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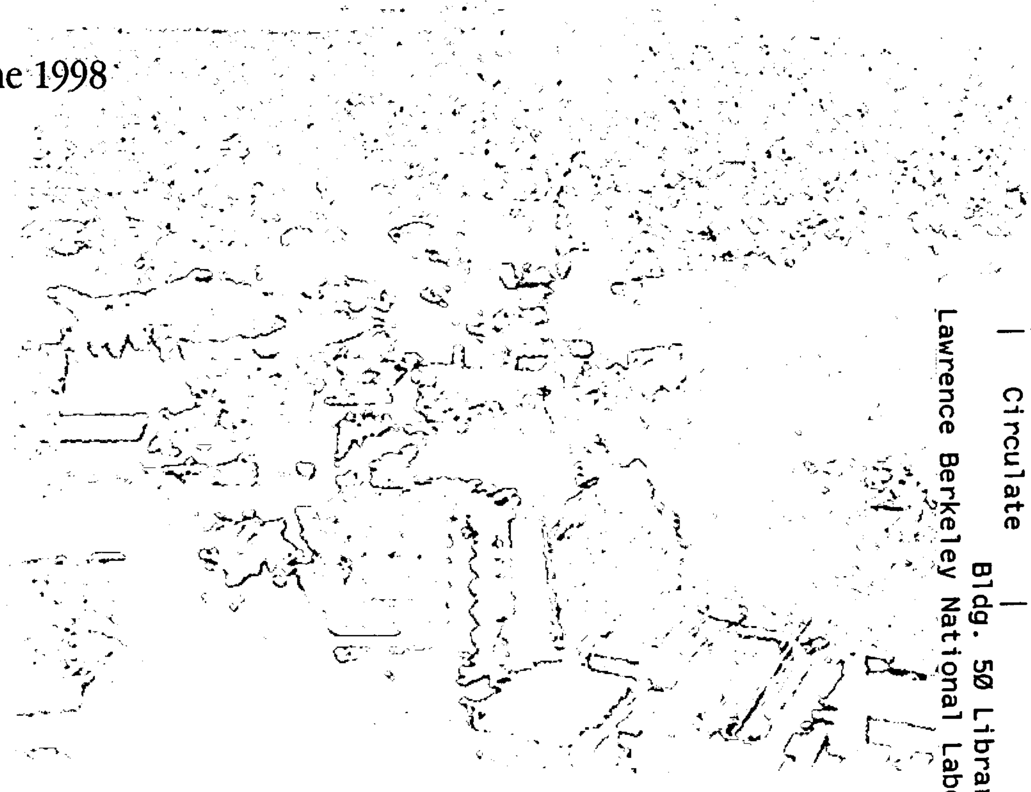

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Acronyms and Abbreviations

AB 1890	California State Assembly Bill 1890
ANPC	Adjusted Net Present Cost
BRPU	Biennial Resource Planning Update
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CTC	Competition Transition Charge
DISCO	Distribution Company
DOE	United States Department of Energy
DSM	Demand Side Management
EDF	Environmental Defense Fund
Elfin	Electric Utility Financial & Production Cost Model
EPRI	Electric Power Research Institute
ER94	1994 Electricity Report of the California Energy Commission
FERC	Federal Energy Regulatory Commission
ICEM	Iterative Cost-Effectiveness Method
IID	Imperial Irrigation District
IOU	Investor Owned Utility
ISO	Independent System Operator
ITRE	Iterative Test for Resource Evaluation
LADWP	Los Angeles Department of Water and Power
MEP	Market Equilibrium Plan
NPC	Net Present Cost
O&M	Operation and Maintenance
PG&E	Pacific Gas and Electric
PURPA	Public Utilities Regulatory Policy Act
PX	Power Exchange
QF	Qualifying Facility under the terms of PURPA
RFP	Request for Proposal
RPS	Renewable Portfolio Standard
RWG	Renewables Working Group
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMUD	Sacramento Municipal Utility District
SO4	Standard Offer #4 QF Contract
TSC	Total Social Cost
WEPEX	Western Power Exchange

Introduction

The California Public Utilities Commission's (CPUC) historic decision of December 20, 1995 signaled the beginning of a new era for the state's electric utility industry. Prompted by some of the highest electricity rates in the nation, the Commission's decision started the phase out of the regulated world of protected utility customer bases and guaranteed returns on investment and replaced it with plans for a competitive environment in which electricity generators will market their product to intermediaries as well as directly to end-use customers. With some modification, the CPUC's vision for a competitive power market was adopted and endorsed by the California State Legislature with the passage of Assembly Bill 1890 (AB 1890), a bipartisan electric industry restructuring bill signed into law by Governor Wilson on September 23, 1996. The new, restructured market for electric power will likely be cutthroat, price-driven, and commodity-oriented; however, the sustainability and environmental impact of generation technologies will be important to some customers, and green marketing strategies are emerging. Nonetheless, restructuring appears to pose significant problems for renewable energy generators, who stand to lose the existing support mechanisms that have helped make their relatively higher-cost resources financially viable. To the extent that AB 1890 offers support to the renewables industry, it is temporary in nature and must be renewed by future legislatures. Should renewable power cease to be viable under restructuring, California would lose the sustainability, environmental, and fuel supply diversity benefits that renewable energy offers.

In this study, we attempt to model the California power sector in the next century in order to assess the potential impact of restructuring on renewably generated electricity. Specifically, we use the Elfin production costing and capacity expansion planning model to address three broad research questions: (1) Are new renewable resources likely to be viable in California's competitive electric industry of the next century? (2) What policies could foster the growth of renewable resources? And (3), what are the costs and benefits associated with these policies? These questions are important not just in California, but across the country and internationally as many other states, regions, and countries have begun to restructure their electricity industry.

In assessing the impact of restructuring on renewables, we focus on several new policies designed to support renewables in a market environment. While competition may favor renewable resources that produce during peak periods (e.g., solar), competitive power markets are likely to be detrimental to renewable resources in as much as the benefits associated with renewables (fewer emissions, resource diversity, reduced fuel price risk exposure) will no longer be considered in a regulated resource planning system. With restructuring, existing renewables support mechanisms—including regulatory proceedings and a variety of state and federal policies—will be modified and in some cases eliminated. New policies already under consideration to support renewables include: minimum renewables purchase requirements (MRPR), also called renewable portfolio standards (RPS), and surcharge-funded renewables programs. Carbon tax policies, if enacted, would also have a major impact on the viability of renewable generation. We attempted to model variants of all three of these policy options in this work. Provisions to support green marketing have also been debated and facilitated, but are not modeled or assumed in this study.

1.1 Approach

Although our general approach is applicable to other jurisdictions considering restructuring, our focus in this report is on the effects of restructuring on renewables in California. California is among the states furthest along in restructuring, and a large share of national renewable generation is in the state. Data sets with detailed operational parameters for generation resources are publicly available, although are rapidly becoming outdated. And, the Elfin model has been specifically adapted for California's regulatory process and has been updated to reflect changing market conditions.

In keeping with our goal to look beyond the uncertainties associated with California's four-year transition period to full competition, we focus on the quarter century after 2005. By looking beyond the transition period, we are able to put aside some complex problems and uncertainties associated with the transition, notably the recovery of stranded assets through the competitive transition charge (CTC) and the renewal of subsidies. Under AB 1890, utilities must retire their traditional ratebase, and the traditional arrangement under which a plant is constructed by utility investors with cost recovery in rates guaranteed for prudent investments disappears. The net outstanding ratebase is to be collected during the transition through the CTC. We assume that this process, along with utility divestiture, will be completed on schedule and that at the beginning of our forecast period, 2006, all generators can be treated as independent competitors. Even though generation companies will likely hold multiple stations and local monopoly power may exist, we assume that each generator bids at its marginal cost and accepts the market share that such bidding provides. Moreover, that transmission constraints may create local market power is overlooked in this work because the computational demands and the limitations of our model argue against consideration of this issue; further, the importance and persistence of transmission constraints well into the next century is hard to gauge.

To determine the effects of restructuring on renewable energy resources, we use Elfin, an expansion planning and production cost model developed by the Environmental Defense Fund (EDF 1997). Elfin was developed in the context of California regulatory proceedings, but EDF has since modified the model to reflect expected market conditions. Traditional production cost models have simulated operations solely on the basis of minimizing cost. Elfin now estimates prevailing pool prices, including an energy payment to generators, and iteratively estimated payments to committed generators with pool prices below their bid prices, and to generators dispatched out of order for purposes of maintaining target spinning reserve levels. The current model version builds only resources that will be profitable over the lifetime of the project; that is, the net present value of the revenue stream exceeds the net present value of all costs for the project lifetime. More detailed information regarding Elfin algorithms is found in Appendix B.

Building a data set for the future California pool was the major task undertaken during this project. The pool is assumed to consist of the electricity demand and generation resources of the current three major California investor-owned utilities (IOU), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The source of the data for these three companies is the ER94 filings by the companies with the California Energy Commission (CEC). The new data set is built on the assumption that the demand forecast by the three current vertically integrated IOUs can be simply summed to represent the future pool demand, and that all of the assets reported by these companies represent the full complement of generating assets currently available to meet this load. Implicit in this assumption is the belief that bilateral contracting will behave in the same way as the pool, overall. That is, the fact that a large segment of demand will be met through bilateral agreements and that the prices for these sales need not directly reflect pool prices and payments can be overlooked, at least initially, because, overall, these transactions will reflect pool prices. Therefore, treating the whole pool as a single competitive market represents a reasonable first approximation of ultimate conditions. Imports to the state are treated as large generators that are also available to meet this demand. Imports from the Southwest are treated as a large coal generator, and imports from the Northwest are treated as a partial hydro and partial coal station.

The outcome of an Elfin run is a profit-maximizing *market equilibrium plan* (MEP) that details when and how many units of possible generic generating technologies will be constructed. An MEP is a construction program for all available generating technologies that guarantees all entrants are profitable but that no additional generator can be built profitably. That is, no additional economic entry is possible and the industry remains in a sustainable equilibrium. Further, of the market equilibrium plans found by Elfin's search algorithm, the one under which entrants make the most overall profit is deemed the best overall plan. In other words, investors in technologies cannot make more total profit with any other combination of new construction. Of course, like any economic concept of equilibrium, this approach represents an idealized outcome, but one that we believe approximates the likely real-world result.

Having established a base plan, we run several scenarios with different combinations of assumptions and renewable energy support policies. For example, we vary the growth rate of gas prices as this will significantly affect the types of resources that Elfin finds profitable. That is, with high gas prices, fewer combustion turbines and combined-cycle plants will make money in the new market environment and this would favor wind, biomass, and other technologies. We also vary capital costs of renewable and gas-fired technologies and assess the costs and benefits of renewable policy options, including carbon taxes, renewable purchase requirements, and renewable subsidies. Costs are defined as the costs of renewable resources in excess of the less expensive resources that Elfin would have chosen. The benefits are measured in terms of reduced emissions, fuel diversity, and energy independence. We quantify these benefits to the extent possible.

1.2 Organization of the Report

The rest of this report proceeds as follows:

- In Chapter 2, we provide some basic background information on support for renewables in California, on the expected operation of the power pool and bilateral markets, and on the three key policy types modeled here.
- In Chapter 3, we discuss the Elfin production cost and expansion planning model as well as key assumptions that we made to model the future California pool.
- In Chapter 4, we present results from the successful Elfin models runs.
- In Chapter 5 we discuss the implications of the study, as well as key areas for future research.
- Additional information on results, Elfin's expansion planning logic, and resource options can be found in the appendices.

Background

2.1 Overview

This chapter provides background information on the development of renewables in California, on the CPUC's restructuring decision, and on key provisions of California's restructuring legislation, AB 1890. We discuss the development of the renewables industry to highlight California's historic commitment to the development and growth of the renewables industry and to illustrate the importance of government policies in fostering this growth. We consider three types of policies: renewable purchase requirements, surcharge-funding subsidies, and carbon taxes. We pay particular attention to the role of the independent system operator (ISO), the power exchange, and the utilities in the restructured environment, and we discuss how market participants will be paid for energy and other ancillary services they provide.

2.2 Public Utilities Regulatory Policy Act and Qualifying Facilities in California

In response to the oil crisis of 1973 and in recognition of the United States' dependence on fossil fuels, Congress enacted the Public Utilities Regulatory Policy Act of 1978 (PURPA). The purpose of PURPA was to open the market to non-traditional electricity supply options in an effort to:

- increase the supply of electricity, leading to lower rates over time;
- reduce reliance on oil and gas, with their high price volatility; and
- increase system reliability by the presence of a large number of smaller facilities, since the probability that a number of facilities will fail at the same time is much smaller than the probability that one large facility will fail.

In response to the passage of PURPA and the adoption of Federal Energy Regulatory Commission (FERC) regulations in 1978, the CPUC established standards for the purchase of power from qualifying independent power facilities (QF). On January 21, 1982, the Commission issued Decision 82-01-103, which developed "standard offer" contracts describing the terms and conditions associated with utilities' obligations to purchase power from a QF at avoided cost. The standard offers represents a complete transaction, with prices, interconnection requirements, and other relevant terms. These offers were to be available to all QFs without exception or conditions.

The commission developed four standard offers—three short-run standard offers based on shortage and running costs of existing utility resources, and a long-run offer based on the costs of a new utility resource that could be avoided by purchasing power from QFs. Because the short-run offers did not appear to provide the desired stimulus to the growth of the QF industry, the CPUC developed an interim long-run offer to be used while it developed the final long-run offer. The interim long-run standard offer contracts guarantee fixed-priced payments over long time periods (up to 10 years) to provide QFs with some certainty in the return on their investments.

Primarily as a result of the fixed-price contracts, the QF industry has grown from a handful of projects to a mature industry representing well over 10,000 MW of installed capacity, although less than this amount in terms of dependable capacity (Kito 1992). Table 2-1 shows the dependable capacity of Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and the total for California in 1994. The non-utility category can be further broken down and it shows QF capacity as well as some self generation (see Table 2-2).

Table 2-1. Dependable Capacity for California Utilities

	PG&E		SCE		SDG&E		State Total	
	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
Oil & Gas	7,080	35%	8,746	43%	1,951	63%	22,579	40%
Coal	0	0%	1,938	10%	0	0%	4,239	7%
Geothermal	756	4%	0	0%	0	0%	1,036	2%
Nuclear	2,160	11%	2,327	12%	430	14%	5,326	9%
Hydro	4,540	22%	785	4%	0	0%	6,830	12%
Pumped Storage	1,188	6%	217	1%	0	0%	3,222	6%
Non-Utility	3,648	18%	4,177	21%	236	8%	8,297	15%
Imports	852	4%	1,913	9%	486	15%	5,136	9%
Total	20,224	11%	20,103	100%	3,103	100%	56,665	100%

Source: "Electricity Report," California Energy Commission, November 1995, Table 7-1.

Table 2-2. Dependable Capacity for California Utilities' Non-Utility Generation

	PG&E		SCE		SDG&E		State Total	
	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
Fossil Cogeneration	1862	51%	2,090	50%	162	69%	4,114	50%
Biomass	627	17%	302	7%	7	3%	936	11%
Geothermal	154	4%	701	17%	0	0%	855	10%
Hydro	36	1%	13	0%	3	1%	73	1%
Wind	167	5%	165	4%	0	0%	333	4%
Solar	1	0%	364	9%	0	0%	365	4%
Self-Generation	801	22%	542	13%	64	27%	1621	20%
Total	3648	100%	4,177	100%	236	100%	8,297	100%

Source: California Energy Commission 1995. "Electricity Report." November. Table 7-1.
Note: Dependable capacity for wind and hydroelectric is usually reduced by 80% to reflect the "firm" or "effective" capacity. This occurs because wind and hydroelectric power projects generally have low capacity factors compared to other resources.

Because the ten-year fixed-price portion of the final long-term Standard Offer #4 (SO4) contracts was based on predictions of high future fossil fuel prices, the terms of the contract were very lucrative for QF projects. At its peak, the net statewide subsidy to renewable QFs under SO4 contracts probably exceeded a billion dollars annually. Once QFs reach the end of the ten-year, fixed-price portion of the SO4 disappears, however, the contract payment becomes variable and is based on the pool price plus an approximately 2.5 ¢/kWh capacity payment. Given that the earlier predictions of high fossil fuel prices were incorrect, and that the market price for electric power is now quite low, QFs with SO4 contracts face a significant revenue drop as they move from the fixed to the variable-price portions of their contracts. In general, revenues to renewable QFs are halved in this shift, and the sudden drop in revenues to renewable QFs is referred to as the "cliff." By the end of the restructuring transition period, the beginning of our forecast period, virtually all renewable QFs holding SO4 contracts will have exhausted the long-run fixed-price portion of their contracts, and will have fallen off the "cliff." In the base case of this study, we assume that renewables compete entirely without any subsidy; that is, all resources are left to compete on economics alone.

2.3 The California Restructuring Decision

2.3.1 Reorganization of the Industry

Independent System Operator

In its December 1995 decision, the CPUC indicated that it intended to establish an independent system operator (ISO) to operate the utilities' transmission systems. Previously, the investor-owned utilities (i.e., PG&E, SCE, and SDG&E) owned and operated their transmission systems. The primary reason for transferring control from the utilities to an ISO is that the utilities could use the transmission system strategically to their benefit and to the detriment of other market participants. The Commission, in its decision, enumerated four immediate and lasting advantages of an ISO:

1. The state will achieve a permanent and functional resolutions of transmission access disputes between the transmission-owning utilities and those dependent upon access to the system.
2. There will be a lasting efficiency gain resulting in cost savings due to combining the now distinct control function of many entities under the auspices of a statewide independent system operator.
3. There will be an operational efficiency inherent in a transmission network which has no economic interest other than fostering open access and the facilitation of supply from generators irrespective of their ownership.
4. There will be a consistent pricing system for the use of the common network facilities that prevents cost shifting and supports the competitive market. (CPUC 1995, p. 30).

Power Exchange

As outlined by the CPUC, the Power Exchange (PX) will be separate from the ISO and will "function as a clearinghouse by providing a transparent market for generation with hourly or half-hourly price signals evident to users and long-term investors" and thus "provide critical information vital to informed market decisions by generators, wholesale buyers, and end users." (CPUC 1995, p.47). The PX will be open to all generators, including municipalities and out-of-state generators, and will work by accepting supply and demand bids and through this process determine time-differentiated market-clearing prices. The utilities are required to bid their generating capacity into the PX and to buy electricity from the PX to serve their customers.

Utilities

Utilities will continue operate their generation and distribution facilities and will be responsible for procuring energy for their full-service customers.

Timetable

The California ISO and the PX became operational in April 1998.

WEPEX and Payment Provisions

The CPUC left many implementation issues unresolved. In particular, the CPUC ordered the investor-owned utilities to submit proposals to the Federal Energy Regulatory Commission (FERC) for the design and operation of the ISO and the PX. The investor-owned utilities formed a working group, WEPEX, and submitted their initial proposal on April 29, 1996 to FERC. On November 29, 1996 FERC approved key parts of the WEPEX filing, conditionally authorizing the establishment of the ISO and PX, subject to a "Phase II" filing of March 31, 1997. For the purposes of this analysis, the WEPEX filings were used to delineate the responsibilities of the ISO and the PX and how bids would be submitted and market clearing prices for energy and ancillary services would be established.

The PX will accept both supply and demand bids. The supply bids will include three parts: the energy bid, the no-load bid, and the start-up bid. The PX will determine the market clearing price, develop a preferred schedule, and submit this schedule to the ISO. The ISO will recommend changes to reduce transmission congestion and, based on this information, the PX will resubmit its schedule. After the final schedule is chosen by the ISO, the PX will provide the supply, demand, and price schedules to the buyers and sellers. This final price schedule is considered a financial commitment. Any unexpected changes in demand will be met with supply from the shorter-term hour-ahead market, at the prices of the hour-ahead market.

2.3.2 Proposed Minimum Renewable Purchase Requirement

In its December 1995 decision, the CPUC indicated its support for a minimum renewable purchase requirement (MRPR). The MRPR would require that a certain percentage of a state's annual electric use (or capacity) come from renewable energy. To implement the policy, a renewables purchase requirement (as a percent of energy or capacity sales) would be applied and enforced upon retail electric suppliers in the state. Individual obligations would be tradeable through a system of renewable energy credits (RECs), which is designed to add flexibility in meeting the MRPR. In advocating such a policy, the Commission left many issues unresolved: what is the appropriate level for such a MRPR, should requirements be equally applicable to all distribution companies (DISCO), what type of noncompliance penalty should be established, should the MRPR be established on a MW or MWh basis, is a transition strategy necessary, are floors for certain technologies appropriate, etc.? A Renewables Working Group (RWG) was authorized by the Commission to assess and provide recommendations on many of these issues. The RWG Report was submitted to the CPUC on August 23, 1996 (Renewables Working Group 1996).

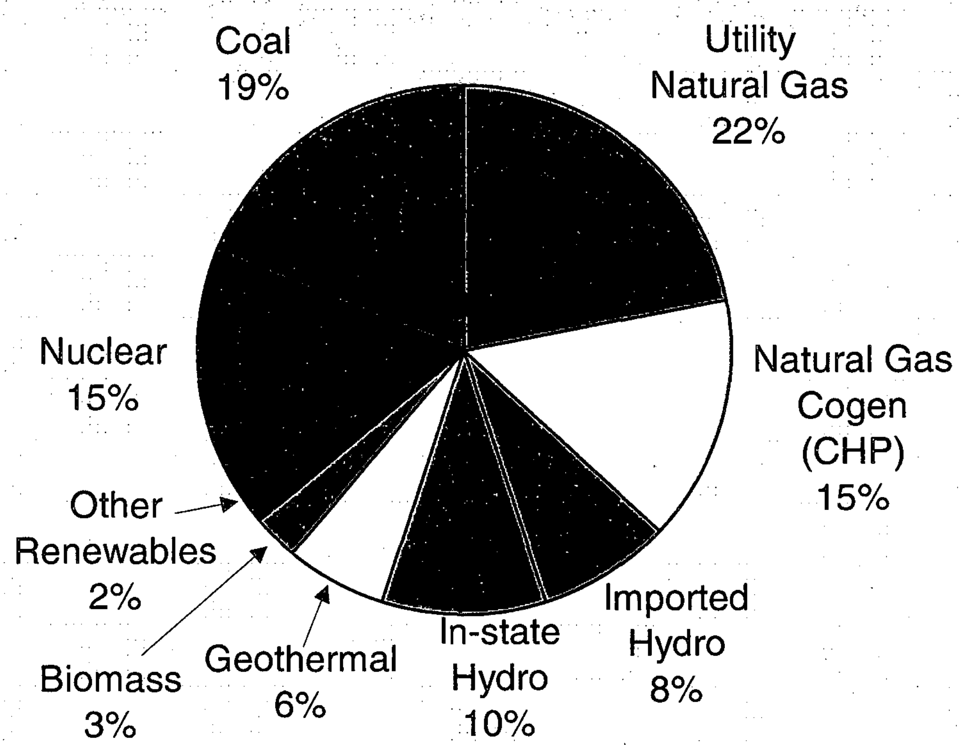
2.4 Legislative Action: AB 1890

Although the CPUC initiated the process of electric power industry restructuring, it was the State Legislature's passage of AB 1890 which will actually bring about restructuring in California because changes beyond the jurisdiction of the CPUC are required. In contrast to the CPUC's MRPR approach, AB 1890 established a surcharge-funded program to partially support existing, new, and emerging renewables in the state between January 1998 and December 2001. The policy will sunset on December 31, 2001, and no additional long-term renewables policy is proposed. Total renewables funding over this four-year period will apparently equal $540 million. These funds are to be collected by the three largest investor-owned utilities (IOUs) through distribution surcharges. The California Energy Commission is to administer the distribution of these funds, with the provision that not less than 40 percent of the monies collected by the IOUs go either to existing or new and emerging renewable projects. AB 1890 directed the CEC to issue a report to the legislature outlining its recommendations on fund distribution. Finalized in late March, 1997, the CEC report calls for a variety of different approaches including: technology-specific production incentives for existing technologies, competitively auctioned production incentives for new technologies, multiple requests for proposals (RFP) using different mechanisms for emerging technologies, customer incentives and customer education (CEC 1998).

2.5 Alternative Policies for Fostering Renewables

In addition to an MRPR and surcharge-based renewables support mechanisms, there are numerous other alternative policies to foster the development of renewable resources. These policies include: imposing criteria pollutant and/or carbon externality taxes on traditional generation sources (e.g., oil, natural gas, coal) and fostering the development of voluntary green markets. Here we examine only three policy types: an MRPR, a surcharge-based production credit, and a carbon-oriented externality tax.

Figure 2-1. Overall Resource Mix for California Power Generation 1994



2.6 The Policy Question

The overall fuel mix of power generated for use in California is shown in Figure 2-1. The state's approximately 250 TWh of electricity consumption is derived from a surprisingly diverse fuel mix. This is partially fortuitous, since there is considerable hydro in the state and nearby, because the state's nuclear stations have operated successfully, and because there is a considerable geothermal resource. There are no coal stations in California, but coal is a factor both because some of the imported electricity is generated from coal and because California utilities own coal-generating capacity out-of-state. California has also actively sought diversity through its policies to foster renewable generation and cogeneration. In fact, California has more than 90 percent of the total U.S. generation of each of geothermal, wind, and solar, and about 15 percent of biomass.

Looking into the next century, however, most of the nuclear capacity was commissioned in the 1980s and so will be nearing retirement by the 2000 teens, the hydro resource is fully developed and output is unlikely to increase significantly, and, most importantly, the pie is growing significantly. Population growth in the state is expected to be around 1.5 percent per year for some time, raising electricity demand. The net effect of these processes will be an inevitable increase in the thermal share in generation, making the state more dependent on imported fuel and less likely to meet Kyoto greenhouse gas emission reduction goals. The challenge is, in the face of falling nuclear and hydro shares in generation, to ensure that the share of the other carbon-free generation does not decline, and, preferably, increases.

The key policy question under consideration in this study then is how can the tools we have available to simulate the future California market be used to evaluate the effectiveness of alternative policy instruments to enhance the renewable share of generation, and how can these simulation tools be improved?

Modeling the California Pool

3.1 Overview

In this chapter, we briefly discuss Elfin's logic for calculating pool prices, including energy, commitment, and spin payments, and discuss key assumptions that were used to create the California pool data set. For the pool data set, we relied primarily on the Elfin data sets that were created for the 1994 Electricity Report (CEC 1995), with some modifications. The expansion planning options were developed using a variety of sources, including the Elfin data sets, EPRI (1993), and DOE (1994).

3.2 Elfin's Pool Price Payments and Iterative Test for Resource Evaluation (ITRE) Logic

3.2.1 Elfin's Pool Price Payments

Energy Payments

The energy payment concept in Elfin works on the assumption that the bid price of the most expensive unit operating in a particular time period (e.g., hourly) sets the pool price for all operators. Elfin does not currently calculate hour-by-hour marginal energy payments, but does calculate (a) the average marginal energy payment over as many as 99 subperiods from a typical week from up to 13 seasons, and (b) the payments that each resource block will receive during each time period. Because the computational requirements of calculating so many subperiods during the search for an MEP are prohibitive, only three subperiods and four seasons were used during the search, although, once the MEP has been found, subsequent estimations of pool prices were made using more subperiods and seasons. The average marginal energy payments in each subperiod are calculated by multiplying the marginal energy costs by the time marginal and summing these blocks. For example, if during the peak period one unit was marginal for 75 percent of the time at a cost of 3 ¢/kWh and one unit was marginal for 25 percent of the time at a cost of 5 ¢/kWh, the average marginal cost during the peak period would be 3.5 ¢/kWh $[(0.75 \times 3.0) + (0.25 \times 5.0)]$. This final amount would be reported in the Elfin results. Elfin also disaggregates these results by resource block—essentially providing the amount of time each resource block would be operating during each subperiod and the average payment this unit would receive for the time that it runs. While nothing in the algorithm requires it, in this work we assume that all generators bid their marginal cost. This is equivalent to assuming that no market power exists and no generator can gain by strategic bidding.

Because generators are not perfectly reliable and there is always a positive probability that load cannot be met, the social cost of outage is properly included as an ultimate high cost supply resource. Therefore, in some instances, the energy payment will be greater than the cost of running existing units. This occurs when the system is expected to be unable to meet load because of unexpected outages, for example. In these instances, we have specified the value of energy not served as $1.00/kWh and this drives up the pool price considerably during peak periods. Another way to think of this is that as the pool develops, some customers may submit demand-side bids, indicating that they will curtail their energy at a price of say, of $1.00/kWh. If the ISO has no other options, they would curtail this load and the $1.00/kWh would be on the margin for a short period of time. While this assumption has a powerful effect on the peak pool price and, therefore, seems to be of great significance and worthy of a sensitivity analysis, in practice prices are so peaky that the overall effect on the year-round pool price is not great.

Commitment Payments

If power systems operated smoothly with generators started, stopped, and dispatched instantaneously, then the energy payment alone would ensure generators covered their fuel costs. However, operations in practice are complex and many other services than simple energy inflow must be provided by generators. Commit and spin payments reflect rewards for two such services.

Because plants cannot be started and stopped instantaneously, generators are forced to run at times when the pool price is below their marginal operating costs. Elfin estimates a commit payment that ensures that during any subperiod, the last generator committed during the subperiod is made whole for its full operating costs. This commit payment is distributed to all generators.

This approach has proven to be a poor representation of actual practice as it is emerging in California, in which generators self-commit, numerous generators are kept running to meet reliability requirements under private ISO must-run contracts, and the ISO purchases four ancillary services in open markets (Klein 1997). Simulating this system is not feasible for long-range planning, so we accept commitment and spin payments as a reasonable proxy.

Spin Payments

At times of high load it becomes more difficult for systems to maintain their spinning reserve requirement, which is a small margin of generating capacity kept fully functional and ready to replace any failing generator. When combustion turbines are started, thermal generators are backed down to provide the spinning requirement. As such, these generators are not creating as much revenue as they potentially could. Elfin makes these generators financially whole by providing them with a spin payment equivalent to their sacrificed revenues.

3.2.2 Elfin's ITRE Logic

For the purpose of this work, the expansion planning logic of Elfin has been considerably restructured. All expansion planning has solves two problems, an upper one in which new capacity is chosen, and a lower one in which existing plant is operated and the pool prices calculated. For the lower problem, Elfin uses a load duration curve model to dispatch resources. Elfin first creates a load duration curve for each specified subperiod and then dispatches the least expensive resources, subject to user-specified constraints (e.g., a unit must operate throughout the week if its committed to meet load any time during the week). For the upper problem, Elfin uses the Iterative Cost Effectiveness Method and the Iterative Test of Resource Effectiveness (ICEM-ITRE).

ICEM tests the cost effectiveness of resources in each year of the optimization. ICEM will calculate the cost effectiveness of all resource options and build the most cost effective, as long as it is cost effective in its first year. ICEM continues to build the most cost-effective resources until no further resources are cost effective and then moves on to the next year. With ICEM, once a resource is built, it cannot be taken out of the resource mix.

ITRE tests the cost effectiveness of resources in each year that resources are eligible for inclusion, and adds the resources in years in which the benefits are greatest. Net benefits might be greater in later years because technology costs could have decreased. ITRE's advantage over ICEM is that ITRE might wait for a few years to build a new technology in order to capture larger benefits, whereas ICEM might build in the early years and thereby foreclose more cost-effective opportunities in the future. Also, ITRE can eliminate chosen resources and can find better solutions as a result.

During this project, EDF has modified Elfin's ITRE logic considerably in order to reflect new market conditions. Under old ITRE logic, Elfin added new plants to the resource mix if they reduced the total net present value of costs of running the entire system during the time period under consideration. In the pool, actual system operations are assumed to be identical to current approaches. That is, the ISO runs the system through time no differently than an existing IOU. What is quite different in the pool is the decision-making process for capacity expansion. Under the new ITRE logic, Elfin only adds new plants if they are able to cover their fixed and variable costs (i.e., if they break even). The most profitable projects are built first and ultimately all projects that break even, or better, are built. An example illustrating how the old and new logic could result in different resource plans is helpful. Imagine an instance where building a new combined-cycle unit would displace an inefficient unit and that these "production" benefits were more than offset by the annualized capital and operation and maintenance (O&M) costs of the new plant. In this case, overall costs are reduced and Elfin builds the new plant. However, imagine now that this new plant does indeed reduce production costs, but the revenues this plant receives are not sufficient to cover its annualized capital expenditures. Thus, under the new logic, even though this plant reduces overall system costs during the time period under consideration, the plant is not profitable and, therefore, will not be built.

The paradigm adopted in the new ITRE logic is that of an investment community which invests in the most profitable resources first. This community will continue to invest until no more profitable opportunities exist. Unfortunately, unlike the simple cost-minimization algorithm of the previous ITRE, the search for plans in which no more profitable entry is possible is unstable and time consuming, and no unique solution exists. All MEPs must be found and the best chosen from among them. All MEPs represent sustainable market equilibria in which all entrants earn positive net present profits on constructed units, but no additional unlimited-entry generation units can be profitably built. Since all existing capacity will, in general, become less profitable as more capacity enters, its profitability cannot be considered in choosing the best MEP. Therefore, the choice of best MEP must be based on the profitability of unlimited-entry generation only. The paradigm, therefore, is one where investors in the unlimited-entry technologies (e.g., gas combined cycle) will find the MEP which maximizes their profits.

As explained above, we adjusted Elfin's iterative test for resource evaluation (ITRE) logic to select the most profitable resource options to be built, rather than those that minimize overall net present cost of a centrally planned utility. In practice, the search for a combination of new capacity construction is completed in two steps. In the first step, the traditional minimum-cost solution is found. This is the expansion plan that Elfin would select if it were run for the previous centrally planned, cost minimizing, regime. We start the search for a market-driven construction plan from this point because we know that in a perfect world, the cost-minimizing and profit-maximizing plans should be the same, or, at least very similar. In the second step, with this given starting plan, Elfin switches to its market simulation mode and calculates projected pool prices, including energy, commitment, and spin payments. Given these projected payments, Elfin evaluates resources based upon their profitability and builds the most profitable resource in its most profitable year. In this search, Elfin is restricted to adding one resource at a time. Elfin then recalculates projected pool prices, and again evaluates potential resource additions. If a previously added resource becomes unprofitable at any time during the search, it is deleted from the expansion plan. Elfin continues this iterative process until no additional resources can be profitably added to the system, and yet all the resources that are in the plan can be profitably built. Unfortunately, there may be several plans that meet this criteria, although, in practice, they tend to be similar plans. To select among these "market equilibrium plans" (MEPs), Elfin selects the one that is most profitable to the new entrants as the "best" plan.

3.2.3 Limitations of Elfin

There are several limitations associated with using Elfin to model the California pool. The computational demands of searching for MEPs is daunting, often taking days of computer time. A tradeoff of accuracy and computer time is inevitable. One of the major sacrifices was the need to run Elfin with only four seasons and three subperiods, meaning the year is represented by 12 load duration curves. While we ran the expansion plan with fewer time periods in order to use the program more efficiently, we then often, in separate production cost runs, developed expected pool prices using a greater number of time periods.

Another limitation associated with Elfin is that the model does not take into consideration transmission constraints. In the near term, these constraints are important. Limits on transmission lines will prevent complete trading between areas and thus the system as whole will not be operated as efficiently as it could in the absence of these constraints and pool prices will differ across the state. While these constraints are important in the near term, we assume that these constraints will be largely eliminated by the year 2005.

A third limitation of the Elfin model is that it does not simulate strategic bidding. For example, we expect that hydro resource owners will strategically bid into the pool in order to maximize revenues. This problem arises because Elfin bases its logic on actual costs, whereas the pool will operate based upon bids submitted by resource owners, who will likely bid strategically. If an external source of strategic bids were available, they could simply replace the cost data in Elfin and all could proceed as before. Unfortunately, there is no easy solution and thus we assume for the purposes of this project that no strategic bidding occurs. Bushnell and Borenstein (1996) look at market power and strategic bidding in the California pool using a Cournot mode and find that the California utilities may be able to exert considerable market power in the pool.

3.3 Key Assumptions in the California Pool

3.3.1 Resources Included in Data Set

We include generating resources from the ER-94 data sets of Southern California Edison (SCE), Pacific Gas & Electric (PG&E), and San Diego Gas & Electric (SDG&E) in the data set (see Table 3-1). The CEC will not release the ER-96 data sets into the public domain. We do not include resources from Los Angeles Department of Water & Power (LADWP), Sacramento Municipal Utilities District (SMUD), or Imperial Irrigation District (IID) (see Table 3-2). The rationale for the exclusion of the municipalities and irrigation districts is that it would be difficult to determine the current and future amounts that they might bid and/or buy from the pool and that these amounts are likely to be relatively small compared to the size of the entire pool. While LADWP was expected to import roughly 19 percent of its energy for 1995, this energy is primarily from the Northwest and Southwest and not from other California utilities. In addition, LADWP is expected to export only a small amount of energy (approximately 2%). SMUD, by contrast, is expected to import nearly 75 percent of its energy, with 2,978 GWh to come from SCE and PG&E. While this represents a large amount of SMUD's power (31%), this is only a small fraction of expected pool sales.

Table 3-1. Peak Week Capacity Included in California Data Set for 1995 (MW)

	PG&E	SCE	SDG&E	TOTAL
Utility-Owned				
Nuclear	2,160	2,324	430	4,914
Oil & Gas	6,740	9,856	1,879	19,607
Oil & Gas‡	874 (347 in)	517 (225,† in)		
Coal	0	1,943	0	1,943
Geothermal	677	0	0	677
Hydroelectric	5,015	1,580	0	6,595
Pumped Storage	1,158	217	0	1,375
Subtotal			2,309	
QFs/Self Generation*	4,054	4,159	315	8,528
Imports				6,600

‡ Long-term reserve
† Huntington, Unit 4
*Includes non-firm QF/self-generation capacity

Table 3-2. Capacity, Sales, Imports, and Exports for LADWP, SMUD, and IID

	LADWP	SMUD	IID
1995 Annual Peak (MW)	5,692	2,362	624
1995 Sales (GWh)	27,911	9,430	2,654
Imports (GWh)	5,223	~6,983	na
Exports (GWh)	626	0	na

Source: ER 1994 files.

In addition, we have represented all of the electricity inflows as generic imports from the Southwest and Northwest. These imports behave as monolithic units. The Southwest is entirely coal, while the Northwest has a hydro lower block and a coal upper block. A more complete analysis would estimate out-of-state resources and associated loads and allow utilities and other private power producers to bid in only excess energy into the California pool.

In terms of actual resources, we included all existing utility assets, including nuclear, coal oil/gas, geothermal, hydroelectric, and pumped and battery storage units, although we did make some modifications. Notably, we took out all penalty factors to ensure that plants were dispatched economically.[1] We included only nuclear, wind, and solar PV units as must runs, and, finally, we did not implement local reliability constraints. We have also included the qualifying facilities found in the three utilities' data sets. We assume that the marginal costs for all of these units is zero or, in other words, that all energy that the QFs produce will be accepted into the pool. This assumption is least plausible for cogeneration units because these units will incur variable costs when they operate. However, in the absence of detailed information on the steam load of each generator, a zero marginal cost assumption is reasonable.

There are, however, some resources that were in the utilities ER94 data sets that we excluded for this analysis. In particular, we exclude the biennial resource planning update (BRPU) resources because the majority of these contracts will not be implemented, DSM resources because the savings estimates are potentially uncertain, and utility-specific contracts because we chose to model these as blocks of energy being imported from the Northwest and Southwest.

3.3.2 Load Forecast and the Annual Load Profile

We combine the load forecasts that were found in the ER94 data set for the planning areas of SCE, PG&E, and SDG&E, taking into consideration that the utilities had different peak days. The combined load for 1995 was approximately 38 GW, growing annually at a rate ranging from 1.3 to 2.2 percent. To simplify, we use a base case of 1.5 percent load growth and specify the high and the low load growth rates at three and zero percent, respectively.

3.3.3 Retirements

Because the ER94 data sets only extend through 2013 and provide little information on expected retirements, and because we expect substantial numbers of retirements within the time frame of this study, we chose to set retirement dates for the nuclear facilities and oil and gas plants. For other types of plants (e.g., hydroelectric, coal, and QFs), we assume no retirement within the time frame of this study on the theory that this capacity will likely be replaced in kind upon retirement.

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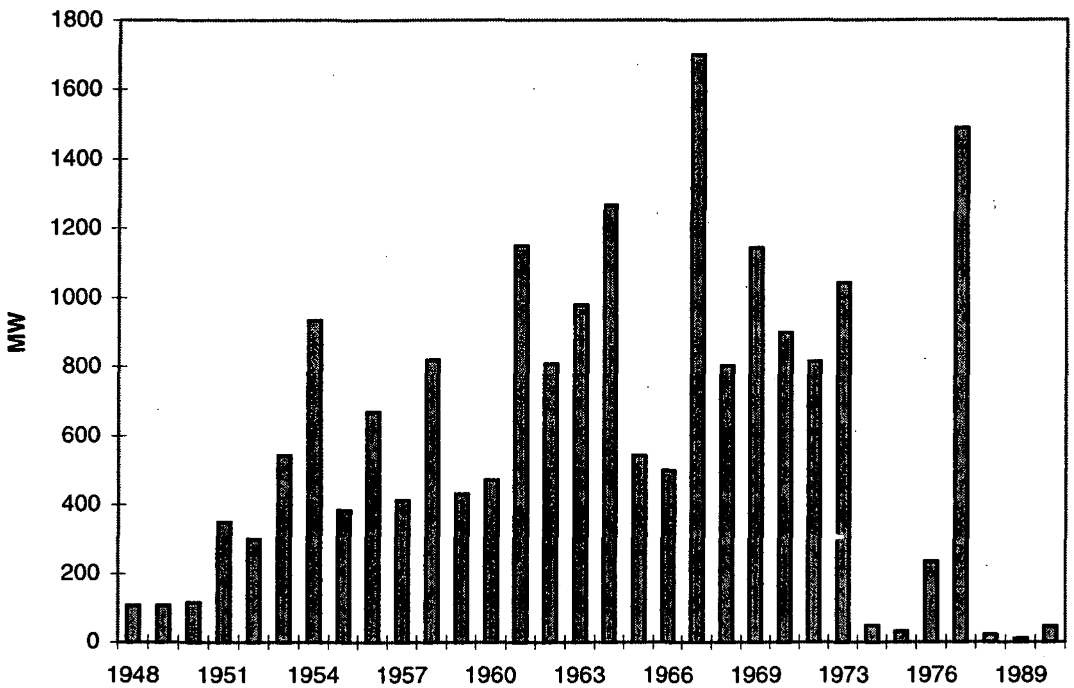
1 These penalty factors are usually added to account for aspects of operations not represented in the model.

Figure 3-1. Gas and Oil Plant Commission Dates



For the nuclear units, we assume that they will be retired after 30 years of operation. This means that the nuclear plants that supply California will retire between 2013 and 2018. We also assume a fairly ambitious retirement schedule for the oil and gas plants in the next century, in large part because many of these plants were built in the 1950s and 1960s (see Figure 3-1) and, therefore, will be quite old in 2010 and beyond. Assuming that these plants have engineering lives of 40 to 50 years, many of these plants will retire between 2000 and 2020. Exactly when these units retire will have important implications for the pace of new construction of generation in California.

We considered a number of scenarios for retirements, including (1) imposing retirement at the end of the engineering life of the plants (2) using the utilities' retirement scenarios through 2013 and imposing mandatory retirements at the end of the engineering lives for the remaining plants, (3) imposing no retirements, but tying repower to retirements and allowing Elfin to retire units economically, and (4) retiring units economically. Ultimately, we selected option 2. The ER94 data sets for PG&E and SDG&E provided data on retirements and plants put on short-term reserve, which we interpreted as early retirement. The ER94 data set for SCE did not provide retirement dates, but retirement dates for some of the plants were obtained from Elfin runs for the ER94 report. For the remaining plants, we implemented the following retirement scheme:

100 MW or less:	retired in 2014 if greater than 40 years old retired in 40th year for remaining plants
101 to 300 MW:	retired in 2014 if greater than 45 years old retired in 45th year for remaining plants
301 MW or greater:	retired in 2014 if greater than 50 years old retired in 50th year for remaining plants
Combustion Turbines:	retired in 2014 or in 30th year, whichever is earlier

No retirement dates were specified for hydroelectric units, coal plants, or QFs. We assume that no hydroelectric plants retire during the time frame of this study. The ER94 data set does not provide retirement dates for SCE's nearly 2,000 MW of coal capacity, roughly three quarters of which came on line between 1969 and 1971. In addition, SCE added 50 MW in 1979, 320 MW in 1986, and 50 MW in 1993. We assume that this capacity does not retire because it will be profitable and would be replaced when it is retired. We use the utilities' estimates of QF retirement through 2013, after which we assume no units retire. We assume that cogeneration plants are tied to an industrial facility and would be replaced upon retirement.

We treat geothermal capacity slightly differently. ER94 indicates that geothermal capacity degrades over time, and we assume that this degradation continues, with the steam reserves depleted by 2026.

3.3.4 Cost of Existing Resources

We obtained much of the cost information for existing resources from the ER94 data sets, although we greatly simplified the fuel costs and developed fixed O&M costs for oil and gas plants. The variable O&M costs for existing plants varied considerably across plants and utilities. SCE used \$0.00098/kWh for its oil and gas plants; SDG&E used \$0.00014/kWh; and PG&E used values varying from \$0.000004/kWh to \$0.005/kWh. PG&E also specified variable costs for its geothermal units of about \$0.001/kWh and for its coal plants, varying from \$0.0014/kWh to \$0.0041/kWh.

The utilities generally used different gas price forecasts. We simplified all of the fuel costs and used base case, high, and low cost scenarios in our analysis. For natural gas, we assume that the price in 1995 varies from the summertime low of \$1.78 to \$2.25/GJ in December with real growth rates of zero, 1.5, and three percent.[2] For SCE's existing coal units, we simplified the utility's estimates of future coal prices, which ranged from \$1.01 to \$1.73/GJ

[2] Recent forecasts predict gas price increases in the 1% per year range

with real growth rates ranging from zero to 1.7 percent. We assume that the coal fuel costs represent contract prices and will not change during our study period. For new coal units, we assume that the coal price is $1.42/GJ in 1995 and escalates at 1.5 percent. In addition, the Northwest and Southwest imports are also tied to this generic coal price. For geothermal, we assume that geothermal operators pay for the steam at a rate of about $0.60/GJ, with real growth rates of zero, 1.5, and three percent. For nuclear plants, we assume fuel costs of approximately $0.005/kWh with a real growth rate of zero percent. Finally, we assume distillate fuel costs $4.58/GJ with real growth of 1.3 percent, and no fuel costs for cogeneration facilities, that is, cogenerators bid a zero price into the pool.

Fixed O&M for existing plants was not contained in the ER94 data sets. We assume that existing oil and gas plants (excluding combustion turbines) have fixed O&M costs of $50/kW, which is roughly double that of new plants. We recognize that the fixed O&M costs will be variable and higher for progressively older plants, but did not want to add this additional level of complexity to our analysis. Note that the fixed O&M costs do not affect the pool price, only the retirement decision. In addition, we did not include fixed O&M data for any other existing plants other than the oil and gas plants.

3.3.5 Resource Options

Some of most important assumptions in any capacity expansion exercise are the specifications of generic resource options. Computational constraints require that the number of options be small, while the desire to represent the true range of technical choices available argues strongly for a large number of options. The ITRE method used by Elfin is, fortunately, much less limiting in this regard than dynamic programming based methods, which quickly reach the limits of computational feasibility when numerous options are considered. For this analysis, we included the following 12 potential resource options:

- NG combined cycle
- NG combined cycle repower
- NG combustion turbine

- advanced coal
- coal gasification

- biomass
- geothermal
- solar thermal
- solar photovoltaic
- wind farm
- wind with combustion turbine

- nuclear

For each option, we specify low, medium, and high capital costs and a variety of operational parameters (e.g., variable and fixed O&M, heat rates, etc.). Appendix C provides a more complete description of the current cost ranges for these various technologies and explains how we chose the capital cost ranges for the technologies examined in this report. This appendix also presents emissions and offset values that are used.

In later work, simulations containing many more options have been conducted, notably ones in which the wind resource has been represented by 36 specific sites, rather than generically (Sezgen, Marnay, and Bretz 1998).

CHAPTER 4

Results of the Elfin Runs of the California Pool

4.1 Overview

In this chapter we present key results of our Elfin runs of the California market. A more expansive set of tables and figures detailing the results of each scenario modeled is presented in Appendix A. In the next section, we discuss the assumptions used for the policies modeled. These policies include imposing a minimum renewable purchase requirement, imposing carbon emission taxes, and providing subsidies to encourage the development of the renewable technology that appears closest to economic viability, namely wind. In the following section, we present the results of these runs. We report results for the construction of new renewable capacity. We also attempt to compare the benefits and social costs of renewables by reporting the emissions resulting from the various scenarios, thermal dependence, and natural gas usage, and the overall net present cost of running the system through the forecast period. We begin by presenting results of runs in which no policy is assumed and the effects of our three renewables environments, "neutral," "good," and "bad," can be plainly seen. Each of our policy cases is modeled under each of these three environments, but here we focus on the results of a "no policy" case under each environment and on other policies modeled in only the "neutral" environment. Results of policies modeled in the "good" and "bad" environments are shown in Appendix A, and serve primarily as sensitivity results for equivalent runs conducted under neutral environment assumptions. In the subsequent section, we present more comparative details of the simulations.

4.2 Scenarios and Policies Modeled in Elfin

Our approach is to conduct full Elfin ITRE runs for a limited set of policy cases under each of three economic environments. The three different future environments are:

1. conventional wisdom or best guess, called "neutral."
2. favorable to renewable technologies (i.e., high gas prices, etc.), called "good"
3. unfavorable to renewables (i.e., low gas prices, etc.), called "bad"

Growth in electricity demand in all three environments is assumed to be 1.5 percent per year. Table 4-1 specifies other aspects of these three economic climates. The actual dollar values of "high," "low," and "base" costs can be found in Table C-12 of Appendix C. In the good environment, coal and nuclear additions are not allowed in order to represent a future in which these resources are excluded on environmental or political grounds.

Table 4-1. Assumptions for Neutral, Good, and Bad Renewables Environments

	Neutral (N)	Good (G)	Bad (B)
Renewable Capital Costs	Base	Low	High
Gas-Fired Capital Costs	Base	Base	Low
Nuclear & Coal Included	Yes	No	Yes
Gas Price Growth (% per year)	1.5	3.0	0.0

Under each of the renewable environments, we modeled a number of policy cases in which efforts to promote the development of renewable technologies are estimated. We report here on the base case plus four example policy cases, as follows:

- Policy 0: no policy (i.e., no new or existing policies present)
- Policy A: non-hydro renewable purchase requirement (15% generation)
- Policy B: surcharge policy ($620M/year to lowest cost renewable)
- Policy D: 15 percent MRPR with technology bands (set at current market shares)

Note that our focus is on the quarter century beginning in 2005. As noted above, we assume no special preferences designed to benefit renewables are in place, other than the policies explicitly being modeled.

The three environments and five policy types combine for a total of 15 scenarios, although we were not able to simulate all cases satisfactorily, as is explained below. Using the adjusted Elfin logic described in Appendix B, we attempted and completed full Elfin runs for most of these cases. Not all of these scenarios are within the bounds of credibility, however. A wide range of improbable cases has been attempted due to our desire to (a) demonstrate the viability and potential pitfalls of our approach, and (b) identify some of the limiting or boundary cases. All cases are named with two-character names, for example, AN implies policy A, the purchase requirement is implemented in the (N)eutral renewables environment.

In this chapter, results are reported for all three Policy 0 scenarios, and for the AN, BN, and DN scenarios. Simulating Policy B created some special simulation problems that are described in Appendix E. Policy H was particularly troublesome and has been relegated to Appendix F. However, summary results are presented for all the N scenarios.

4.3 Results

4.3.1 Policy 0: No Policy

In our Policy 0 cases, renewable generation competes head-to-head with all other technology options. In this first set of runs, we sought to determine whether unsubsidized renewable generation would be viable in the California market under our best estimate of current costs and trends, and given other circumstances that are both favorable and unfavorable to renewables as represented in the good and bad environments. Results for the final forecast year, 2030, are summarized in Table 4-2, and cumulative new capacity construction is shown in Figure 4-1. Despite large new total capacity additions of approximately 40 GW, no renewable capacity is added. In fact, all new capacity is of just three types, repowers of existing units, new combined cycles (CC), and new combustion turbines (CT). This result reflects conventional wisdom that only new gas-fired capacity can compete in the future California market, absent subsidies, taxes, or significant increases in the gas price. The steady increase in thermal dependency results in a steady increase of carbon emissions. Per kWh carbon emissions rise from 113 g in 2010 to 126 in 2030 and because of increasing generation, total carbon emissions are 50 percent higher. Here then is the heart of the California dilemma. Absent policy intervention, while in many ways clean compared to electricity generation elsewhere, the power sector will become increasingly thermal dependent and increasingly undesirable from a greenhouse gas perspective.

Figure 4-1. Cumulative New Capacity Under Scenario ON

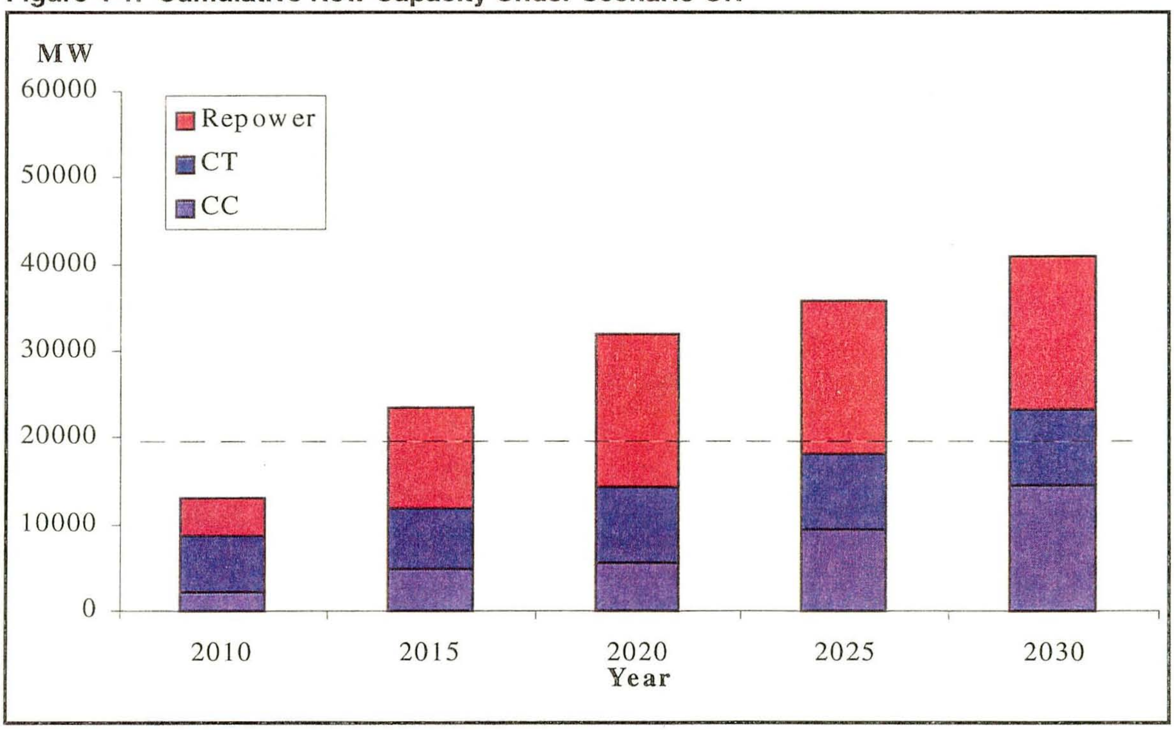


Table 4-2. Summary of Elfin Pool Results with No Renewables Policies

	Neutral (ON)	Good (OG)	Bad (OB)
2030 Cumulative New Renewable (GW)	0	85	0
2030 NOx Emissions (kt)	224	188 (84%)	152 (68%)
2030 Carbon Emissions (Mt)	40	21 (53%)	37 (94%)
2030 % Thermal	81%	36%	81%
2030 Gas Consumption (EJ)	1.6	0.5 (32%)	2.0 (125%)
NPV System Costs (10^9 $)	132	153 (116%)	102 (78%)

Table 4-2 indicates that renewable technologies would be built in California only under the favorable circumstances of the good environment (i.e., high gas prices and low renewable costs), but in this environment, a remarkable 85 GW of wind capacity is chosen, as can be seen in Figure 4-2. Because of the low capacity factor of wind generation, more capacity of this technology than thermal generation must be built to meet energy requirements. Wind generation is first built in 2016, by which time wind capital costs have fallen to $792/kW.[3] Furthermore, wind is the only renewable technology adopted, a result that derives directly from the fact that no artificial limits are imposed on the availability of wind generation at the assumed cost.[4]

In terms of NOx emissions, the *good* environment results in a 16 percent reduction from the neutral case, while the *bad* environment produces a 32 percent reduction. The *bad* environment results in greater NOx emissions reductions because low gas price growth (i.e., 0%) leads to greater gas generation displacing coal which has significantly higher NOx emissions per kWh generated. In contrast, the *good* environment results in a 47 percent reduction in carbon emissions, whereas the *bad* environment delivers only a six percent reduction, surprisingly little benefit compared to the reduction in NOx emissions. The *good* environment's sharp drop in carbon emissions is due to the increase in wind generation.

In the *neutral* and the *bad* environments, California remains dependent upon gas and other thermal technologies, such as coal, while the *good* case shows a marked reduction in thermal dependence and gas consumption. In both the *neutral* and *bad* environments, 81 percent of

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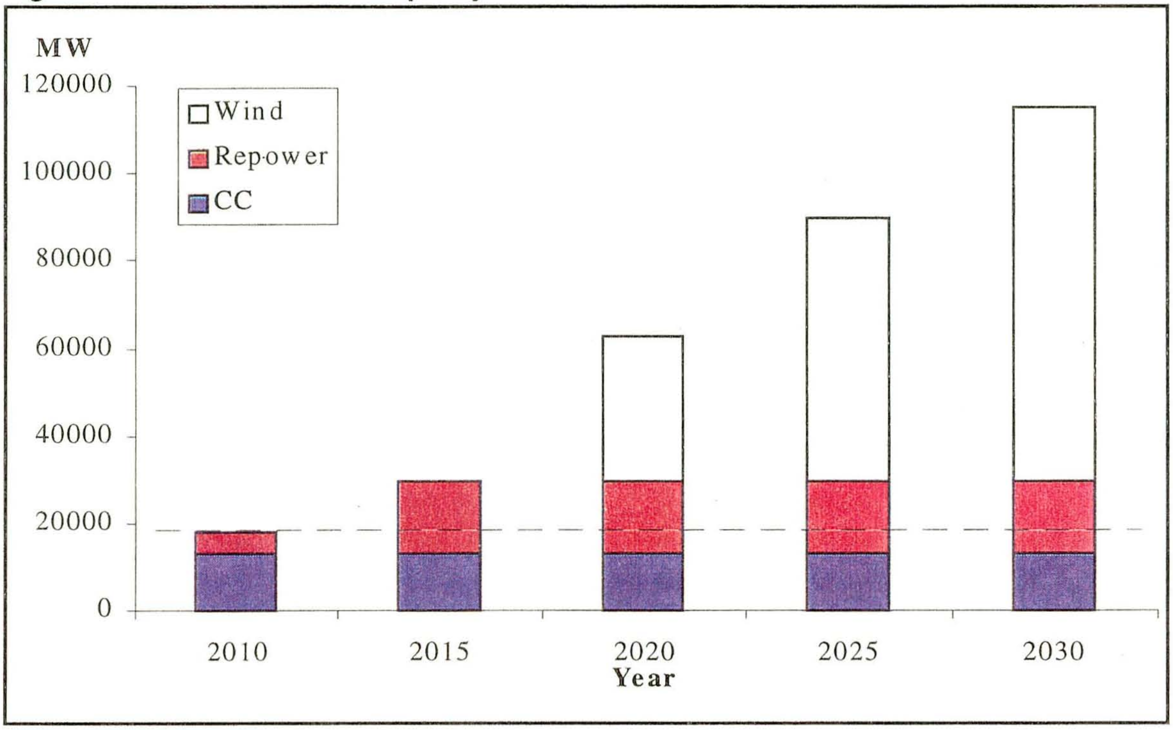
3 Note that in Elfin, technical change is represented by predetermined declines in costs and/or improvements in operating characteristics. There is no internal logic that relates costs and performance of technologies to indicators of technical experience, such as installed capacity.

4 In new work (Sezgen, Marnay, and Bretz 1998), the availability of new wind generation to the California pool relative to its cost is being studied to better understand constraints on the supply of wind. Of course, other constraints exist on the construction of generic resources, which should also be studied.

Figure 4-2. Cumulative New Capacity Under Scenario OG



the electricity generated comes from thermal technologies, while in the *good* case, only 36 percent of the energy comes from thermal technologies. Gas consumption in 2030 rises well above today's level of about 0.43 EJ in all three environments. It reaches 1.6 EJ in the *neutral* case, climbs to nearly 2.0 EJ in the *bad* case, and to 0.5 EJ in the *good* case.

System costs are driven mostly by gas price growth. The *bad* environment has lower costs because we assume a gas price growth of zero percent for this scenario, whereas we assume 1.5 percent gas price growth in the *neutral* case. The *good* environment has higher costs because we assume gas price growth of three percent, and this assumption leads to the construction of a technology with higher capital costs, namely wind.

The 0, or *no policy* case under the neutral environment (0N) serves as our base case for subsequent policy comparisons. The *good* and *bad* environments serve primarily to demonstrate that the model responds to test stimuli and shows how results might vary under diverse economic conditions. As with all simulations run, detailed results can be found in Appendix A.

4.3.2 Policies A and D: Purchase Requirements With and Without Technology Bands

In policy case A, we modeled a minimum renewable purchase requirement. Under this policy, we assume that 15 percent of energy must come from the cheapest non-hydroelectric renewable technology—wind. This compares with a current non-hydro renewables California energy share of about 11 percent (Renewables Working Group 1996). In general, existing renewable energy projects are assumed to persist into the indefinite future because we were unable to determine whether these technologies would fold for economic reasons or because they had reached the end of their engineering lives. The one exception is geothermal capacity owned by PG&E, which gradually degrades over time, and for which data were available in the PG&E data set. As a result of these assumptions, existing renewables meet a slowly declining percentage of the 15 percent purchase requirement, and new wind generation, clearly the least expensive technology under our assumptions, meets the remaining portion of the requirement.

In Policy D, we modify the MRPR by adding purchase requirements for specific renewable technologies. These technology bands are designed to ensure purchases of less competitive and more expensive renewable technologies, such as biomass and PV. We set the technology bands in Policy D at levels consistent with current market share.

The results of these runs are summarized in Tables 4-3 and 4-4, and cumulative capacity construction is shown in Figures 4-3 and 4-4.

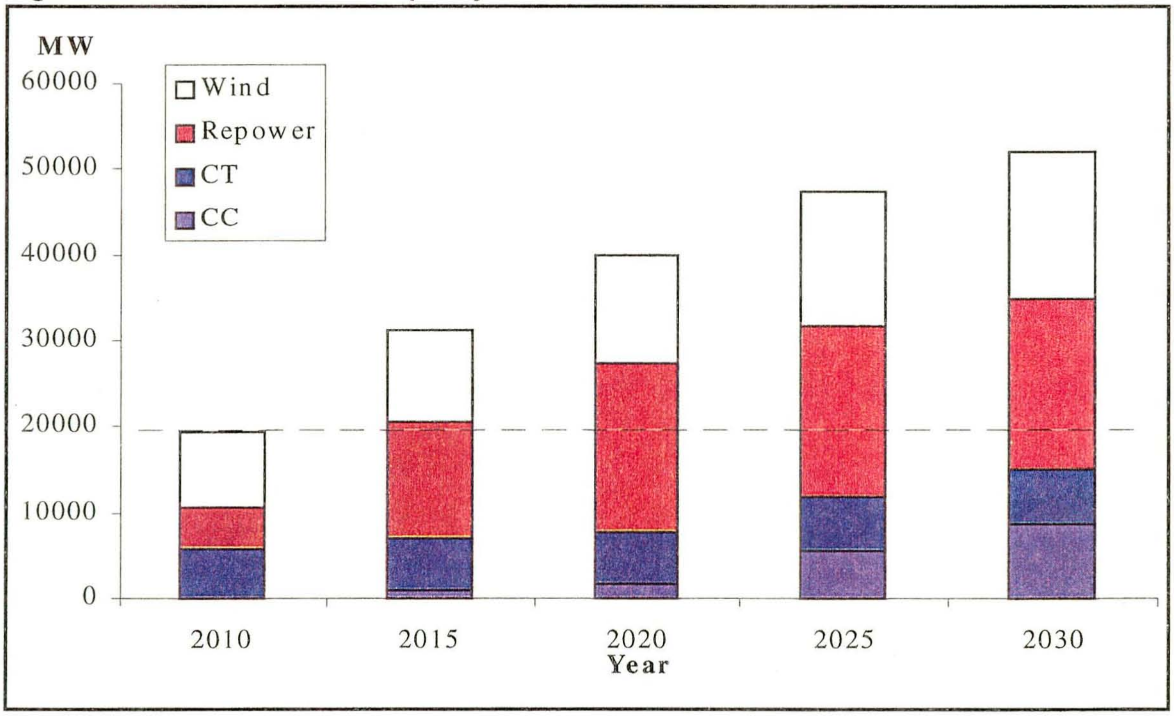
Table 4-3. Summary of Elfin Pool Results with a Straight Purchase Requirement and a *Neutral* Environment

	No Policy (0N)	15% Purchase Requirement Without Technology Bands (AN)
Cumulative New Renewable (GW)	0	17
2030 NOx Emissions (kt)	224	224 (100%)
2030 Carbon Emissions (Mt)	40	36 (91%)
2030 % Thermal	81%	71%
2030 Gas Consumption (EJ)	1.6	1.3 (84%)
NPV System Costs (10^9 $)	132	135 (103%)

Table 4-4. Summary of Elfin Pool Results with a Banded Purchase Requirement and a *Neutral* Environment

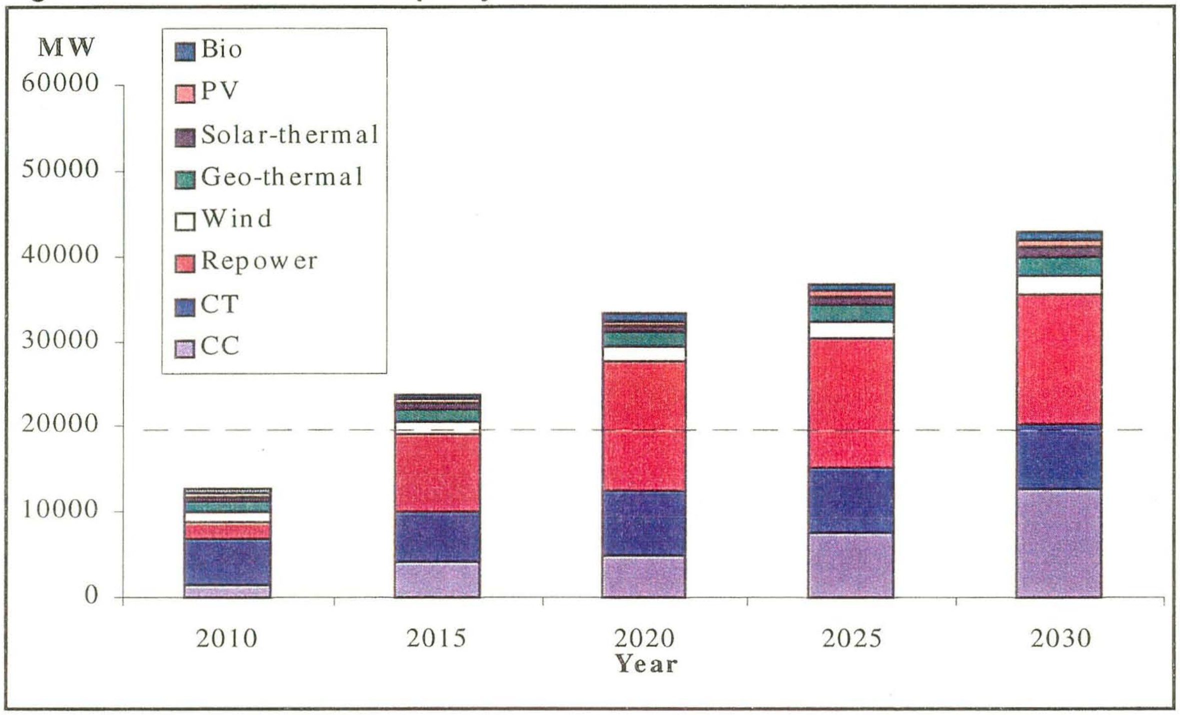
	No Policy (0N)	15% Purchase Requirement with Technology Bands (DN)
Cumulative New Renewable (GW)	0	7
2030 NOx Emissions (kt)	224	224 (100%)
2030 Carbon Emissions (Mt)	40	37 (93%)
2030 % Thermal	81%	73%
2030 Gas Consumption (EJ)	1.6	1.3 (86%)
NPV System Costs (10^9 $)	132	148 (112%)

Figure 4-3. Cumulative New Capacity Under Scenario AN



In both runs, NOx emissions are unchanged. This is a disappointing result and one not easily explained. One would certainly expect the fall in thermal generation to result in measurable NOx emissions reductions, but this is not the case. It could be that the generation being displaced is from clean new plants, and, at the same time, generation is shifting among generators in such a way that emissions from existing resources are increasing. This could also happen if the share of generation is shifting from air basins with more stringent regulations towards ones with less stringent regulations. However, this is a puzzle that cannot be resolved here. In future work, a more careful accounting should be made of the

Figure 4-4. Cumulative New Capacity Under Scenario DN



origin and shift in NOx emissions between these scenarios. In contrast, there is a slight drop in carbon emissions. Both policies result in reduced thermal dependence and gas consumption. However, Policy A does appear to result in more new renewable construction and lower carbon emissions, thermal dependence, and gas consumption than Policy D. This is not surprising given that the "bandless," least-cost MRPR approach of Policy A results in greater renewable energy generation. Policy A produces 33 TWh of new renewable electricity in 2030, all wind, whereas Policy B produces 28 TWh because of the higher overall cost of the mixed renewable generation compared to wind. In other words, while both policies result in higher renewable generation, Policy A is more effective than D from the point of view of pure renewable development because gas competes more effectively against the mix of technologies required by Policy D than against wind only in Policy A.

While both policies are more costly than the base case, the purchase requirement with technology bands is decidedly more expensive than the straight purchase requirement. Again, this is not surprising given that one of the goals of Policy D is continued purchases from more expensive renewable technologies. However, in both of these cases, sustained orderly development of renewable technology is assured, and this should be recognized as a benefit because this will avoid a "boom and bust" cycle.

4.3.3 Policy B: Surcharge Policy

In Policy B, a $620 million per year surcharge-based policy was simulated. While there are many ways to distribute surcharge monies collected to fund renewables programs (Wiser and Pickle 1997), we assume that monies are simply distributed to the least-cost renewable developers via an auction mechanism. It should be noted that the level of surcharge collection in this policy is quite large compared to many current surcharge policies and proposals. In California, for example, a total of $540 million is to be collected for renewables over a period of *four* years. Again, however, our goal here is to merely assess the viability of our approach and test some limiting cases. We did not actually choose the value of $620 million per year, as will be clear from the discussion below. However, we did seek to simulate an overall subsidy level in this general range because conventional wisdom during California's MRPR debate was that the cost of a 15 percent MRPR could well be in this range. We therefore hoped to produce a case that would be roughly comparable to our MRPR simulations. Obviously, both A and B cases are somewhat extreme as we were seeking to exercise the model and identify boundaries We hope to assess smaller surcharge levels in future work.

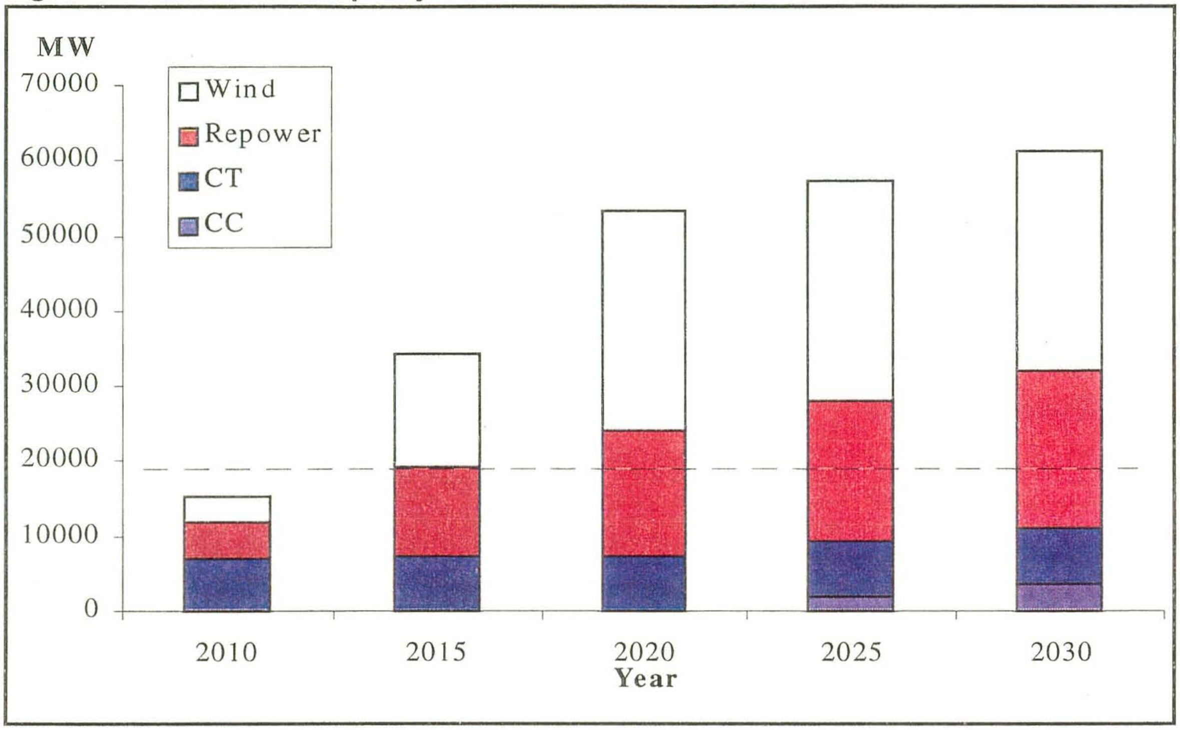
Our results are shown in Table 4-5 and Figure 4-5.

Table 4-5. Summary of Elfin Pool Results with Surcharge Policy and a Neutral Environment

	Neutral (ON)	$620M$/a Surcharge (BN)
2030 Cumulative New Renewable (GW)	0	29
2030 NOx Emissions (kt)	224	224 (100%)
2030 Carbon Emissions (Mt)	40	34 (85%)
2030 % Thermal	81%	64%
2030 Gas Consumption (EJ)	1.6	1.1 (73%)
NPV System Costs (10^9 $))	132	132 (100%)

Compared with the base, or neutral, case, a $620M per year surcharge policy results in 29 GW of new renewable construction, 15 percent lower carbon emissions, thermal dependence of 64 percent and 27 percent less gas consumption. As in previous policy scenarios, however, there is no change in NOx emissions.

Figure 4-5. Cumulative Capacity Construction Under Scenario BN



4.4 Comparing Scenario Results

In this section, the results of all policy cases are compared directly. Table 4-6 reports the total generation for each case in each of five benchmark years. Elfin does not have hard generation or capacity constraints. That is, the level of construction of new capacity and the overall output are chosen economically, in this case, such that the returns to investors in new capacity is maximized. No unprofitable investments are made. Dispatch is organized on traditional cost-minimizing principles and failing to serve load under the assumed cost structure, notably the cost of unserved energy itself, is a less costly dispatch outcome, then it is chosen. In other words, adequate capacity to meet reserve requirements is not necessarily built, and load is not necessarily met. In comparing results, therefore, an important first question to consider is how much demand went unserved.

The one notable result in Table 4-6 is that generation is lower in all years for the HN carbon tax case that is fully reported in Appendix F. This result emerges because costs are significantly higher in the HN case, and, therefore, unserved energy appears as a more attractive option to Elfin.

Table 4-6. Total Generation (GWh) for N Cases

	2010	2015	2020	2025	2030
ON	255,921	276,039	298,532	321,070	346,167
AN	255,921	276,037	298,532	321,069	346,153
BN	255,920	276,034	298,524	321,047	346,183
DN	255,921	276,038	298,532	321,070	346,170
HN	255,911	276,016	297,986	320,012	343,450

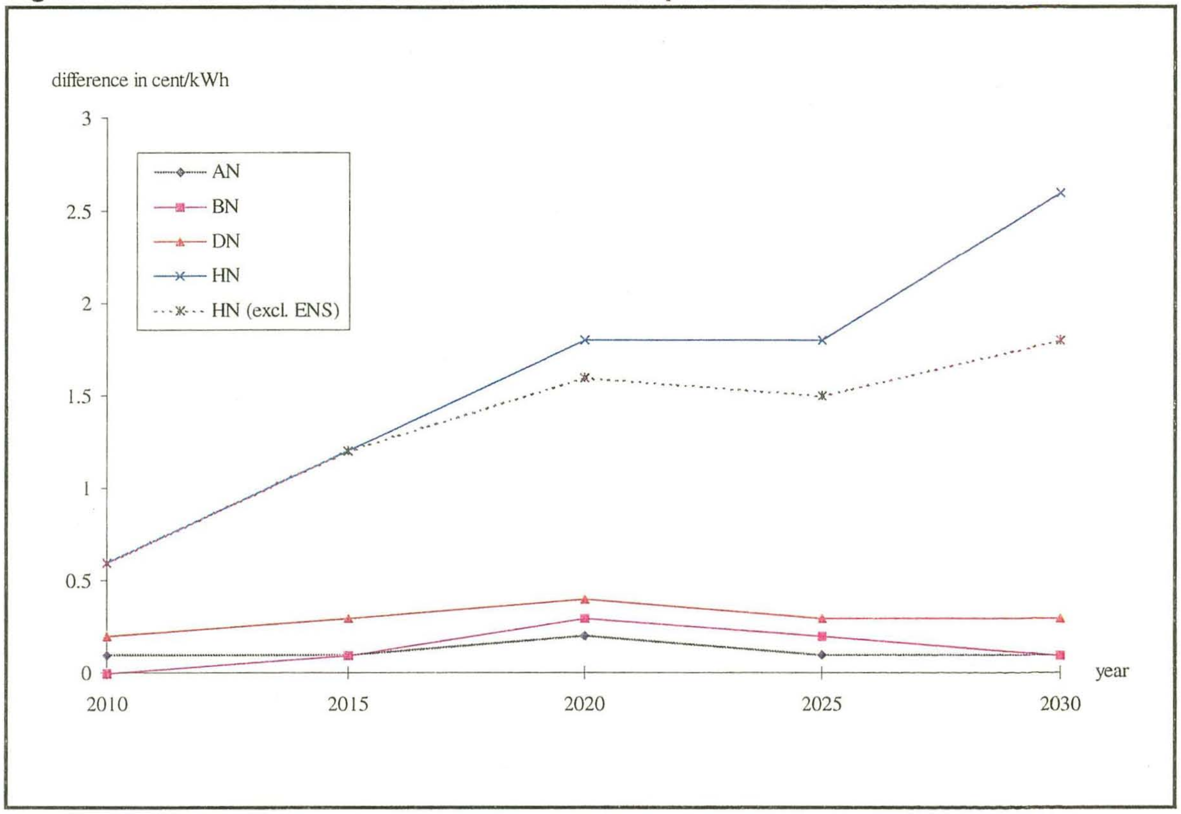
Table 4-7 shows the overall costs for the base and four policy cases, and Figure 4-6 shows how costs deviate from the ON case. The first column shows the internal net present cost of the scenario. This value represents the total cost of running the generation system through the end of the forecast period, including the cost of unserved energy.

Table 4-7. Costs for N Cases

	NPC M$ (1995)	ANPC M$ (1995)	TSC per Generation per year (¢/kWh)					Subsidies to B Cases (¢/kWh)				
	2006-2055	2006-2055	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
ON	132,002	132,002	1.6	2	2.2	2.5	2.7					
AN	135,370	135,370	1.7	2.1	2.4	2.6	2.8					
BN	132,001	139,506	1.6	2.1	2.5	2.7	2.8	2.7	2.0	1.8	1.5	th
DN	148,382	148,382	1.8	2.2	2.6	2.8	3					
HN	237,312	236,093	2.1	3.2	3.9	4.3	5.3					

NPC (Net Present Cost)
ANPC (for Benefits and Emission Taxes Adjusted Net Present Cost)
TSC (Total Social Cost)

Figure 4-6. Total Social Cost of Generation in Comparison to ON Case



The second column reports an adjusted net present cost. The purpose of this value is to represent a more realistic picture of scenario costs by adjusting the NPC for the costs of subsidies and taxes faced by the electricity sector, which are transfer payments and not true economic costs. The AN and DN cases involve no tax or subsidy, so the adjustment is zero. However, in the BN case, because wind generators are receiving a subsidy, the true cost is higher than calculated internally by Elfin. On the other hand, true costs are lower in the carbon tax case because the tax revenue does not represent a true cost because the tax revenue is available for other purposes. Figure 4-8 summarizes these results by reporting deviations for each policy scenario from the ON case. Again, the HN case stands out, and, as discussed above, has to be regarded with suspicion. Here however, it serves a useful purpose. Because costs are high in this simulation the amount on unserved energy is high, and this raises overall costs. In the figure the effect of this phenomenon is shown by reporting HN exclusive of the unserved energy cost. This just reinforces the notion that in Elfin, decisions are economic. In this simulation, a significant share of demand went unmet, and a cost was incurred as a result.

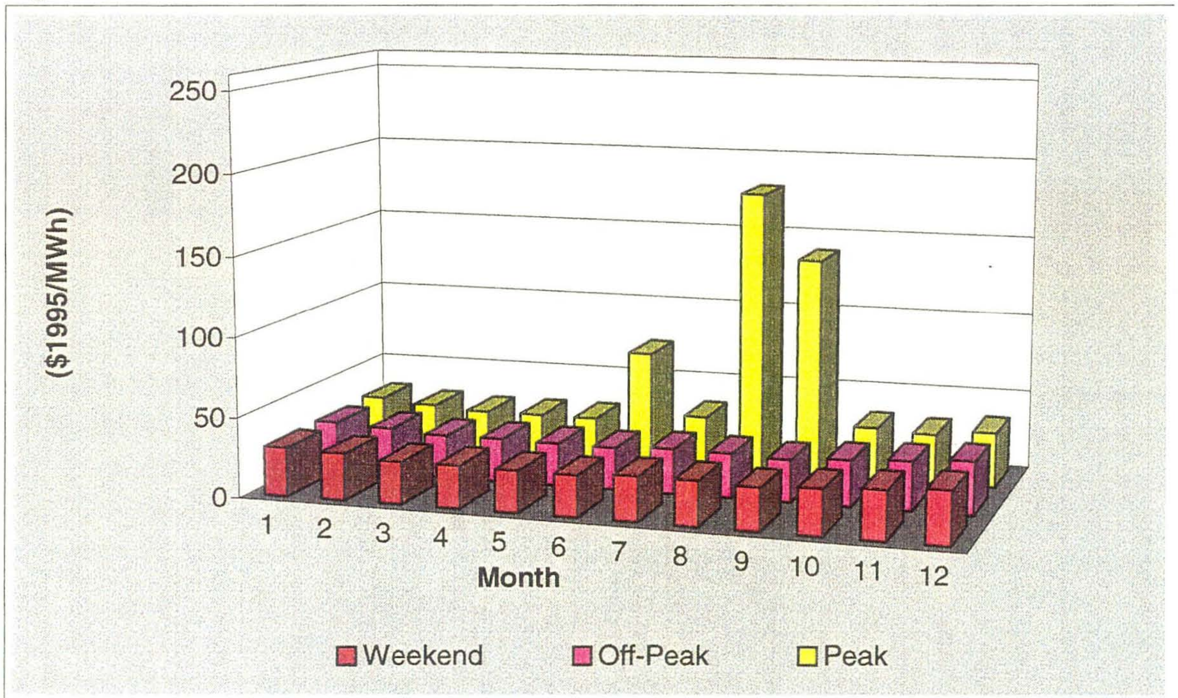
The following columns show the per-kWh generation costs after the adjustment. These are average production costs and do not reflect the costs of transmission, distribution, billing, etc. For reference, Table 4-8 shows the comparative emission and thermal dependency results, which have been discussed above.

Table 4-8. Benefits for N Cases in Terms of Reduction of Emissions and Thermal Dependency

	C (Mt)					NOx (kt)					Thermal Dependency (%)				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
ON	26.3	30.9	34.7	37	39.7	223	226	227.8	226.5	224.3	60	71	77	79	81
AN	24.4	28.7	32	33.5	36.1	222.2	225.8	227.2	225.3	223.9	53	64	69	69	71
AN $\%_{red.}$	-7.5	-7.2	-7.8	-9.4	-9.1	-0.4	-0.1	-0.3	-0.5	-0.2					
BN	25.8	27.8	28.2	30.7	33.6	225.7	225.4	223.5	223.8	223.9	57	61	58	61	64
BN $\%_{red.}$	-1.9	-10.1	-18.7	-17.1	-15.2	1.2	-0.2	-1.9	-1.2	-0.2					
DN	25.1	29.3	32.6	34.7	36.9	221.0	224.7	226.8	227.0	223.7	55	65	70	72	73
DN $\%_{red.}$	-4.9	-5.3	-5.9	-6.2	-6.9	-0.9	-0.6	-0.5	0.2	-0.3					
HN	16.4	12.2	16.8	18.9	21.7	177.3	138.5	184.0	180.1	184.9	53	60	63	66	68
HN $\%_{red.}$	-37.7	-60.4	-51.4	-48.9	-45.4	-20.5	-38.7	-19.2	-20.5	-17.6					

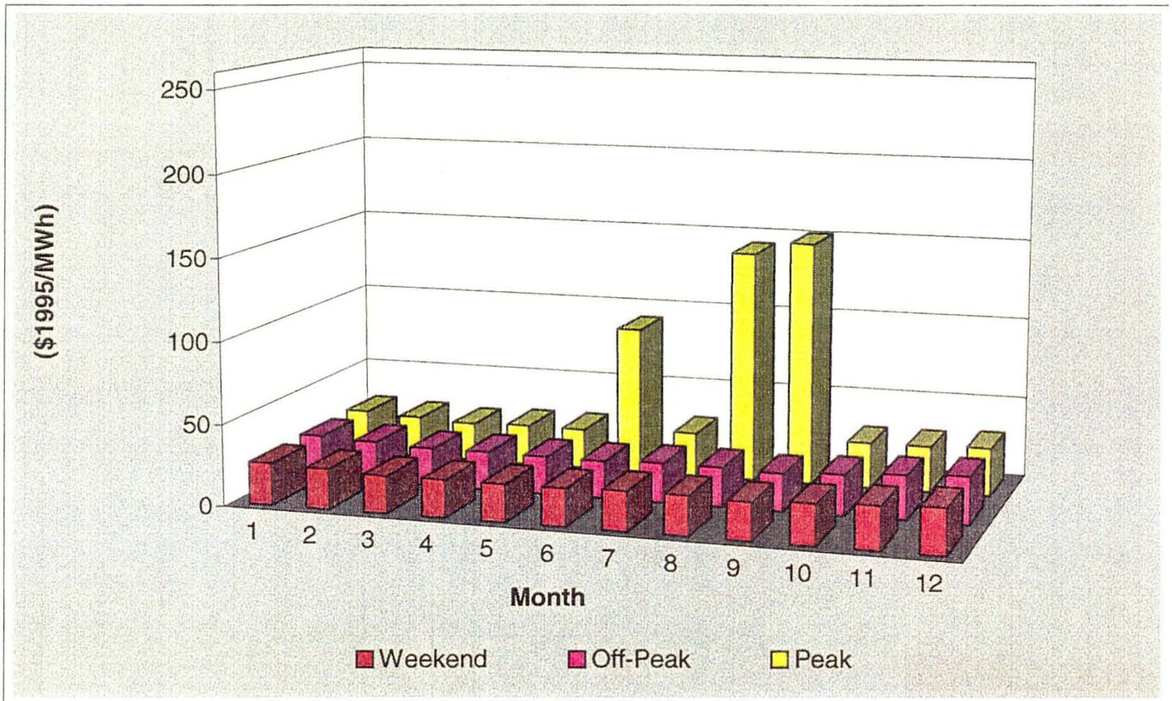
Before presenting these benefits and costs in graphical form, it would be interesting to focus briefly on market electricity prices. As has been emphasized above, these prices are the Holy Grail of competitive market simulation. With a reasonable estimate of prices in hand, other aspects of simple project analysis are relatively trivial, but without them no accurate revenue forecast is possible. Figures 4-7 and 4-8 show some simplified price results. In this instance, the simulation has been run using only three subperiods for each of 12 typical weeks. The *peak* subperiod is each afternoon from 12:00 to 18:00 and the *weekend* is 18:00 Friday to 8:00 Monday. All remaining hours are *off peak*. Remembering that in these simulations, all dispatch is assumed centralized, we will refer to these prices as pool prices in this section. In actual fact, of course most prices will be set by bilateral contracting, and PX prices will serve primarily as a basis for comparison.

Figure 4-7. ON Pool Price in 2025



One immediately interesting aspect of the results is how flat pool prices are overall. Outside of the later summer peak periods, pool prices stay within the range of $26 to 36 per MWh, the highest non-peak prices coming in the early winter period. The flatness of prices is somewhat of a surprise given the nature of the California electrical system. Load varies considerably, both diurnally and seasonally in the state, and the hydro resource, both in-state and imported, is also highly seasonal. However, the pool price appears to be dominated by the fact that traditional gas-fired resources almost always end up as the price-setting bidders, and, consequently, prices never collapse.

Figure 4-8. AN Pool Price in 2025



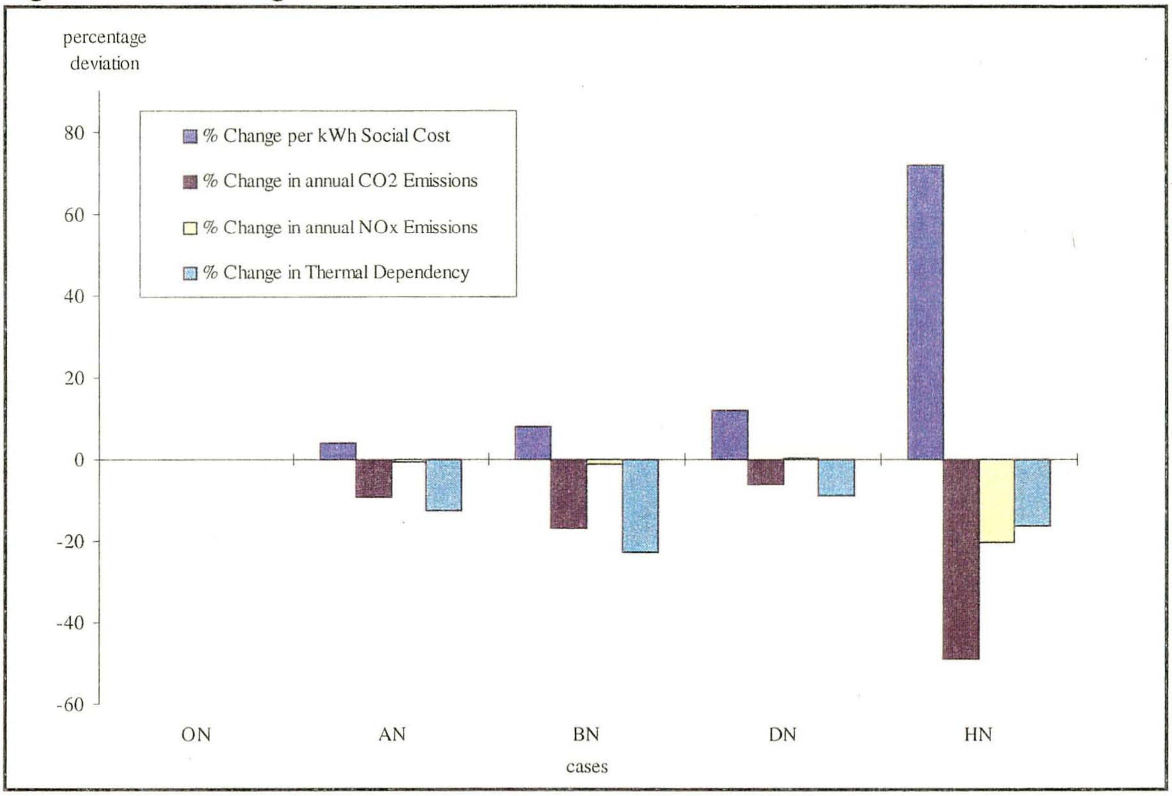
The second interesting aspect of the pool price results, quite obviously, is the extreme peak prices seen in the June to September period. The shortage of resources in this period is real, and quite clearly, none of the investment options we make available to Elfin can be profitably undertaken, despite these high prices. In other words, none of the peaking technologies available in these simulations, primarily solar and gas turbines, can be profitable despite the high peak pool prices, most likely because they appear in too few hours. It should also be noted that our simulations are incomplete in several ways that will tend to diminish the accuracy of on-peak pool price estimation. First, the peak pool price is heavily determined by the cost of unserved energy, as in all load duration curve based simulation. Second, imports together with other high cost options are treated quite crudely, and high cost bidders are likely to appear to peak periods that are not included in our simulation. Third, no demand response exists in the current version of Elfin. In a restructured industry, we expect more customers to face a real-time rate related to the pool price, and therefore, we can be sure that pool prices as high as these would result in load shifting. In ongoing work, a demand response module is being incorporated into Elfin that will allow demand in subsequent years to respond to high prices in any year.

Another obvious question that comes to mind is how well do these prices reflect actual retail prices as the ratepayer will see them. A reasonable rule-of-thumb for this time period, that is well beyond the transition, might be that transmission and distribution costs will remain as they are now, and these plus the pool price might represent a reasonable estimate of retail energy rates, although marketing costs could be a significant factor. Currently transmission and distribution cost about 4 ¢/kWh.

Figure 4-8 reports equivalent data for the AN scenario. The general pattern of results remains the same, but pool prices overall appear lower. This result actually must be true because a large amount of wind capacity appears in this scenario, bidding into the pool at a zero price. While the pool price is still being set by gas resources, the effect of the large block of wind generation is that pool prices are somewhat suppressed. This result raises a very interesting question, which is how much does this reduced pool price compensate for the cost of the various policies. In the AN case, the 2025 year-round average revenue going to generators is $37.4 per MWh compared to $44.1 per MWh in the ON case. In other words, the consumer comes out clearly ahead as a result of the AN policy. Although production costs rise, as seen in Table 4-8, pool prices fall, meaning a transfer takes place from the generator to the consumer. In other policy cases, when a subsidy is being given to a zero marginal cost generator, the value of the subsidy is partially offset by the falling pool price resulting from increased renewable participation. While quite predictable, this is an interesting result that merits further study. It should also be noted that not all renewable generators operate at close to zero marginal cost. In the DN case, for example, pool prices rise slightly over the ON case. In the BN case, direct evaluation of the benefit of the falling pool price relative to the increase in production cost is make significantly more complex by the fluctuations in the effect across the forecast period, and a much more detailed analysis would be needed in this case.

Figure 4-9 summarizes the benefits and costs for the policy cases. All data are presented as percent deviations from the ON case. The positive values are the increases in costs. These represent the cost side of the policies. These are the total societal costs that represent true economic costs, free of transfers. The three subsequent indicators are all benefits, and are negative. In other words, falling thermal dependence and/or emissions is a benefit. As expected, the AN and BN cases have similar costs but BN delivers bigger benefits. This result is predictable because the total renewable construction is higher in the BN case, and because the additional renewable is wind in each case. This reinforces the earlier observation that the subsidy case is more effective than a purchase requirement in terms of total effect. However, development is less orderly.

Figure 4-9. Percentage Deviation in Costs and Benefits from ON Case in Year 2025



CHAPTER 5

Conclusions

In this study, considerable progress has been made towards the goal of developing algorithms for simulating the operation of competitive electricity markets, and, specifically, of building a model capable of simulating the future operation of the competitive California market. Such models are useful both as planning and policymaking tools, and as a means of evaluating possible investments. Such models are particularly important to intermittent renewable generators because their revenue streams and the benefits they provide in terms of environmental benefits and reduced pool prices are hard to forecast.

The expansion planning logic of Elfin, based on the ITRE algorithm, has been enhanced so that it more clearly represents conditions in a competitive market. A new algorithm has been developed that permits ITRE to choose only the most profitable investments and then find combinations of new market entry that result in a sustainable equilibrium with no new profitable entry possible. The likely equilibrium is the one that results in the maximum return to investors. When entry has been determined, by incorporating non-energy payments into dispatch decisions, market prices can be derived using traditional algorithms.

The data sets of the incumbent utilities have been merged into one that contains all the key assets in California and those owned by California utilities but situated in neighboring states. Potential imports are represented by two single resources, one for the Northwest and one for the Southwest.

The new algorithms and the California data set have been used to forecast investments in generation in the future California market in the post-restructuring quarter century, 2006-2030. Under best-guess assumptions, no new renewable capacity is added and the state's thermal generating dependency increases to 81 percent by 2030 with natural gas consumption 3.5 times today's levels, and the overall carbon emissions of generation increasing from 113 to 126 g/kWh.

A 15 percent renewable purchase requirement lowers the 2030 thermal dependency to 71 percent and lowers carbon emissions by nine percent. Such a policy raises production costs but lowers market prices, so consumers benefit but generators lose by the policy intervention. The same level of purchase requirement with technology bands delivers much less benefits and incurs higher costs.

A direct subsidy to wind generators that averages $620M per year over the forecast period, but is fixed only in net present value terms, results in more benefits for similar costs. However, deployment of renewables is prone to a boom-and-bust cycle as developers tend to only invest during the time periods when it is clearly the most profitable. Therefore, a policy trade off exists between maximizing the benefits and achieving a sustained orderly development.

This work represents a bold step towards simulation of competitive markets, but many technical problems remain to be solved. In our opinion, the key areas for future work fall into the two following areas:

1. Algorithm Development

Subsidy simulation algorithms need to be developed that can estimate the effects of subsidies in a stable fashion. Currently, the search for sustainable equilibriums with subsidies in place is unstable because of the interplay of various effects of a change in the subsidy, especially across time periods.

The search algorithm for MEPs performs satisfactorily for searches limited to small clusters of profit maxima, but needs to be enhanced such that it more effectively finds solutions that are remote from other local profit maxima.

In this work, transmission constraints have been assumed away, but a more realistic analysis would bring these into the analysis.

Current production cost modeling still functions without realistic account of demand response, a glaring deficiency given the effect that new load-shifting technologies and greater customer exposure to real-time prices might have.

Repowering of existing stations is one of the most likely forms of entry into the California market. Unfortunately, the economics of investments in repowering are quite different under a competitive market in which alternative uses of the site are not only possible but potentially more profitable than in power generation. Furthermore, repowering potential is particularly hard to incorporate in models because the possibilities are numerous at any one site and data local to the site is needed. New algorithms for retirement and repowering decision making are needed as is better data on repowering options.

2. Data Enhancement

The current data set focuses on in-state resources, whereas competition from out-of-state generators will be a key determinant of market conditions. The data set should be extended to incorporate these competitors.

The renewable technology options used in this study are quite simplistic. Now that more realistic simulation of market operations is possible, better data on the characteristics of the renewable resources in California and nearby is needed.

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Detailed Results

In this appendix we provide a more detailed set of figures and tables for each scenario modeled. Again, three environments for renewables were considered (neutral, good, and bad) and the policies modeled were:

- Policy 0: No policy (i.e., no new or existing policies present)
- Policy A: Non-hydro minimum renewable purchase requirement (set at 15% of total generation).
- Policy B: Surcharge policy ($620M/a to lowest cost renewable)
- Policy D: Policy A's minimum renewable purchase requirement with technology bands (set at current market shares)
- Policy H: Carbon tax (3 $/t$_C$)

Labels for each policy and environment combination are then:

	Environment		
Policy	**Neutral**	**Good**	**Bad**
None	*0N*	*0G*	*0B*
A	*AN*	*AG*	*AB*
B	*BN*	*BG*	
D	*DN*	*DG*	*DB*
H	*HN*	*HG*	*HB*

Figure A.1 Resource Mix Under Scenario 0N

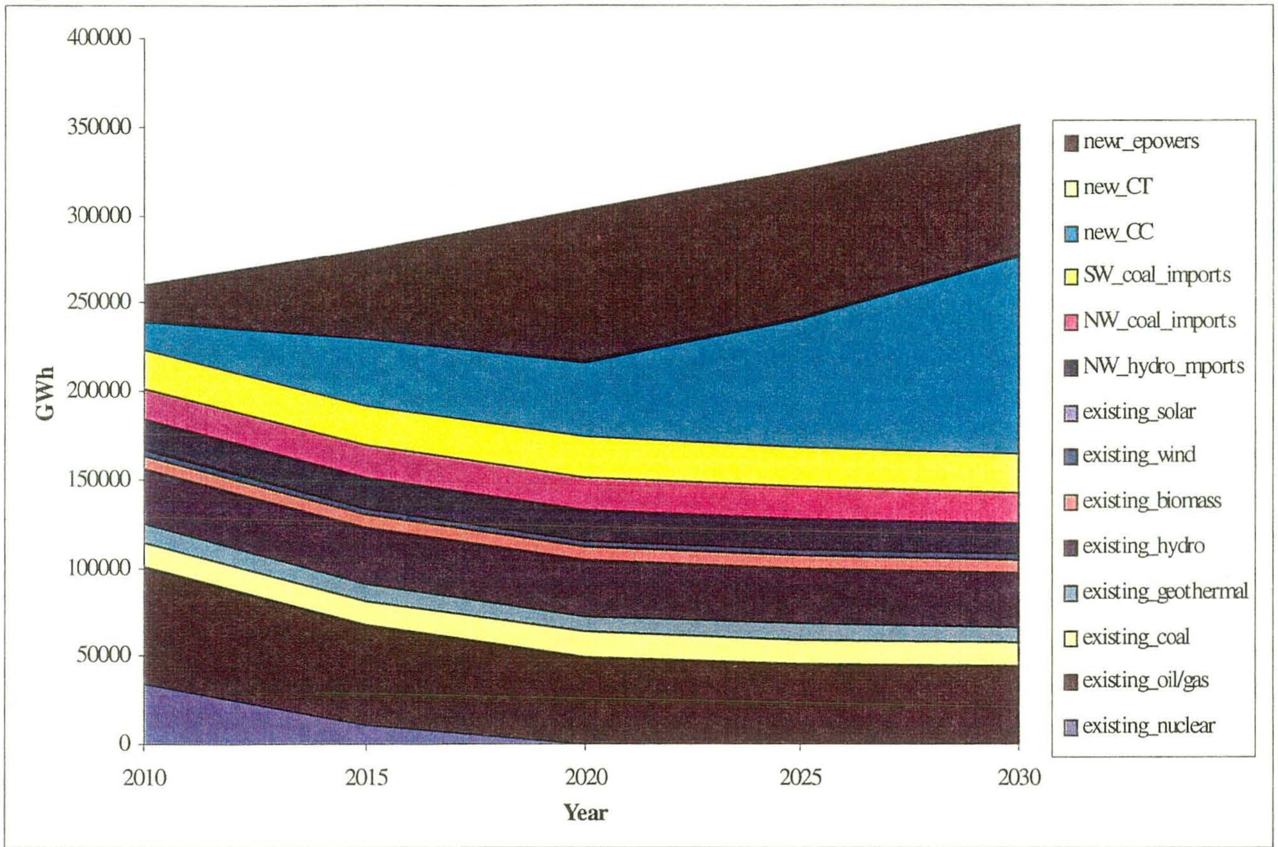


Table A.1 Resource Mix Under Scenario 0N (GWh/a)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	66411	56143	49044	45238	43900
existing_coal	14121	14286	14444	14097	13995
existing_geothermal	10463	9937	9414	8827	7820
existing_hydro	31500	31508	31600	31509	31508
existing_biomass	7245	7245	7264	7245	7245
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16574	16575	16634	16575	16575
NW_coal_imports	16881	18158	18487	18314	17636
SW_coal_imports	21713	22559	22815	22684	22173
new_CC	16533	37485	42566	71928	111409
new_CT	1022	961	1092	1666	1520
new_repowers	19868	50414	85348	83049	72598
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	0	0	0	0	0
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	0
Other	4	61	66	187	0
Pumped storage	781	414	366	393	508

Tables A-2 to A-6. Key Indicators for Scenario 0N

Construction (units)

	2010	2015	2020	2025	2030
CC	10	22	25	42	65
CT	43	46	58	58	58
Wind	0	0	0	0	0
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
Photo-voltaics	0	0	0	0	0
Repower	11	29	44	44	44

Emissions (t)

	2010	2015	2020	2025	2030
NO	222986	225962	227828	226539	224277
SU	82708	85247	86427	86016	84775
PM	9701	11930	13715	14819	15906
RG	33524	34899	36100	36684	37204
CO	68793	68741	69212	69399	69719
CX	26344706	30883172	34651154	37006603	39683706
NG	233432	179637	134195	126077	126077

Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	60%	71%	77%	79%	81%
EJ Gas	0.640	0.933	1.187	1.362	1.563
Billion m3	17	24	31	36	41

Cumulative Present Values 2006-2055 (1995B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Present Cost
91429	0	0	12945	27628	132002

Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Revenue	Fuel	Variable O&M	Fixed O&M	Capital	Total Cost	Ind. Profit
218944	9203	1333	229480	85214	4862	12945	27628	130649	98832

Figure A-2. Resource Mix Under Scenario 0G

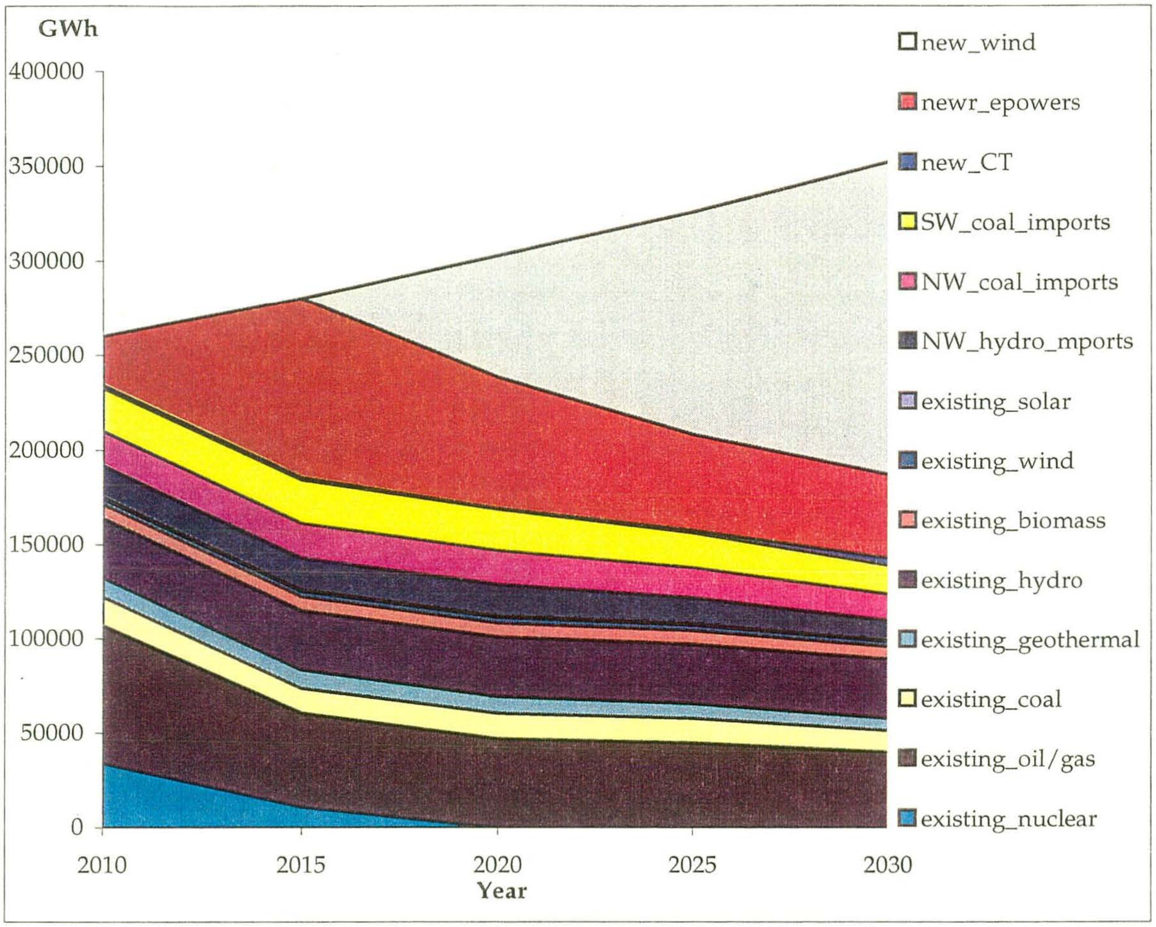


Table A-7. Resource Mix Under Scenario OG (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	73200	49616	46947	44721	39791
existing_coal	15144	12970	13464	12900	11519
existing_geothermal	10366	9940	9049	8091	6500
existing_hydro	31496	31511	31601	31471	31363
existing_biomass	7245	7245	7256	7125	6663
existing_wind	3069	3069	3075	2924	2534
existing_solar	911	911	913	883	796
NW_hydro_mports	16574	16575	16448	13779	10663
NW_coal_imports	18319	18465	18002	15779	13765
SW_coal_imports	22642	22776	21852	18298	15206
new_CC	0	0	0	0	0
new_CT	1474	1311	589	1590	3851
newr_epowers	25905	94891	69314	50645	44187
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	0	0	64345	117708	165422
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	0
Other	4	29	107	0	14
Pumped storage	866	423	1020	1961	2340

Tables A-8 through A-12. Key Indicators for Scenario OG

A-8. Construction (units)

	2010	2015	2020	2025	2030
CC	0	0	0	0	0
CT	58	58	58	58	58
Wind	0	0	131	241	341
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	0
Repower	12	42	42	42	42

A-9. Emissions (t)

	2010	2015	2020	2025	2030
NO	228826	223672	222057	207683	187765
SU	87175	83368	82419	73463	63847
PM	9564	12203	10949	9774	8921
RG	33526	35012	34401	33193	31200
CO	69908	67683	66669	64955	60020
CX	26882477	30833779	27243183	23618085	21097815
NG	250777	149228	128664	124858	116044

A-10. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	60%	71%	56%	44%	36%
Gas (EJ)	0.634	0.947	0.704	0.548	0.495
Billion (m^3)	17	25	18	14	13

A-11. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$67,705	$0	$0	$28,745	$56,871	$153,320

A-12. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$234,407	$7,745	$1,229	$243,381	$63,522	$3,739

Fixed O&M	Capital	Total Cost	Ind. Profit
$28,745	$56,871	$152,876	$90,505

Figure A-3. Resource Mix Under Scenario 0B

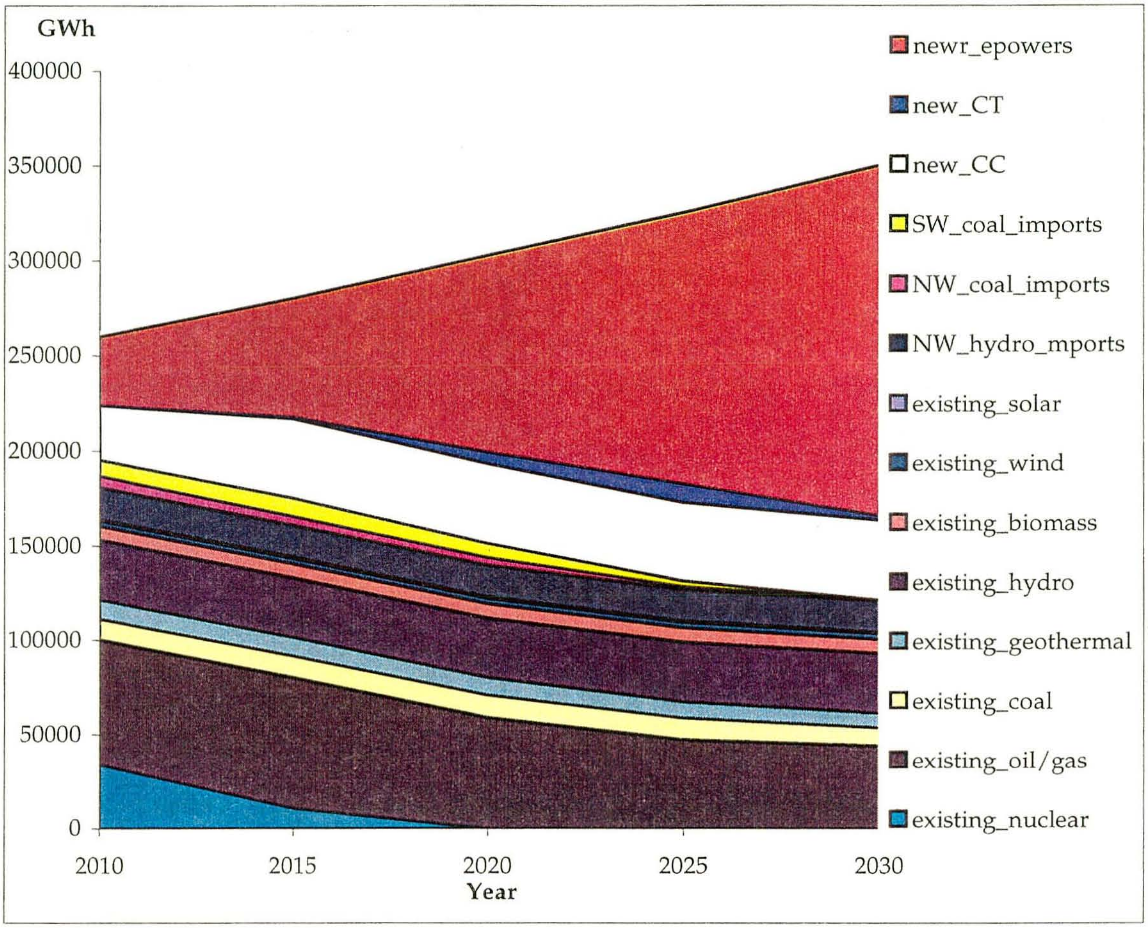


Table A-13. Resource Mix under Scenario OB (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	66454	69451	59010	47257	43900
existing_coal	10909	11320	11822	11435	9716
existing_geothermal	10439	9935	9414	8827	7820
existing_hydro	31507	31505	31596	31507	31512
existing_biomass	7245	7245	7264	7245	7245
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16575	16575	16634	16575	16575
NW_coal_imports	5877	4567	3945	1452	72
SW_coal_imports	8236	9589	7376	2962	245
new_CC	28930	41806	42129	41600	42265
new_CT	27	820	6136	9635	2443
newr_epowers	36039	62447	103416	142759	184638
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	0	0	0	0	0
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	0
Other	0	56	9	24	4
Pumped storage	443	371	362	361	358

Tables A-14 through A-18. Key Indicators for Scenario OB

A-14. Construction (units)

	2010	2015	2020	2025	2030
CC	17	24	24	24	25
CT	9	43	71	71	71
Wind	0	0	0	0	0
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	0
Repower	22	26	38	53	77

A-15. Emissions (t)

	2010	2015	2020	2025	2030
NO	177499	181858	177836	164306	151726
SU	48942	50413	48892	39318	27849
PM	9660	11667	13733	15197	16115
RG	33877	35356	36746	37629	38000
CO	69278	71406	71931	71419	70822
CX	24261221	29463608	33252907	35256617	37253430
NG	244801	224099	158584	126077	126077

A-16. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	60%	71%	77%	79%	81%
Gas (EJ)	0.847	1.190	1.488	1.728	1.958
Billion (m^3)	22	31	39	45	51

A-17. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$66,551	$0	$0	$12,118	$23,831	$102,500

A-18. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$185,520	$13,907	$980	$200,406	$58,037	$8,287

Fixed O&M	Capital	Total Cost	Ind. Profit
$12,118	$23,831	$102,273	$98,133

Figure A-4. Resource Mix Under Scenario AN

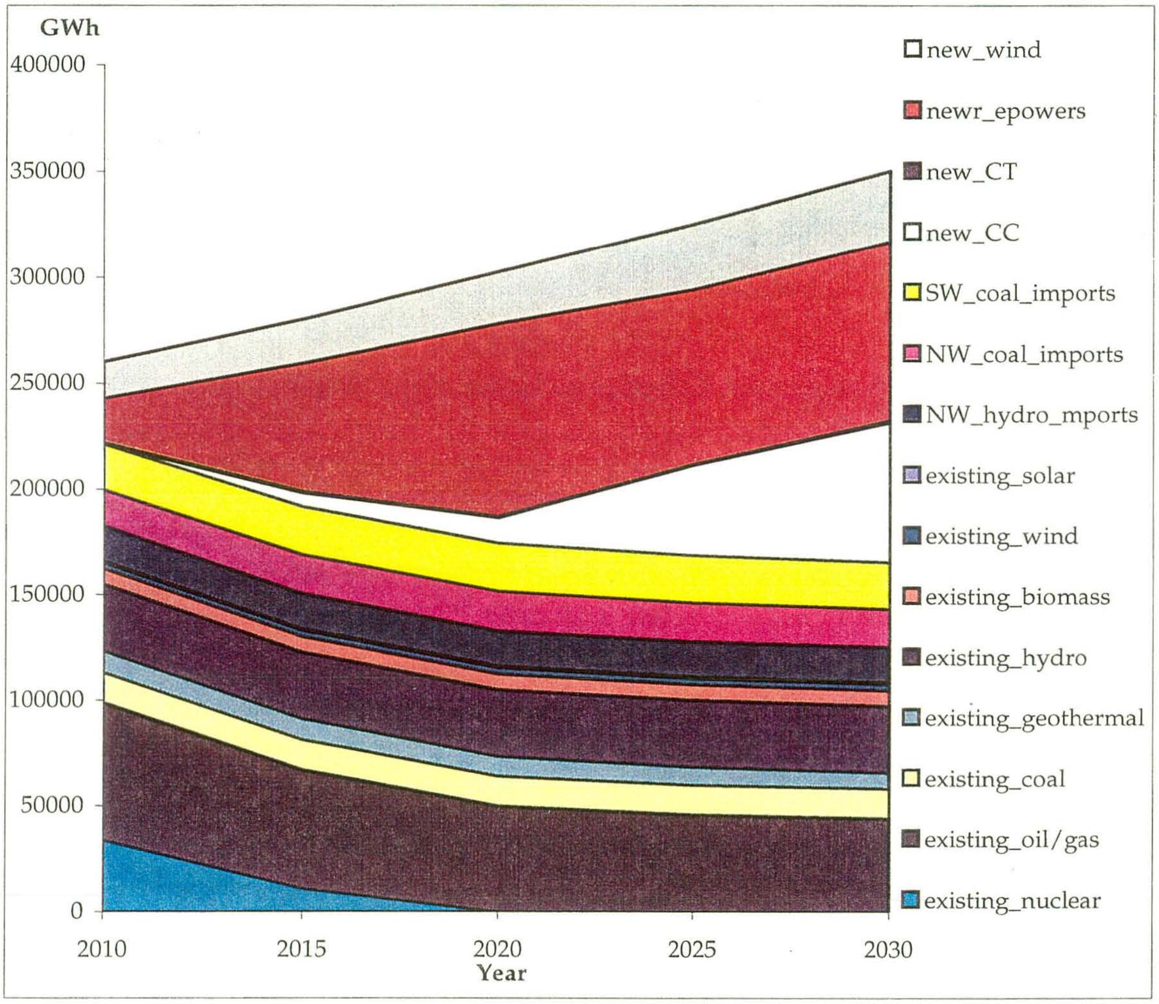


Table A-19. Resource Mix under Scenario AN (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	64988	56062	49854	45804	43900
existing_coal	14289	14257	14207	13955	14102
existing_geothermal	10445	9937	9414	8822	7820
existing_hydro	31501	31509	31601	31510	31509
existing_biomass	7245	7245	7264	7245	7245
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16521	16575	16634	16575	16575
NW_coal_imports	16872	18308	18482	18194	17911
SW_coal_imports	21498	22580	22806	22388	22102
new_CC	0	6611	12072	42757	66395
new_CT	849	672	549	575	1031
newr_epowers	20925	60846	91191	82405	84293
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	17231	20672	24637	31008	33469
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	0
Other	3	43	62	77	0
Pumped storage	880	366	361	389	442

Tables A-20 through A-24. Key Indicators for Scenario AN

A-20. Construction

	2010	2015	2020	2025	2030
CC	0	4	7	25	39
CT	39	41	41	41	41
Wind	35	42	50	63	68
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	0
Repower	12	34	49	50	50

A-21. Emissions (t)

	2010	2015	2020	2025	2030
NO	222178	225815	227198	225297	223901
SU	82134	85301	86025	85135	84823
PM	8984	11067	12647	13465	14476
RG	33074	34381	35487	35934	36323
CO	68000	68069	68575	68582	68629
CX	24372114	28666873	31962740	33522160	36067691
NG	232244	176894	137484	126077	126077

A-22. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	53%	64%	69%	69%	71%
Gas (EJ)	0.501	0.777	1.002	1.125	1.309
Billion (m^3)	13	20	26	29	34

A-23. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$79,066	$0	$0	$16,836	$39,468	$135,370

A-24. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$214,934	$9,079	$1,066	$225,079	$72,712	$4,958

Fixed O&M	Capital	Total Cost	Ind. Profit
$16,836	$39,468	$133,974	$91,105

Figure A-5. Resource Mix Under Scenario AG

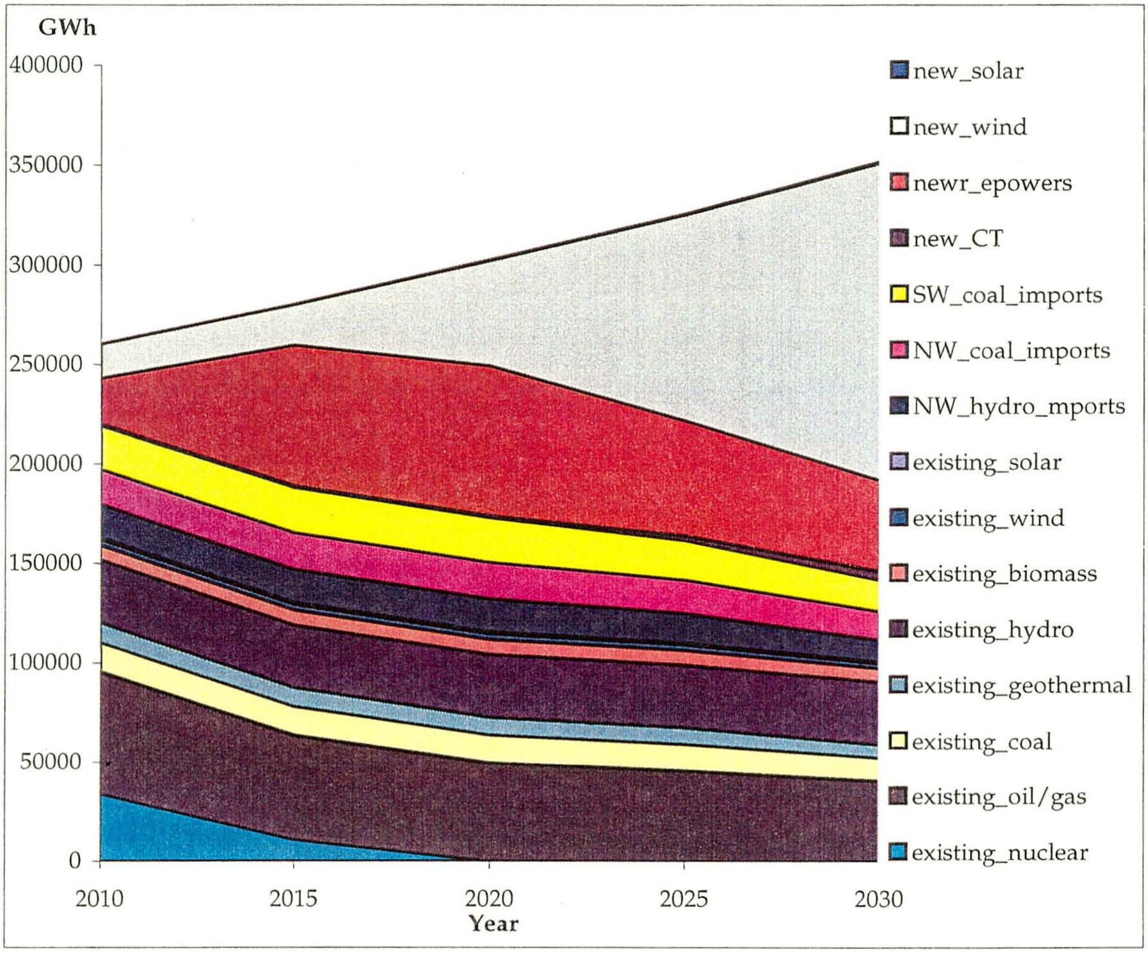


Table A-25. Resource Mix Under Scenario AG (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	61607	52773	49720	45588	40344
existing_coal	14817	14317	14050	13599	11965
existing_geothermal	10186	9618	9076	8346	6823
existing_hydro	31497	31509	31599	31493	31388
existing_biomass	7245	7245	7264	7211	6710
existing_wind	3069	3069	3076	3020	2602
existing_solar	911	911	913	906	869
NW_hydro_mports	16524	16575	16612	14888	11094
NW_coal_imports	17578	18453	18345	16675	14214
SW_coal_imports	21961	22742	22405	19825	15761
new_CC	0	0	0	0	0
new_CT	869	604	963	2515	4485
newr_epowers	23007	70802	75174	57731	45504
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	17232	20672	53101	103592	159790
new_geothermal	0	0	0	0	0
new_solar	0	0	342	340	338
Other	1	30	232	15	27
Pumped storage	1329	439	792	1874	2530

Tables A-26 through A-30. Key Indicators for Scenario AG

A-26. Construction (units)

	2010	2015	2020	2025	2030
CC	0	0	0	0	0
CT	41	41	41	41	41
Wind	35	42	72	212	329
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	4	4	4
Repower	12	38	40	40	40

A-27. Emissions (t)

	2010	2015	2020	2025	2030
NO	224373	226219	225491	215382	191962
SU	84734	85960	84461	78073	66226
PM	9105	11209	11391	10383	9162
RG	33110	34458	34757	33889	31639
CO	67582	67700	67715	66193	61025
CX	24475132	28720813	28716385	25396181	21789267
NG	213427	159996	135355	125876	117116

A-28. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	53%	64%	59%	48%	37%
Gas (EJ)	0.488	0.775	0.785	0.621	0.514
Billion (m^3)	13	20	20	16	13

A-29. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$64,094	$0	$0	$29,429	$58,380	$151,904

A-30. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$251,315	$14,303	$1,858	$267,477	$59,908	$3,389

Fixed O&M	Capital	Total Cost	Ind. Profit
$29,429	$58,380	$151,107	$116,369

Figure A-6. Resource Mix Under Scenario AB

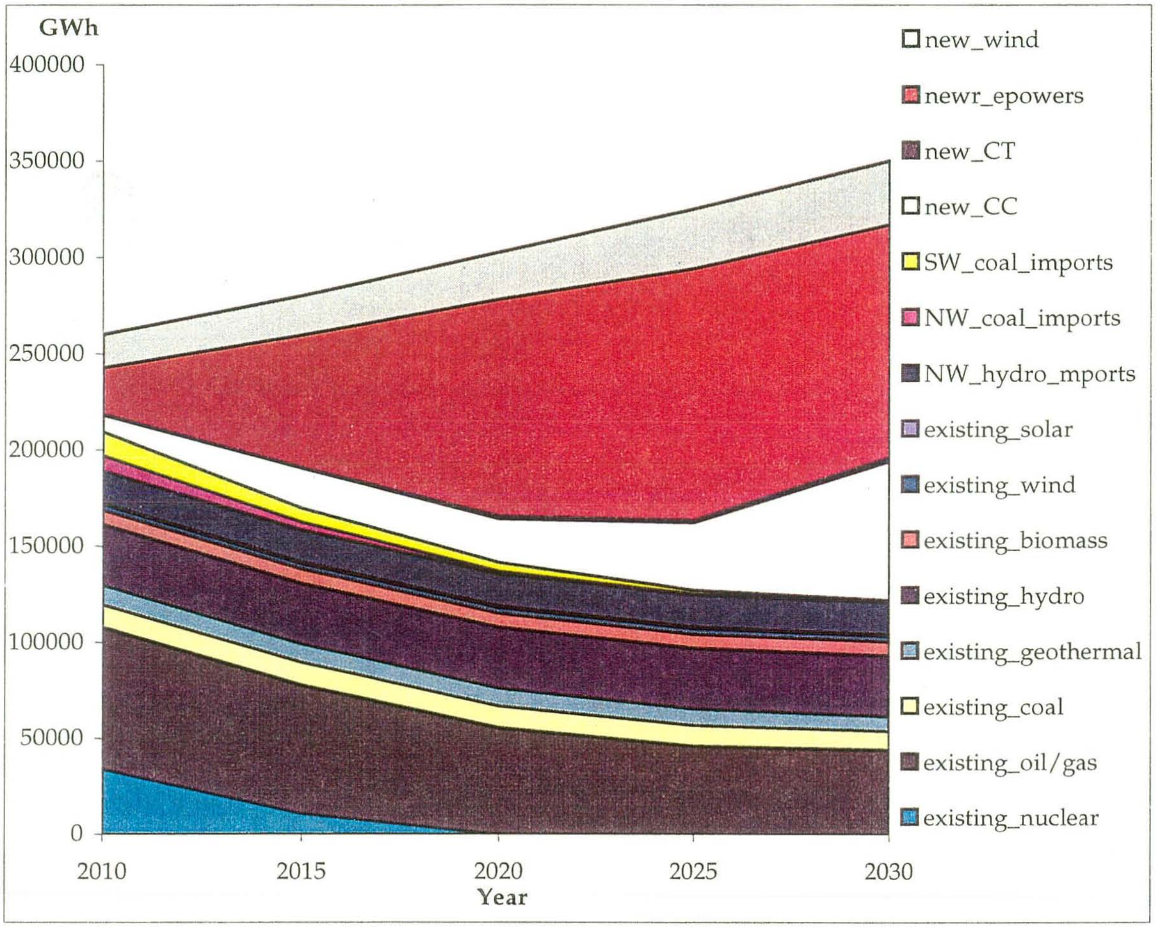


Table A-31. Resource Mix under Scenario AB (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	74048	66934	55471	45937	43900
existing_coal	11741	11537	11397	10739	9782
existing_geothermal	10423	9927	9413	8826	7820
existing_hydro	31502	31505	31596	31508	31509
existing_biomass	7245	7245	7264	7245	7245
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16516	16575	16634	16575	16575
NW_coal_imports	7804	3822	1265	390	228
SW_coal_imports	12360	7303	4398	2069	834
new_CC	8617	20799	22817	34768	72327
new_CT	521	401	1405	1640	2086
newr_epowers	24265	68582	112452	130550	120674
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	17232	20672	24637	31008	33469
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	0
Other	1	18	14	32	23
Pumped storage	525	384	364	364	410

Tables A-32 through A-36. Key Indicators for Scenario AB

A-32. Construction (units)

	2010	2015	2020	2025	2030
CC	5	12	13	20	43
CT	33	36	44	44	44
Wind	35	42	50	63	68
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	0
Repower	12	30	45	57	57

A-33. Emissions (t)

	2010	2015	2020	2025	2030
NO	190555	175291	167033	158537	152858
SU	57508	47226	40602	34365	28971
PM	8761	10843	12642	13599	14498
RG	33308	34813	36139	36629	36996
CO	69593	70418	70548	69656	69558
CX	23193838	26873604	29817279	31067270	33233060
NG	268848	220397	150687	126077	126077

A-34. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	53%	64%	69%	69%	71%
Gas (EJ)	0.677	1.051	1.323	1.469	1.662
Billion (m^3)	18	27	35	38	43

A-35. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$56,998	$0	$0	$17,457	$39,819	$114,275

A-36. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$156,846	$14,824	$884	$172,555	$50,216	$6,425

Fixed O&M	Capital	Total Cost	Ind. Profit
$17,457	$39,819	$113,919	$58,635

Figure A-7. Resource Mix Under Scenario BN

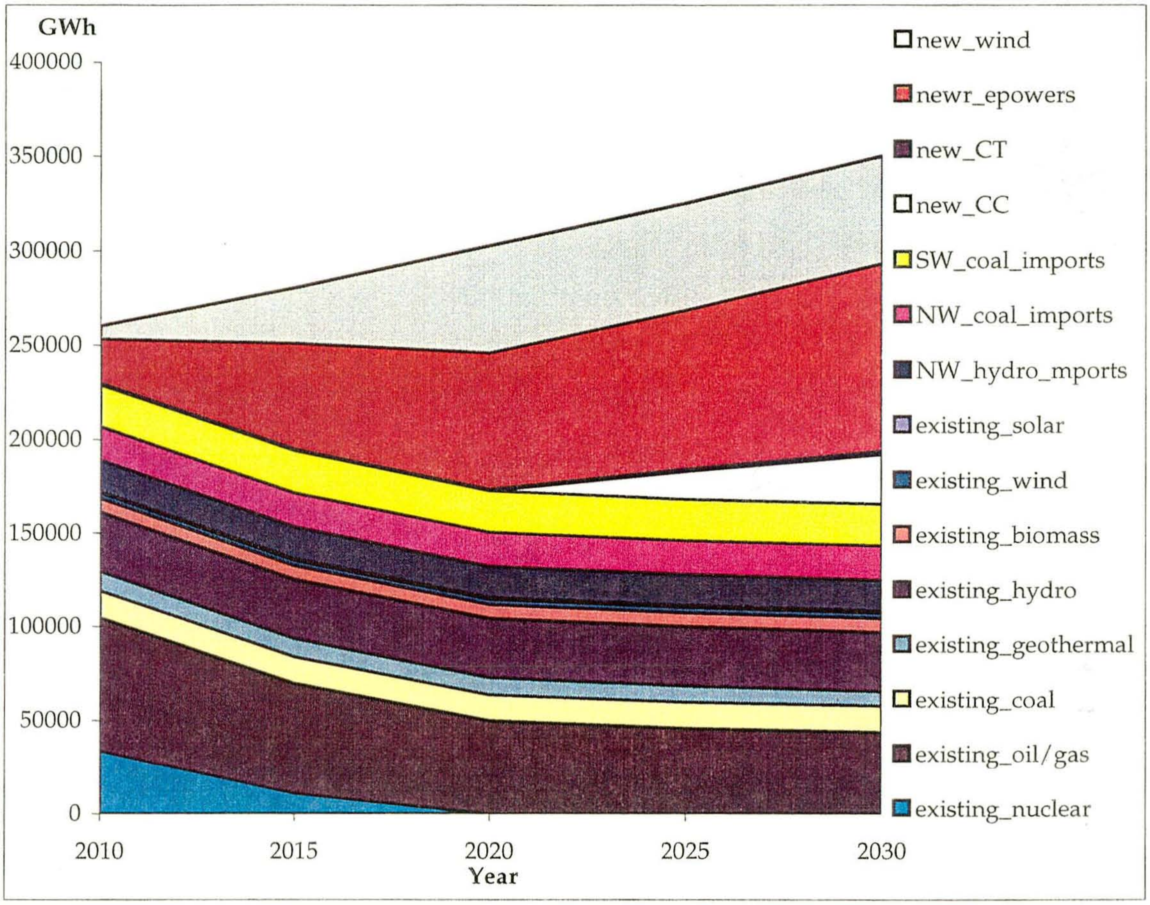


Table A-37. Resource Mix Under Scenario BN (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	70785	58830	49985	45971	43900
existing_coal	14543	14267	13751	13876	14024
existing_geothermal	10477	9801	9195	8815	7820
existing_hydro	31499	31507	31599	31508	31510
existing_biomass	7245	7245	7264	7245	7245
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16573	16574	16588	16563	16573
NW_coal_imports	17657	18183	18061	18040	18219
SW_coal_imports	22149	22414	22014	22007	22232
new_CC	0	0	0	14811	26545
new_CT	1175	1082	787	1370	1759
newr_epowers	23299	55865	72505	84115	99596
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	6904	29532	57029	56978	56994
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	0
Other	5	40	24	72	0
Pumped storage	702	478	460	603	605

Tables A-38 through A-42. Key Indicators for Scenario BN

A-38. Construction (units)

	2010	2015	2020	2025	2030
CC	0	0	0	9	16
CT	47	49	49	49	49
Wind	14	60	116	116	116
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	0
Repower	12	30	42	47	53

A-39. Emissions (t)

	2010	2015	2020	2025	2030
NO	225727	225427	223521	223805	223894
SU	84254	84720	83565	84126	84455
PM	9294	10610	11199	12377	13502
RG	33327	34143	34589	35281	35730
CO	69243	68195	67424	67827	67872
CX	25842860	27774071	28185354	30696316	33640414
NG	249285	186661	137874	126070	126077

A-40. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	57%	61%	58%	61%	64%
Gas (EJ)	0.585	0.717	0.762	0.937	1.137
Billion (m^3)	15	19	20	24	30

A-41. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$67,004	$0	$0	$19,177	$42,820	$132,001

A-42. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$219,672	$9,202	$1,054	$229,928	$67,588	-$2,048

Fixed O&M	Capital	Total Cost	Ind. Profit
$19,177	$45,820	$130,536	$99,392

Figure A-8. Resource Mix Under Scenario BG

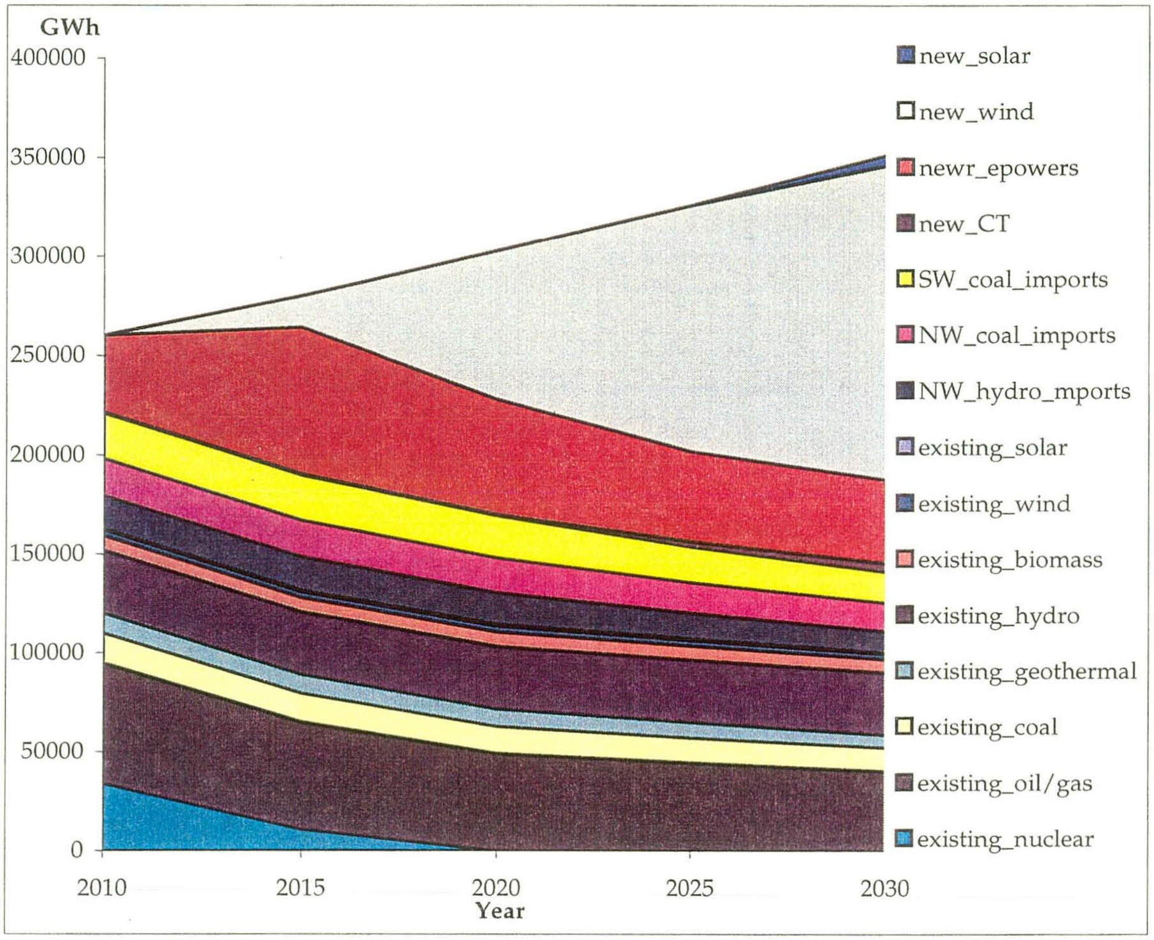


Table A-43. Resource Mix Under Scenario BG (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	61077	54313	49213	44562	40319
existing_coal	15177	14323	13701	12632	11793
existing_geothermal	10394	9744	8930	7969	6655
existing_hydro	31499	31509	31597	31452	31382
existing_biomass	7245	7245	7264	7072	6725
existing_wind	3069	3069	3072	2890	2600
existing_solar	911	911	913	897	817
NW_hydro_mports	16575	16575	16023	13028	10918
NW_coal_imports	18395	18463	17534	15304	14187
SW_coal_imports	22675	22761	21215	17736	15543
new_CC	0	0	0	0	0
new_CT	728	698	671	2827	4532
newr_epowers	38564	73372	57872	45293	41965
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	0	16243	74967	124268	158702
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	5229
Other	3	81	82	13	21
Pumped storage	761	394	1300	1976	2542

Tables A-44 through A-48. Key Indicators for Scenario BG

A-44. Construction (units)

	2010	2015	2020	2025	2030
CC	0	0	0	0	0
CT	36	36	36	36	36
Wind		33	153	255	327
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	62
Repower	19	37	37	37	37

A-45. Emissions (t)

	2010	2015	2020	2025	2030
NO	227852	226449	220817	204607	190926
SU	87345	85409	81125	71564	65406
PM	9897	11344	10452	9523	8977
RG	33622	34562	34170	32893	31523
CO	68177	68081	66879	64408	60856
CX	26511775	29272982	26130936	22904290	21264936
NG	211359	164898	134337	124211	117082

A-46. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	60%	66%	53%	42%	36%
Gas (EJ)	0.606	0.814	0.636	0.519	0.486
Billion (m^3)	16	21	17	14	13

A-47. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
64953	0	0	28601	56894	150449

A-48. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
287549	15550	2576	305676	62223	1377

Fixed O&M	Capital	Total Cost	Ind. Profit
28,601	56,894	149,096	156,579

Figure A-9. Resource Mix Under Scenario DN

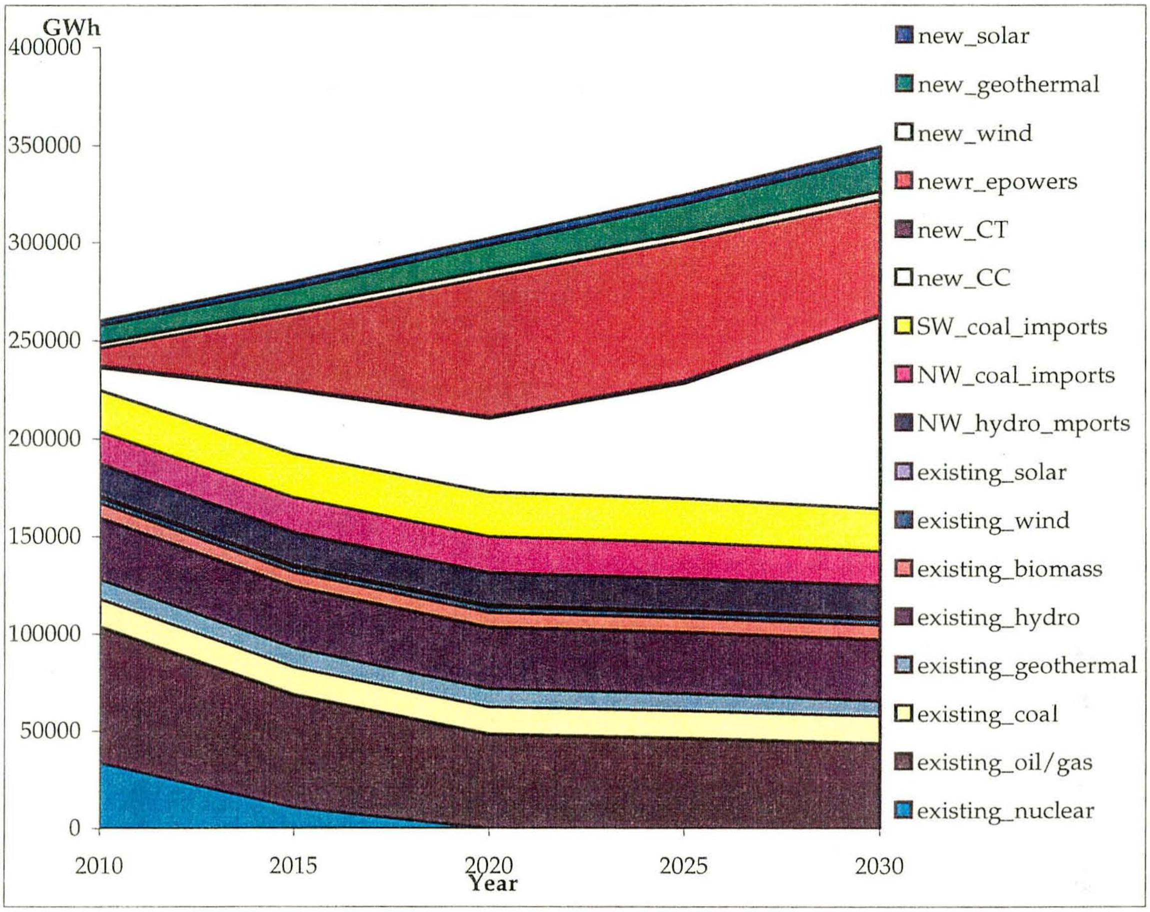


Table A-49. Resource Mix Under Scenario DN (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	69866	57962	48560	46456	43900
existing_coal	14196	14083	14021	14086	14054
existing_geothermal	10438	9931	9413	8825	7820
existing_hydro	31497	31507	31600	31508	31508
existing_biomass	7245	7245	7264	7245	7245
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16561	16575	16634	16575	16575
NW_coal_imports	15957	17716	18398	18153	17214
SW_coal_imports	21062	22237	22761	22551	21780
new_CC	11665	32404	37604	58859	98161
new_CT	1173	988	1004	1497	1028
newr_epowers	8806	37977	71286	71392	59040
new_coal/nuke	0	0	0	0	0
new_biomass	56	64	114	410	956
new_wind	2466	2958	3454	3942	4435
new_geothermal	8822	10379	12870	15147	17741
new_solar	2571	3225	3731	4458	5061
Other	26	97	63	213	0
Pumped storage	1043	478	378	411	737

Tables A-50 through A-54. Key Indicators for Scenario DN

A-50. Construction (units)

	2010	2015	2020	2025	2030
CC	7	19	22	34	57
CT	35	38	50	50	50
Wind	5	6	7	8	9
Geo-thermal	11	13	16	19	22
Solar-thermal	7	9	10	12	14
PV	9	10	12	14	15
Bio	6	6	8	9	10
Repower	5	23	38	38	38

A-51. Emissions (t)

	2010	2015	2020	2025	2030
NO	221040	224704	226766	227021	223665
SU	80959	84140	86072	85646	83984
PM	9070	11240	12989	14311	15893
RG	33118	34468	35551	36231	36495
CO	68923	68579	68504	69277	69138
CX	25066855	29260940	32596073	34721397	36949270
NG	245648	185091	134294	126077	126077

A-52. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	55%	65%	70%	72%	73%
Gas (EJ)	0.550	0.813	1.028	1.177	1.347
Billion (m^3)	14	21	27	31	35

A-53. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$88,168	$0	$0	$17,494	$42,719	$148,382

A-54. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$225,047	$12,396	$1,539	$238,983	$82,258	$4,469

Fixed O&M	Capital	Total Cost	Ind. Profit
$17,494	$42,719	$146,941	$92,042

Figure A-10. Resource Mix Under Scenario DG

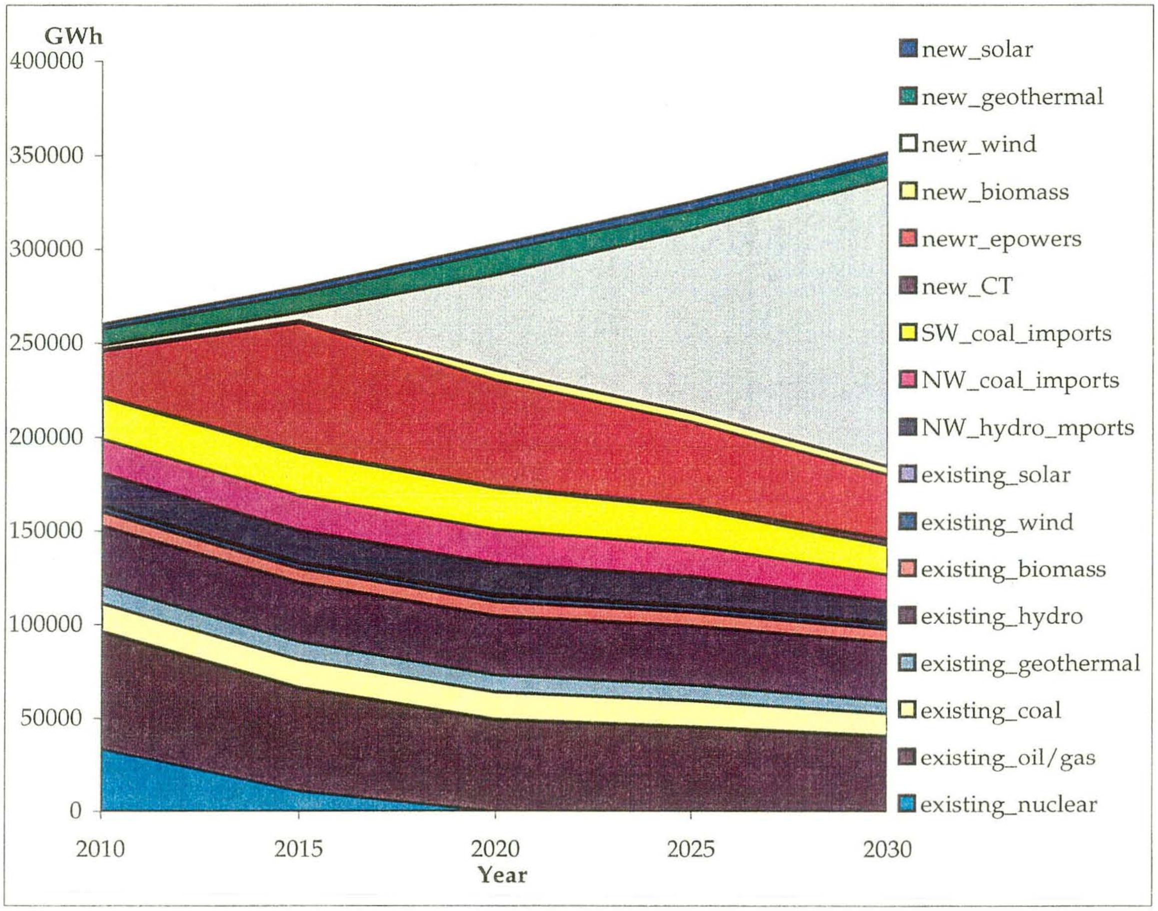


Table A-55. Resource Mix Under Scenario DG (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	62368	55356	49348	45654	40695
existing_coal	14979	14734	14510	13867	11855
existing_geothermal	10257	9932	9305	8448	6910
existing_hydro	31498	31506	31597	31497	31398
existing_biomass	7245	7245	7264	7229	6781
existing_wind	3069	3069	3076	3035	2713
existing_solar	911	911	913	907	877
NW_hydro_mports	16573	16575	16567	15091	11458
NW_coal_imports	18027	18464	18110	16501	14124
SW_coal_imports	22425	22774	22096	19932	15693
new_CC	0	0	0	0	0
new_CT	632	1202	936	1894	3460
newr_epowers	24019	68169	56596	44114	33968
new_coal/nuke	0	0	0	0	0
new_biomass	651	1399	5254	4959	4403
new_wind	2466	4436	51144	97795	153679
new_geothermal	8663	10136	12240	10256	9094
new_solar	2680	3302	3833	4569	4670
Other	1	90	162	11	11
Pumped storage	1199	380	1007	1800	2384

Tables A-56 through A-60. Key Indicators for Scenario DG

A-56. Construction (units)

	2010	2015	2020	2025	2030
CC	0	0	0	0	0
CT	41	44	44	44	44
Wind	5	9	104	200	316
Geo-thermal	11	13	16	19	22
Solar-thermal	7	9	10	12	14
PV	9	10	12	14	15
Repower	12	31	33	33	33

A-57. Emissions (t)

	2010	2015	2020	2025	2030
NO	226815	228363	229180	220215	195893
SU	86232	86459	85440	79507	66336
PM	10030	12967	17226	16080	14212
RG	33175	34497	34431	33787	31659
CO	67958	68496	68283	67075	62160
CX	25101437	29310753	27044122	24325920	20775604
NG	217551	173320	133604	125987	117704

A-58. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	54%	64%	53%	43%	34%
Gas (EJ)	0.500	0.787	0.630	0.502	0.410
Billion (m^3)	13	21	16	13	11

A-59. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$65,670	$0	$0	$31,942	$64,578	$162,191

A-60. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$250,817	$19,678	$1,872	$272,368	$61,281	$3,771

Fixed O&M	Capital	Total Cost	Ind. Profit
$31,942	$64,578	$161,576	$110,794

Figure A-11. Resource Mix Under Scenario DB

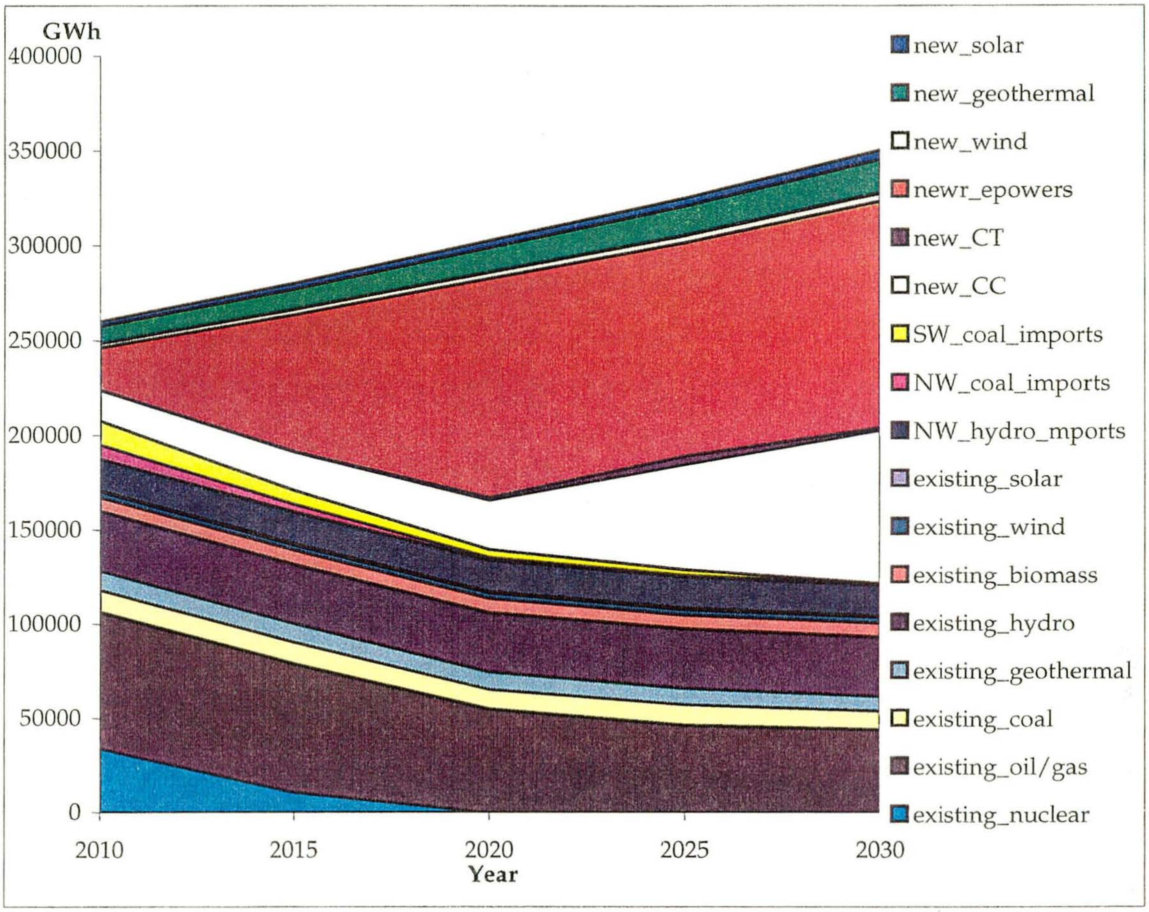


Table A-61. Resource Mix Under Scenario DB (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	72706	68045	54786	46452	43900
existing_coal	11507	11423	10471	10671	9912
existing_geothermal	10439	9938	9414	8826	7820
existing_hydro	31502	31504	31593	31507	31510
existing_biomass	7245	7245	.7264	7245	7245
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16563	16575	16634	16575	16575
NW_coal_imports	7299	3777	1197	736	139
SW_coal_imports	12400	7395	3929	2755	377
new_CC	16421	20338	26331	55724	81146
new_CT	479	407	1558	4722	1473
newr_epowers	21790	72008	115547	112356	119305
new_coal/nuke	0	0	0	0	0
new_biomass	11	18	12	34	13
new_wind	2466	2958	3454	3942	4436
new_geothermal	8880	10494	12951	15337	17759
new_solar	2551	3148	3606	4354	4846
Other	1	37	14	59	11
Pumped storage	492	364	361	366	373

Tables A-62 through A-66. Key Indicators for Scenario DB

A-62. Construction (units)

	2010	2015	2020	2025	2030
CC	10	12	15	32	50
CT	27	30	42	42	42
Wind	5	6	7	8	9
Geo-thermal	11	13	16	19	22
Solar-thermal	7	9	10	12	14
PV	9	10	12	14	15
Repower	11	30	45	45	57

A-63. Emissions (t)

	2010	2015	2020	2025	2030
NO	189864	175807	164275	160946	152254
SU	56089	46659	36735	35766	28834
PM	8923	11030	12834	14009	14803
RG	33361	34972	36272	36834	37165
CO	69468	70851	70579	70233	69897
CX	23689766	27619192	30430917	32398537	34269989
NG	263281	219570	148020	126077	126077

A-64. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	55%	65%	71%	72%	73%
Gas (EJ)	0.704	1.085	1.370	1.524	1.711
Billion (m^3)	18	28	36	40	45

A-65. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$62,600	$0	$0	$17,637	$44,212	$124,450

A-66. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$156,848	$15,364	$1,023	$173,237	$55,630	$6,659

Fixed O&M	Capital	Total Cost	Ind. Profit
$17,637	$44,212	$124,139	$49,097

Figure A-12. Resource Mix Under Scenario HN

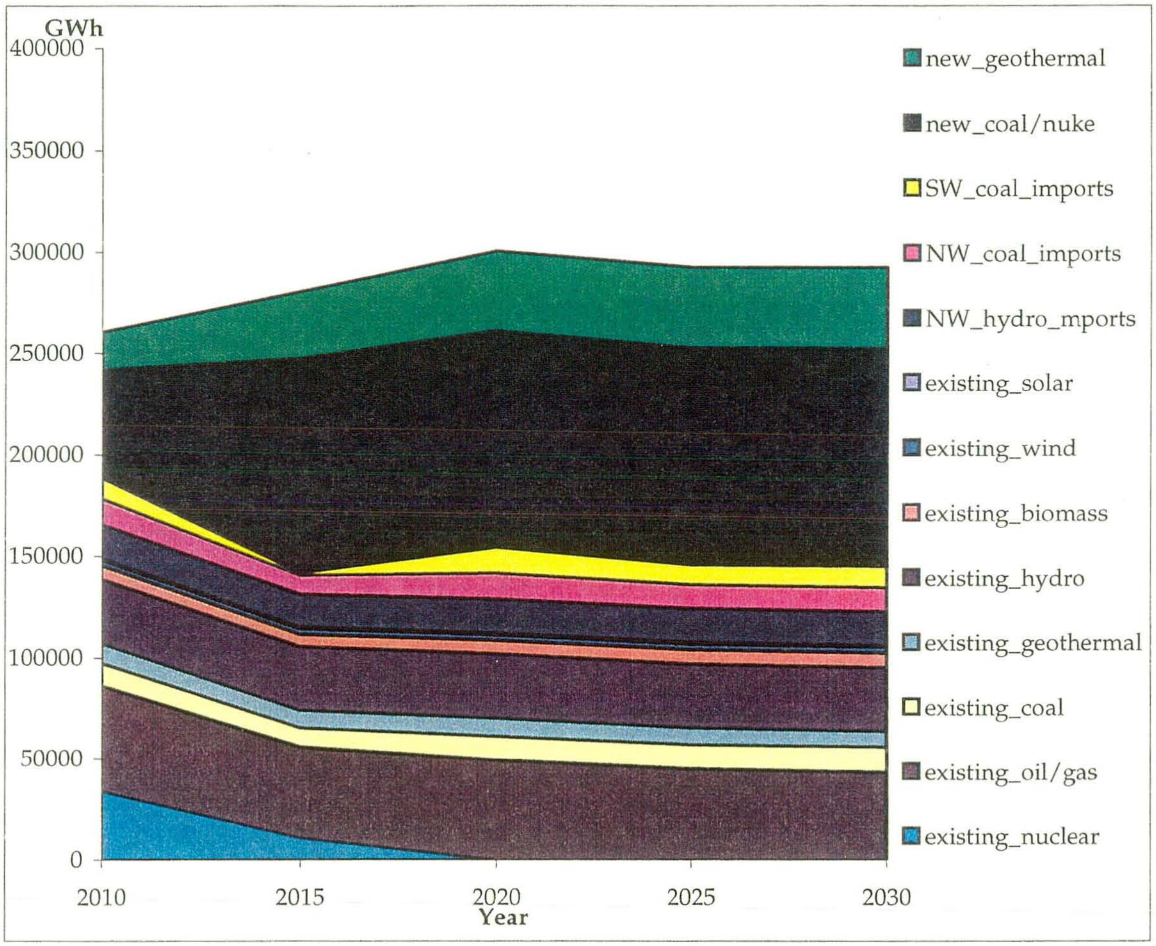


Table A-67. Resource Mix Under Scenario HN (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	52360	45144	49455	45072	43466
existing_coal	10921	9347	11826	12003	12610
existing_geothermal	9961	8817	9062	8585	7813
existing_hydro	31498	31494	31586	31489	31462
existing_biomass	6536	5684	6486	6762	7023
existing_wind	3069	3063	3075	3069	3069
existing_solar	911	909	912	910	911
NW_hydro_mports	16552	15778	16575	16558	16568
NW_coal_imports	12502	9258	12750	11447	11586
SW_coal_imports	10254	1404	12555	9810	10600
new_CC	0	0	0	29907	53072
new_CT	0	0	0	0	0
newr_epowers	0	0	0	0	0
new_coal/nuke	53290	105530	106740	106914	107358
new_biomass	0	0	0	0	0
new_wind	0	0	0	0	0
new_geothermal	18848	33244	39663	39931	40107
new_solar	0	0	0	0	0
Other	81	462	2202	2174	2353
Pumped storage	1884	2527	2502	2342	2473

Tables A-68 through A-72. Key Indicators for Scenario HN

A-68. Construction (units)

	2010	2015	2020	2025	2030
CC	0	0	0	22	38
CT	0	0	0	0	0
Wind	0	0	0	0	0
Geo-thermal	25	50	50	50	50
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	0
Nuclear	12	24	24	24	24
Repower	0	0	0	0	0

A-69. Emissions (t)

	2010	2015	2020	2025	2030
NO	177294	138479	184038	180111	184892
SU	54490	35160	60033	56308	59132
PM	6486	5240	6637	7909	9034
RG	30232	27665	30389	31796	32777
CO	59002	50883	58308	60912	63005
CX	16421002	12220729	16840799	18903321	21679018
NG	174045	140593	140219	125327	125830

A-70. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	53%	60%	63%	66%	68%
Gas (EJ)	0.230	0.165	0.176	0.360	0.519
Billion (m^3)	6	4	5	9	14

A-71. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$138,631	$0	$0	$31,207	$67,351	$237,190

A-72. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$1,481,163	$10,646	$8,291	$1,500,101	$79,304	$5,852

Fixed O&M	Capital	Total Cost	Ind. Profit
$31,207	$67,351	$183,716	$1,316,384

Figure A-13. Resource Mix Under Scenario HG

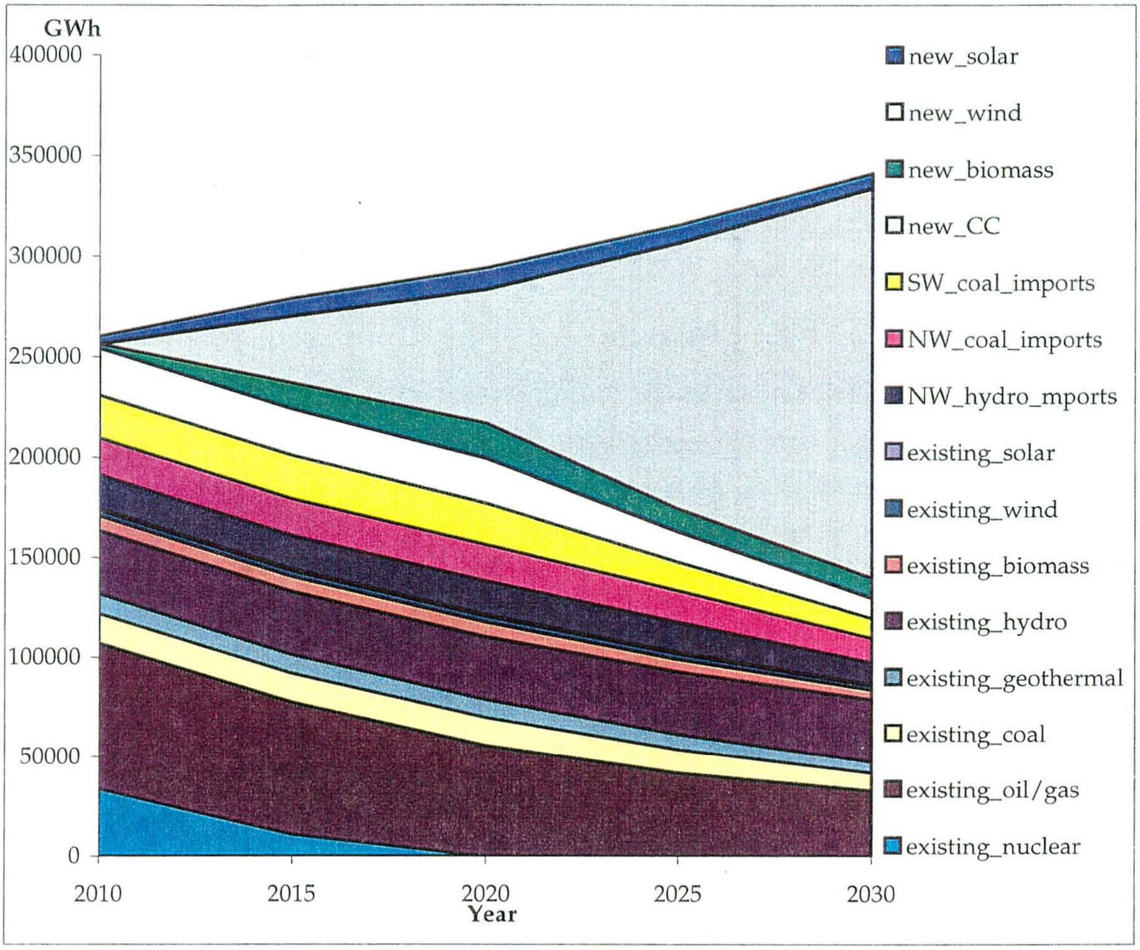


Table A-73. Resource Mix Under Scenario HG (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	73172	66415	55672	41930	32831
existing_coal	14869	14470	14055	11665	9109
existing_geothermal	10051	9661	9184	7763	5816
existing_hydro	31496	31498	31444	31322	31081
existing_biomass	7244	7236	7151	6122	4797
existing_wind	3069	3069	3076	2972	2348
existing_solar	911	911	913	897	744
NW_hydro_mports	16575	16575	16633	14960	10590
NW_coal_imports	18456	18412	18261	15639	12296
SW_coal_imports	21161	21569	20690	14299	9889
new_CC	23352	23201	22252	15290	10156
new_CT	0	0	0	0	0
newr_epowers	0	0	0	0	0
new_coal/nuke	0	0	0	0	0
new_biomass	2187	12831	17639	11412	10064
new_wind	0	33437	66609	132283	194198
new_geothermal	0	0	0	0	0
new_solar	3929	8949	10642	8871	7378
Other	136	1293	1093	1004	493
Pumped storage	1756	1948	2612	2516	2763

Tables A-74 through A-78. Key Indicators for Scenario HG

A-74. Construction (units)

	2010	2015	2020	2025	2030
CC	15	15	15	15	15
CT	0	0	0	0	0
Wind	0	68	136	272	408
Geo-thermal	0	0	0	0	0
Solar-thermal	15	30	30	30	30
PV	0	0	0	0	0
Bio	36	36	36	36	36
Repower	0	0	0	0	0

A-75. Emissions (t)

	2010	2015	2020	2025	2030
NO	227143	235185	235545	194649	157271
SU	84625	85514	83694	65490	49612
PM	12019	25513	31403	21793	18457
RG	33367	33943	33969	30357	26375
CO	70398	71924	71027	58286	45590
CX	26127316	25570417	23991051	18147924	13770713
NG	246190	197899	148432	116535	96503

A-76. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	58%	51%	44%	31%	22%
Gas (EJ)	0.597	0.513	0.399	0.237	0.155
Billion (m^3)	16	13	10	6	4

A-77. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$144,646	$0	$0	$37,222	$75,953	$257,823

A-78. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Rev.	Fuel	Var. O&M
$1,306,863	$21,987	$7,084	$1,335,935	$61,939	$3,442

Fixed O&M	Capital	Total Cost	Ind. Profit
$37,222	$75,953	$178,558	$1,157,377

Figure A-14. Resource Mix Under Scenario HB

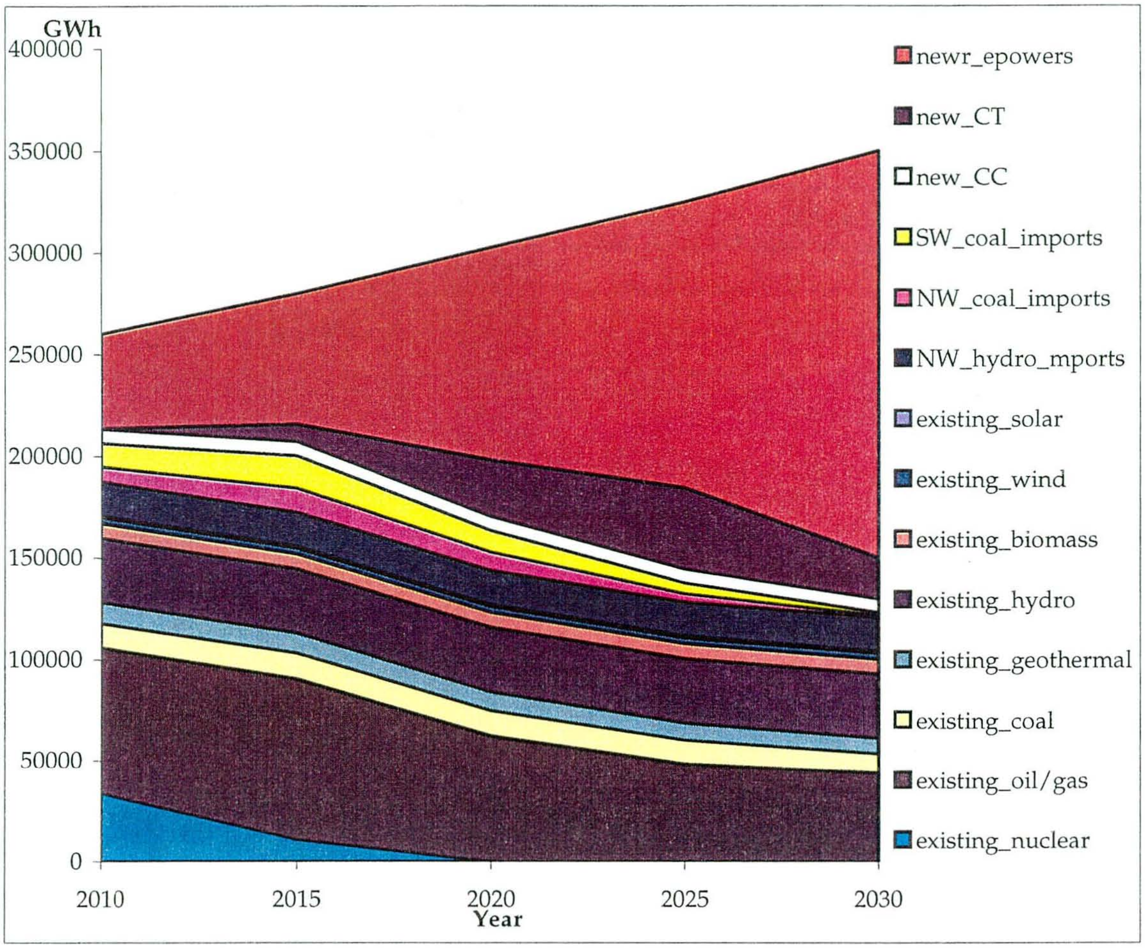


Table A-79. Resource Mix Under Scenario HB (GWh)

	2010	2015	2020	2025	2030
existing_nuclear	33936	10960	0	0	0
existing_oil/gas	71895	79705	62461	48414	43900
existing_coal	11898	12605	12433	11772	9666
existing_geothermal	10484	9940	9414	8827	7820
existing_hydro	31506	31510	31601	31510	31511
existing_biomass	7245	7245	7264	7245	7244
existing_wind	3069	3069	3076	3069	3069
existing_solar	911	911	913	911	911
NW_hydro_mports	16575	16575	16634	16575	16575
NW_coal_imports	7349	11844	8906	4171	1089
SW_coal_imports	11619	16017	10664	5027	1338
new_CC	6996	7002	7022	7002	6740
new_CT	258	8623	27816	40026	20340
newr_epowers	46391	64208	104526	140646	200131
new_coal/nuke	0	0	0	0	0
new_biomass	0	0	0	0	0
new_wind	0	0	0	0	0
new_geothermal	0	0	0	0	0
new_solar	0	0	0	0	0
Other	1	31	29	90	34
Pumped storage	371	363	362	362	361

Tables A-80 through A-84. Key Indicators for Scenario HB

A-80. Construction (units)

	2010	2015	2020	2025	2030
CC	4	4	4	4	4
CT	27	77	102	102	102
Wind	0	0	0	0	0
Geo-thermal	0	0	0	0	0
Solar-thermal	0	0	0	0	0
PV	0	0	0	0	0
Bio	0	0	0	0	0
Repower	22	22	34	46	70

A-81. Emissions (t)

	2010	2015	2020	2025	2030
NO	188540	205647	191219	172346	155255
SU	56669	68563	58087	44900	29989
PM	9588	11591	14137	15875	16535
RG	33742	35140	36973	38063	38241
CO	69777	72809	72989	72329	71084
CX	25006726	31144145	35011739	37259209	38481713
NG	266286	234874	161701	126077	126077

A-82. Thermal Usage

	2010	2015	2020	2025	2030
% Thermal	60%	71%	77%	79%	81%
Gas (EJ)	0.818	1.132	1.514	1.811	2.018
Billion (m^3)	21	30	40	47	53

A-83. Cumulative Present Values 2006-2055 (1995 B.O.Y Million $)

Production	Emission	Shortage	Fixed O&M	Capital	Net Cost
$71,130	$0	$0	$10,171	$21,110	$102,412

A-84. Market Revenues and Costs 2006-2055 (1995 B.O.Y. Million $)

Energy	Commit	Spin	Total Revenue	Fuel	Variable O&M
$168,077	$14,713	$1,544	$184,335	$62,202	$8,561

Fixed O&M	Capital	Total Cost	Profit
$10,171	$21,110	$102,046	$82,288

The Expansion Planning Logic of Elfin

B.1 Traditional Cost-Minimizing Capacity Expansion Planning

The tradition of electric utility expansion planning using production cost models is based on the paradigm of the centralized, vertically integrated company, and applies cost-minimizing assumptions. The objective function is a grand net present cost function, C, which is the discounted cost of all utility operations from the beginning to the end of the planning period at time T. This cost function is the sum of several components as follows:

$$C = \sum_{t=1}^{T} \left[\frac{\sum_{n=1}^{N} c^{g}_{n,t} + c^{u}_{t} + c^{e}_{t}}{(1+d)^{t}} \right]$$

Within the Elfin context, C can be considered total net present cost, and $c^{g}_{n,t}$ as the costs of running various n generating assets available to system. The denominator is the familar discounting term at a discount rate of d. The social cost of leaving energy unserved, that is, of letting the lights go out, is c^{u}_{t}. Within traditional dispatch logic, resources are dispatched to meet load irrespective of cost. That is, demand is seen as fixed, and the need to meet it as absolute. No demand response of any type exists, although an interruptible load might be considered a supply-side asset. In other words, c^{u}_{t} does not appear in the dispatch cost function meaning service cannot be interrupted on economic grounds alone.. Elfin, unlike most expansion planning models, takes a more social welfare oriented approach to expansion planning. New capacity is built only if and only if it lowers cost, including the cost of not serving customers. Unserved load is treated no differently than other costs. The external costs of power generation, such as uninternalized environmental damage is represented by c^{e}_{t}. These costs can be included in Elfin simulations if, appropriate values are specified by the user.

Each $c^{g}_{n,t}$ term can be thought of as a sum of the various elements of operating cost for a generator. These costs are normally summarized by categories of costs as follows:

$c^{g}_{n,t}$ = fuel costs + variable O&M (including labor) + fixed O&M + capital costs + other

The *other* category can be a negative, if, for example, there is some subsidy, such as a renewables production credit, for which the resource is eligible.

B.2 The MC-ITRE Algorithm

In expansion planning, keeping the search area within the limits of computational tractability is accomplished by representing potential new additions as a small number of generic alternatives. Elfin uses multiple algorithms for solving the expansion planning problem but here we focus on just one alternative, MC-ITRE. The MC-ITRE algorithm searches on the *C* cost surface as follows:

1. A table is built of the per MW net present value (NPV) of adding or deleting each generic resource in each year of the planning period.

2. Elfin adds new units up to a user-specified limit of the available expansion options.

3. Elfin then recalculates the table with the chosen additions in place. This operation completes one iteration.

4. The next iteration is commenced and Elfin again searches for cost reducing additions and reductions. On this and all subsequent iterations, Elfin also tests the benefits of deleting prior additions from the plan.

5. When no further cost reducing additions or deletions can be found, searching ceases. However, the final lowest cost plan is further tested by swapping in and out construction choices to verify that the plan is truly is lowest cost.

This search algorithm has proven to be quite stable and efficient. Some tricks are used to avoid getting trapped in a local cost minimum, but, in general, costs fall quickly as the iterations progress and a minimum is found that can be verified to be a reasonable minimum by the simple swapping of resource options in search of lower costs.

B.3 Towards a Competitive Expansion Logic

While traditional dispatch logic may persist in competitive market systems, clearly, expansion decision making will be performed in quite a different way from what the current centralized utility paradigm encourages. Investment decision making will be decentralized and based on individual investor returns rather than net present system operating cost. The goal here is to move Elfin's expansion planning logic incrementally towards a credible model of a competitive market system, of the kind proposed for California. The key change made to Elfin's expansion planning logic for the purposes of this study is a move away from the omnipotent centralized cost minimizing view of the old logic and towards a competitive paradigm driven by the decentralized entry decisions of new generating technologies. Remembering that the intent of expansion planning models is not the accurate simulation of actual operations, but rather the approximation of outcomes at a level sufficient only for mid to long run forecasting (beyond 5 years), and that computational burdens must be kept to a minimum to enable lengthy search procedures to complete, the basic logic of the approach is three-pronged.

1. It is assumed that either an ISO will continue to run system unit commitment and dispatch in a similar way as territorial utilities operate today, or competitive pressure will lead towards similar minimum cost solutions. Therefore, simulation of actual operations need be only modestly revised. (Section 4, below.)

2. The most important determinant of capacity construction under a competitive regime is free entry as far as is profitable. (Section 5, below.)

3. The search algorithm must be similar to the current one so that changes to Elfin are manageable and understandable. (Section 7, below.)

B.4 Market Dispatch Logic

A key initial assumption made here is that overall unit commitment and dispatch will tend towards the same sort of result current models would achieve for the same system and demand; that is, the cost minimum solution subject to constraints imposed by limits on various operations will be the outcome of both traditional and ISO dispatch unit commitment. The significant difference is the manner in which investments in new capacity are made. Elfin does not currently have good multi-area modeling capability that might be used to simulate the effect of local transmission constraints, and, therefore, strategic bidding is assumed non-existent. The modifications required to Elfin are manageable and need only address the fact that payments from the market will diverge from the simple minimum cost in the following minor ways.

1. An *energy payment* accrues to each generator that produces during a period. The payment is equal to the generators output times a weighted market price. The weighted market price is the sum of bid prices of generators that emerged as the marginal one dispatched during the period weighted by the share of the time each was marginal.

2. A *commit payment* is assumed to exist. This payment is made to the last generator committed during a period if it fails to break even from its market revenues. The payment simply makes this last generator whole and is given to all generators who are committed during the period.

3. A *spin payment* is assumed to exist. This payment is made to any generator whose output was curtailed to meet the spinning requirement even though it bid below the

market price. The payment is specific to the generator ramped down and is equal to the lost revenue that it would have collected if it had been free to generate.

Consequently, the revenue stream obtained by any generator is the sum of three payment types, although the energy payment is by far the largest of the three.

B.5 How Much Entry Will Occur

A net present profit function can be written for the industry as follows:

$$\pi^i = \pi^x + \pi^e$$

where, π^i = profits of the industry as a whole
π^x = profits of existing generating assets, and
π^e = profits earned by entering generating assets

The paradigm adopted is one of competing technologies. Consider first the profits accruing to exiting capacity, π^i. Given that dispatch in this study almost follows the traditional rules and no strategic bidding exists, existing generating capacity is essentially passive. It has no control over its profit function and passively accepts its lot. If its net present market revenues exceed its net present costs, then it generates profits, otherwise not. However, since these generating assets are typically largely depreciated and bid into the market at their marginal cost including variable O&M, only failure to cover fixed O&M results in losses. In a sense, existing assets have no entry decisions to make. Their profits will most likely be highest if no entry occurs, thereby pushing up market prices, and vice-versa. The one complication is that in some cases, the retirement of existing units is linked to repowers at the same site. From this perspective, this amounts to a unit being removed from the existing term of the profit function as its repower appears in the entering term. For the repower to be profitable, the overall profitability of the site must exceed the profit stream at the site were the existing plant to remain in place.

The focus here, of course, is on profits accruing to entering capacity, π^e. Note that, from a modeling point of view, entering capacity never becomes existing capacity. Entering capacity covers all capacity built throughout the study period. There are two fundamental assumptions governing entry. First, entry by at least one technology is unrestricted, and second, investors as a group will try to establish the pattern of new entry that will result in their own maximum profit.

Consider a breakdown of the entering capacity net present profit function by technology and year of construction. That is, capacity net present profit function by technology and year of construction. That is,

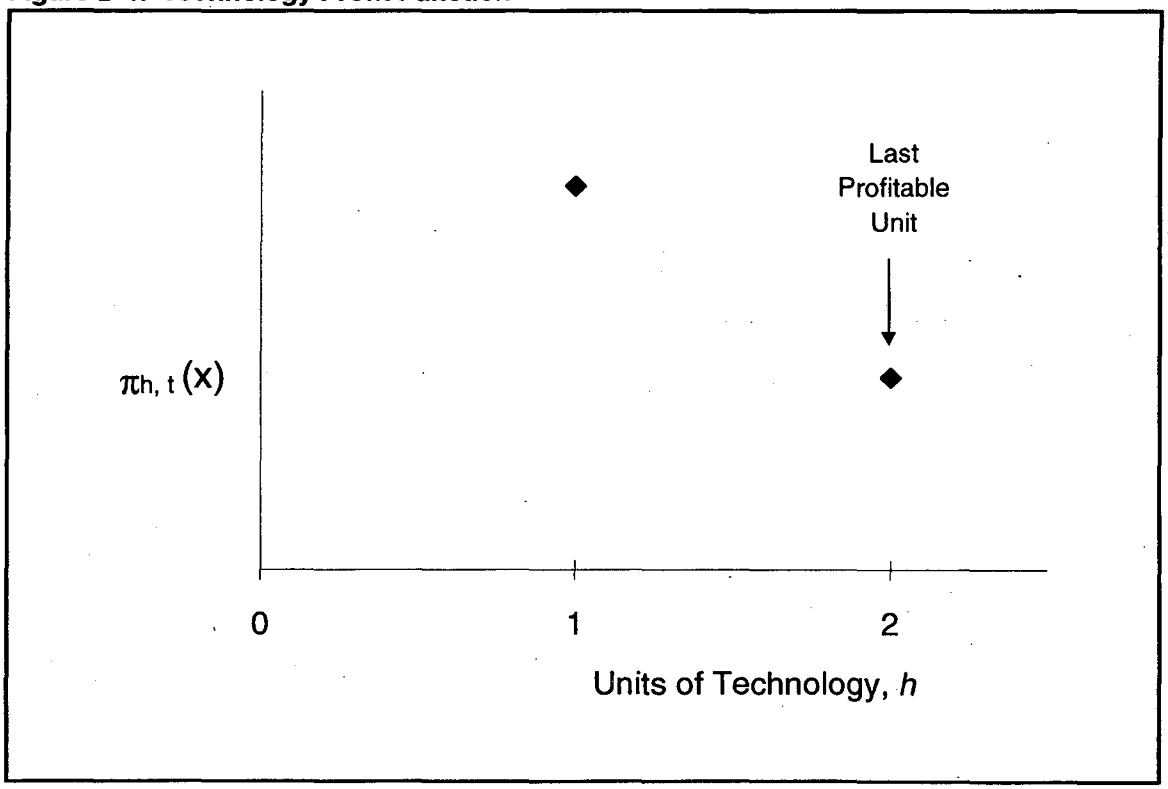
$$\pi^e = \sum_{h=1}^{H} \sum_{t=1}^{T} \pi_{h,t}$$

where, h = entering technologies, i.e. nuclear, gas combined cycle, wind, etc.
and t = the years of the study period

The net present profit function for any technology built in any year, $\pi_{h,t}$, depends on how much total capacity is built which will determine the revenue stream from market payments, and, of course, on the costs of the technology. This perspective essentially treats the construction of units of one given technology in one given year as a separate competitor. Since all units of a given technology are identical, and clearly more capacity lowers the market price, we can picture this profit function as follows.

In Figure B-1, the first two units of technology h built in year t generate profits and the net present profit function stays positive. If the third unit is built, however, the profit function turns negative. By the rule that all profitable entry occurs, this industry will build two units in this year. This rule is equivalent to saying that while we are looking at one technology as represented by one industry, it is, nonetheless, a competitive industry and it cannot increase

Figure B-1. Technology Profit Function



profits by restricting entry. Further, all producers in this industry are homogeneous; that is, all plants built are identical. However, for at least two reasons, positive profits can exist. First, the lumpiness of this and all other technologies precludes entry to the point of zero profits. This phenomenon makes careful specification of generic resources imperative. The realities of limited computation time require the use of as small a number of generic options as possible, and the specification of large generic resources. However, if resources are specified as too large, artificial lumpiness is being introduced. This is a particularly big problem with renewable technologies, such as wind, which, obviously, could be built on quite small scales. And second, since the Elfin algorithm looks at all years in deciding which additions to choose, not absolutely all profitable entry is made in every year. Elfin chooses the most profitable entry throughout the forecast period, which means that in the short-run, entry will not continue to the zero profit point. Note that the value of the net present profit function is much more complex than it seems because it depends not only on the build of this technology but also on the decisions made by all other technologies regarding their builds.

$$\pi_{h,\,t}\left[X_{h,\,t},\ P(X_{h,\,t},\ Y_{h,\,t},\ Z_t),\ C_{h,\,t}\right]$$

That is, the net present profit for technology *h* in year *t* depends not only on $X_{h,t}$, the number of units of technology *h* built in year *t*, but also on the stream of expected market revenues, *P*, which depends of the capacity of technology *h* built in all years, $X_{h,t}$, and the capacity build decisions of all other entrant technologies in all years, $Y_{h,t}$, and on the existing capacity stock in all years, Z_t, and the net present costs of construction and operation, $C_{h,t}$.

The profit function of entering technologies, π^e, can be further broken down into those technologies that have limited entry and those which are unlimited. The later category are the true generic resources. How many units of these technologies are built is entirely at the discretion of the model. And, each simulation must contain at least one unlimited technology if entry is to be truly free. The limited entry technologies are more troubling. For example, consider a specific type of geothermal site on which no more than two generating units can be constructed. This technology will benefit if the two units are built and yield profits, but, assuming that they are built, they will benefit the most if further entry is limited. Therefore, it seems at first blush that these technologies must be excluded from consideration in the same way that existing technologies are excluded. However, this is not so. The key to this paradox is that entry can still occur, even though not of this specific technology. Investors will seek the entry combination that results in maximum profit including the limited entry technologies. Even though a plan in which both of the limited entry technology units are built may seem inadmissable, in fact it is. A combination of new construction under which no further new capacity can be profitably built; that is, no additional entry is possible, is called a market equilibrium plan (MEP). Obviously, multiple MEPs exist for any combination of expansion alternatives.

B.6 Finding the Best Plan

Once as many of the MEPs as possible have been identified, choosing a winner from them is trivial. In as much as those investing in the industry will choose the plan that maximizes their private profit, the plan with the highest π^e must be selected.

B.7 Revised Algorithm

Given the goal of approximating a market system with free entry rather than traditional cost minimization, the following adjusted MC-ITRE algorithm has been developed and implemented in Elfin:

1. Because there is good reason to believe that MEPs lie close to the minimum cost point, and because minimum cost searches are efficient and stable, the minimum cost point is found.

2. Beginning at the minimum cost point, the first step in the algorithm, then is to build a table akin to the MC-ITRE table that shows whether any entry by a given technology in a given year can be profitable, given all other entry (and exit) decisions. The basic format of MC-ITRE is retained. For example, all decisions are made in discrete one-year time steps. If there is potentially profitable entry, then it assumed to take place.

3. This process continues until all the entrant profit functions are positive, but if a unit of any technology anywhere is built, then the profit function of its industry turns negative; that is, given the response of all other technologies, the last unit built loses money, which, because by definition, all units of a given technology are homogeneous, means they all lose money.

4. Unfortunately, because the profit surface is craggy but fairly level, numerous combinations of construction may meet this basic criterion. Therefore, the search algorithm must make subsequent searches in such a way that as many candidate plans as possible are identified in an unbiased manner.

5. When Elfin finds itself searching in a place it has visited before, searching ceases.

6. A swap step attempts to find new productive areas for searching.

7. When as many MEPs as possible have been found, the one with the highest entrant profit is selected as the winner.

B.8 Conclusion

A variation on the MC-ITRE algorithm has been developed to simulate entry into a competitive electricity market. Estimates are made of the profitability of construction of one new unit of generating capacity for each candidate technology. The most profitable capacity in the most profitable year is built first and the future operation of the system resimulated with the additions in place. Subsequent iterations add more profitable entry until no more is possible, combination of investments called an MEP. The choice between multiple MEPs is made so as to maximize overall profits to entrants. This algorithm has been implemented in Elfin together with a system of energy, commit, and spin payments.

Resource Options

C.1 Overview

In this appendix, we summarize the ranges of costs and operational parameters that were found in the literature for the 12 potential new resource additions modeled in this project and the assumptions that we ultimately used to model these resources.

C.2 Ranges of Costs and Other Operational Parameters

In this section, we describe the range of cost and other parameters we found in the literature for the 12 resource options that we included in our data set. The primary sources for this information were EPRI (1993), U.S. DOE (1994), and the resource characteristics of California utilities found in the Elfin data sets created for the 1994 Electricity Report. In each section, we summarize costs and other parameters in a table to facilitate side-by-side comparison of the range of cost and other parameters that we found from these various sources. We have converted all of the cost figures to 1995 dollars using the Gross Domestic Product (GDP) implicit price deflator and assume that natural gas costs will be the same for new units as for existing ones. In most cases, we found very wide ranges of costs for these 12 technologies and, thus, we have represented the resource options with base case, high, and low capital costs. We have also chosen representative parameters from the ranges presented for plant size, plant life, variable O&M, fixed O&M, heat rates, fuel costs, forced outage rates, and maintenance rates. The costs and other parameters ultimately selected for inclusion in this analysis are presented in Section C.3.3.

C.2.1 Gas Combined Cycle

We found a wide range of costs for combined cycle (CC) technologies, with capital costs ranging from approximately $600/kW to $1,400/kW (see Table C-1). Siting differences explain at least some of these differences. Construction of CCs at existing sites with appropriate infrastructure tends to cost less than new sites, with potentially more stringent permit requirements and possible public opposition. For this study, we use a range of different capital costs: $600/kW for the base case, $500/kW for the low-cost case, and $800/kWh for the high-cost case. The base case of $600/kW is consistent with EPRI (1993), SDG&E ER94 data, and Hadley, Hill, and Perlack (1993). The low-cost assumption assumes technical progress by 2005, which is the year in which we consider resource additions. In addition, we use the other data elements specified by EPRI (e.g., 225 MW for plant size, 30 $\frac{\$}{kW{\cdot}a}$ for fixed O&M, etc.). EPRI's variable and fixed O&M costs differ from the utilities' because EPRI assumes that more of the O&M costs are fixed and the utilities assume that more are variable. The fuel for this and all gas-fired technologies is ordinary natural gas, priced equally for all technologies.

Table C-1. Gas Combined Cycle Costs and Other Parameters

Data Elements	EPRI Tag (1993) CT/ CC 16.3	ER94, SCE Option #7, Existing Site In-Basin	ER94 SCE Option #10, New Site Out-of-Basin	ER94 SDG&E Option #13, In-County CC	ER SDG&E Option #10, Out-of-County CC
Capital Costs (1995$/kW)	623	979	1384	702 (692 for 2)	794 (911 for 2)
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	27.8	10.2	10.2	8.84	8.85
Variable O&M Costs (1995$/kWh)	0.0004	0.0027 (0.87% real esc.)	0.0027 (0.87% real esc.)	0.0040 (0.66% real esc.)	0.0040 (0.66% real esc.)
Heat Rate (AHR kJ/kWh) - Block Size (MW)	11,089 - 56 8,778 - 113 7,934 - 169 7,702 - 225 7,934 - AA	8,810 - 124 8,388 - 157 7,702 - 210	9,443 - 115 9,021 - 146 8,229 - 195	11,848 - 44 8,552 - 131 7,808 - 218 8,156 - 292 7,770 - 366 7,723 - 436	11,896 - 43 8,616 - 129 7,840 - 216 8,189 - 289 7,801 - 362 7,755 - 428
Forced Outage Rate	4.6%	3%	3%	4.2%	4.2%
Maintenance Rate	6.9%	5%	5%	4.2%	4.2%
Unit Capacity (MW)	225	210	195	472 (NC) 436 (DC)	464 (NC) 428 (DC)
Plant Life (a)	30	29	29	30	30

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
++Natural gas fuel costs will be the same for existing and new units in the Elfin model.
+++ Heat Rate and Block Sizes for SDG&E are summer values (June to October).
AA = Average Annual
NC = net capacity
DC = dependable capacity for reliability calculations

C.2.2 Repowers

As discussed elsewhere in this report, repowers are one of the most important yet difficult to characterize capacity options. On reason repowers are inherently problematic resources in capacity expansion modeling is because repower projects are unique to specific sites and equipment, whereas the computational constraints of modeling dictate that expansion options be as small a set of generic options as possible. In other words, it is inherently difficult to represent repower resources as a generic option. In addition, possible repower options at any one site are numerous and, obviously, the choice of any one project will have a major impact on other projects. For the purposes of this study, the data used for repowers was a low-end estimate made on the basis of green field gas-fired combined cycle technology and ER94 data on potential repowers. The fuel is ordinary natural gas.

C.2.3 Gas Combustion Turbine

We also found a wide range of costs for gas combustion turbines (see Table C-2). We use \$450/kW as the base-case option, \$350/kW for the low-cost option, and \$600/kW for the high-cost option. The base-case costs are consistent with EPRI (1993), the low cost are consistent with Hadley, Hill, and Perlack (1993), and the high costs are consistent with SCE's ER94 data set. The low-cost assumption assumes technical progress by 2005, which is the year in which we consider resource additions. We use EPRI operational parameters (e.g., fixed and variable O&M, plant capacity, etc.), except for forced outage and maintenance rates, where we use SCE's values. EPRI's variable O&M costs are substantially lower than the utilities'.

Table C-2. Gas Combustion Turbine Costs and Other Parameters

Data Elements	EPRI Tag (1993) CT 15.4	ER94, SCE Option #11, Existing Site In-Basin	ER94, SCE Option #12, Existing Site Out-of-Basin	ER94, SDG&E Option #16, GT-GE7F	ER94, SDG&E Option #18, GT-LM 6000
Capital Costs (1995\$/kW)	453	610	1330	621	1047
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	10.7	8.2	8.2	3	4.3
Variable O&M Costs (1995\$/kWh)	0.0001	0.0053 (0.87% real esc.)	0.0053 (0.87% real esc.)	0.0061 (0.66% real esc.)	0.0087 (0.66% real esc.)
Heat Rate (AHR kJ/kWh) - Block Size (MW)	18,031 - 38 13,230 - 75 11,827 - 113 11,711 - 150 12,882 - AA	11,817 - 144	12,080 - 139	32,707 - 15 19,191 - 42 14474 - 69 12,959 - 97 11,966 - 124 11,682 - 151	29,177 - 8 16,209 - 10 13,399 - 17 12,157 - 24 11,195 - 31 10,806 - 38
Forced Outage Rate	10.4%	4%	4%	4.2%	4.2%
Maintenance Rate	6.9%	4%	4%	4.2%	4.2%
Unit Capacity (MW)	150	144	139	151 (DC) 163 (NC)	38 (DC) 42 (NC)
Plant Life (a)	30	29	29	24	24

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
++Natural gas fuel costs will be the same for existing and new units in the Elfin model.
+++ Heat Rate and Block Sizes for SDG&E are summer values (June to October).
AA = Average Annual
DC = dependable capacity
NC = net capacity for reliability calculations

C.2.4 Wind

Wind capital costs range from a low of \$620/kW in 2005 to a high of \$1,600/kW for at least one SDG&E option. In addition, DOE (1996) estimates that capital costs will move from a current \$825/kW to \$625/kW in 2030. The ranges we use in our analysis differ slightly from those found in Table C-3. For the base-case capital costs, we assume that capital costs are \$900/kW in 1995 and fall to \$600/kW in 2030. These costs are generally consistent with DOE (1996), EPRI (1993), Wiser and Kahn (1996), Hadley, Hill, and Perlack (1993), Hamrin and Rader (1993), and Williams and Bateman (1995). For low capital costs, we assume that capital costs fall from \$800/kW in 1995 to \$500/kW in 2026. For the high cost, we assume that current prices of approximately \$900/kW remain constant. We assume fixed O&M costs of 26 $\frac{\$}{kW \cdot a}$, no variable costs, maintenance rates of 2.5 percent, forced outage rates of zero percent, and a nameplate capacity of 250 MW.

Table C-3. Wind Plant Costs and Other Parameters

Data Elements	EPRI Tag (1993) Wind 24.1 (1995 Costs)	EPRI Tag (1993) Wind 24.1 (2005 Costs)	ER94 SCE Option #21	ER94 SCE Option #20	ER94 SDG&E Option #28	ER94 SDG&E Option #42
Capital Costs (1995\$/kW)	860	620	1159	969	1632	957
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	26.4	26.4	15.5	15.5	71.8	2.6
Variable O&M Costs (1995\$/kWh)	0	0	0.0082 (0.87% real esc.)	0.0082 (0.87% real esc.)	0.014 (0.66% real esc)	0.014 (0.66% real esc)
Load Shape					see WIN1	see USWP
Forced Outage Rate			2.5%	2.5%	5.8%	5.8%
Maintenance Rate			2.5%	2.5%	4.8%	4.8%
Plant Capacity (MW)	50 (NC)	50 (NC)	50 (DC) 250 (NC)	50 (DC) 250 (NC)	11 (DC) 75 (NC)	12 (DC) 80 (NC)
Plant Life (a)	30	30	29	29	20	50

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
++EPRI Tag O&M numbers are expected to decline in the future. We have used 1995 and 2005 capital costs
DC = dependable capacity
NC = net capacity for reliability calculation

C.2.5 Wind with Combustion Turbine Backup

There were no existing capital costs or operational parameters for a wind plant backed up by a combustion turbine (CT). We combined the costs of a wind and a CT plant for the capital cost options. We assume that costs fall from $1,350 to $1,050 in 2030 for the base case, that costs fall from $1,150 to $850 in 2030 for the low-cost case, and that costs remain constant to $1,500/kW for the high-cost case. We assume a 250 MW facility, with maintenance and forced outage rates of four percent, no variable O&M costs, and fixed costs O&M costs of 40 $\frac{\$}{kW \cdot a}$. We assume no fuel costs when the wind plants are generating energy and a heat rate of 12,000 units when the CT is operating and using gas. Emissions are the same as for the CT provided above.

C.2.6 Geothermal

Table C-4. Geothermal Costs and Other Parameters

Data Elements	EPRI Tag (1993) Binary 21.1	EPRI Tag (1993) Dual Flash 21.2	ER 94 SCE Option #35, Binary	ER94 SCE Option #22, Dual Flash	ER94 SDG&E Option #24, Binary	ER94 SDG&E Option #26, Dual Flash
Capital Costs	2158	1275	4658	4244	4359	3891
Fixed O&M Costs	51.5	39.1	192.2	268.5	192.2	107.2
Variable O&M Costs	0	0	0.0015 (0.87% real esc)	0.0068 (0.87% real esc)	0.015 (0.66% real esc)	0.0099 (0.66% real esc)
Heat Rate (AHR kJ/kWh) - Block Size (MW)	43,732 - 3 37,233 - 7 36,446 - 10 36,273 - 13 35,144 - AA	29,753 - 24 30,649 - AA				
Forced Outage Rate	1.5%	1.0%	5%	5%	7%	4%
Maintenance Rate	2.3%	2.7%	3%	3%	3.1%	3.8%
Unit Capacity (MW)	2 x 13 MW	24 MW	100 MW	100 MW	30 (DC) 70 (NC)	33 (DC) 40 (NC)
Plant Life	30	30	29	30	25	25

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
++No fuel costs because steam field has been purchased for the utilities' options.
AA = Average Annual

In addition to the numbers presented above (Table C-4), DOE technology characterizations presents capital cost figures for geothermal binary, geothermal flashed steam, and geothermal hot dry rock. For a 30-MW geothermal binary plant, DOE estimates capital costs of $3,590/kW for 1995 falling to $1,870/kW in 2030 and O&M costs of 114 $\frac{\$}{kW \cdot a}$ in 1995 falling to $58/kW in 2030. For 50-MW geothermal flashed steam plant, DOE estimates capital costs of \$2,310 in 1995 falling to \$1,560/kW in 2030 and O&M costs of 124$\frac{\$}{kW \cdot a}$ in 1995 falling to 60 $\frac{\$}{kW \cdot a}$ in 2030. Finally, for a 10-15 MW geothermal hot dry rock plant, DOE estimates capital costs of \$5,640/kW for a base system, \$2,530/kW for a second generation system, and \$1,880/kW for a goal system, with corresponding O&M costs of 181 $\frac{\$}{kW \cdot a}$, 78 $\frac{\$}{kW \cdot a}$, and 62 $\frac{\$}{kW \cdot a}$. These figures are in 1990 dollars, so 1995 values would be about 7.5 percent higher.

For our analysis, we use capital costs of \$2,300 falling to \$1,600 in 2030 for the base case, with most of the decrease occurring by 2000. This assumption is taken from DOE (1996) and is consistent with Hadley, Hill, and Perlack (1993), Hamrin and Rader (1993), and Williams and Bateman (1995). We use \$1,300/kW for the low cost case, which is consistent with EPRI (1993). Finally, we use \$2,300/kW for the high cost case, essentially using DOE (1996) numbers but assuming no technological innovation or cost decreases over time. We also use low, medium, and high fixed O&M costs of 40 $\frac{\$}{kW \cdot a}$, 50$\frac{\$}{kW \cdot a}$, and 190$\frac{\$}{kW \cdot a}$. We assume a plant size of 100 MW, a forced outage rate of five percent, maintenance rate of three percent, no variable costs, and fuel costs similar to PG&E geothermal facilities (i.e., heat rate of 22,000 and steam price of \$0.63/mbtu).

C.2.7 Solar Thermal

Table C-5. Solar Thermal Costs and Other Parameters

Data Elements	EPRI Tag (1993) 23.1 Hybrid	ER94 SCE Option #18, ST w/gas	ER94 SCE Option #19, ST w/o gas	ER94 SDG&E Option #33, ST Pond	ER94 SDG&E Option #32, ST w/gas
Capital Costs (1995$/kW)	3399	5150	4862	6085	3575
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	35.7	61.3	53.6	82.9	40.9
Variabe O&M Costs (1995$/kWh)	0.0049 does this include fuel?	0.0102 (0.87% real esc)	0.0102 (0.87% real esc)	0	0.0041 (0.66% real esc)
Heat Rate for Gas (AHR kJ/kWh) - Block Size (MW)	12,977 - 20 11,922 - 40 10,867 - 60 9,835 - 80				
Forced Outage Rate	4%	7%	7%	2%	7%
Maintenance Rate	3.8%	7%	5%	2%	3.8%
Unit Capacity (MW)	80	80	80	3 (DC) 5 (NC)	80 (DC) 91 (NC)
Plant Life (a)	30	33	33	30	30

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
++Backup fuel is gas.

In addition to these figures (Table C-5), DOE (1994) provides capital cost figures for the following solar thermal technologies: power tower system, parabolic dish, 7.5-kW module, parabolic dish, 25-kW module, parabolic through power plant. The capital costs and O&M costs for these technologies are as follows:

Table C-6. DOE Solar Thermal Plant Costs

	Power Tower System	Solar Thermal Parabolic Dish, 7.5 kW Module	Solar Thermal Parabolic Dish 25 kW Module	Solar Thermal Parabolic Through Power Plant
Capital Costs (1995$/kW)	2,310 in 2000 falling to 2,240 in 2005	5,700 in 1995 falling to 3,800 in 2000	2,000 in 2005 falling to 1,400 in 2012	3,125 in 1995 falling to 2,573 in 2000
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	28 in 2000 falling to 25 in 2005	77	45 in 2005 falling to 34 in 2010 and 23 in 2020	52 in 1995 falling to 45 in 2000 and 33 in 2010

For the base case, we assume that costs fall from $3,100 in 1995 to $2,600 in 2000. This assumption is consistent with DOE (1996) estimates for solar thermal parabolic through technology and Hadley, Hill and Perlack (1993), Hamrin and Rader (1993), and Williams and Bateman (1995). For the low cost scenario, we assume that capital costs fall and remain constant at about $2,200/kW. This is consistent with DOE's estimate for a power tower system. Finally, for high capital costs we assume that solar thermal costs remain constant at $3,100/kW. In addition, we generally use the operational parameters specified by EPRI, although we assume fixed costs of $55/kW, maintenance rates of five percent, and forced outage rates of seven percent (from SCE).

C.2.8 Photovoltaic

Table C-7. PV Plant Costs and Other Parameters

Data Elements	EPRI Tag (1993) 22.1B	EPRI Tag (1993) 22.1C	EPRI Tag (1993) 22.3	EPRI Tag (1993) 22.3	SCE PV Central Station Flat Plate	SDG&E Distributed PV
Capital Costs (1995$/kW)	2986	2659	3463	2870	2592	5067
Fixed O&M Costs (1995 $\frac{\$}{kW\cdot a}$)	9.2	6.6	23.4	6	5.9	11.3
Variable O&M Costs (1995$/kWh)	0	0	0	0	0	0
Load Shapes or Heat Rates for Gas?						
Forced Outage Rate	3%	3%	3.%	3%	1%	7%
Maintenance Rate	3.8%	3.8%	3.8%	3.8%	1%	1%
Plant Capacity (MW)	5	50	5	50	50	2.5
Plant Life(a)	30	30	30	30	32	20

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.

In addition to the values given above, DOE (1994) estimates that costs for a concentrating photovoltaic plant would be about $5,000/kW in 1995 falling to $1,200 in 2028. We use this estimate as our base case. For our low-cost case, we assume that photovoltaic costs would fall from $4,000/kW to $1,000/kW in 2020. Finally, for our high-cost case, we assume that costs would fall from $5,000/kW to $3,000/kW in 2030. We are aware current photovoltaic costs are about $7,000/kW for small projects, but we are assuming that with larger scale projects, current costs could easily fall to $5,000/kW and to $4,000/kW in the most optimistic scenario. For other operational parameters, we rely primarily upon EPRI (1993).

C.2.9 Nuclear

Table C-8. Nuclear Plant Costs and Other Parameters

Data Elements	EPRI Tag (1993) 28.1 - Evolutionary ALWR	EPRI Tag (1993) 28.2 - Passive Safety ALWR	EPRI Tag (1993) 28.3 - ALMR
Capital Costs	1562	1938	1818
Fixed O&M Costs (1995$/kW)	63.2	78.9	68.7
Variable O&M Costs (1995$/kWh)	0.0003	0.0031	0.0003
Heat Rate (AHR kJ/kWh) - Block Size (MW)	10,762 - 1350 11,089 - AA	10,973 - 600 11,300 - AA	10,271 - 1,488 10,582 - AA
Forced Outage Rate	9.8%	7.7%	5.3%
Maintenance Rate	8.2%	7.3%	3.7%
Unit Capacity (MW)	1350	600	1488
Plant Life	30	30	30

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
AA = Average Annual

For the base-case scenario, we assume capital costs of $2,500/kW, which is consistent with EPRI (1993). For low capital costs, we assume $1,800/kW and for high costs, we assume $5,000/kW, roughly the cost of building the Diablo Canyon plant in California. We assume variable O&M costs of 0.3 ¢/kWh, fixed O&M costs of 75 $\frac{\$}{kW \cdot a}$, and fuel costs of 0.5 ¢/kWh.

C.2.10 Coal Gasification—Combined Cycle

Table C-9. Coal Gasification Combined Cycle Plant Costs and Other Parameters

Data Elements	EPRI Tag 10.1A - Entrained Flow - Medium Integration	EPRI Tag 10.3A - Entrained Flow - Nonintegrated	EPRI Tag 10.4B - Moving Bed - High Integration	SCE #30
Capital Costs	1776	2044	1784	2829
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	53.6	61.9	52.5	20.4
Variable O&M Costs (1995$/kWh)	0.0004	0.0006	0.0015	0.0112 (0.87% real esc)
Heat Rate (AHR kJ/kWh) - Block Size (MW)	16,058 - 125 11,426 - 250 9,833 - 375 9,211 - 500 9,485 - AA	15,984 - 125 11,374 - 250 9,791 - 375 9,168 - 500 9,443 - AA	15,024 - 125 10,688 - 250 9,205 - 375 8,620 - 500 8,884 - AA	12,661 - 93 11,817 - 186 10,129 - 278 9,707 - 371
Forced Outage Rate	10.1%	11.6%	10.1%	4.6%
Maintenance Rate	4.7%	4.7%	4.7%	3%
Unit Capacity (MW)	500	500	500	371
Plant Life	30	30	30	29

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
AA = Average Annual

For base case capital costs, we use $2,000/kW falling to $1,500 in 2030. For low costs, we assume $1,500/kW and for high costs, we use $2,800/kW, which is consistent with SCE's ER94 data set. We use EPRI's operational parameters for an entrained flow—medium integration unit.

C.2.11 Advanced Coal

Table C-10. Advanced Coal Plant Costs and Other Parameters

Data Elements	EPRI 5.1A - Atmospheric Fluidized-Bed Combustion-Bubbling	EPRI 5.5A - Atmoshpric Fluidized- Bed Combustion - Circulating	EPRI 6.1 - Pressurized Fuidized-Bed Combustion - Bubbling - Subcritical (reheat)	EPRI 6.2 - Pressurized Fuidized-Bed Combustion - Bubbling - Subcritical (non reheat)	SDG&E #22 - Atmospheric Fluidized Bed
Capital Costs (1995$/kW)	1630	1956	2109	1448	3111
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	37.9	39.4	7435	44.8	41.7
Variable O&M Costs (1995$/kWh)	0.0024	0.0013	0.0036	0.0035	0.0041
Heat Rate (AHR kJ/kWh) - Block Size (MW)	13,777 - 50 11,321 - 100 10,717 - 150 10,521 - 200 10,731 - AA	14,215 - 50 11,679 - 100 11,058 - 150 10,855 - 200 11,072 - AA	- 20 9,976 - 40 9,501 - 60 9,248 - 80 9,525 - AA	- 20 10,196 - 40 9,712 - 60 9,452 - 80 9,736 - AA	15,332 - 48 15,012 - 77 12,928 - 106 12,780 - 134 12,338 - 163 12,265 - 192
Forced Outage Rate	4.7%	4.1%	11.7%	12.2%	1.02%
Maintenance Rate	5.7%	5.7%	8%	8%	9.4%
Unit Capacity (MW)	200	200	80	80	192 (DC) 220 (NC)
Plant Life (a)	30	30	30	30	30

+We have converted all of the figures into 1995 dollars using the GDP Implicit Price Deflator.
++ Heat Rate and Block Sizes for SDG&E are summer values (June to October).
AA = Average Annual

We use $1,500/kW for base-case capital costs, consistent with EPRI (1993), $3,100/kW for high capital costs, consistent with SDG&E's ER94 data set, and $1200/kW for low capital costs.

C.2.12 Biomass

Table C-11. Biomass Plant Costs and Other Parameters

Data Elements	EPRI (1993) 26.1 Wood	EPRI (1993) 26.2 Wood	EPRI (1993) 26.3 Tree	EPRI (1993) 26.4B	SDG&E Agricultural Waste	SDG&E Biomass Forest Waste
Capital Costs	1973	2304	1474	2279	2773	2157
Fixed O&M Costs (1995 $\frac{\$}{kW \cdot a}$)	91.9	97.5	61.3	107.2	31.7	26.5
Variable O&M Costs (1995$/kWh)	0.0085	0.0093	0.0074	0.0093	0.0049 (0.66% real esc)	0.0048 (0.66% real esc)
Fuel Costs					2/mmbtu	2.5/mmbtu
Heat Rate (AHR kJ/kWh) - Block Size (MW)	14,658 - 50 15,098 - AA	14,627 - 50 15,066 - AA	11,241 - 100 11,578 - AA	13,050 - 100 12,740 - AA	vary	vary
Forced Outage Rate	10.0%	10.0%	na	na	9.8%	9.8%
Maintenance Rate	5.6%	5.6%	na	na	5.7%	5.7%
Plant Capacity	50	50	100	100	17.8 (DC) 28 (NC)	21.2 (DC) 26.3 (NC)
Plant Life	30	50	30	30	20	20

AA = Average Annual

In addition to the data provided above, DOE (1994) estimates costs for a number of biomass technologies, including biomass to electricity direct fired technology (na), biomass power gasification system ($1,200 falling to $1,000 for this near commercial technology), and biomass power-biocrude combustion turbine ($2700 to $1,500 in 2030 for this technology currently under development).

We use $2,000/kW falling to $1,500/kW for the base case. This falls within the parameters provided by SDG&E's ER94 data set, EPRI (1993) and Hadley, Hill, and Perlack (1993), Hamrin and Rader (1993), and Williams and Bateman (1995). For low cost, we use $1,600/kW falling to $1,200/kW in 2030, which is slightly higher than the DOE costs for the biomass power gasification system.

C.3 Summary of Parameters Used in this Analysis

For this analysis, we include 12 resource options. For each option, we specify low, medium, and high capital costs (see Table C-12). Although non-capital costs and other parameters vary among sources, for simplicity's sake, we only vary capital costs. For each option, we also specified the size of the plant, plant life, variable operation and maintenance (O&M), fixed O&M costs, fuel costs, forced outage rates, and maintenance rates (see Table C-13). Emissions rates are found in Table C-14 and offset values are shown in Figure C-1.

Table C-12. Summary of Capital Costs Assumptions

Resource Options	Base Case ($/kW)	High Cost Case ($/kW)	Low Cost Case ($/kW)
Combined Cycle	600	800	500
Combustion Turbine	450	600	350
Repower			
Wind Power Plant	900 - falling to 600 in 2030	900	800 - falling to 500 in 2030
Wind Power w/CT	1,350 - falling to 1,050 in 2030	1500	1,150 - falling to 850 in 2030
Geothermal	2,300 - falling to 1,600 in 2030	2300	1300
Solar Thermal	3,100 - falling to 2,600 in 2000	3100	2200
Photovoltaic	5,000 - falling to 1,200 in 2030	5,000 - falling to 3,000 in 2030	4,000 - falling to 1000 in 2020
Nuclear	2500	5000	1800
Coal Gasification	2,000 falling to 1,500 in 2030	2800	1500
Advanced Coal	1500	3100	1200
Biomass	2,000 falling to 1,500 in 2030	2000	1,600 falling to 1,200 in 2030
Repower	500	700	400

Table C-13. Other Characteristics of Generic Technologies

	Plant Size (MW)	Plant Life (a)	Variable O&M (1994$/kWh)	Fixed O&M (1995 $\frac{\$}{kW \cdot a}$)	Fuel Costs	Heat Rate (Block Size) kJ/kWh MWh P_{min} to P_{high}	Forced Outage	Maintenance
CC	225	30	0.0004 (0.75%)	30	$2/MMBtu (1.5%)	11,089 (56); 8,778 (113); 7,934 (169); 7,702 (225)	4.6%	6.9%
CT	150	30	0.0001 (0.75%)	10	$2/MMBtu (1.5%)	18,031 (38); 13,230 (75); 77,827 (113); 11,711 (150)	4%	4%
Wind	250	30	0	26	na	na	0%	2.5%
Wind w/CT	250	30	0	40	$2/MMBtu (1.5%)	12,661 (250)	4%	4%
Geothermal	100	30	0	40/50/190	$0.63/MMBtu+	23,211 (100)	5%	3%
Solar Thermal	80	30	0.0049 (0.75%)	55	$2/MMBtu (1.5%)	12,977 (20); 11,922 (40); 10867 (60); 9835 (80)	7%	5%
Photovoltaic	50	30	0	7	na	na	3%	4%
Nuclear	600	30	0.0031	75	0.005	na	7.7%	7.3%
Coal Gasification	500	30	0.0004 (0.75%)	54	$1.5/MMBtu (1.5%)	16,058 (125); 11,426 (250); 9,833 (375); 9,211 (500)	10.1%	4.7%
Advanced Coal	30	30	0.0024 (0.75%)	38	$1.5/MMBtu (1.5%)	13,777 (7.5); 11,321 (15); 10,717 (22.5); 10,521 (30)	4.7%	5.7%
Biomass	100	30	0.0074 (0.75%)	62	$2.50/MMBtu	10551 (100)	10%	5.6%
Repower	400	30	0.0027 (0.75%)	10	$2/MMBtu (1.5%)	9,232 (236); 8,810 (300); 8,177 (400)	5.0%	5.0%

+ Escalated at same rate as gas price

Table C-14 Emissions Characteristics of Generic Technologies (lbs/mbtu or lbs/kWh)

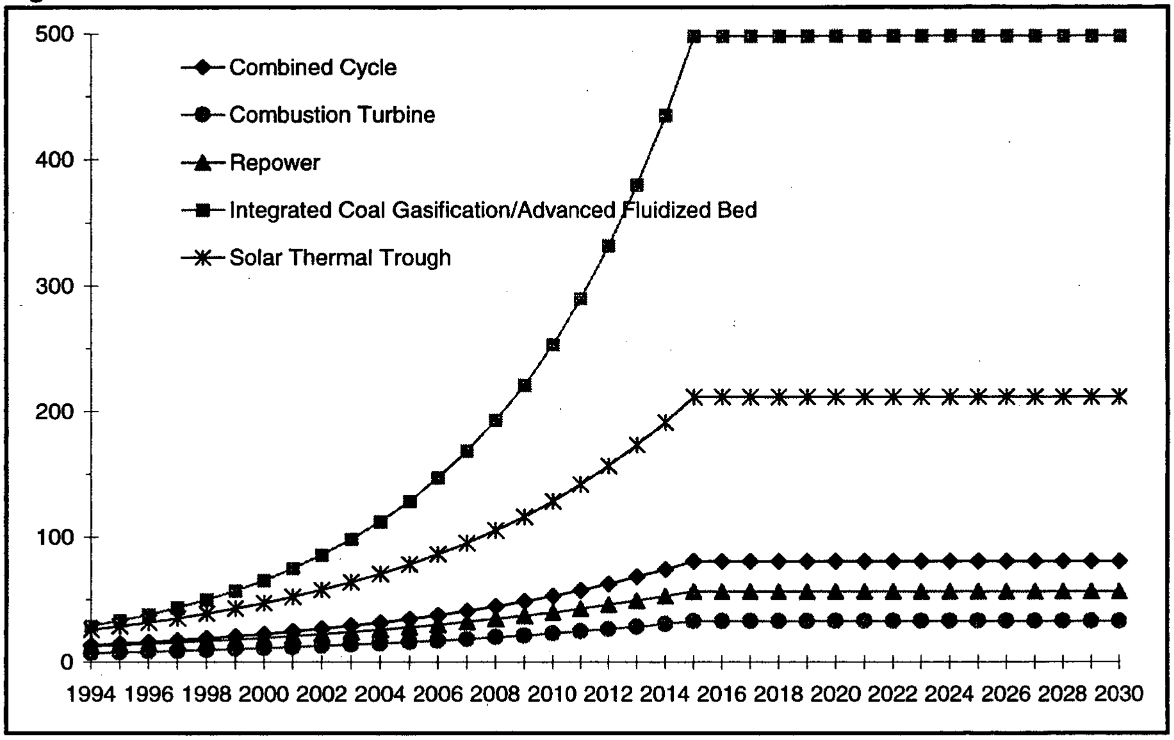
	NOx	SO_2	PM	ROG	CO	Carbon
cc & repower	0.005/mbtu	0.001/mbtu	0.013/mbtu	0.008/mbtu	0.01/mbtu	33/mbtu
ct	0.005/mbtu	0.001/mbtu	0.013/mbtu	0.008/mbtu	0.01/mbtu	33/mbtu
repower	0.005/mbtu	0.001/mbtu	0.013/mbtu	0.008/mbtu	0.01/mbtu	33/mbtu
wdct	0.005/mbtu	0.001/mbtu	0.013/mbtu	0.013/mbtu	0.01/mbtu	33/mbtu
geothermal	0	0	0	0	0	0.041/kWh
solar thermal	0.08/mbtu	0.001/mbtu	0.007/mbtu	0.002/mbtu	0.037/mbtu	33/mbtu
photovoltaic	0	0	0	0	0	0
nuclear	0	0	0	0	0	0
coal gasification	0.0002/kWh	0.0004/kWh	0.0001/kWh	0.000001 /kWh	0.000002 /kWh	1.91/kWh
advanced bed	0.038/mbtu	0.038/mbtu	0.013/mbtu	0.003/mbtu	0.083/mbtu	64.9/mbtu
biomass	0.17/mbtu	0.03/mbtu	0.28/mbtu	0.01/mbtu	0.05/mbtu	0.0815/kWh

Table C-14. Emissions Characteristics of Generic Technologies (g/kWh⁺)

	NOx	SO_2	PART	ROG	CO	C
cc & repower	0.017	0.003	0.043	0.027	0.033	109.369
ct	0.025	0.005	0.066	0.04	0.054	166.3
repower	0.018	0.004	0.046	0.028	0.035	116.111
wdct	0.027	0.005	0.071	0.044	0.054	179.784
geothermal	0	0	0	0	0	18.614
solar thermal	0.339	0.004	0.03	0.008	0.157	139.662
photovoltaic	0	0	0	0	0	0
nuclear	0	0	0	0	0	0
coal gasification	0.091	0.182	0.145	0.0005	0.001	867.14
advanced bed	0.172	0.172	0.059	0.014	0.376	298.746
biomass	0.772	0.136	1.271	0.045	0.227	37.001

⁺ At Average Full Load Heat Rate

Figure C-1. Forecasts of Offset Costs



C.4 Offsets

Offset costs are required for combined cycles, combustion turbines, wind plants backed by combustion turbines, solar thermal backed by gas, coal gasification, advanced coal, and biomass. The offset costs differ considerably depending upon which air quality basin the plant will be located.

Combined cycles, combustion turbines, and repower show the most variation in offsets across basins. We use the lowest offset values for combined cycles, combustion turbines, and repowers. The solar thermal offset values remained constant across utilities as all were building these plants in Mohave Air Quality Management District (AQMD). We chose the highest value for integrated coal gasification (and assume that advanced coal is similar), and the only value for biomass. Biomass costs start at $475/kW in 1995 and increase well above $3,000/kW by 2030. Biomass presumably has such high offset costs because it has high emissions compared to the other technologies. No offsets are required for wind, geothermal, photovoltaic, or nuclear.

Extreme Search Test For Market Equilibrium Plans

The Elfin search for the best Market Equilibrium Plan (MEP) is not based on a global optimization procedure. Elfin starts with the minimum cost plan and searches for a profit maximizing plan which does not allow any further profitable entry. It is likely that this process is path independent. The following test was done to see if Elfin converges to the same plan when it starts at plans which are radically different.

The intention of this exercise is to look more closely at Elfin's behavior when searching for MEPs and how broad an area of possible technology combinations as MEP candidates Elfin considers. The search domain can very well be displayed in a picture of a volcanic crater. The starting point is a costly expansion plan, and could be considered a point high on the rim. The valley of the crater is a quite flat but craggy area and represents roughly the minimum cost level. Since MEPs must be close to the minimum cost solution, they can be pictured as small peaks scattered over the crater floor. The best MEP is a plan in which no further entry is possible and profits are maximized, so it can be thought of as the highest of these local peaks. In general in this work, MEPs are found by beginning with a minimum cost search, which is equivalent to finding a quick route the bottom of the crater. Then the crater is searched for MEPs. The highest peak found is declared the best MEP.

In this exercise the search area for MEPs, and thus often the result (the best MEP), is shown to be path dependent, meaning dependent on the combination of technologies that serves as starting point for the MEP search. Different starting points are used and the progress of the exploration reported. While some cases cover big areas, some are local, leading to very different results for the generation plan chosen by Elfin.

D.1 Procedure

In our extreme search MEP test runs, the search is started from different extreme plans shown in Table D-1, rather than from the minimum cost plan. Each starting point depends on a large amount of one specific technology, in addition to combustion turbines. The start plan for the minimum cost (MINC) case is the usual minimum cost plan.

Table D-1. Start Plans for the MEP Search Test

Extreme Case	NUCL	SOLAR	COAL	WIND	GEO	MINC
Start Plan (number of units of the technologies in place in final year)	nuke 67 cts 81	solar 81 cts 46	coal 67 cts 81	wind 67 cts 81	geo 67 cts 81	ccs 10 cts 67 rpcc 69 wind 3

We then ran these cases searching for market equilibrium in the neutral policy environment (ON) case. Since we did not pay attention to meeting a specific generating capacity expansion in creating our start plans, Elfin initially needed to add or delete many resources, in some cases, before starting to search for market equilibria, notably in the GEO case, where the capacity of a plant is only 100 MW .

D.2 Findings

Elfin found multiple potential market equilibrium plans for each case and chose the best market equilibrium plan among these, except for the COAL case which was stopped after 188 iterations. The results of the searches starting at different initial plans are shown in Table D-2 and Figure D-1. In all cases, the extreme technologies given in the start plans are deleted and only combustion turbines, repowers, and combined cycles remain in the MEPs. Combined cycles only exist in the GEO case. Two distinct clusters of MEPs can be seen in Figure D-1, ones with over 80 combustion turbines (cts) and about 65 repowers (rpcc) and ones with 45-58 cts and 79-83 rpcc. Note from Table D-1 that MEPs which appear close in the plot can exhibit wildly different profits, and that the same plan can apparently yield different profits because construction programs involving different years can reach the same end year construction totals.

Looking more carefully at the cases:

NUCL: The nuclear case searches in both clustered areas. The best market equilibrium plan is one with high rpcc and lower cts.

MINC: The minimum cost case only searches in one of the two areas and never reaches the second cluster. Its best MEP is also one with high rpcc and lower cts.

SOLAR: The solar case behaves like the minc case with lower profits.

COAL: The coal case is special in that it, as the nuclear case, reaches both areas but it picks its best MEP in the opposite area, the one with high cts and lower rpcc. It is the only one which identifies this market equilibrium plan with the second highest profits of all cases of $895 M.

GEO: The geothermal case is outstanding in it is the only three-dimensional case. It searches the area with high rpcc and lower cts as well as the one with lower rpcc and higher cts but differs in that it for the second area (high cts, low rpcc) includes a third technology (ccs). Since this case is undominated and gives highest profits, it represents the best MEP.

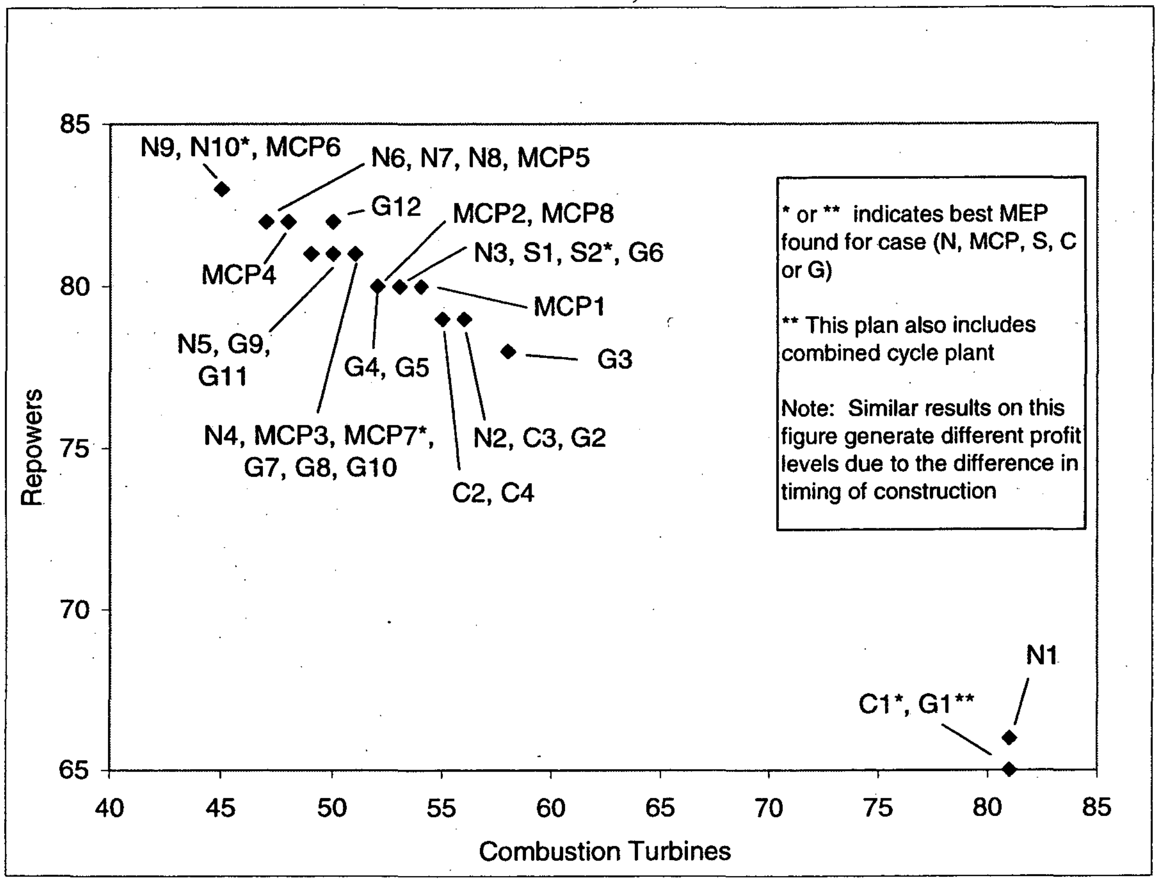
WIND: We did not consider the wind case more closely since it gives lower profits and would not lead to more insights.

Table D-2. MEPs Found by Each Search

	Combustion Turbines	Repowers	Combined Cycle	Profit
N1	81	66		123
N2	56	79		36
N3	53	80		88
N4	50	81		97
N5	49	81		155
N6	47	82		47
N7	47	82		76
N8	47	82		113
N9	45	83		203
N10*	45	83		265
MCP1	54	80		265
MCP2	51	81		245
MCP3	50	81		265
MCP4	48	82		72
MCP5	47	82		240
MCP6	45	83		237
MCP7*	50	81		484
MCP8	51	81		82
S1	53	80		159
S2*	53	80		188
C1*	81	65		895
C2	55	79		296
C3	56	79		206
C4	55	79		299
G1*	81	65	2	1250
G2	56	79		618
G3	58	78		405
G4	52	80		552
G5	52	80		532
G6	53	80		211
G7	50	81		230
G8	50	81		264
G9	49	81		518
G10	50	81		200
G11	49	81		566
G12	50	82		200

* best MEP found in case

Figure D-1. MEPs Found by Each Search



D.3 Conclusion

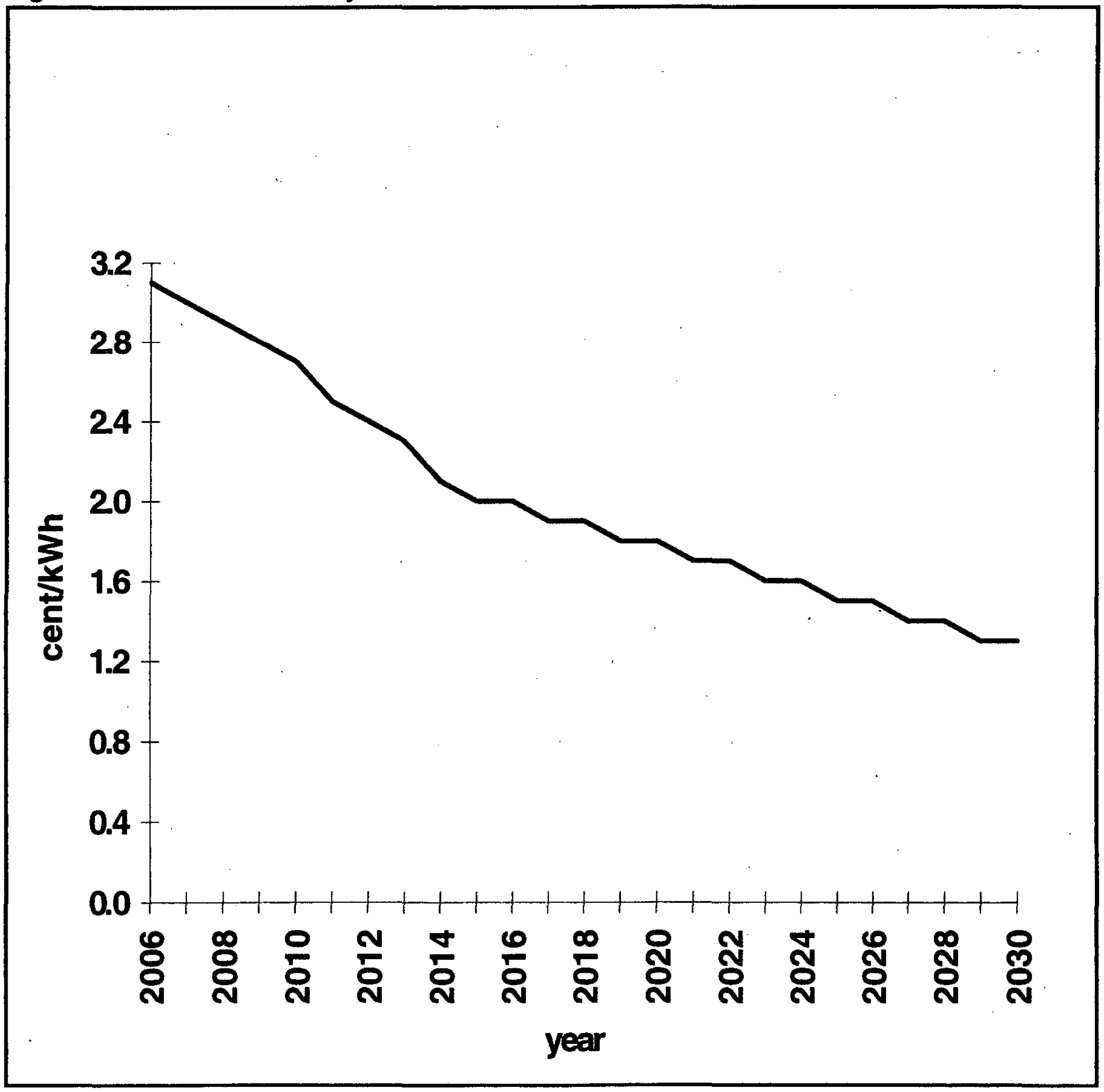
Elfin does not necessarily reach all relevant areas in its search algorithm and does not lead to one consistent 'best MEP' for all different cases. This shows that the MEP search algorithm is path dependent. While for some starting plans the area may well be explored, in others it is not. This is particularly well displayed investigating the coal and solar cases. The coal case searches both clusters in Figure D-1 and finds its best MEP in the area with very high profits. The solar case, on the other hand, restricts the search to only one area and never reaches the cluster where the coal case MEP is located. This indicates that Elfin occasionally misses potentially better combinations of technologies.

These results underscore the difficulty of finding the solution sought in this work. Plans that differ in small details can result in significantly divergent profits, and the path by which the results can be found is not at all clearly marked. On the other hand, qualitatively MEPs do appear to cluster and if all clusters could be found and searched, reasonable results are feasible. In future work, the search algorithm will be further refined.

Simulation Difficulties in the B Policy Simulation

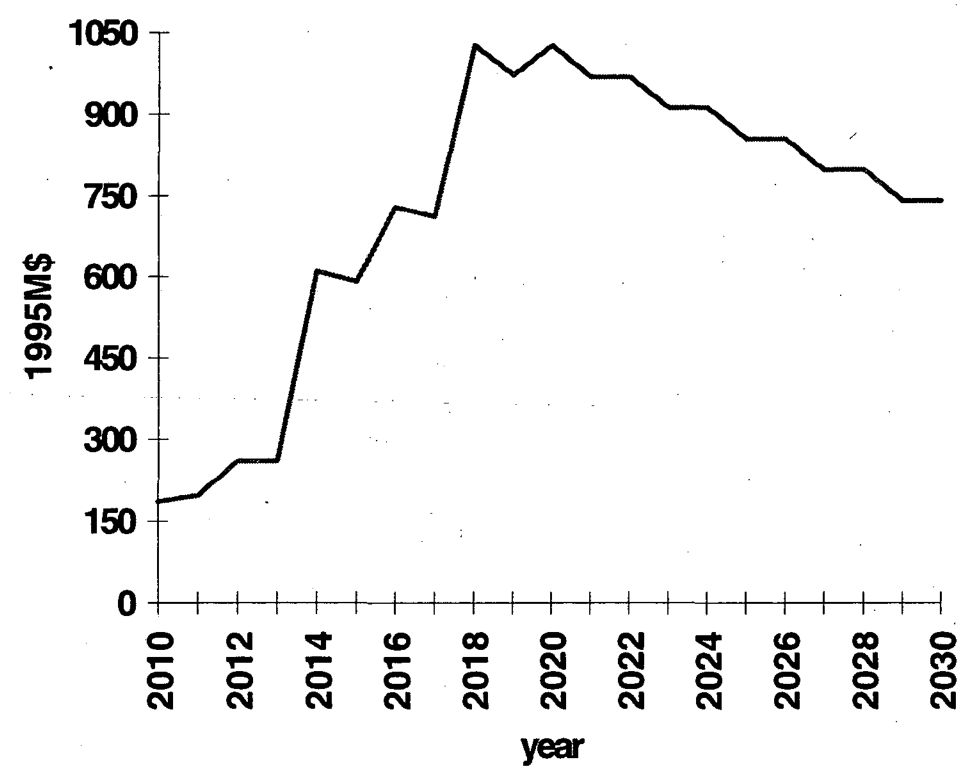
We encountered a fundamental problem with the B case, unfortunately, one not amenable to ready solution. The problem is simply that meeting a target level of total subsidy payments by searching across various levels of subsidy results in a highly unstable search. Consider the per kWh and total subsidy results of the run that we report here, as shown in Figures E-1 and E-2. Figure E-1 shows the average per-kWh subsidy applied in the B policy, while Figure

Figure E-1. Per kWh Subsidy to Wind - BN



E-2 shows the total annual cost of the subsidy. The first obvious characteristic of these two graphs is that, although the level of subsidy declines in an apparently predictable manner, the overall cost of the subsidy is erratic, rising dramatically, then falling from 2013 to 2018. The second interesting feature of the subsidy level is that required subsidies are high, starting at over 3 ¢/kWh and never reaching 1 ¢/kWh.

Figure E-2. Net Total Subsidy to Wind - BN



The cause of these results is simply that the search for the correct level of subsidy required to meet a predetermined target total subsidy cost is highly unstable. This effect apparently arises from three sources. First, changes made in any year affect the construction choices made in all other years. Therefore, a minor change in the level of subsidy in any year will change not only the amount of subsidy collected by new resources built in that same year, but also the amount of subsidy required to meet the obligation to new generation built in all other years. Second, the level of the subsidy must not only compensate the investor in a renewable technology for the high cost of today's technology but also for the lost opportunity to invest in future years' improved technology. For example, if a wind generator is built this year, not only is it not viable compared to thermal generation options, but it is also not viable compared to wind technology in future years. Therefore, the subsidy must compensate for both of these effects, effectively raising the required subsidy level in early years beyond expectations. And third, increasing generation by zero marginal cost generators tends to dampen market prices, thereby diminishing the value of the subsidy to developers.

These problems underscore one feature and one limitation of Elfin. First, a key feature of the ITRE logic is perfect foresight. New construction is chosen not only by technology but also by year. A new plant will never be built today if it is more profitable in present value terms to wait for a future year's technology. An alternative search algorithm, such as ICEM, that lacks this foresight would result in more early construction of falling-cost technologies, but neither perfect nor absent foresight are credible assumptions.[5] Second, Elfin lacks the capability of imposing a fixed level of subsidy directly. While developing a suitable algorithm for this feature was beyond the scope of this project, it must be undertaken if useful analysis of fixed subsidies is to be possible.

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5 The Iterative Cost Effectiveness Method (ICEM) is an alternative search algorithm to ITRE that considers investments year-by-year without foresight.

Carbon Tax Policy: Policy H

In Policy H, the introduction of a modest carbon tax of $3.00/t_C$ is assumed. Our results are shown in Table F-1.

Table F-1. Summary of Elfin Pool Results with a Low Carbon Tax and a Neutral Environment

	Neutral (ON)	Carbon Tax (HN)
2030 Cumulative New Renewable (MW)	0	5000
2030 NOx Emissions (t)	224277	184,892 (82%)
2030 Carbon Emissions (t)	39683706	21,679,018 (55%)
2030 % Thermal	81%	68%
2030 Gas Consumption (EJ)	1.563	0.519 (33%)
NPV System Costs ($M)	$132,002	$237,190 (180%)

Curiously enough, Policy H results in only 5 GW of new renewable construction (all geothermal). However, this case results in a staggering 14.4 GW of new nuclear construction, producing the most dramatic reductions in emissions, thermal dependence and gas consumption of any policy modeled relative to the neutral, or base, case. Under the policy's carbon tax, NOx emissions are cut by 18 percent, carbon emissions by 45 percent, thermal dependence by 13 percent, and gas consumption by a stunning 67 percent. Naturally, these savings are not achieved on the back of just 5 GW of new renewable energy source capacity alone, and major source of these benefits is the nuclear construction. Total costs for Policy H are 180 percent of costs in the neutral case. Costs increase in all components of overall system costs. Production costs rise by over 50 percent, and because of the high cost of nuclear construction and O&M, these costs also rise significantly.

As discussed below, Policy H represents the high end for both potential emissions reduction and total cost of any of the policies modeled here. However, the results of this carbon case should be viewed with some suspicion. The equivalent HB and HG cases result in quite different outcomes, neither of which involve nuclear. Interestingly, the HG case includes biomass, the only case in which that renewable proves competitive under our assumptions. The HB results in an outcome quite similar to the OB case, although output is lower. The results of the HN case, then, are quite disturbing. It seems that our search has not found a credible MEP in this instance. We report the HN case here primarily to demonstrate that the MEP search algorithm, described in Appendix B, exhibits quirky behavior and work is ongoing to improve its performance. However, it should be noted that the nuclear results can be highly sensitive to carbon tax scenarios. In other work conducted at Berkeley Lab, this effect has been investigated more rigorously.[6]

6 See Marnay and Pickle (1998).

Cost Duration Curves for the California Pool

This appendix contains some cost duration curves for busbar cost. Remembering that in this work, marginal cost bidding is assumed, these curves show the basic pattern of competitive prices. Curves are shown for each fifth year from 2010 to 2030 in Figures G-1 to G-5. The qualitative pattern of prices is the same in each graph, and similar to the pattern shown in the body of this report. The numbers presented are for the best guess scenario (ON case). For most hours, the variation in prices is minimal. The peaks occur during summer afternoons. Gas is clearly the marginal fuel most of the time, and variation in prices is driven by heat rate variation. For a few hours, however, prices peak dramatically, and these peaks become more spectacular in later years.

The marginal costs increase during the years 2010 to 2030. The peaking hours aside, marginal costs for the flat region in Figure G-1 range from 27 \$/MWh to 19 \$/MWh. This range moves up to 34 \$/MWh to 26 \$/MWh by the year 2030 and this escalation happens evenly during the period studied. The marginal cost during the peak hour escalates from 50 \$/MWh in 2010 to about 275 \$/MWh in 2025, and from there on declines to about 150\$/MWh by the year 2030.

One possible interpretation of these results is that since our expansion planning options contain a limited number of alternatives, once it is no longer profitable to built the technology most suited for peaking duty, no more capacity is built, resulting in a shortfall and the inevitable peak in prices. Together these graphs show more clearly the basic pattern of pool price results described in the body of this report.

Figure G-1. Cost Duration Curve for 2010

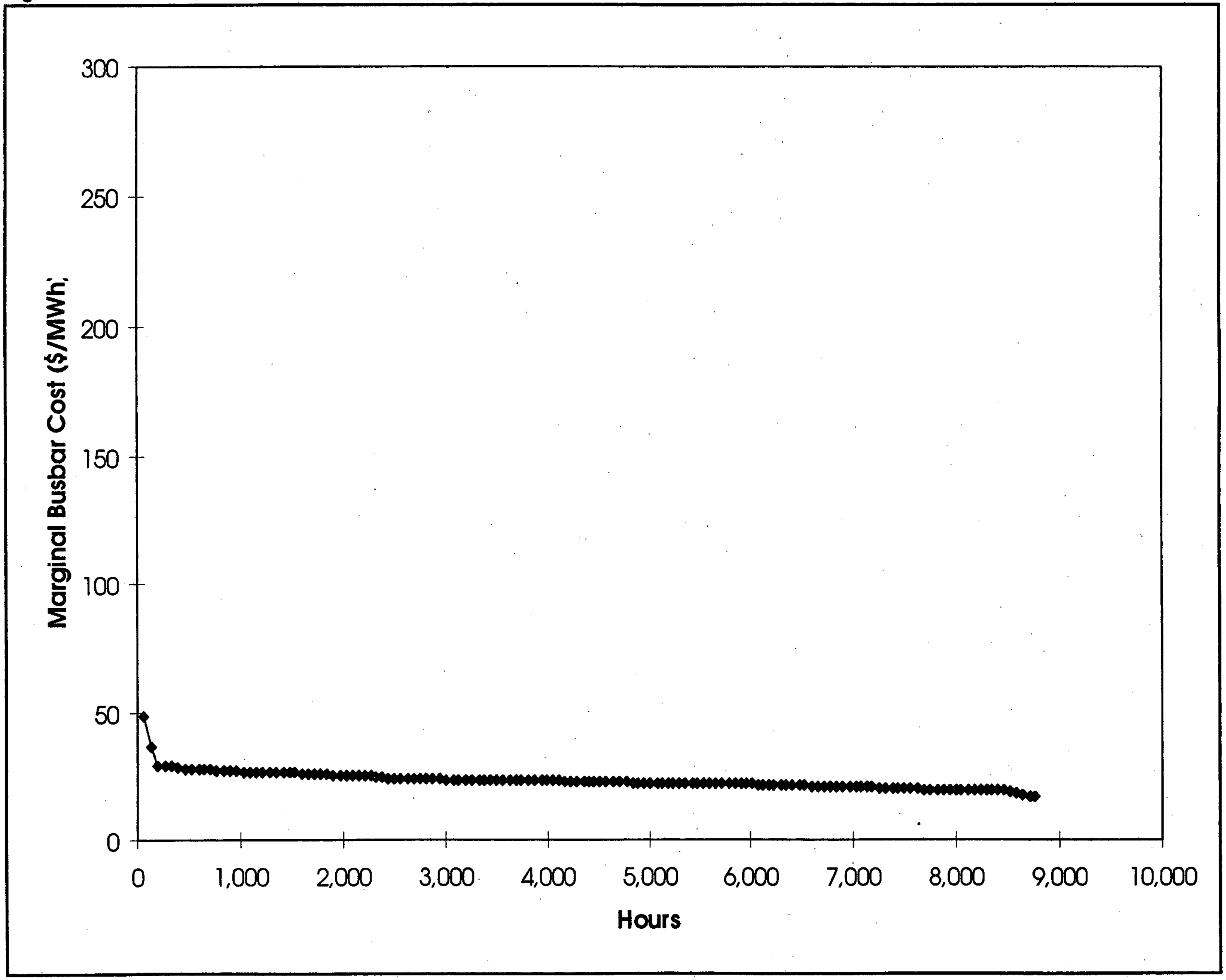


Figure G-2. Cost Duration Curve for 2015

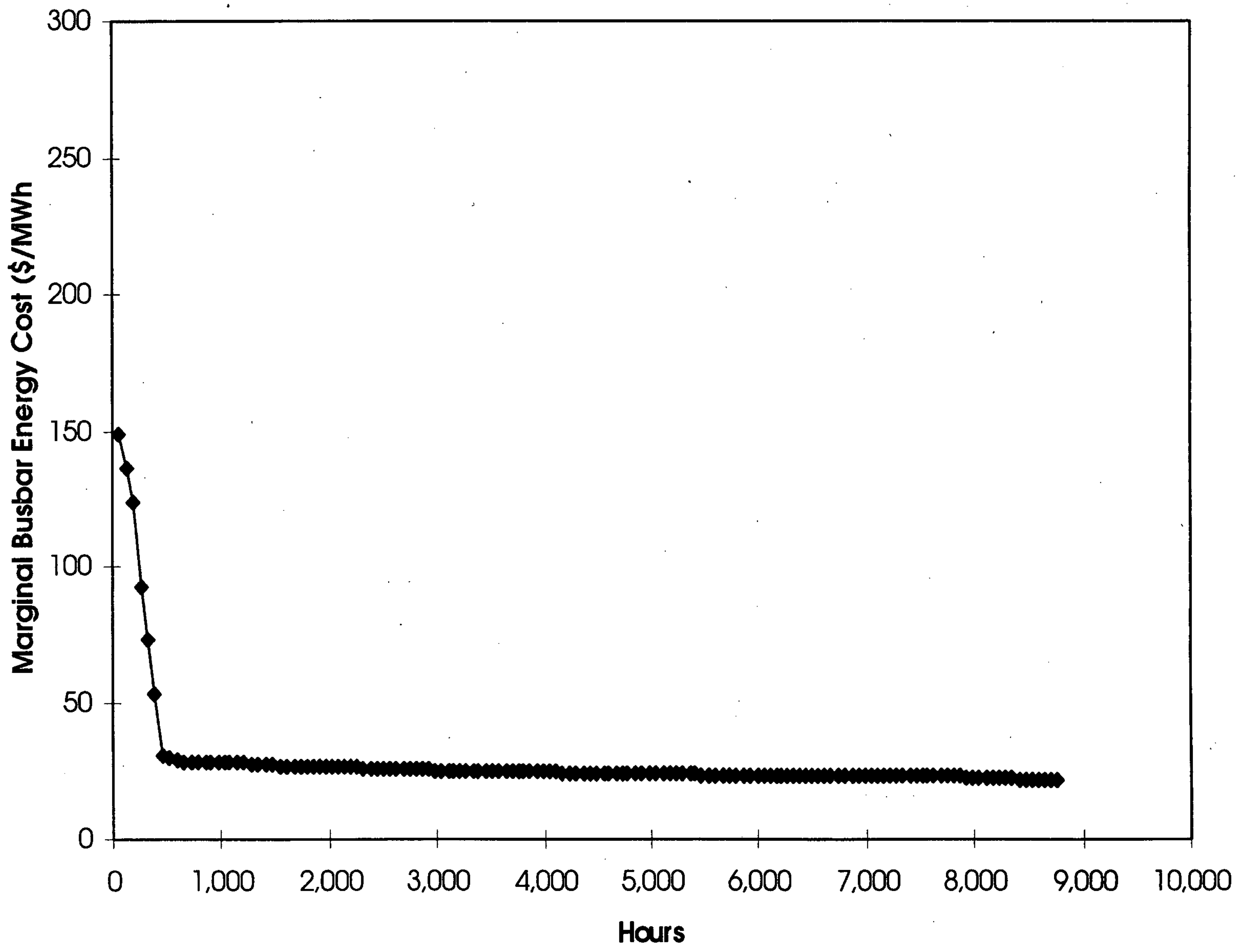


Figure G-3. Cost Duration Curve for 2020

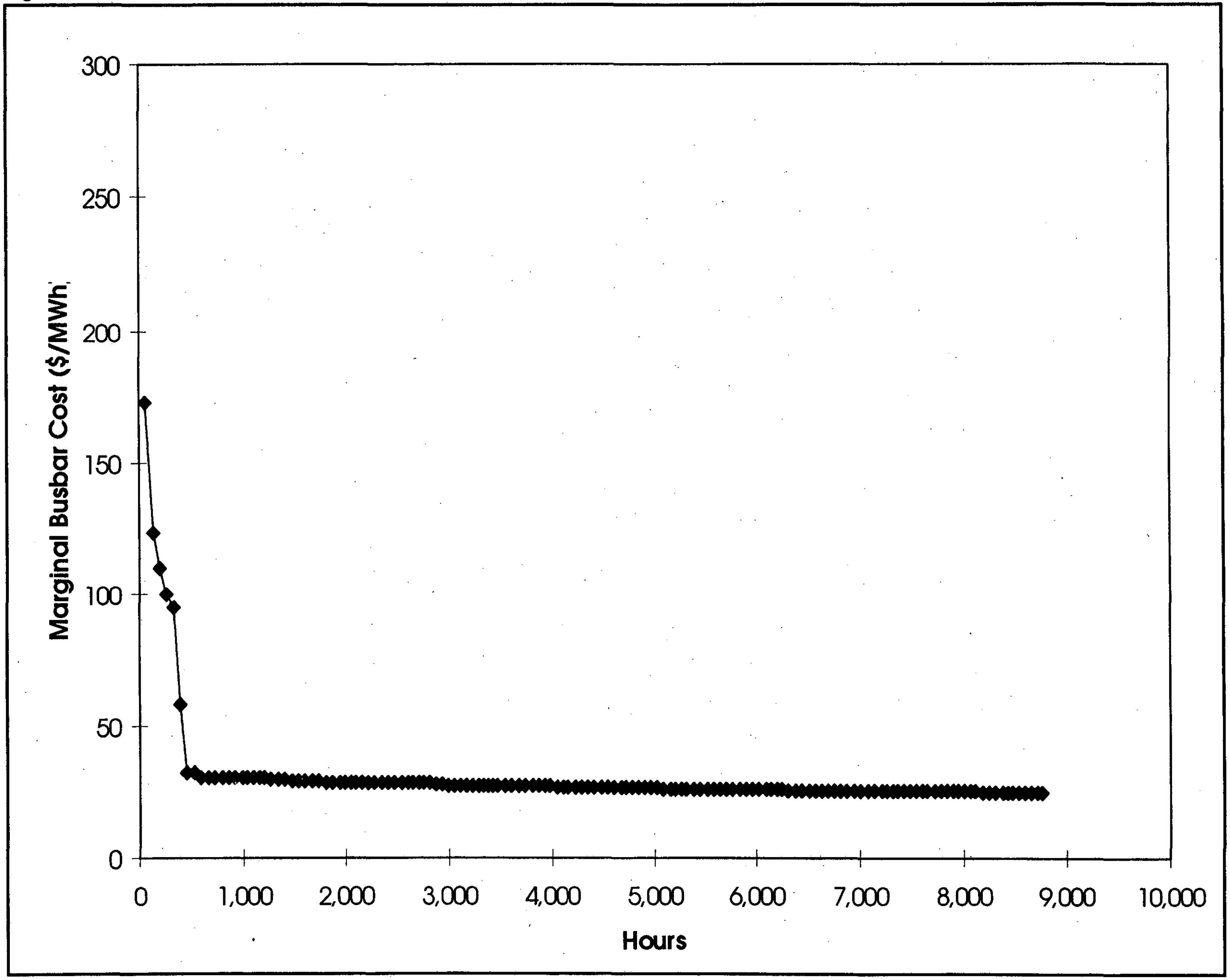


Figure G-4. Cost Duration Curve for 2025

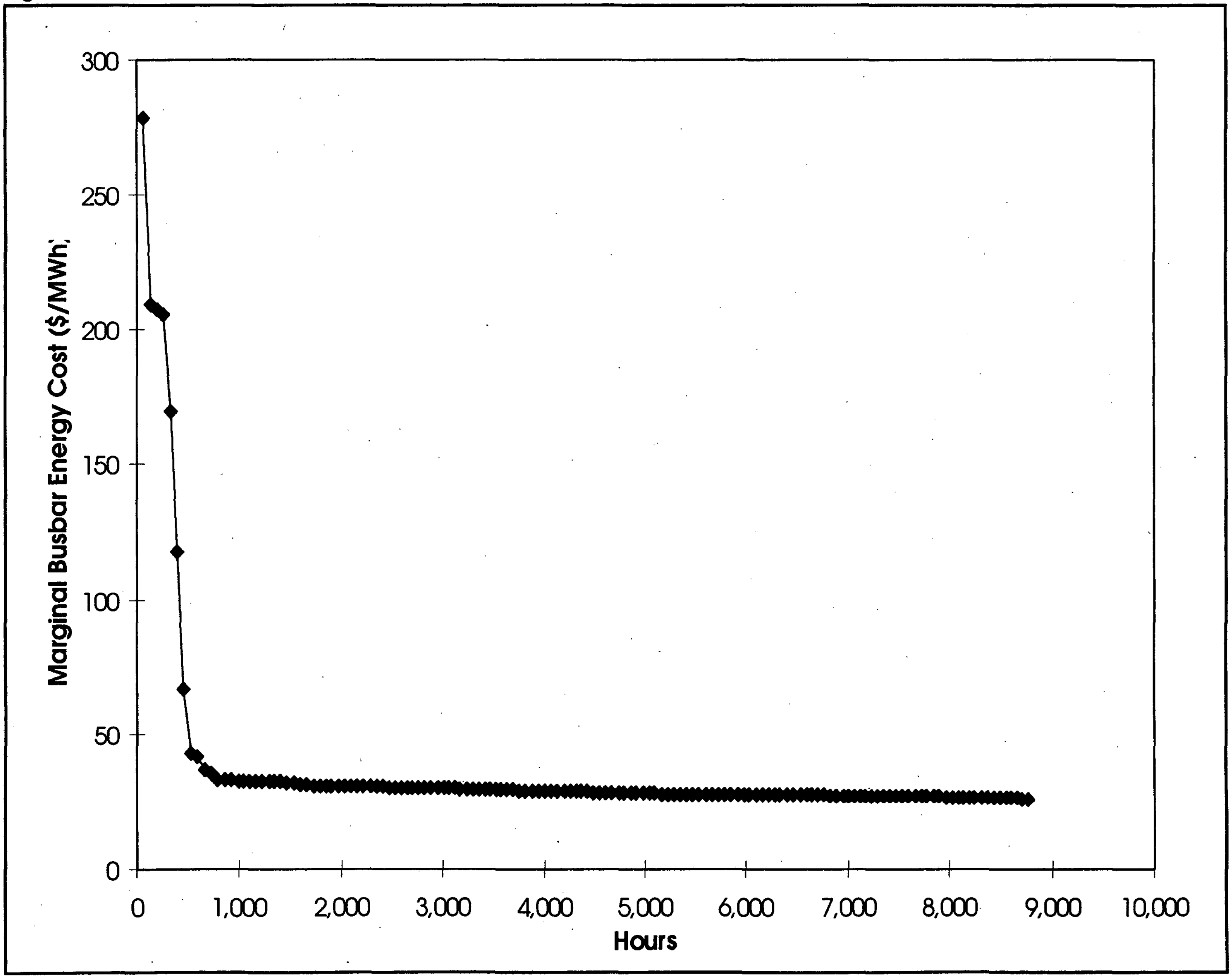
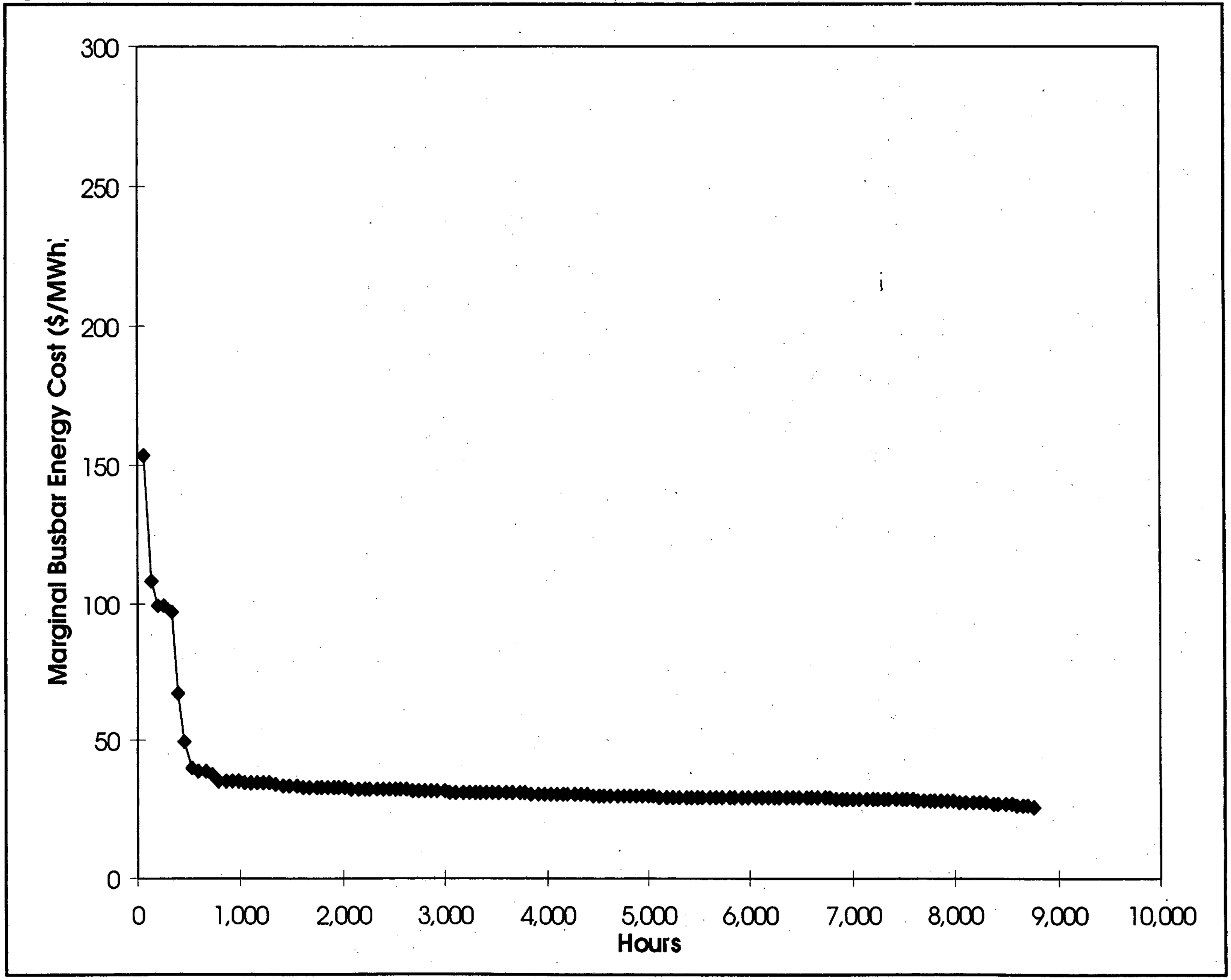


Figure G-5. Cost Duration Curve for 2030



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