ATTACHMENT C

SYSTEM ECONOMIC AND OPERATIONAL CHARACTERIZATION

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INTRODUCTION

1.1 PRIMARY QUESTION - LEVEL OF OPERATION

San Diego Gas and Electric Company (SDG&E) has submitted an application to the California Public Utilities Commission (CPUC) for the sale of its fossil-fueled power plants within California including steam-driven units at South Bay, Encina, and various combustion turbines located throughout the SDG&E service area. The primary question addressed in this system economic and operational characterization analysis is whether a new owner of the divested power plants would have a tendency to operate, maintain or repower differently than under continued utility ownership. Basically, the analysis examines the economic and operational factors that could create different incentives for the new independent owners versus the utilities.

The analysis concludes that a set of general and plant-specific incentives exist that will tend to cause new owners to operate the divested plants differently than if SDG&E continued to own the facilities.[1] In general, the new owners (especially any new owners that do not currently own power plants in the region) would have a strong incentive to operate the more efficient divested fossil-fueled units and/or those strategically located for “direct connect” or “over the fence” sales more than the utilities would operate them if the units were not divested. Although the South Bay plant may be sold to the San Diego Unified Port Authority for future closure, during the interim period before closure, the plant operators will still have different incentives and constraints on operations than if SDG&E continued to own the plant.

1.2 BASIC PREMISES

This analysis contains three basic premises . The first basic premise is that restructuring as directed through legislation and Commission decisions will lead to substantial, fundamental changes in how California’s electric utility industry operates. The most dramatic changes may be deferred to the end of the transition period on or before March 2002. At that point, the investor-owned utilities (IOUs) no longer can recover their stranded asset costs (except for specified nuclear plants and most qualifying facilities contracts). Most generators, particularly those that establish market prices, will have to recover most of their investments through power contracts or

[1] Table C-1, at the end of this Attachment, summarizes "Key Facts, Axioms and Commonly Accepted Principles" employed in this analysis.

open market sales instead of through a separate regulatory-established rate of return. The incentives for choosing new generating or energy management resources and how much to run any resource will be much more responsive to consumer demands than was the case in the past.

The second basic premise is that the overall restructuring process will continue to proceed rapidly. Both the Independent System Operator (ISO) and Power Exchange (PX) are now operational, although they do not yet provide all of the services they plan to offer. This effort is being supervised by a large group of stakeholders representing all facets of investor utilities, consumers, generators, and marketer interests.

The third 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, and better ensure that the goals of restructuring will be achieved. Moving from a monopoly on generation to competition should lower prices and benefit consumers. In addition, the CPUC has directed SDG&E to divest its generation as a condition in approving the merger of Enova and Pacific Enterprises to form Sempra.Energy.[2] Nevertheless, saying that divestiture benefits ratepayers is not the same as saying that the CPUC should approve a particular divestiture proposal, although ratepayer benefit is an important factor in favor of approval. The CPUC will consider otherfactors, including environmental impacts of divestiture, in deciding whether to approve SDG&E's divestiture application.

Conducting any analyses about future events requires some judgment about the likelihood of various courses of action. The proposed action almost always appears more concrete than any alternative because the decisions and milestones are more clearly specified in the proposed action. For example, the expected construction and other activities related to development of a proposed office building will more likely be clearly delineated than other alternatives for a plot of land that is currently vacant. In the case of divestiture, the sale of the plants is the identified action; what SDG&E would do if it did not sell the plants is not so clearly defined. Yet through careful consideration, alternative scenarios without the specified action can be constructed and used as a baseline against which the potential impacts can be measured. This approach is the principle used in this analysis.

1.3 UTILITY SYSTEM CHARACTERISTICS

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

[2] CPUC D.98-03-073.

California's generation resources also are unique. First of all, California is the load center for the Western U.S. This creates the need for a large amount of electric power imports from neighboring states. However, the physical limitations of the transmission network require that a number of in-state power plants must be running at all times to meet demand. As a result, the state's utilities largely import their cheapest power while running more expensive plants to maintain system reliability and stability. Second, California has the largest concentration of renewable resources (other than large hydro) in any state, mainly due to a set 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 United States. Large amounts of utility-owned coal-fired power comes from the Rocky Mountain states, and nuclear-powered electricity is generated from both in-state and out-of-state locations. Most coal-fired, nuclear and QF resources are "baseloaded" (i.e., run constantly at their maximum output levels whenever available) and have either low operating costs or "must-take"[3] contractual provisions. The result is that California must finely balance the desire to lower costs and the need to "keep the lights on."

The power plants proposed for divestiture can be put into two groups:

- The Encina and South Bay fossil-fueled plants where all of the steam generation units are located, along with two combustion turbines, and

- The 17 combustion turbines (CTs) located at seven sites around SDG&E's service area.

The steam generation units provide most of the reliability support for the SDG&E service area, with the CTs standing as back up for emergencies and peak loads. The steam units are subject to an air quality rule that limits their total mass emissions, while the CTs are subject to emission rate limits.

In general, fossil-fueled plants are composed of some combination of steam turbine units and or CT units, or a combination of the two called combined cycle units. In steam turbine units, boilers are heated by fossil fuel and the steam routed through a turbine generator. These units were originally designed to run baseloaded (i.e., in a constant mode) and were constructed before 1979. To operate in load-following manner as these plants do today (i.e., with power levels following changes in demand), these units must either (1) use a large amount of fuel during daily startup[4] to simply heat the boilers to a level where 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.

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[3] Must-take generation is generation that, for a variety of reasons, must be purchased by the local utility. Generally, reasons are contractual – such as the mandatory purchase by utilities of power produced by qualifying facilities (QFs) under PURPA – or because of the nature of the power plant, such as nuclear plants that run at full power 24 hours per day because of physical limits that prevent rapid increases or decreases of power levels.

[4] Typically equivalent to from one to two hours of full load operations.

The CT units, on the other hand, each consist of a combustion chamber that burns natural gas, JP-5 jet fuel or diesel fuel oil and produces an exhaust that spins the turbine-generator, producing electric power. CTs are most valuable for system reliability since they can be started and fully loaded in 10 minutes or less. Because of high operating costs, CTs tend to be used only at times of peak demand when all other sources of supply are fully employed, during transmission system disturbances or emergencies, or when other units are forced off line. They also provide black start capability.[5] This is especially important when a transmission link goes down, which would cause the remaining transmission to overload in the absence of backup units.

Natural-gas-fired steam boiler units throughout California, including those now proposed for divestiture, have similar fuel efficiencies distributed over a narrow range. Their efficiencies at maximum output generally lie within about 7 percent 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; i.e., the unit will be more likely to be selected by the Power Exchange and dispatched by the ISO more frequently because of its lower cost. For example, a 10 percent cost reduction by a relatively expensive gas-fired unit can move it earlier in the merit order by 15,000 megawatts (MW).[6] Thus, if an operator can reduce costs by changing operational mode or reducing the cost of fuel by even a small amount, sales from that unit can rise substantially. This reduction in variable cost of operation could be realized by either the investor-owned utility, if the facility were retained, or by the new owner if the facility were divested, but the incentive to do so may vary depending upon the portfolio of generation from which the individual plant owner can bid into the PX.

1.4 MUST RUN CONTRACTS AND AREA RELIABILITY

Electricity, unlike any other commodity or service, must be supplied in a manner that instantaneously balances with demands and it is not readily storable.[7] These characteristics impose certain physical constraints on the generation and transmission system that limit the ability to use only economic signals in dispatching generation. These rules lead to specific generating units being designated “Must Run” (Reliability Must Run or RMR) in order to prevent: 1) the extreme consequences of an electric service interruption to highly concentrated areas, 2) overloads on generators, 3) transmission facilities overloads, 4) cascading outages, 5) voltage collapse, and 6) total grid blackouts.

The purpose of Reliability Must Run Agreements (RMRAs) between the ISO and specific unit owners is to ensure reliability of service to customers without overpaying. If the owner of an RMR unit failed to operate when the unit was needed, then electrical service would be jeopardized or disrupted. If the owner of a needed unit were allowed to set any price, then ratepayers might be overcharged whenever the unit was needed to maintain reliable service.

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5 Black start capability is the ability of a generator to start operations independent of any outside electrical power source. Most generation units require external auxiliary power to start.

6 Sam Lovick, “SDG&E Divestiture CEQA Workshop Presentation,” (San Francisco, California: London Economics, Inc. June 27, 1997.)

7 Water can be retained behind dams, within specified limits, for future hydroelectric generation .

All 28 of the units that SDG&E currently proposes to divest are designated Must Run by the ISO. Designation as an RMR unit by the ISO does not mean the unit literally must run or operate all the time. An RMR unit may only be needed by the ISO for a few hours each year. It means the owner must commit to maintaining the unit and to responding on a best efforts basis to a directive from the ISO to operate the unit. All of the units proposed for divestiture are deemed RMRs because they are all required to support either local or area reliability requirements. As discussed below, this designation tends to diminish the differences in operational incentives for the new owners versus SDG&E.

1.4.1 MUST RUN GENERAL CONTRACT TERMS

There are three different versions of the ISO RMRA,[8] “A”, “B” and “C.” Each version is intended to serve a particular availability niche: (A) economic and needed, (B) uneconomic and often needed, and (C) uneconomic and rarely needed. At page 36 of the Executive Summary of the March 31, 1997 ISO Tariff filing with FERC, the RMRA is described as follows:

> *The standard form of Must Run Agreement is a Master Agreement to which three different sets of conditions – A, B and C – can apply. The Master Agreement and the three sets of conditions are included in the filing as Appendix G to the ISO Tariff. Only one set of conditions can apply to a must run unit at one time. The agreement provides that all Reliability Must Run plants will be subject to the predominately market-based approach contained in the A conditions beginning on January 1, 1998.*
>
> *These conditions are in the form of an ancillary services style call contract with no penalties. Under A conditions, the ISO may call upon the Reliability Must Run unit to run up to a maximum number of hours in different months or seasons of the year based upon the ISO’s forecast of its Reliability Must Run requirements. When not called upon to run by the ISO for reliability purposes, the owner may bid the unit into the PX or participate in other markets. For those periods when the ISO calls on the unit for reliability reasons, the ISO pays the owner an agreed price per MWh for capacity and energy services rendered. Agreement A conditions permit the owner to retain all revenues from sales of energy through bidding into the PX or under direct contracts.*

The executive summary describes the “B” conditions as follows:

> *Under the B conditions the unit is available to be called upon to run when required for reliability purposes. The owner is paid the fixed costs of the unit as an availability payment and the running costs when the ISO calls on the unit to run. The owner is allowed to bid the unit into the PX or other markets when not called upon by the ISO, but bids submitted to the PX are subject to a floor. If the bid is successful and the units are run in merit order, the difference between the market clearing price and the running costs is credited back to the availability payment.*

The executive summary describes the “C” conditions as follows:

[8] These are often titled “Master Must Run Agreements” (MMRA) or “Reliability Must Run Agreements” (RMRA).

> *Under the C conditions, the unit is available to the ISO to be called upon when required to run for reliability purposes. The owner is paid the fixed costs of the unit as an availability payment and the running costs when the ISO calls on the unit to run. The owner is not allowed to bid the unit into the PX or any other market, however.*

Many of the terms of the different sets of conditions are similar. Some of the more important terms are discussed below. Designation as an RMR unit is not permanent. The ISO can cancel an RMRA on 90 days notice. The owner, however, has no such right. Any unit designated as Must Run by the ISO must enter into an RMRA.

Under “A” and “B” conditions, unless dispatched by the ISO, the RMR unit is under the control of its owner. If owned by SDG&E, the RMR unit must be bid into the PX until the end of the transition period. After the transition period, if SDG&E still owns the RMR unit, SDG&E may bid into the PX, enter into bilateral or multilateral sales, or engage in direct sales. The new owner of a divested unit may bid into the PX, make bilateral or multilateral sales or engage in direct sales.

Under the “A” and “B” conditions, the owner of an RMR unit may run the unit to its permitted maximum technical limits if the owner so desires. The contract with the ISO allows the ISO to direct the owner of an RMR unit to generate under certain conditions. The “A” and “B” conditions of the RMRA in no way allow the ISO to stop generation.

1.4.2 RELIABILITY MUST RUN UNIT OBLIGATIONS

The owner of an RMR unit is contractually obligated to fuel, operate, and maintain the units in accordance with good industry practice. The owner is required to notify the ISO of each forced outage, its expected duration, and when the unit is again available to generate electricity. The owner is required to perform routine and overhaul maintenance at times mutually agreed to by both the operator and the ISO.

When called upon, the owner must generate up to the maximum hourly commitment of the unit. The ISO can direct that the unit generate less than its maximum, but not less than its minimum, capability. For example, the ISO might direct a unit with a maximum of 200 MW and a minimum of 50 MW to generate 100 MW. In this example, under the A and B conditions, the owner could elect to generate up to the full 200 MW but the ISO would only pay for the first 100 MW and the owner would have to sell the remainder through the PX or through direct access (if the owner either is not SDG&E, or is SDG&E after the CTC recovery period).

The ISO can only dispatch an RMR unit up to its maximum monthly generation commitment. These specified amounts under RMRA “A” are typically less than under RMRA “B” or “C.” The maximum monthly generation commitment is a contractual number and does not necessarily reflect a technical maximum. The ISO is also limited in the number of annual startups that can be required of any Must Run unit. The ISO is further obligated to honor unit generator constraints such as ramp-up time or minimum run time, and all other operating constraints such as the fish preservation requirements. The ISO also agrees to honor any existing contractual constraints on the operation of an RMR unit.

If an owner fails to respond to a dispatch order from the ISO and does not generate the requested electricity, then the consequences stated in the proposed contracts for RMR units are: 1) no payment for missing generation, 2) requested energy amounts do not count against the maximum monthly generation commitment, and 3) if the unit started but failed to deliver, then it does not count against the maximum annual startups for the unit.

2.1 QUALITATIVE RESTRUCTURING BASELINE

This baseline analysis attempts to characterize how SDG&E, as the existing investor-owned utility owner of the resources proposed for divestiture, would likely operate these plants under restructuring. The analysis focuses on the different incentives that exist in the transition and post-transition periods, and how these incentives affect both market performance and SDG&E's behavior.

The analysis presented here relies, to the extent possible, on observations of how the nascent trading system is operating and, where not apparent from current ISO/PX operations, on assumptions that are conservative with respect to potential environmental impacts resulting from divestiture under a restructured regulatory regime, i.e., so as not to underestimate the possible operational changes by a new owner. Policy directives and critical dates spelled out in CPUC's *Preferred Policy Decision* and AB 1890 were used. For example, market valuation of all generation resources 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 to the extent that it is not changed explicitly by restructuring.

2.2 MARKET BIDDING AND PRICING ALTERNATIVES

The market clearing price, as reflected in the PX and the ancillary services markets managed by the ISO,[9] is likely to follow one of two paths in the future. On the first path, as described by witnesses for Pacific Gas and Electric and Southern California Edison in the first round of divestiture, bidding behavior would follow the least incremental cost dispatch criteria used by the utilities before restructuring.[10] In this future, plant operators would only bid their incremental

9 The ISO support services or 'ancillary' services will include automatic generation control (needed to balance generation with demand for generation), spinning reserve (synchronized generating capacity that immediately available), non-spinning reserve (generating capacity with less than 10 minutes of response time), and replacement reserve (generating capacity available within 60 minutes). They will be provided through a competitive market where market participants will make bids through the PX for the necessary reserves that are required by the ISO. Other ancillary services that the ISO will provide include reactive power (to maintain system voltage and reduce circulating currents), and generation black start (to provide for recovery during a major outage).

10 Sam Lovick, "Impact of divestiture on plant operation," by London Economics before California Public Utilities Commission in Application of Pacific Gas and Electric Company for Authorization to Sell Certain Generating Plants and Related Assets Pursuant to Public Utilities Code Section 851 (U 39 E), A.96-11-020, (San Francisco, California: Pacific Gas and Electric Company, 1997); Paul L. Joskow, "Affidavit of Paul L. Joskow," before

fuel costs for each hour to best ensure that the plant wins the auction and sells power in that hour. However, to achieve this type of pricing behavior, at least two conditions are necessary: (1) an ample generation supply in excess of demand, and (2) generators able to enter the market, both in the short-term and long-term, at little or no cost. The electricity markets fail to meet these conditions because (1) transmission and physical plant investment limit generation availability, particularly during peak loads, and (2) start-up fuel and cycling-duty costs are significant in the short-term, and investment risks are large in the long-term.[11]

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, a particular plant can substantially increase generation with quite small decrements in plant costs and bidding strategies, if the market price follows the first path of incremental bidding. In other words, a generator could bid using, for example, average daily costs rather than hourly incremental costs. The result is increased output and net revenues from that unit, despite apparently losing money in certain hours when the market price falls below the unit's incremental heat rate. The key is that the unit can avoid other costs for start-up, maintenance and transactions by running at a constant output level.

On the second path, the bidders would adjust their bids to reflect the responsiveness of the market to increasing prices and to account for how operating costs in any one hour are directly linked to operating costs and levels in both previous and subsequent hours.[13] In this second future, operators would bid above incremental costs during higher load hours to recover fixed and startup costs incurred during low-load periods, and could even underbid incremental costs during low-load periods to avoid excessive cycling.

The differences between these two futures have important implications. If bidding continues to simply reflect incremental costs, the market clearing price differential between on and off-peak periods will be much smaller than if bidders adjust their bids to reflect the differences in demand characteristics between the two periods. The latter pricing behavior will tend to reward cycling operations and system support to a greater extent than the former. It also could lead to higher overall bulk power costs because the higher prices would occur during the period of greatest

California Public Utilities Commission in Application of Southern California Edison Company (U-338-E) for Authority to Sell Gas-Fired Electrical Generating Facilities, A.96-11-046, (San Francisco, California: Southern California Edison Company, 1997).

11 Paul L. Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives* 11, no. 3 (1997): 119-138.

12 Joe Pace, "Testimony on Market Power Issues," by Law and Economics Consulting Group before Federal Energy Regulatory Commission in Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company: Application for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange, ER96-1663-000, (Washington, D.C.: Pacific Gas and Electric Company, 1996); and Paul L. Joskow et al., "Report on Market Power Issues," before Federal Energy Regulatory Commission in Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company: Application for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange, ER96-1663-000, (Washington, D.C.: Southern California Edison Company, 1996).

13 Joel B. Klein, *Interim Staff Market Clearing Price Forecast For the California Energy Market: Forecast Methodology and Analytical Issues* (Sacramento, California: California Energy Commission, Electricity Analysis Office, Energy Information and Analysis Division, December 11,1997).

generation, and inframarginal[14] units would earn greater net revenues with little change in their own operations and costs.

In the large-scale deregulation effort in England and Wales, the plant operators initially used marginal costs as the basis for their bids, but moved to a strategic bidding approach within a year.[15] The strategies varied depending on the characteristics of the owners and the resources controlled. For example, a large portfolio owner controlling fossil-fueled plants would often bid above marginal costs, while another controlling nuclear plants woul bid below marginal costs. A recent study of deregulating the Australian market expects similar strategic bidding to occur.[16]

The first several months of operations for the PX energy and ISO ancillary services markets provide some evidence about the likely behavior of this market.[17] From the opening of the market April 1 through July 24, the off-peak price averaged less than $16 per MWh, and included many hours when the market clearing price was zero. With the spot price of gas at $2.20 per MMBtu or more during this period, this implies that either gas-fired plants were off-line a substantial period unless they were running under an RMRA, or the owners were accepting prices that were below the equivalent of the spot-market gas price. Of course, a large proportion of the fossil-fueled plants are removed from the PX market during these periods either through the RMRA or "must take" contractual provisions. Those gas-fired units that are "must run," which are virtually all of the units running during this period, are being paid start-up fuel costs to be brought back on-line each day. For this reason, these unit owners need not bid sufficient amounts into the PX to recover their full operational costs. The result is that PX prices are depressed, but all of the costs that would have been recovered through PX revenues are shifted to the ISO. As the ISO approaches the limits on start ups for each unit, and assuming little or no FERC relief on this matter, the ISO will then have to pay the RMR units to operate overnight. In this case, the late-night PX prices are likely to be depressed even further, with more hours approaching a zero price. If gas-fired generators are accepting below incremental-cost prices without being called by the ISO, this would imply that the owners of the gas-fired power plants are willing to accept short-run losses overnight to minimize cycling costs by running at as high a level as possible.

As the peak electric demand season arrived in July, on-peak prices rose substantially, usually averaging more than twice off-peak prices during each week. These prices are substantially above the incremental generating costs for the gas-fired units that are actually setting the market clearing prices. ISO ancillary services market prices also have risen considerably since July 1. This behavior is consistent with strategic bidding by generators to ensure recovery of fixed costs and investment from the marketplace. The large differential between on- and off-peak prices indicates that the market appears to be proceeding down the second path, where cycling

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[14] "Inframarginal" means that the plants have operating costs below the market clearing price and therefore their operations are insensitive to how the market clearing price might change.

[15] Australian Bureau of Agricultural and Resource Economics, *Strategic behavior in the national electricity market* (Canberra, Australia: Prepared for Australian Competition and Consumers Commission, 1997).

[16] Ibid.

[17] California ISO, "Weekly Market Watch," (Folsom, California: Market Surveillance Office, May 22 to August 14, 1998).

operations will be rewarded more than constant generation, at least during the summer peaking season.

2.3 TRANSITION VS. POST-TRANSITION PERIODS

The effects of the restructuring reforms are being phased in during a mandated "transition period."[18] The measures implemented during this transition period, particularly including the competitive transition charges (CTCs) imposed upon essentially all sales, and the simple inertia of existing plant and operating procedures, will act to moderate any changes in operations.

Because of 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 transition period in the baseline.[19] Without divestiture, new firms would be further discouraged from entering the market and the IOUs would continue to dominate the generation market, while holding the lion's share of existing dispatchable capacity.

Several companies have announced plans to bring new plants on-line during the transition period, in spite of having to factor in the CTC on direct sales to existing customers and the relatively low PX price. One plant is already under construction near Boulder City, Nevada,[20] applications for nearly 2,800 MW of generation have been recently filed before the CEC, and another 3,500 MW are planned.[21]

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 for SDG&E during the transition period that would be little different from the dispatch rules used by the utilities before restructuring. Through the transition period, the IOUs are expected to bid only their short-run marginal costs into the PX, with no added margin of investment return, as is done today with the IOU-owned resources.[22] 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 (equivalent to return on rate base), 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

[18] The CTC officially ends for a given IOU the earlier of March 31, 2002 or three month after full collection of CPUC adopted CTC for that IOU.

[19] However, local conditions, such as those in San Francisco and San Diego may dictate capacity additions sooner than 2002.

[20] The ENOVA-Houston Gas Company jointly owned combined cycle, gas fired generation plant.

[21] The CEC currently is considering four applications of certification (AFCs), and is expecting up to another eight (California Energy Commission, *The Energy File*, Sacramento, California, August, 1998).

[22] For example, FERC Docket Nos. EC96-10-001 and ER96-1663-001, *Transmittal Letter to the Phase II Filing of the Trustee for the California ISO Corp. and the California PX Corp.*, March 31, 1997.

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.[23]

If the SDG&E plants did not go through the divestiture process, the CPUC would determine their total outstanding asset value. These plants would then receive revenues from the PX. These revenues would cover total operating costs first; the remainder would be credited against the total remaining investment in plants excluding the CTC portion. The remainder would be the "stranded asset" amount that would be rolled into the CTC, which would "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 period and are limited in how much PX margin they can credit to their CTC account (undepreciated book value of generation plus operating cost until they recover all of their stranded assets or through 2001, whichever comes first), SDG&E would apparently have little incentive to bid above its marginal operating costs as long as it believes the full CTC period provides sufficient opportunity to recover its full CTC. To the degree it believes the full recovery is in jeopardy and/or a commercial advantage can be gained by terminating the CTC recovery period early, it would have an incentive to bid higher in hopes of increasing immediate margin.

Only utility fossil plants deemed necessary for reliability purposes have any incentive to earn revenues above operating and maintenance costs because the extra revenue would acclerate the CTC recovery period. However, because the RMRAs are specifically enforced by the ISO when the needed units are <u>not</u> selling to the PX, or if these units could exercise local market power, SDG&E would have little incentive to bid above any unit's marginal operating costs during this period.

Thus, with the temporary exception of payment after RMRA start-up provisions are exhausted, 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.

If the plants proposed for divestiture are not sold, they will 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, the divested plants receive a "fixed" CTC from the market-valuation point through 2001 (i.e., a single lump-sum award), versus the "floating" CTC for plants not going through the divestiture process (i.e., a payment that is determined annually after the fact and varies with actual PX prices). The IOUs will then need to

[23] See, for example.: Rajat Deb, Richard Alpert, Hsue Lie-Long, *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 Marvin Feldman, (Resource Decisions) and Richard McCann, (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.)

recover the remaining "market value" of these plants exclusively from the PX revenues. The IOUs will want to maximize their PX revenues to maximize net generation revenues.[24] Depending on the magnitude of the market value, the IOUs will 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. Under Section 377 of AB 1890, after 2001 the IOUs may sell these plants without CPUC approval once the plants are market-valued.

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.[25] Generators will 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.

HOW OWNERSHIP INFLUENCES OPERATIONAL AND INVESTMENT DECISIONS

3.1 INTRODUCTION

The SDG&E units currently proposed for divestiture operate in diverse ways. The fossil-fueled steam-generation plants proposed for divestiture serve to follow load because they are some of the higher-cost sources of dispatchable generation. All of these units are physically capable of increasing their capacity factors substantially. The combustion turbine units are some of the most expensive units to operate in California, and only run a few hours of the year in any case.

This section provides a theoretical analysis of the likely operation of the divested power plants under new ownership, particularly if the plants were purchased by entities without considerable interests in other electricity-generating resources in the region or the state. This analysis does not quantify the expected change in operations at the divested power plants. The economic and operational analysis only answers the question of whether divested power plants would have a tendency to operate differently than SDG&E would if it retained the plants.

3.1.1 BIDDERS' CHARACTERISTICS FROM INITIAL DIVESTITURE ROUND

A key issue in assessing the potential environmental impacts of divestiture is determining if the plants might operate differently under new ownership than under continuing investor-owned utility (IOU) control. One part of making this assessment is examining the differences in

[24] 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 both their CTC and net PX revenues.

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

financial and structural characteristics of the new owners. For example in California, qualifying facilities (QFs) that use natural gas for fuel rarely operate in a load-following mode, and attempts by the utilities to induce such operations have not been successful to date. While this example may not be parallel, it illustrates how two different sets of firms can have different operational approaches for meeting their financial goals.

In the first round of divestitures by the Pacific Gas and Electric and Southern California Edison Companies, the CPUC did not have information on the firms that might bid for these plants; in this round we now know, at least, about the six successful bidders from the first round of divestiture. We can use this information to make comparisons among this group of potential bidders and the IOUs. At the moment, the available sample of potential bidders for the fossil-fueled plants is represented by the six successful bidders from the first round.

The new owners can be separated into two distinct groups from a financial and resource ownership standpoint:

(1) The parent companies of Duke Power (Duke Energy), Houston Industries and NRG (Northern State Power or NSP) are large utility holding companies that control large utility generation plant portfolios in their service areas. In addition, Duke and Houston control large natural gas pipeline and distribution companies located primarily in the southern U.S. These three companies have financial characteristics generally similar to those of California's investor-owned utilities with comparable or better bond ratings, price-to-earnings (P/E) ratios and debt-to-equity ratios. While their new generation plants are isolated from their existing portfolios, these firms can be expected to make plant investment decisions that would be similar to those that might be made by Sempra Energy, parent of SDG&E.

(2) NGC (now Dynegy and parent of Destec), AES (Applied Energy Systems) and Thermo Electron (parent of Thermo Ecotek) are merchant and cogeneration power plant developers that appear to be aggressively entering the restructured utility industry. Dynegy is perhaps better known as a natural gas supply company with the fourth-largest holdings of reserves in the U.S. AES is a pioneer in the independent power industry. Dynegy and AES each own about 5,000 MW of generating capacity in the U.S. beyond the divested plants in California. AES owns another 13,000 MW internationally. Thermo Electron has been more active in the international market, with 95 percent of its 11,000 MW outside the U.S. These companies have substantially higher price-to-earnings ratios than either the first group or the California utilities.[26] This characteristic typically reflects companies with higher expected profit growth rates. AES also is substantially leveraged with a 70 percent debt-to-equity ratio, suggesting more risk potential. Dynegy and Thermo Electron have debt structures similar to the first group.

A comparison of bond ratings for each firm is instructive in measuring the market's assessment for each of these firms. The market clearly views the second group of companies as greater risks than either the first group or SDG&E. To compensate for this risk, investors will demand a higher rate of return on investment from these firms. In turn, these firms will use a higher discount or investment "hurdle" rate in choosing investments. As a result, these firms will have

[26] As of December 31, 1997.

to tolerate greater risk in their investments in exchange for higher potential investment returns than would SDG&E.

As a bidder, Dynegy presents a second important distinguishing characteristic from Sempra. Dynegy has large natural gas production capability and controls a large number of gas contracts. Dynegy markets about 8 billion cubic feet per day (bcf/d) of natural gas as a wholesale supplier. In comparison, SDG&E and Southern California Gas deliver about 2.6 bcf/d to retail customers.[27] Perhaps more important, Dynegy has firm transportation contracts for 1.3 bcf/d on the El Paso Pipeline. Southern California Gas Co. is the next largest holder of firm capacity with 1.18 bcf/d. By controlling large gas reserves and substantial firm transportation capacity, Dynegy (or a similarly situated firm such as Enron) would face low opportunity costs for burning natural gas in its newly acquired plants. In other words, the natural gas costs for such a firm are probably well below the spot price for gas seen in the marketplace. In such a case, the firm would not find it profitable to trade off generation against the gas market price.

We can draw three conclusions about the potential bidders for SDG&E's fossil-fueled plants:

(1) Some of the more serious bidders will likely fall into one of two categories: either large utility holding companies with similar characteristics to Sempra Energy, or merchant plant developers that may possess large natural gas reserves or pipelines. The first group will have more experience and infrastructure for participating in California's power market. As a result, their transaction costs would be lower.

(2) The merchant plant developers would require higher investment returns from their acquired power plants to satisfy their shareholders, and increasing the production from acquired units is one approach to increasing the rate of return from their power plant investments.

(3) A bidder with large natural gas holding and transportation capacity would incur lower costs for gas than the market spot price. This would provide incentives for it to burn more gas and generate more power in its plant.

3.1.2 DIFFERING INCENTIVES

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

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 recover much of their existing "sunk" investment through the non-bypassable CTC, and accelerate the depreciation on these plants to ensure full recovery by 2002. The new owners will probably have a larger investment exposure created through the plant purchase, and will need to recover their investments over a longer period, which will likely be based on each plant's remaining economic life, rather than the accounting

[27] Within California.

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 would with the same facilities.

In contrast to these differing ownership incentives, those units that enter into an RMRA Contract C with the ISO will most likely operate the same under either new or utility ownership. RMRA Contracts A and B will also tend to reduce the difference in generation between restructuring without divestiture and restructuring with divestiture, and although the actual effects are unknown, they are likely to be substantially less than from Contract C. All of the plants proposed for divestiture currently possess RMRA contracts from the ISO and at this point each of these is class "B."

The analysis conducted for this report indicates that four factors could provide the new owners with incentives to operate the divested fossil-fueled power plants, particularly the more efficient ones, differently than the utilities would operate them: (1) allocation of market-participation transaction costs, (2) gas contracting practices, (3) direct-access market participation, and (4) different treatment under the existing air quality rule. However, unlike PG&E or Edison, SDG&E does not possess a large portfolio of generation resources, and the "portfolio effect"[28] is not a significant influence on differences in behavior between SDG&E and any new owners.

3.2 CAUSAL FACTORS

3.2.1 CHOICES FACING A SINGLE POWER PLANT OPERATOR

The basic choice facing the new independent owners of one of the more efficient divested plants would be whether to operate the plant in the load-following or cycling mode in which the plants are currently operating or, in the case of the more efficient units, to operate continuously at the most efficient operating level of the power plant, which is close to its maximum capacity.[29]

A single-plant owner will probably shut its power plant off during the low-load spring-runoff period unless required for local reliability purposes.[30] The combination of mild spring weather and abundant hydro output during the spring runoff creates a low-demand/high-supply situation, and the lowest prices for electricity during the year. At these times, a profitable strategy is to shut down a gas-fired power plant and fill any obligations to deliver electricity with purchases from lower cost producers.

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[28] See Sect. 3.2.2.

[29] 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 periodically shut the plant down and produce no electricity for an extended period of time.

[30] The revision in the recently-signed sale of the Long Beach plant reflects this strategy. The agreement between Edison and NGC/Destec allows for seasonal operation with extended shutdown periods.

During the remaining 70-percent-plus hours of an average hydro year, gas-fired power plants are presumed to be operating. A new independent owner of a divested power plant could operate continuously during those hours of the year. Alternatively, the new owner could 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 would tend to discourage cycling by new owners except during the very low-cost spring-runoff period.

As discussed previously in Section 2.2, the market price is likely to follow one of two courses:

(1) The market-clearing price will reflect only the incremental cost of fuel use during all but a few peak-load hours a year, or

(2) The on-peak price will rise sufficiently to recover fixed and cycling costs, and off-peak prices will fall to discourage continuous operations.

Under this first market scenario with incremental-cost bidding only, the strategy most likely to increase net revenues is to increase generation when the owner's forecast of the average market prices for a daily, weekly, or monthly period are above average costs for the same period. A logical goal of any new owner would be to arrange, either directly or through an intermediary, 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 for a majority of the hours in a year. Under the second scenario, a new owner would load-follow to the extent that the apparent losses during low-load and price periods exceed the cycling, start up and transaction costs incurred by load-following.

COSTS OF CYCLING POWER PLANTS

If the power plant is shut down or curtailed in order for the owner to fully participate in the PX and to follow load based on price signals, there are additional costs beyond the apparent hourly fuel costs. Restarting or cycling a unit involves increased fuel costs for startup and ramp up (i.e., to return the plant to its optimal generation output) that would not be incurred in constant output operation. Startup fuel costs typically are equivalent to one to two hours of full load operation for boilers. Operating a power plant at less than its optimal level increases the per kWh fuel cost. Each power plant has a level of operation at which it is 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. In addition, maintenance costs increase, caused by the increased thermal and mechanical stresses on the power plant unit from turning the unit on and off; baseload operation reduces heat stress from expansion and contraction of unit equipment. As an example, SDG&E assumes that each startup adds the equivalent of 20 operational hours for scheduling maintenance cycles.[31] One start per month would add about 4 percent to the maintenance costs alone for a unit on line 70 percent of the hours.

Both cycling and shutdowns tend to increase forced outages, which further increase maintenance expenses and cause the operator to incur increased power replacement costs. Each time the plant is stressed with either cycling or a shutdown, the odds increase for a forced outage in which a piece of equipment fails. These failures must be repaired, thereby causing additional expense. While the plant is out of service for these repairs caused by changing the output level based on changes in the PX price, the owner may have to buy replacement power to fulfill contractual commitments to deliver electricity. Replacement power during a forced outage is invariably more expensive than self generation since it is produced by the power plant with highest operating costs which sets the market clearing price.

These cycling-duty costs, including startup fuel use and increased O&M expenses, must be recovered through market revenues (e.g., PX sales) as fixed costs allocated on top of the incremental fuel costs incurred from hourly operation. To a single-plant owner, these cycling duty costs are significant and must be recovered solely from the revenues of that plant alone. As stated previously, the average costs for gas-fired plants in California lie within a band 10 percent above or below the average. Thus, the single-plant owner has a strong incentive to minimize those cycling duty costs. Baseload operation is the simplest way to accomplish this goal. This is one reason that QFs operate baseloaded.

TRANSACTION COSTS OF TRADING IN THE PX

In order to trade in the PX, the owner of any plant must incur a number of transaction costs. The first is the fee charged and bonding requirements by the PX for using the PX trading exchange. Also, to directly participate in the PX requires investment in 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.

While SDG&E will incur similar transaction costs, it will have at least two distinct advantages over an owner of one or a few plants. First, SDG&E has already made the necessary infrastructure investment necessary to participate in the market during the pre-restructuring period. SDG&E always has dispatched its own system. Second, SDG&E also will participate in the PX as a buyer for its utility customers. While some of the costs between these two activities can be separated, there certainly will be synergies to SDG&E’s advantage. A single-plant or even multiple-plant owner will possess none of these qualities. For these reasons, the transaction costs for new owners are likely to be more significant than for a utility such as SDG&E.

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31 San Diego Gas and Electric Company, Data Response No. 12, SDG&E Divestiture Application No. A-97-12-039, May, 1998. SDG&E has filed confidential information with the ISO which also show substantial cycling costs.

An additional risk of PX trading is that the new owner will not know with certainty the price for electricity or gas if it elects to cease generation and instead 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 pay if its generation is shut down and the PX must supply the replacement 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.

3.2.2 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. However, unlike PG&E and Edison, SDG&E owns a small portfolio of power plants, which would not differ substantially from a portfolio owned by a potential new buyer. A buyer of either the Encina or South Bay plants will own at least 33 percent of the steam generation resources now controlled by SDG&E (South Bay, Encina and its SONGS ownership interest). In fact, SDG&E now owns less capacity than Houston Industries or AES, winners in the Edison auction, and about 500 MW more than Duke, winner of the PG&E auction. Given the likely similarity in generation portfolios between SDG&E and any new owners, we are unlikely to see a large difference in operations attributable to a portfolio effect, except perhaps related to transaction costs of participating in the electric or gas markets.[32]

3.2.3 DIFFERENT TREATMENT UNDER AIR QUALITY RULES

Under Rule 69 of the San Diego Air Pollution Contol District (SDCAPCD), SDG&E faces a declining annual aggregate nitrogen oxides (NOx) emission limit on its steam generation plants if it retains ownership.[33] The annual aggregate NOx emission limit applies to the accumulative emissions of both the Encina and South Bau plants together. The current limit allows 2,100 tons per year of nitrogen oxides (NOx), a limit that declines to 650 tons by 2005. While SDG&E would be expected to install additional pollution control devices to meet this declining cap,[34] it currently meets this rule by limiting generation from its plants.

On the other hand, a new owner will meet a daily emission rate standard under Rule 69, which sets a limit of 0.15 pounds of NOx per megawatt-hour when using natural gas, and 0.40 pounds

[32] This is in direct contrast with the findings in the previous environmental assessments of the PG&E and Edison divestiture applications because both PG&E and Edison owned substantial portfolios of generating facilities.

[33] SDCAPCD, Rule 69(d)(4)(i)

[34] SDG&E Data Responses 5 and 95.

of NOx per MWh when burning fuel oil.[35] To meet this standard, the new owners will have to install additional emission control devices within two years of the sale (and not later than January 1, 2001) on the units. However, the new owners will not be constrained by an annual aggregate emission limit as SDG&E is now (and will likely continue to be in the foreseeable future). During the two year period after the sale (or until January 1, 2001) the new owner will be in a compliance period when neither the annual aggregate NOx emission limit nor the unit specific daily NOx emission rates apply.

In addition, as discussed in Section 3.2.4 below, the new owners may have an incentive to burn more fuel oil due to natural gas delivery constraints that arise during the winter heating season. The new owners will not have to meet an annual emission cap, and thus do not have to trade off the higher oil emissions against lower gas emissions. As a result, the existing constraint that limits fuel oil use by SDG&E will no longer be in place under the existing Rule 69.

3.2.4 PURCHASE OF NATURAL GAS

The price of gas is determined by a commodity cost and the costs of transportation. The commodity cost in the western market varies by location 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 geographically sensitive and subject to variation depending upon special arrangements with suppliers and pipeline owners (as discussed below).

SDG&E has a fairly unique problem among California utilities in that it has a limited capability to deliver natural gas to its generation plants during certain periods of the year.[36] Because both the Encina and South Bay plants have dense development between the plants and the large interstate pipelines, some gas is siphoned off to other customers during the heating season months. As a result, these plants cannot run at full load continuously over an extended period of time. To meet any substantial increase in natural gas demand at these plants, the Sempra gas system would have to be expanded and fortified to increase deliverability rates.

FUEL PROCUREMENT BY NEW OWNERS

If a new owner owns gas supplies or has pre-existing superior transportation capability, it would likely run the plant at a higher level than SDG&E currently does, because of these fuel cost advantages. Without such advantages, the new plant owners will likely procure fuel differently than the utilities do, employing a much greater range of specialized procurement practices.

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[35] SDCAPCD, Rule 69(d)(7)

[36] SDG&E, Data Response, September 1, 1998.

These procurement practices are likely to increase gas consumption through increased power generation.

As with many commodities, purchases of natural gas can involve quantity discounts. A commitment to purchase sufficient natural gas to run a 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 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 transaction cost of actively trading in the PX and following load to match incremental costs to PX prices. In contrast, a contract to purchase natural gas whenever a power plant is available (other than the spring-runoff period) is simple and easy to administer. Many gas transportation contracts specify firm service, and are sized to maximum rate of gas flow; with these contracts, very little additional cost is incurred in more intense use of gas transportation capacity. Thus, incremental gas use can be much cheaper and would impel plant owners with such contracts to increase generation.

The new owner may not have the volume of natural gas purchases needed to be an attractive firm-supply-contract customer to a supplier if the plant follows load. The new owner of just one plant may not be able to justify the cost of staff, software and telecommunications needed to be constantly active in the natural gas market. The new owner may find a constant delivery-rate contract the most feasible to administer at the least cost per unit of gas.

One means to control natural gas costs would be to enter into a "net back" contract with the natural gas supplier. Such a contract (which would likely exclude the spring-runoff season) ties 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. The price of gas under such a contract would rise and fall with the electricity price received by the new owner. Net-back arrangements with new power plant owners would certainly elevate the generation from the plants.

It is notable in the non-divestiture case evaluated in Edison's divestiture application,[37] the two Edison plants that were forecasted to have the highest capacity factors had special, lower-priced, gas transportation contracts. These two plants, Mandalay and Cool Water, had projected capacity factors of nearly 50 percent under continued utility ownership. In stark contrast, among the remaining plants – all of which have a common, higher cost of gas transportation – the next highest forecasted capacity factor was only about 18 percent. This behavior illustrates the extremely flat supply curve for gas-fired generation found within the state.[38] Even the slight discounts in transportation costs present for both of these Edison plants drove their expected capacity factors much higher than those of the remaining plants, which have comparable fuel efficiencies but higher gas costs. Much like Edison, in instances of cheaper gas, the new owners of plants in San Diego County would not dispose of this gas on the spot market because the price

[37] A. 96-11-046
[38] Lovick (June 27, 1997), op. cit.

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 did, that the profit-maximizing 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 or Dynegy were to purchase and operate 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 its generation close to zero in the PX in order to achieve an objective in its natural gas business.

Because of the gas deliverability constraints to the South Bay and Encina plants, the new owners would face another choice as well: whether to supplement natural gas with fuel oil to increase generation output. The choice would be based on evaluating the potential economic gains from using fuel oil versus the added costs. Over at least the last 10 years, and probably back to 1982, natural gas has been less expensive than fuel oil in California, particularly given the air quality constraints on burning oil. Oil emits more NOx and SOx than natural gas, and the air quality districts have written their rules to discourage fuel oil use as much as possible. However, with continuing low oil prices, burning fuel oil may become economic under certain conditions. At $15 per barrel – a world price seen within the last year – fuel oil costs the equivalent of $2.40 per million Btu (MMBtu). However, the low-sulfur oil required by the SDCAPCD typically costs somewhat more. In comparison, natural gas prices have ranged from $1.40 to $2.50 per MMBtu over the last several years, and typically rise to the upper end of that range during the winter. Given that the winter period is when natural gas delivery is most constrained in the SDG&E service area, natural gas and fuel oil prices may converge so that some additional fuel oil is burned by the new owners which would not have occurred under the SDG&E emissions cap.

Given that fuel oil transportation costs are substantially variable and avoidable, and that a new owner is unlikely to obtain a low-priced oil contract for a small and variable amount, the new owners are not likely to see any discounts off the spot oil market price. This contrasts with potential parameters of a gas contract that provides a discount in exchange for larger and fixed delivery volumes. Additionally, the new owners would have to arrange for delivery of additional fuel oil stock by tanker ship or trucks, while the gas delivery infrastructure is in place. For these reasons, natural gas costs are likely to remain below those for fuel oil in most scenarios, particularly for a large gas volume customer such as an electric generator.

Nevertheless, the gas delivery constraints can be anticipated to a certain extent by the new owners, who can easily switch one of their units (probably the least efficient) over to fuel oil during the winter months to increase natural gas deliverability to the remaining units at a plant. If that unit is needed for reliability purposes by the ISO, the full costs of burning fuel oil would be paid under the RMRA. The new owner would face no economic penalty from switching to the more costly fuel oil while increasing the amount of natural gas available to burn in its other units.

3.2.5 DIRECT ACCESS MARKETS

During the transition period from 1998 to 2002, 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. If the new owners are successful, utilities will be left to serve customers with low-load factors.

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. For example, Dynegy can sell power directly "over the fence" from the El Segundo power plant to the neighboring Chevron refinery while avoiding at least a large proportion of the transmission and distribution charges.[39] Enron has announced plans to construct a 500 MW plant in Pittsburg that would at least in part serve the USS-Posco steel mill directly, and would endeavor to sell to other local industrial customers.[40] The South Bay plant is well situated in an industrial zone to serve high load-factor customers, perhaps even bypassing the utility distribution company (UDC) system.

It is the more efficient of the divested units that will operate more intensively because of 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, unless needed for reliability. Rather, these units will more likely shut down for extended maintenance when it is more profitable to buy from the PX.

3.3 THE INFLUENCE OF MUST-RUN STATUS ON OPERATIONS

The level of potential variability of operations of the plants proposed for divestiture is significantly affected by the RMR status of the individual plants. RMR plants are eligible for special contracts (i.e., ISO Reliability Must Run Agreement [RMRA] Types "A," "B" and "C" specially tailored to each plant) 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.[41] Further, pursuant to these tariffs, the ISO has the determinative authority to classify plants as RMR, though the plant owners have some discretion as to which of the RMR contracts to accept.

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39 This is an extreme example of a direct-access sale or "direct connect," which avoids at least the IOU's T&D charges, and perhaps might even bypass the CTC, depending on how the CPUC interprets Section 369 of AB1890. Such direct connect service only enhances the direct access incentive discussed here, but quantifying the difference in effect is beyond the scope of this analysis.

40 Arthur O'Donnell, "Enron would build merchant plant in Pittsburg," *California Energy Markets*, May 8 1998, 2.

41 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.

3.3.1 MUST-RUN STATUS DIMINISHES POTENTIAL DIFFERENCES IN OPERATIONS

Any comparison of operations before and after divestiture will vary with the RMR status of each plant. The more stringent the RMR requirements on a plant, the less variation that can arise in the plant's operations regardless of plant ownership. At the extreme, if all of the divested plants were required to be RMR at all times (i.e., subject to RMRA "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. All of the units being offered for divestiture are required to sign an RMRA "B."

An important aspect of the RMRA "A" and "B" contracts is that the plant operators can essentially cause the ISO into paying the owners for at least their start-up costs, if not all of their fixed costs. For example, suppose the unit was shut down over the weekend, but the ISO will probably need the plant at some point on Monday. Knowing this likely demand, the plant operator can put in a bid on Monday morning that would recover all of the unit's startup costs. If the bid were rejected by the PX, as is likely, then the ISO would have to pay the operator to start the unit. With the unit started, the operator could then bid into the PX at the unit's incremental fuel cost for the remainder of the week, assuming that the unit stays up overnight. The owner can be sure of recovering almost all of its other variable costs. On the other hand, if a second unit does not have an RMRA, the owner must structure the bids throughout the week to try to recover at least the startup costs. The second unit would be at a distinct cost disadvantage compared to the first unit because of the "extra-market" startup subsidy provided by the ISO.

The RMRA thus becomes a valuable component of the plant sale. For example, all of the plants that sold below book value in the first round of the divestiture were <u>not</u> designated as must run.[42] Possessing an RMRA "A" or "B" gives the plant owner the option to recover at least a portion of its cycling costs from a side-payment through the ISO. Depending on how often a plant must be called by the ISO, an RMRA can diminish the differences in incentives between independent and utility owners as the differences in recovering cycling costs diminish.

3.4 DECISION TO REPOWER DIVESTED PLANTS

"Repowering" an electric generation unit involves salvaging the useful components of an existing plant and adding new technology to enhance its efficiency, reliability and remaining life. Most repowering projects now raze the existing steam boiler and replace it with a combustion turbine (CT), which in turn fires a heat-recovery steam generator (HRSG) with its exhaust. The steam from the HRSG is routed through the existing steam turbine. The repowered combined-cycle unit typically will have fuel efficiencies or heat rates of 8,000 Btu per kilowatt-hour or better, versus heat rates (prior to repowering) in excess of 10,000 Btu per kilowatt-hour.

[42] These were Long Beach, Ormond Beach, San Bernardino and Highgrove. Coolwater is an efficient combined cycle plant with advantageous gas access. While Moss Landing or Morro Bay sold for prices above book value, which plant would be RMR was unclear, and because they were purchased as a package, we cannot distinguish their relative values to Duke Energy.

In evaluating repowering, this analysis considers three possible outcomes: (1) the unit would not be repowered within the time frame analyzed; (2) the unit would be repowered within the same time frame regardless of ownership; or (3) the new owner would repower earlier than a utility owner because of the difference in market incentives and costs. (However, the analysis does not attempt to analyze the difference in Encina repowering strategies between SDG&E and a new owner because SDG&E must divest the plant under the conditions of the CPUC's approval of the Enova/Pacific Enterprises merger. The analysis also assumes the Port of San Diego will not repower the South Bay plant.)

The decision by a new owner to repower a plant in San Diego County is based on evaluating two factors: (1) comparing the expected net market revenues from operating the old facility versus the new facility, including the influence of potential competitors; and (2) the costs to invest in a new facility compared to the expected investment return. 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.

SDG&E's position is that a large surplus exists on the Western grid and that this surplus will defer repowering, so repowering is likely to occur after 2013 for the vast majority of divested plants.[43] In addition, the new generation either announced or currently under construction (see Section 4.3.1) would act as a damper on repowering zeal. However, several plants divested previously by Edison are now likely to be repowered. Current planning calls for High Grove to be repowered by 2000 and San Bernardino by 2001.[44] Neither of these plants would be economic to operate without repowering under any ownership scenario.

To serve San Diego's growing load and to meet existing reliability requirements, new transmission capacity or new power generation will likely be needed within SDG&E's service territory. In fact, SDG&E has recently proposed a transmission upgrade that would increase import capability by 400 MW, which if built promptly could defer a repowering of a divested plant until well after the study period of this analysis.

However, repowering of existing plants may still be the most economical way to meet future demand. The incentives for a new owner differ from those of SDG&E with regards to repowering versus transmission upgrades. If the plants were not divested (which is not an option because of the merger order), SDG&E would weigh the relative costs of each option because it bears at least the initial costs of each, being both a generation company and utility distribution company (UDC). In fact, SDG&E may be biased toward transmission because the risks of cost recovery as a transmission owner may be substantially less, given ISO ratemaking authority over transmission versus having to recover generation costs in the market, and the expressed need for reliability inherent in upgrading transmission.

[43] SDG&E has stated 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, July 1997, op. cit.).
[44] The Thermo ECOTek Corporation stated that it was repowering these two plants in May 29, 1998 motion made in A. 96-11-046.

A new owner, on the other hand, will actually directly compete with the transmission upgrades. Thus, a new owner may repower as soon as possible to reduce the potential economic benefits of a transmission upgrade to the ISO. Also, it is unclear as to who will approve such transmission upgrades, and who will bear the costs and risks of these type of upgrades, because the ISO has yet to reveal its policies for considering proposed transmission projects. Given these uncertainties, this analysis cannot adequately assess whether the new owners will have a substantial difference in incentives to repower the divested plants.

In addition, if the South Bay plant is sold to the Port Authority, which apparently has reached an operations agreement with U.S. Generating Co., [45] construction of the Otay Mesa combined-cycle plant is much more likely. If the South Bay plant were decommissioned consistent with the Port's stated intention, U.S. Generating would have sufficient air emission credits to operate a new facility at Otay Mesa. With the introduction of a large, highly efficient plant into the local power market, such as the contemplated 1050 MW Otay Mesa plant, the new owner of the Encina plant may have a strong incentive to repower its facility to remain competitive with such a new, efficient facility. A repowered Encina plant would probably have a higher capacity factor than does the present facility because of its improved competitive position relative to the entire state. However, whether such repowering would be financially attractive is dependent on two factors: the effect on Encina's generation caused by the replacement of South Bay with Otay Mesa and the expected pattern of power market prices. If Otay Mesa does not depress Encina's output substantially, as is predicted by the computer modeling done for this analysis, then the new owner's incentive to repower would be little different from SDG&E's.

The new owner of the combustion turbines also may have a somewhat greater incentive to repower its facilities than SDG&E, especially those units concentrated in a single location, (e.g., the nine CTs totaling 167 MW at Kearney). With the increased capacity from the planned Otay Mesa facility, the CT usage may drop so low as to become uneconomic to maintain solely for reliability purposes (especially if the Encina plant is repowered). To increase generation and associated revenues, the new owner of the CTs may have to greatly increase the efficiency of its assets in order to compete with the planned Otay Mesa facility. However, the new owner of the CTs would not own the land underneath the CTs, which could greatly complicate any attempt to repower the CTs. Additionally, the Kearney site is located in a residential area, and local planners may oppose any attempt to construct a new plant in that area. For these reasons, determining the likelihood that the new owner would repower one or more of the divested CTs would be highly speculative.

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[45] *California Energy Markets*, No. 482, September 18, 1998, p. 11.

SUMMARY

New owners of the divested plants are likely to differ from SDG&E in at least four different ways:

- Many of the new owners will have different financial characteristics that require more rapid recovery of investment.
- The new owners will be able to make direct-access sales to selected customer groups, especially those who have higher load factors, which would accommodate higher generation output. Higher market-participation transaction costs for the new owners versus SDG&E will only further encourage direct-access sales.
- The new owners may make different gas purchasing arrangements, which are more likely to require higher throughput volumes relative to contracted pipeline capacity because of the lower total volume purchased for the smaller generation portfolio.
- Under the provisions of Rule 69, the new owners will no longer have to meet annual limits on total nitrogen oxides (NOx) emissions from the steam-generation plants. However, within two years of the sale (but not later than January 1, 2001) the new owners will be required to meet unit-specific daily NOx emission rates that are more stringent than existing emission rates at any of the steam-generation units. During the two-year period after the sale of either plant (but not later than January 1, 2001), Rule 69 will not require an annual emissions limit or the more stringent unit-specific emission rate.

Each of these factors will tend to encourage higher generation levels by the divested owners. The need to accelerate investment returns requires either higher market prices, which are largely beyond the control of the new owners, or increased generation sales. The inability to spread transaction costs across other utility operations and previous investments implies that the new owners will be less willing to operate the plants in a cycling mode, so the plants are more likely to run at a constant output level. Direct access sales to higher load-factor industries will accommodate higher sales and will allow the owners to avoid market participation costs. Higher gas throughput means higher generation levels, since resale back into the spot gas market will incur some costs. Even if the South Bay plant is sold to the San Diego Unified Port Authority for future closure, the plant operators will still have different incentives and constraints on operations during the interim period before closure than if SDG&E continued to own the plant.

These changes may be attenuated by shifts in the power market price, which provide incentives for the new owners to operate the divested plants in a manner similar to SDG&E. In addition, the Must-Run Agreements with the Independent System Operator (ISO) may play a dominant role in the operation of these plants, and this would tend to diminish the difference in incentives between SDG&E and the new owners.

TABLE C-1
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
Institutional/Restructuring Policy	
The PX and ISO began operation on April 1, 1998.	Historic fact, 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 April 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.	Utilities’ ECACs
Traditional form of daily and weekly commitment is based on expectations and variance of peak demand during those periods.	Utilities’ 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

TABLE C-1 (continued)
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
System Engineering and Characteristics (continued)	
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.	Utilities' testimony in CPUC ECAC and CEC Electricity Report, SDG&E Data Response 12
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 percent of the year.	Joskow, FERC Filing, May 29, 1996, p. 9
Edison and SDG&E gas-fired generation units currently operate at levels well below maximum technical and permitted output levels.	PEAs
ThermoECOTek is repowering the San Bernardino and Highgrove power plants.	ThermoECOTek filing, A. 96-11-046, May 29, 1998.
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*, PX Price History, May 1998
Portfolio Effects	
IOUs possess vertical and horizontal market power in generation.	PPD, FoF 29, CoL 34, 35
Owners of large generation pools in the United Kingdom (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

TABLE C-1 (continued)
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
Portfolio Effects (continued)	
"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
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 had special contracts that reduced costs of gas supply.	Edison, ECAC filings; SCG, BCAP filings

TABLE C-1 (continued)
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
Natural Gas Fuel Procurement (continued)	
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 that is fixed over a monthly or annual period, and a commodity rate that 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