ATTACHMENT C
SYSTEM ECONOMIC AND OPERATIONAL CHARACTERIZATION

SECTION 1.0 INTRODUCTION

1.1 PRIMARY QUESTION - LEVEL OF OPERATION

PG&E and Edison have submitted applications pending before the CPUC for the sale of fossil-fueled power plants within California. The primary question addressed in this system economic and operational characterization analysis is whether the divested power plants will operate differently under independent ownership than under utility ownership. The remainder of this document explains the approach taken and the results derived. Basically, the analysis examines the economic and operational factors that will influence the behavior of the new independent owners. The analysis concludes that the new owners will have a tendency to operate the more efficient divested units more than the utilities would operate them if the units were not divested. The analysis does not specify which plants will operate more, nor does it quantify the expected increase in operations.

Table 2, at the end of this Attachment, summarizes "Key Facts, Axioms and Commonly Accepted Principles" employed in this analysis.

1.2 BASIC PREMISES

There are two basic premises of this analysis. The first is that restructuring will go forward on schedule. The California state legislature and the CPUC have made a commitment to restructuring the state electric utility industry by January 1, 1998. To accomplish this goal, significant sums are being expended to build the software and infrastructure needed for both the Independent System Operator (ISO) and Power Exchange (PX). This effort is being supervised by a large group of stakeholders representing all facets of consumers, generators, and transmission interests.

The second basic premise is that divestiture in tandem with other facets of restructuring policies will benefit ratepayers. Divesting power plants and disbursing them among a group of new owners will increase competition. Moving from a monopoly on generation to competition should lower prices and benefit consumers. Nevertheless, saying that divestiture benefits ratepayers is not the same as saying that a particular divestiture proposal should be approved, although it is an important factor in its favor. Other considerations, including environmental impacts of divestiture, will be considered by the CPUC in deciding whether to approve the divestiture applications.

1.3 UTILITY SYSTEM CHARACTERISTICS

California's utility system has some key characteristics that influence the analysis of how the restructured industry will operate, and in turn how divested plants might change their operations from those of a large utility owner. The California electricity market has its highest loads during the summer air conditioning season, and has large daily load swings created by warm afternoons followed by cool nights. While average rates are 50% higher than the national average, some customer class bills, such as residential, are lower than the national level owing to the high penetration of natural gas appliances and the relatively small amount of overnight air conditioning load.

California's generation resources are also unique. It has the largest concentration of renewable resources (other than large hydro) in any state, mainly due to a group of qualifying facility (QF) contracts called "Standard Offers" issued in the mid-1980s. In addition, California utilities operate some of the largest hydropower systems in the U.S. Large amounts of coal-fired and nuclear-powered electricity are generated as well. Most of these resources are "baseloaded" (*i.e.*, run at a constant level), have low operating costs, or have "must-take" contractual provisions.

The highest operating cost resources that also have operational flexibility are the natural-gas fired plants being offered for divestiture in the pending applications. The plants are composed of some combination of steam turbine units and combustion turbine (CT) units. In steam turbine units, boilers are heated by natural gas and the steam routed through a turbine generator. These units were originally designed to run baseloaded and were constructed before 1978. To operate in load-following manner (i.e., operating in a manner to follow changes in demand), these units must either (1) use a large amount of fuel to simply heat the boilers to a critical level before steam can be routed to the turbines and electricity generated, or (2) be turned down overnight to a "minimum load" level at which fuel use is relatively inefficient. In either case, the average cost per kilowatt-hour rises substantially when operating to follow load rather than at a constant output level. CT units, on the other hand, consist of a single turbine that burns natural gas or distillate oil and produces electricity directly. CTs can connect with the grid and be up to full load in ten minutes or less. Because of high operating costs, they tend to be used only at times of peak demand, system emergencies, or when other units are forced off line. Because the combustion turbines to be divested tend to have limited emission control equipment, they are restricted in their hours of operation to control air emissions from these units.

The state's natural-gas-fired steam units have similar fuel efficiencies distributed over a narrow range. Efficiencies at maximum output generally lie within 5% of the system average for on-line gas-fired units. In such a case, if a unit can lower its operating costs by a small increment, it can move up substantially earlier in the merit dispatch order. For example, a 10% cost reduction by a relatively expensive gas-fired unit can move it earlier in the merit order by 15,000 megawatts (MW).[1] Thus, if an operator can reduce costs by changing operational mode, sales from that unit can rise substantially. This can be realized by either the Investor-Owned Utilities (IOU), if the facility is retained, or by the new owner if the facility is divested.

SECTION 2.0 RESTRUCTURING BASELINE

In this system economic and operational characterization, the changes in the electric industry due to restructuring are evaluated with and without divestiture occurring with the effects of divestiture being distinguished clearly.

The analysis presented here relies, to the extent possible, on assumptions that are conservative with respect to potential environmental impacts resulting from divestiture under a restructured regulatory regime. Policy directives and critical dates spelled out in the *Preferred Policy Decision* (*q.v.*) and AB 1890 were used. For example, the PX market is assumed to begin operation on January 1, 1998 and market valuation is assumed to occur by the December 31, 2001 deadline mandated in AB 1890. Where no guidance was given or no supporting documentation existed, the analysis assumed that the *status quo* would continue into the future. On this basis, the analysis assumes that if restructuring occurred without divestiture, the utilities would continue to hold the identified generation plants and, further, that in such a case, other market-power mitigation measures would be adopted by the FERC and CPUC, likely based on measures included in utility and ISO/PX filings at the FERC. In the restructured industry without divestiture, the IOUs would continue to own and operate most of the existing generation facilities in California as shown in Table 1.

TABLE 1: 1994 DEPENDABLE GENERATION CAPACITY (MW)

Control Area	PG&E	Edison	SDG&E
Utility-Owned	15,724	14,013	2,381
Non-Utility Owned	3,648	4,177	236
Out-of-State[2]	852	1,913	486
Total Capacity	20,224	20,103	3,103
% Utility Owned	77.7%	89.7%	76.7%

SOURCE: CEC 1994 Electricity Report

1 Lovick, Sam, Workshop Presentation, London Economics, Inc. June 27, 1997.
2 The Out-of-State figures do not fully reflect the transmission line capacities or limits from the Northwest or Southwest regions.

2.1 Must-Run Contracts and Plant Operations

All steam units within plants proposed for immediate divestiture that were labeled as "Must-run" (M/R) by PG&E and Edison in their divestiture applications were so treated in the quantitative assessment shown in Table 3.1 (Section 3). In the modeling of Edison, it was assumed that the proposed transmission upgrades contemplated by Edison would not occur and that the steam units of the following six plants would be M/R during the weekday peak load period: Mandalay, El Segundo, Redondo, Alamitos, Huntington Beach and Etiwanda. In the modeling for PG&E, Moss Landing was assumed to be must-run.. . No consideration was given to operational distinctions that might arise through use of the various proposed Master Must Run Agreements (MMRAs).[3]

Consideration of ISO Sponsored Must Run Study

The Phase 1 Reliability Study report by Power Technologies Incorporated (PTI) was issued to the ISO Board during the comment period for the draft Initial Studies (DISs).[4] The PTI study found many more plants that were recommended for M/R status. In particular, the study identified many units within additional plants slated for divestiture as being needed as M/R, at least during specific times of peak load. Further, the M/R units were found to be more evenly spread among the plants and not just concentrated in a few plants. Thus, for example, one unit of Edison's Ormond Beach plant, which was not designated as M/R in the Edison application, is shown in the PTI study as having to generate 639 MW during some peak periods. Likewise, PG&E's Oakland Plant is not considered as M/R by PG&E but all three units are identified as needed by PTI at their full collective output of 225 MW in some peak scenarios. In spite of the general tendency of the report to find higher M/R levels than those assumed by the utilities, at least one contrary example was also identified among the plants scheduled for divestiture: PG&E identified the Moss Landing plant as M/R and the Morro Bay plant as not-M/R, while the PTI study found exactly the converse for selected load conditions.

The ISO Board has decided not to adopt the results of the PTI study until its technical staff has performed further technical analyses to confirm the PTI results. The initial ISO-designated must-run generators will be the M/R generators previously identified by the participating transmission owners, including PG&E and Edison.[5] At this time, it is unknown which plants will be redesignated in regard to their M/R status. In keeping with the current ISO Board decision, this analysis adheres to the utility designations of M/R plants.

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3 These Master Must Run Agreements (MMRAs) were included in the ISO/PX March 31, 1997 filing with the FERC. They include three different versions, A, B, and C, each intended to serve a particular availability niche: economic and needed, uneconomic and often needed, and uneconomic and rarely needed.

4 Austria, R.R. *et al*, *Final Report (DRAFT) Phase 1 Operating Reliability Requirements Study*, Power Technologies Inc., June 30, 1997.

5 Adopted at the July 9 ISO Governing Board Meeting.

2.2 TRANSITION VS. POST-TRANSITION PERIODS

2.2.1 Transition Period: 1998 to 2002

The effects of the restructuring reforms are being phased in during a mandated "transition period." The measures implemented during this transition period, particularly including the competitive transition charges (CTCs) being imposed upon essentially all sales, and the simple inertia of existing plant and operating procedures, will act to moderate any changes in operation. Due to the large surplus of existing generating capacity relative to demand in the western U.S., in the absence of restructuring, it is improbable that much new net capacity to serve California would be added during the next decade. Without divestiture, new firms would be discouraged from entering the market and the IOUs would continue to be the dominant players in the generation market, while holding the lion's share of existing dispatchable capacity.

The bidding and dispatch rules contemplated for the PX and ISO, combined with the investment subsidy provided through the CTC, would, without divestiture, create economic incentives during the transition period for the IOUs that would be little different from today's dispatch rules. Through the transition, the IOUs are expected to bid into the PX only their short-run marginal costs with no added margin of investment return, as is done today with the IOU-owned resources.[6] The CTCs will extend the existing "two-part" tariff revenue-recovery mechanism by providing a "fixed" portion of generation revenue based on the book value for IOU plants, and an "operational" portion from PX revenues. Since the IOUs derive most if not all of their profits from this fixed portion, they will choose a mix of resources that will minimize their overall costs while observing required reliability standards and procedures. As a result, without divestiture, the generation patterns at least through the end of the CTC recovery period (no later than March 2002) could be quite similar to what would have occurred under today's operating regime.[7]

If these plants do not go through the divestiture process, the CPUC will determine their total outstanding asset value based on either the undepreciated book value or remaining contract payments. These plants will then receive revenues from the PX. The revenues will cover total operating costs first; the remainder will be credited against the total remaining investment in plants excluding the CTC portion. The remainder is the "stranded asset" amount that will be rolled into the CTC which will "float" with the difference between the sales revenue reflecting the transition period rate ceiling and all of the other revenue requirements including the varying PX revenues. Because the IOUs are not permitted to raise rates for their customers during the CTC recovery

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6 For example, FERC Docket Nos. EC#96-10-001 and ER#96-1663-001, *Transmittal Letter to the Phase II Filing of the Trustee for the California ISO Corp. and the California PX Corp.*, March 31, 1997.

7 See, *e.g.*: Deb, Rajat, Alpert, Richard, Lie-Long Hsue, *Modeling Competitive Energy Market in California: Analysis of Restructuring*, Draft, Los Altos California, prepared for California Energy Commission by LCG Consulting, October 3, 1996; and Feldman, Marvin (Resource Decisions) and McCann, Richard (M.Cubed), *The Effects of California Electricity Market Restructuring on Emerging Technologies.* Final Report, San Francisco, California: Submitted to California Energy Commission Research Development and Demonstration Office, August 18, 1995.

period and are limited in how much PX margin they can credit to their CTC account (undepreciated book value of generation plus operating cost through 2001), they appear to have little incentive to bid above their marginal operating costs.

Only utility fossil plants deemed necessary for "reliability" purposes have any incentive to earn revenues above operating and maintenance costs.[8] For the Edison plants of this type, the net revenue from sales to the PX may first be earned as a 150 basis point increase in revenues on distribution plant ratebase,[9] rather than being applied to reducing stranded asset costs; PG&E can retain all net earnings from these plants. Assuming that this relatively small revenue producing feature will not markedly distort the rational economic behavior of the utilities, they will have little incentive to bid above their marginal operating costs.

Thus the utilities have essentially the same opportunity of recovering their investment either from the PX or the CTC during the transition period. If the divested plants were not sold or "market valued" through the bidding process, they would be valued in the same manner as the remainder of the IOUs' generating systems within the transition period.

2.2.2 Post-Transition Period: After 2001

In the post-transition period, both the IOUs and the new entrants to California's power market will have to recover their generation investments directly from sales revenue.[10] Generators bid electricity prices to the PX at rates that recover their investments as well as their operating costs, as opposed to the current practice of considering only short-run marginal costs in the dispatch rules.

If the divested plants were not sold, they would have a "market value" determined by the CPUC either through an appraisal or an auction bid if such is deemed appropriate. The IOUs would then receive a CTC valuation for each plant based on the difference between the undepreciated book value and the market value. Thus these plants would receive a "fixed" CTC through 2001, versus the "floating" CTC for plants not going through the divestiture process. The IOUs would then need

8 For PG&E "operating costs for particular utility-owned fossil power plants or units, at particular times when reactive power/voltage support is not yet procurable at market-based rates... the commission shall allow [PG&E] to retain any earnings from operations of the ...plants or units and shall not require the utility to apply any portions to offset recovery of transition costs." (AB 1890, Section 367(c)(1)). For Edison, "the 150 basis point allowance in the Preferred Policy Decision applies only to fossil plants deemed needed for reactive power/voltage support." (D. 97-04-042, April 9, 1997, p. 18, interpreting *Preferred Policy Decision,* Conclusion of Law No. 63.)

9 "Basis points" is a measure of rate of return or interest rate used in financial analysis. One hundred (100) basis points equals one percentage point in interest or return. Regulated utilities typically are "allowed" a set rate of return on their capital investment, or "rate base," established as a total percentage rate. The addition of 150 basis points means that the utility can earn up to 1.5 percentage points more on the specified rate base. Based on a distribution rate base of about $5 billion each for Edison, this provision allows Edison to keep up to $75 million per year of net generation revenues rather than reducing the CTC by that amount.

10 There are exceptions to this rule: (1) plants necessary for system reliability and other services which will have contracts with the ISO; (2) utility plants which could still be regulated under performance-based ratemaking (PBR) or other special agreements such as hydropower and nuclear power facilities; and (3) QFs. However, for even these facilities, a certain portion of their revenues will be likely tied to the power market and their operations will affect the revenues of other facilities.

to recover the remaining "market value" of these plants exclusively from the PX revenues. The IOUs would want to maximize their PX revenues to maximize net generation revenues.[11] Depending on the magnitude of the market value, the IOUs would have a greater incentive to bid above operational marginal costs to recover the "market value" and to keep shareholders whole than during the transition period when any added profit would be first credited toward the CTC before shareholders saw any additional return.

SECTION 3.0 DIFFERENCES IN OPERATIONS

3.1 INTRODUCTION

The plants proposed for divestiture serve to follow load because they are the highest cost sources of dispatchable generation. They tend to operate most during weekdays, helping to meet the daily peak. They currently run at relatively low levels and have the potential for significant increases in generation. This section provides a theoretical analysis of the likely operation of the divested power plants under new ownership. The analysis focuses on potential individual plant impacts, and does not perform a system wide analysis.

This analysis does not quantify the expected change in operations at the divested power plants. The analysis does not state which specific divested power plants will likely increase or decrease in generation. Nor does the analysis specify the exact amount by which any particular divested power plant will increase or decrease in generation. The economic and operational analysis only answers the question whether divested power plants are likely to increase operations under new owners.

3.1.1 Differing Incentives

Divestiture is primarily the transfer of ownership of electrical fossil-fueled generating plants from the IOUs to currently unknown buyers. A number of factors could motivate changes in operations and planned investment as a result of new ownership, both in timing and amount.

The analysis conducted for this report concludes that the new owners have incentives to operate the more efficient of the divested power plants differently than the utilities would operate them. The main argument underlying the differing incentives to operate is the combination of three factors: (1) size and nature of the portfolios, (2) gas contracting practices, and (3) selling to the direct access market. These factors will provide the incentives that account for the differences in power plant operation under new ownership in the near term.

In the long term, the new owners of the divested plants will have to ensure a level of net revenues above operating costs to recover the investment incurred by purchasing the divested plants. During the transition period, the IOUs will be able to recover much of their existing "sunk" investment

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[11] We are ignoring the issue of how this difference in the bidding strategies affects the floating CTC paid to other plants. Including additional plants requires that the IOUs optimize across both their CTC and net PX revenues.

through the non-bypassable CTC, and accelerate the depreciation on these plants to ensure full recovery by 2002. These new owners will probably have a larger investment exposure through the plant purchase, and will need to recover their investments over a longer time period, which will likely be based on the remaining economic life rather than the accounting basis now used by the utilities. For new owners, these costs are not "sunk," but rather are "opportunity" costs represented by the value at which the plants could be resold and the proceeds invested elsewhere. This means that the new owners may bid different prices and quantities than the IOUs might have with the same facilities. In contrast to these differing ownership incentives, those units that are designated must-run by the ISO and enter into an MMRA Contract C with the ISO will most likely operate the same under new and utility ownership. MMRA Contracts A and B will also tend to reduce the difference in generation between restructuring without divestiture and restructuring with divestiture.

3.2 CAUSAL FACTORS

3.2.1 Portfolio Effects

The difference in behavior between the owner of a mix of power plants and the owner of a single power plant or just a few plants is the portfolio effect. PG&E and Edison each own a portfolio of power plants. Between the two of them, they own combinations of hydroelectric, nuclear, geothermal, coal, gas and oil fired units. The new owners may have a portfolio of plants in the California market although this is currently unknown.

In summary, independent owners of single power plants will tend to operate their plants at a constant efficient rate in order to minimize costs and maximize profits, while the utilities will cycle the plants if they retain them to maximize profits across all their plants.

Mix of Power Plants

The utilities have lower cost resources available to meet loads before turning on higher cost plants to produce revenues. PG&E has hydro, geothermal and nuclear units which they will not curtail to allow a gas fired unit to operate. In addition to nuclear and hydro, Edison has coal units which they will not curtail in favor of gas fired units.

Neither PG&E nor Edison could operate the plants as intensively as an independent single plant owner because they each own a large portfolio of plants and would run their more efficient plants first, and there would be insufficient load demand to run all of their plants at maximum load. Electricity is different from all other products in that demand must be present to allow generation; it cannot be stored for later use. The independent owner is not constrained by overall system load behavior.

Choices Facing Single Power Plant Operator

Under restructuring, a single power plant operator can choose to operate continuously at the most efficient operating level of the power plant, or to cycle the plant. To cycle a power plant is to raise and lower the output of the plant in response to market conditions. An extreme case of cycling would be to shut the plant down and produce no electricity for an extended period of time.

The basic choice facing the new independent owners of one of the more efficient plants to be divested is whether to operate the plant in the load following mode in which the plants are currently operating or, in the case of the more efficient units, to operate in a more constant mode closer to their maximum capacity. PG&E and Edison have little economic choice. There is insufficient demand to justify or permit running *all* of their plants steadily at their maximum capacities. The utilities must run their lower cost plants and idle their gas fired units when low demand requires curtailments or shareholders will question such unnecessary higher fuel costs.

Most of California's gas-fired units have nearly identical fuel-use characteristics, and these units will set the PX price 70 percent to 90 percent of the time.[12] As a result, the market price is expected to differ little over a large period of the year. In such a market, the strategy most likely to increase net revenues is to increase generation so long as average market prices are above average costs. A logical goal of any new owner would be to, either directly or through an intermediary, arrange to contract with high load factor customers so that, combined with sales to the PX or another power exchange, the plants'more efficient units can be operated at or near their maximum capacities the majority hours in a year.

A single plant owner will probably shut its power plant off during the low load spring runoff period in the spring. The combination of low loads due to mild weather and abundant hydro output due to the spring runoff produce the lowest prices for electricity during the year. At these times, it is a profitable strategy to shut off a gas fired power plant and fill any obligations to deliver electricity with purchases from lower cost producers.

During the remaining 70-percent-plus hours of the average hydro year, gas fired power plants are operating. A new independent owner of a divested power plant could be in a position to operate continuously during those hours of the year. Alternatively, the new owner can cycle its plant whenever purchasing from the PX would increase its profits. However, cycling power plants and purchasing from the PX is not without its costs. These costs are significant and will tend to discourage cycling by new owners except during the very low cost spring runoff period.

[12] Paul Joskow, MIT, FERC Testimony for Edison, May, 29, 1996; Joe Pace, LECG, FERC Testimony for PG&E, July 1996.

Transaction Costs of Trading in the PX

In order to trade in the PX, the owner of a single plant must incur a number of transaction costs. The first is the fee charged by the PX for using the PX trading exchange. Also, to directly participate in the PX requires a commitment to staff and software. It is not possible to simply call up the PX and make a trade. Just as in purchasing stocks on the stock exchanges, one must either become a broker or use a broker to make trades. These are substantial costs compared to the likely difference between the cost per kWh of constant operation of one of the more efficient of the plants to be divested and the likely PX price.

An additional risk of PX trading is that the new owner will not know with certainty the price for electricity or gas if they elect to cease generation, buy electricity from the PX and sell gas to the spot market. The new owner will only know the clearing price at the PX. The new owner will not know the price that it will have to be paid if its generation is shut down and the PX must supply the additional electricity. The new owner only knows in advance that the price will tend to be higher, not lower. Similarly, the published gas spot price reflects the market balance. If the new owner withdraws its demand for gas and releases its supply of gas into the market, the price will tend to fall. As a result, both markets will tend to move against the new owner if it tries to replace generation with purchases. The new owner will also incur significant transaction costs to participate in these markets.

Costs of Cycling Power Plants

Operating a power plant at less than its optimal level increases the per kWh fuel cost. Each power plant has a level of operation which is the most efficient. Producing less than the optimal level of generation increases the fuel needed to produce each kWh. If the new owner participates in the PX by reducing output below the optimal level, then the cost of each kWh that is produced will increase. This is just one of the costs of cycling a power plant to participate in the PX. Another increased expense is the additional fuel cost of ramp up, the additional fuel needed to return the plant to its optimal generation output.

If the power plant is shut down or curtailed in order for the owner to participate in the PX, there are additional costs. Restarting or cycling a unit involves increased fuel costs for startup and rampup that would not be incurred in constant output operation. In addition, maintenance costs increase due to the increased stress on the power plant unit from turning the unit on and off. Baseload operation reduces heat stress from expansion and contraction of unit equipment.

Both cycling and shut downs increase forced outages, which increase maintenance expense and cause the operator to incur increased power replacement costs. Each time the plant is stressed with either cycling or a shut down, the odds of a forced outage in which a piece of equipment fails increases. These failures must be repaired, thereby incurring additional expense. While the plant is out of service for these repairs caused by participation in the PX, the owner may have to buy replacement power to fulfill contractual commitments to deliver electricity. Replacement power is invariably more expensive than self generation since it is produced by the power plant with highest operating costs.

Evidence of the Portfolio Effect

The London Economics consulting firm reports that in restructured England and Wales, single station owners operate their power plants even if they have to accept some losses on days when prices are low, but portfolio owners are able to avoid doing the same. In a report to the PX Trust, London Economics stated:

> Our analysis indicates that portfolios are better able to manage the risks of trading in the PX than are non-portfolio bidders (e.g., participants that may own only a single station). It is not immediately apparent whether it is possible to develop PX rules which entirely remove this portfolio advantage; we suspect that this it may not be. This problem is not unique to California; single station bidders in other markets, most notably England and Wales, tend to have contracts to cover this type of risk. The contracts have the effect of making these generators into price takers, bidding to ensure that they are dispatched, even if they have to accept some losses on days when prices are low.[13]

Spares and Maintenance Policies

The portfolio effect influences spares and maintenance philosophies. The utilities, with their mix of hydro, coal and nuclear plants, benefit from higher PX prices. PX prices will increase on average the more frequently the more efficient gas fired units are out of service. The utilities, therefore, have an incentive to minimize spares and maintenance expenses and incur more frequent and longer duration outages.

The reason that a reduced expenditure on spares and maintenance has such a high payoff for the utilities is that, under restructuring, all of the utilities' power plants receive the highest bid price accepted by the PX. This means that if a 25 mills per kWh unit is the last power plant accepted by the PX, then all of the power plants owned by the utilities will be paid 25 mills. This is true even for the hydro power plants which have zero operating costs.

If the utility skimps on spares and maintenance so that the 25 mills per kWh plant is less available, then a more expensive power plant such as a 28 mills per kWh power plant will set the PX price. This means that the utility will earn an extra 3 mills per kWh on all of its hydro, nuclear and coal power plants, without incurring any additional costs at those plants. A new owner would have no such incentive.

An independent owner with a portfolio of one or a few gas fired plants has every incentive to attain a higher level of availability. The independent owner will have the opposite spares and

[13] London Economics, Inc., "PX Auction Testing: A Report for the California Restructuring Trust," dated March 3, 1997, filed as Appendix 3, PX Phase II filing with FERC, filed March 31, 1997, page 20.

maintenance policy from the utilities. Such a result was observed by the consultants to the PX Trust who reported:

> The incentive for the owners of divested plant in Australia to maintain high reliability, resulted in a 5% to 10% increase in power plant availability under new ownership. (Lovick 1997)

Under restructuring, spending less on spares and maintenance of gas fired units will increase the profits of the utilities. This is a mathematical certainty. The higher the PX price, the greater the profit on the hydro, coal and nuclear power plants. If the utilities do not divest these plants, they cannot be expected to minimize profits by spending at the high end of the range of possible spares and maintenance amounts.

3.2.2 Fuel Procurement Effects On Plant Operations

Effect of Utility Ownership

Currently, both PG&E and Edison procure fuel for their natural-gas-fired power plants to meet multiple objectives. Both companies, while aiming to achieve the lowest cost for the ratepayer, also strive to assure that plant availability is not compromised by lack of fuel. PG&E further has the complication of procuring fuel for both its gas plants and the remainder of its gas utility demand. The IOUs are able to pursue these sometimes conflicting objectives because they are judged by the "prudence" standard used by the CPUC.

For example, if the best available forecast predicts a high load for the following day, then the company might arrange for firm delivery of natural gas to meet that demand. If the demand is not as high as expected, the company might utilize the delivered natural gas in its gas fired units and curtail purchases on the spot power market or choose to have it injected into storage to be withdrawn and consumed later. Even though this gas procurement strategy would result in higher costs to the ratepayer, these costs would be paid by the ratepayer, because they were prudently incurred on the basis that system reliability is paramount.

In addition, PG&E as an integrated utility (electricity and natural gas) has different incentives in procuring gas than an electricity-only operation, as Edison is and the new owners are likely to be. PG&E has a continuing obligation to procure gas for its core customers. Since it is impossible to always precisely estimate core demand, there will be instances when PG&E will have surplus gas that may be employed at minimal marginal cost by its gas-fired units.

During the transition period, as long as the IOUs continue to own the power plants, they will continue to be judged by the prudence standard. For example, AB 1890 specifically provides that Edison can recover 100 percent of the costs associated with fuel-price hedging mechanisms, thus shifting these risks to ratepayers. As a further response to potential competition it is likely that Edison, at least, would pursue more vigorously special gas transportation contracts such as the one currently being provided to the Mandalay Station. Such agreements can further reduce Edison's cost of gas supply, but at some sacrifice of operational flexibility.

After the transition period if the utilities own any natural-gas-fired power plants, and they do not have must-run ISO contracts, the prudence standard will change. The companies would be able to collect the winning bid price regardless of their fuel costs, but they would also bear the risks associated with their fuel purchases. If the plant is divested, on the other hand, the new owners will immediately bear the full brunt of risks incurred in fuel contracts.

The new owner may not have the volume of purchases of natural gas to be attractive to a natural gas supplier if they follow load. The new owner may not be able to justify the cost of staff, software and telecommunications to be constantly active in the natural gas market for just one plant. The new owner may find a constant supply contract the most feasible to administer and the least cost per unit of gas.

As with many commodities, purchases of natural gas can involve quantity discounts. A commitment to purchase sufficient natural gas to run the power plant steadily 70-plus percent of the hours of the year will normally draw a lower price per unit than a commitment to purchase less than half that amount -- and only when demand is high for both gas and electricity. A contract to purchase natural gas whenever a power plant is available (other than the spring runoff period) is simple and easy to administer. A contract to purchase natural gas for a single power plant that follows load is complex and difficult to administer. The cost of staff and risks of managing such complex contracts is another transactions cost of trading in the PX. Many gas transportation contracts are made for firm service. Such gas transportation contracts are sized to maximum rate of gas flow and very little additional cost is incurred in more intensely using the gas transportation capacity. Thus, incremental gas use can be much cheaper and will impel plant owners with such contracts to increase generation.

One means to control natural gas costs would be to enter into a "net back" contract with the natural gas supplier. Such a contract would tie the price of natural gas to the price paid for electricity whether in a bilateral contract or in the PX. This would remove any incentive for the new owner to follow load, since the owner would be indifferent to the fluctuating price of electricity because the price of gas under such a contract would rise and fall with the price received by the new owner for electricity. Such contracts would also likely exclude the spring runoff season.

Fuel procurement practices by the various new plant owners will change from those exhibited by the utilities. These changes are expected to provide a much greater range of specialized purchase practices that are likely to increase gas consumption through increased power generation. The price of gas is determined by a commodity cost and the costs of transportation. The commodity cost in the western market is locationally varying at the point of production depending upon the transportation options available. For example, gas that is produced in west Texas (e.g., Anadarko field) can flow both to eastern and California markets and its price varies with the market price in both regions. California source gas, on the other hand, is limited to a California market. Transportation costs include return on investment and operations of the pipelines and compressor fuel consumption. Typically, in today's market, transportation costs can represent up to one third of the total fuel costs. These costs (and transportation costs in particular) are very locationally sensitive and subject to variation depending upon special arrangements with suppliers and pipeline owners. For example, producers commonly make "net back" arrangements with consumers through which the consumer guarantees to take the gas in exchange for which the producer will adjust (i.e., net back) his price so that the gas total price remains competitive. Such arrangements with new power plant owners would certainly elevate the generation from such plants.

It is notable in the non-divestiture case the two Edison plants that are forecasted to have the highest capacity factors have special, lower priced, gas transportation contracts. These two plants, Mandalay and Cool Water, have projected capacity factors of nearly 50 percent. In stark contrast, among the remaining plants -- all of which have a common, higher cost of gas transportation -- the next highest forecasted capacity factor is only about 18 percent. This behavior is illustrative of the extremely flat supply curve for gas fired electricity found within the state.[14] Even the slight discounts in transportation costs present for both of these Edison plants drive their expected capacity factors much higher than those of the remaining plants, which have comparable fuel efficiencies but higher gas costs. Much like Edsion currently practices, in instances of cheaper gas, the new owners would not dispose of this gas on the spot market since the price discount is only on the transportation component and is quite modest in any case. Rather, the future owners would be likely to find, as Edison does today, that the minimum cost solution involves much heavier use of these plants.

The most significant change in fuel procurement could occur if a natural gas company such as ENRON purchases and operates a divested plant. A company that owns natural gas reserves and has the capability to deliver gas to its plant does not have procurement costs, but, rather, has an opportunity cost. While a procurement cost is largely fixed once a contract is signed, an opportunity cost is fluid with the market and requires a more complex assessment of the situation. Such a company can operate its power plant differently than a company that must purchase its natural gas. For example, such a company might always bid close to zero and accept the winning bid to be assured of constantly operating in order to achieve an objective in its natural gas business.

3.2.3 Direct Access Markets

During the transition period, only the new owners may sell into the direct access market. Basic business strategy suggests that the new owners will attempt to enter into agreements to serve customers with the highest load factors, which have the lowest cost per unit to serve. Customers with low load factors will be left to the utilities to serve.

[14] Lovick, Sam, presentation by PG&E on DIS, June 27, 1997.

The ability to select customers will separate the new owners from the utilities in a significant way during the transition period. The utilities cannot choose who to serve. The new owners can build a business based on serving only high load factor customers or loads aggregated to support constant running of their plants.

It is the more efficient of the divested units that will operate more intensively due to sales to the direct access market. These more efficient plants selling into the direct access market will probably not operate during the low load spring run-off period when wholesale prices are at their lowest. Rather, these units will more likely shut down for extended maintenance when it is more profitable to buy from the PX.

3.3 MUST-RUN STATUS DIMINISHES POTENTIAL DIFFERENCES IN OPERATIONS

The level of potential variability of operations of the plants proposed for divestiture are significantly affected by the M/R status of the individual plants. M/R plants are eligible for special contracts (i.e., ISO MMRA Types "A", "B" and "C") under which the plants or some individual units within the plants would be guaranteed payments that range from partial to full fixed and variable cost reimbursement in exchange for their operations being dictated by the ISO.[15] Further, pursuant to these tariffs the ISO has the determinative authority to classify plants as M/R though the plant owners have some discretion as to which of the M/R contracts to accept and whether or not to bid in M/R solicitations to the degree that the ISO has such solicitations.

Any comparison of operations before and after divestiture will vary with the M/R status of each plant. The more stringent the M/R requirements on a plant, the less variation that can arise in the plant's operations regardless of plant ownership. At the extreme, if all the divested plants were required to be M/R at all times (i.e., subject to MMRA Type C), then the operation of the in-state, fossil-fired generation would reduce to a single commitment and dispatch outcome without permissible variation regardless of varying ownership inclinations.

In considering what the likely operational profiles of the divested plants will be, it is necessary to make assumptions as to the number of the to-be divested plants that will be M/R and the contracts assigned to the individual units in these plants. The approach undertaken here is to adopt the more limited number of M/R plants recommended by the utilities and to assume that steam units, at least, in these plants will only be eligible for "A" MMRAs under which, most of the time, their owners will have the discretion as to each unit's operations. This approach avoids underestimating differences in operations since it is expected that new purchasers will have a tendency to operate their units more than the selling utilities. However, it is also quite logical to note that units covered

15 Master Must-Run Agreement and Appendices A, B, and C included as Addendum G, Independent System Operator Tariff filed as part of Phase II FERC filing by Independent System Operator dated March 31, 1997.

by MMRA Type C will not likely operate much differently after divestiture than they did before divestiture.

3.4 Decision to Repower Divested Plants Unaffected by Ownership Status

The decision to repower is based on evaluating three factors: (1) comparing the expected net market revenues from operating the old versus new facilities; (2) the costs to invest in a new facility compared to the expected investment return; and (3) the "portfolio effect." The first factor is driven by how operations would differ with changed ownership and the cost improvements from a new technology. The second factor reflects how investment "hurdle rates" will differ between smaller independent and larger utility owners. The final factor is the impetus for the portfolio owner to retain existing low-capacity-factor generation in order to preserve existing, higher PX clearing prices and maximize portfolio net revenues.

In evaluating repowering, there are three possible outcomes: (1) the unit would not be repowered within the time frame analyzed; (2) the unit would be repowered at the same time regardless of ownership; or (3) the new owners would repower earlier than a utility owner due to the difference in market incentives and costs. The large surplus on the Western grid will defer repowering, and most repowering is likely to be delayed beyond 2013 for the vast majority of divested plants.[16] Several Edison units, notably at San Bernardino, Long Beach, and Highgrove, are not economic to operate in any manner unless they receive a MMRA Type C from the ISO. In these cases, the units are likely to be retired or possibly repowered immediately regardless of ownership status.[17] A preliminary screening analysis indicated that none of the other units were likely to be repowered in any case before the end of the time horizon used in the analysis. Given these factors, the analysis is considered only indicative, and not sufficiently conclusive to identify the specific plants that would be repowered, let alone which of these plants would experience reduced capacity factors as the repowered units backed them down. *As such, the Final Initial Study does not consider the environmental effects that might arise from repowering.*

[16] PG&E states in its comments on the Draft Initial Study that "the large surplus capacity across the Western grid is likely to result in low wholesale prices which deter new investment. Under these conditions, we doubt that there are significant new investment opportunities that.... earn a reasonable hurdle rate." (Lovick 1997).

[17] Under CPUC D.97-04-042, the utilities are allowed to retire units without notifying the CPUC and still recover associated stranded assets.

Table 2: KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES	**CITATION/SOURCE**
Institutional/Restructuring Policy	
The PX and ISO will begin operation on January 1, 1998	AB 1890, Sec. 330
IOU generation plants will be market valued by December 31, 2001	AB 1890, Sec. 377
The IOUs will receive transitional costs to compensate for the stranded generation assets by March 31, 2002. The CTC account shall track accrual and recovery of costs through the period.	AB 1890, Sec. 367
Whether owned by the IOUs or independents, any "going forward" or operational costs must be recovered from the PX, through ISO contracts, or direct access sales.	AB 1890, Sec. 367
The IOUs must sell into the PX until generation plants are market valued.	PPD, CoL 18.
Owners of divested plants and other non-IOU plants may sell into the direct access market beginning January 1, 1998.	AB 1890
Sales of IOU plants must be reviewed for effects on system reliability	AB 1890, Sec. 362.
System Engineering and Characteristics	
Traditional form of hourly dispatch is "merit order" by short-run fuel costs plus some portion of "variable" O&M.	Edison and PG&E ECAC
Traditional form of daily and weekly commitment is based on expectations and variance of peak demand during those periods.	Edison and PG&E ECAC
Large variations in daily loads plus inability to store electricity prevents simultaneous maximum output by all generators. Increased generation at one unit generally must cause a decrease at another.	CEC demand forecast; laws of physics
Maximum output from any thermal-source generator is limited by: temporary or intermittent derating, forced outages, scheduled maintenance, permit limitations, and transmission constraints.	CEC Electricity Supply Planning Assessment Report (ESPAR), PEA
Gas-fired steam plants must burn fuel without generating electricity to attain critical steam level before selling into the electricity market.	CEC ESPAR
Repeatedly starting up and ramping up and down plants places mechanical stresses on steam-fired generation units.	Edison and PG&E testimony in CPUC ECAC and CEC Electricity Report

Table 2: KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES (Continued)	CITATION/SOURCE
System Engineering and Characteristics (cont.)	
Most natural-gas fired units in California were built for baseload operation.	CA Foundation on the Environment and the Economy, "Coal Use in California," 1982.
The incremental heat rate of a generation unit changes with its output level.	CEC ESPAR reports.
The incremental heat rates of California's natural gas plants when operating at full load fall into a narrow range.	Lovick, Workshop June 27; Joskow, FERC Filing, Fig. 1.
Gas-fired plants are the marginal resource in California at least 70% of the year.	Joskow, FERC Filing, May 29, 1996, p. 9.
Edison and PG&E gas-fired generation units currently operate at levels well below maximum technical and permitted output levels.	PEAs
Western U.S. grid bulk power market prices are below incremental natural-gas fuel costs during the spring run-off periods during off-peak hours.	California Energy Markets
Portfolio Effects	
IOUs possess vertical and horizontal market power in generation	PPD, FoF 29, CoL 34, 35
Owners of large generation pools in England and Wales, and Australia have exerted market power in the deregulated electricity market.	Lovick, Responses to Questions; Green, 1997; Wolfram, 1997.
Owners of large generation portfolios in England and Wales manipulated the availability of their plants to increase total net revenues by placing their most expensive plants on the margin more often.	Wolfram, POWER Conference, March 14, 1997.
"Portfolios are better able to manage the risks of trading in the PX than are non-portfolio bidders...It is not immediately apparent whether it is possible to develop PX rules which entirely remove this portfolio advantage; we suspect that it may not be."	London Economics, PX Filing, Attachment A, March 3, 1997.
In England and Wales, single-station owners operate their plants even if they have to accept some losses on days when market prices are low.	London Economics, PX Filing, Attachment A, March 3, 1997.
Participating in a market has transaction costs to both buyers and sellers in addition to the direct purchase price of the commodity.	McCann, Contemporary Economic Policy, July 1996

Table 2: KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES (Continued)	CITATION/SOURCE
Direct Access Market Characteristics	
Direct access contracts disconnect the contract price from those in the spot market in the England and Wales market.	Green, POWER Conference, March 14, 1997.
Large industrial and water district customers have higher load factors than the system average load factor.	CEC, Demand forecasting documents.
Large industrial customers represented by CA Manufacturing Association (CMA) led negotiations on the Memorandum of Understanding (MOU) for restructuring, which reintroduced direct access into the Proposed Policy Decision.	MOU, signed September 1995.
Association of California Water Agencies (ACWA) was one of the first groups to initiate contracting for direct access service.	ACWA Newsletters, 1996.
Natural Gas Fuel Procurement	
Several natural "gas" spot markets exist throughout the U.S.	New York Mercantile Exchange (NYMEX)
Mandalay and Coolwater generation plants currently have special contracts that reduce costs of gas supply.	Edison, ECAC filings; SCG, BCAP filings.
PG&E purchases electric generation (UEG) fuel as part of its larger portfolio of system natural gas purchases.	PG&E ECAC, BCAP
Independent power plant (QF) operators currently use different gas contracting terms than those used by the IOUs.	Public Utility Fortnightly, Review of confidential contracts
Gas contracts and published tariffs typically have a transportation rate which is fixed over a monthly or annual period, and a commodity rate which varies with the amount of gas consumed.	Wholesale gas contracts.
"Net back" gas contracts exist where the consumer pays the producer a price equal to cost of an alternative fuel or energy source.	Public Utility Fortnightly, Review of confidential contracts

Acronyms Used in Table

AB = Assembly Bill
BCAP = Biennial Cost Adjustment Proceeding
CEC = California Energy Commission
CoL = Conclusion of Law
CTC = Competition Transition Charge
ECAC = Energy Cost Adjustment Clause
FERC = Federal Regulatory Commission
FoF = Findings of Fact
IOU = Investor Owned Utility
ISO = Independent System Operator
PEA = Proponent's Environmental Assessment
PPD = Preferred Policy Decision
PX = Power Exchange
SCG = Southern California Gas Company