some analyses.

Finally, we could expand the number of pollutants analyzed beyond CO_2.

Although we developed ORCED as an in-house research tool, we are glad to share it with others. Those interested in using ORCED should contact the lead author (HadleySW@ornl.gov).

In summary, ORCED includes the key features required for analysis of competitive bulk-power markets. Although it lacks the details of large, sophisticated models, it offers important strengths. In particular, the model is easy to use and it can be run very quickly. Thus, analysts can test many different situations in a limited time. Finally, the model's simplicity enhances the ability to glean insights from model runs. As Barker et al. (1997) note, "You cannot be a true believer in competition and remain an agnostic about sector structure." ORCED, as the four examples here demonstrate, allows one to analyze bulk-power sector structure, operations, competition, and costs.

ACKNOWLEDGMENTS

We thank James Turnure, our U.S. Environmental Protection Agency program manager, for his support, interest, and advice throughout the course of this project. We thank Gale Boyd, Laura Church, Chris Marnay, and Terry Morlan for their very helpful comments on a draft of this report. We thank Fred O'Hara for editing the report and Ethel Schorn for managing the approval, printing, and distribution processes.

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