REPORT ON PLANT OUTAGES
IN THE STATE OF CALIFORNIA

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Contents

Page

Tables

Figures

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EXECUTIVE SUMMARY

On December 13, 2000, the Staff began an audit of generating plant outages in California focusing on whether unplanned maintenance or outages occurred to raise prices. Staff reviewed about 60 percent of the outages by conducting telephone calls to selected generators using a uniform questionnaire (telephone audits) and on-site inspections of three generator plant sites. Staff was accompanied by two utility engineers specializing in plant operations for the on-site inspections. During these inspections Staff physically inspected and evaluated planned and unplanned maintenance.

Staff also made site visits to the companies' headquarters offices in Houston, Texas. This allowed Staff to obtain: (1) a further understanding of the outages, (2) information of how these outages correlate to scheduling practices, maintenance and capital programs, and (3) an understanding of the relationship between the plant manager and individuals that makes daily marketing and commercial decisions.

The telephone audits and the on-site inspections disclosed that the outages occurred at generating plants that were 30 to 40 years old. These generating facilities were operated at a significantly higher rate in 2000 than in previous years. Most of the generating facilities were out-of-service because of tube leaks and casing problems, turbine seal leaks and turbine blade wear, valve failure, pump, and pump motor failures.

Staff did not discover any evidence suggesting that the audited companies were scheduling maintenance or incurring outages in an effort to influence prices. Rather, the companies appeared to have taken whatever steps were necessary to bring the generating facilities back on-line as soon as possible by accelerating maintenance and incurring additional expenses. Also, the outages did not necessarily correlate to the movement of prices on a given day.

The audit discussed in this report was not designed to determine whether the companies involved were withholding capacity from the market by refusing to bid or schedule the capacity, or by bids or prices at a level that would not be accepted by buyers.

I. Introduction

On December 13, 2000, Staff began to monitor generating plant outages in California on a daily basis using plant outage reports provided on a confidential basis by the California Independent System Operator (ISO). Staff developed a monitoring methodology and consulted with the ISO on that methodology, then:

- Made telephone calls to selected facilities using a uniform questionnaire, and

- Randomly selected three plants sites to visit in California.

Staff began its review with daily outage reports provided by the ISO on a confidential basis. Staff first reviewed all outages that involved planned maintenance and reviewed these outages with the ISO to assure that the ISO had accepted them as planned outages. Staff focused its review on thermal units with a nameplate capacity over 100 megawatts (MW), excluding facilities that could not operate due to NOx limitations, hydro facilities or those owned by municipalities. All plants with unscheduled or forced outages that met the criteria were called and questioned. The results of these calls are discussed in Part II below. Staff will continue to review the ISO outage reports. By means of the calls and the visits, the Staff was able to review approximately 60 percent of the major outages contained in the outage reports that were obtained from the ISO.

While the telephone audits were helpful in validating the reasons for the outages that are listed on the ISO's outage reports, Staff concluded that some field audits were required in order to gather detailed information on outages and test whether there was any pattern to the outages that were not justified by mechanical factors, or which might have reflected an effort to influence the price or output of wholesale electricity. Staff therefore selected three plants for visits in the greater Los Angeles area based on the size of the units that had been off-line in December and their geographic proximity. This resulted in the selection of two plants owned by Reliant Energy Company (Reliant), which were visited on December 18 and 19, 2000. On December 19, Staff also visited one plant owned by West Coast Power LLC (West Coast), a limited liability company owned equally by NRG, Energy Inc. (NRG) and Dynegy Inc. (Dynegy). Staff was able to review in detail the operating history of two other plants owned by Reliant and one other owned by West Coast. Both companies volunteered maintenance and operating plant information on all of their gas and oil-fired plants located in the Western Systems

Coordinating Council (WSCC) area. The three Staff members were accompanied by two utility engineers from Black and Veatch. [1]

It became clear from the site visits that a more detailed understanding of certain issues was required than could be obtained at the plant level. This included scheduling practices and criteria, the relationship between the plant manager and individuals making daily marketing and commercial decisions, maintenance and capital programs, and the relationship of regulatory practices to maintenance activities and to long-term plans for the use of the facilities. Staff therefore traveled to Houston, Texas, and visited Reliant's headquarters on January 3, 2001, and the morning of January 5, and Dynegy's headquarters on January 4 and the afternoon of January 5. [2] Both companies cooperated in making their senior level and mid-level corporate officials available, as well as providing requested information, subject to assurances that confidentiality would attach to certain particularly sensitive commercial and financial information. However, in no instance was access to data denied nor did the individuals involved decline to answer any questions by Staff. The results of these site visits are discussed in Parts III and IV below.

The instant audit occurred in the context of increasing shortages of wholesale supply in California in November and December after a period of relative stability in October. In October, the ISO issued no alerts stating that there were inadequate reserve margins within California. However, in November and December, the ISO began to issue alert notices of narrowing margins between supply and demand with increasing frequency. Figure 1 summarizes the notices for November and December, including the level of the alert (Stage 1, 2, or 3). In the same time frame, wholesale prices increased and in early to mid-December reached historically high levels for what would normally be an off-peak season in the California wholesale electric market. Figure 2 displays the megawatts attributable to forced, forced/planned, and planned outages during December, 2000. Figure 3 graphs the average daily unconstrained day ahead PX peak price for the same period against figure 2.[3] Figure 4 overlays figure 3 with total ISO actual daily load

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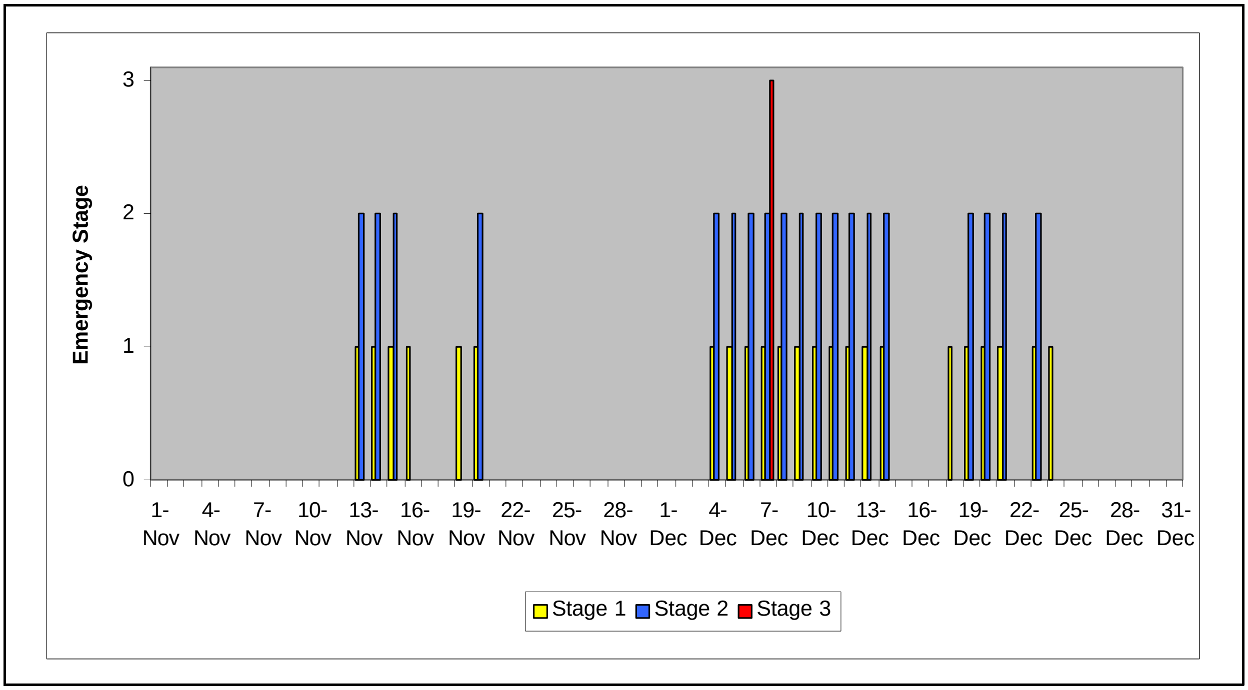
[1] The Staff members were Lyle Hanagami, Auditor; Brad Johnson, Auditor; and John Robinson, Attorney. John Manual, PE, and John Hickerson, PE were from Black and Veach.

[2] The engineers from Black and Veatch did not travel to Houston.

[3] A forced outage is one that is unplanned and requires a short term cessation of operations to correct a maintenance issue that may damage the unit or creates a situation that may preclude safe operations. A forced/planned outage occurs when a forced outage is severe enough that the unit cannot be brought back on-line quickly and managers must

in December 2000. Thus, the three figures permit a correlation of outages, prices, and demand in California at an aggregate level.

Figure 1. ISO Declared Staged Emergencies: Nov-Dec 2000



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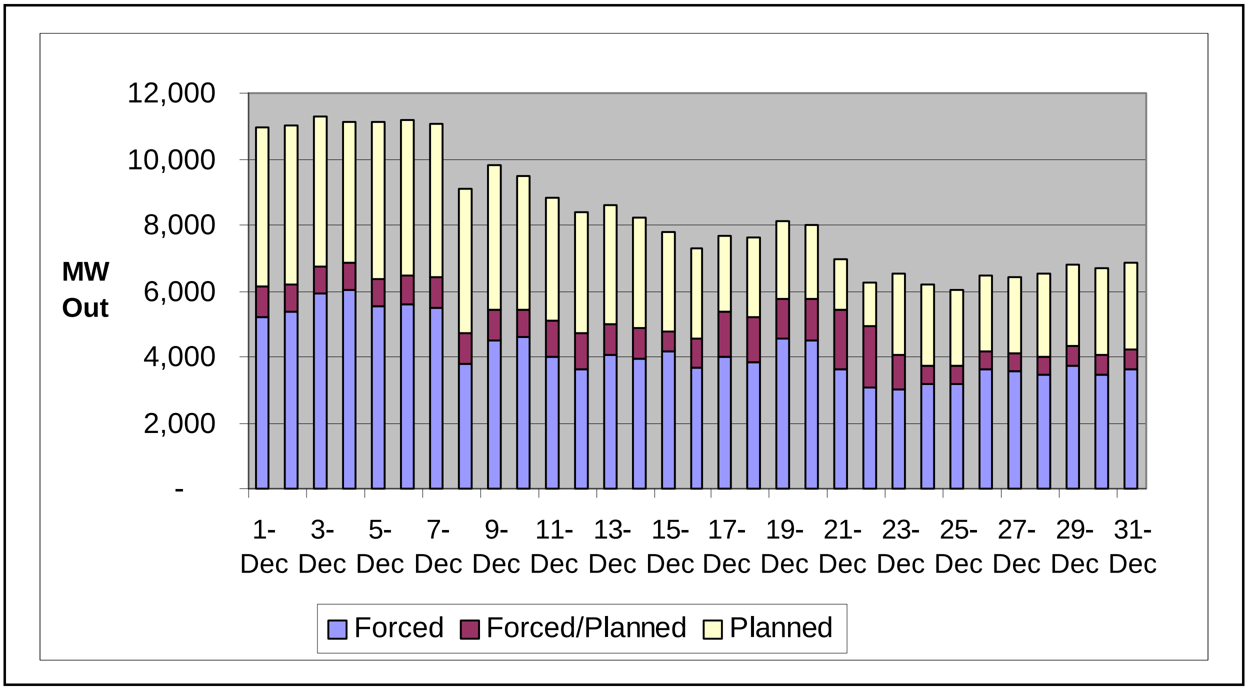
plan to take the unit down to make the necessary repairs. See the discussion of Units 3 and 4 at El Segundo, infra, for an example. Planned maintenance is scheduled in advance with before a forced outage occurs, usually with the concurrence of the ISO.

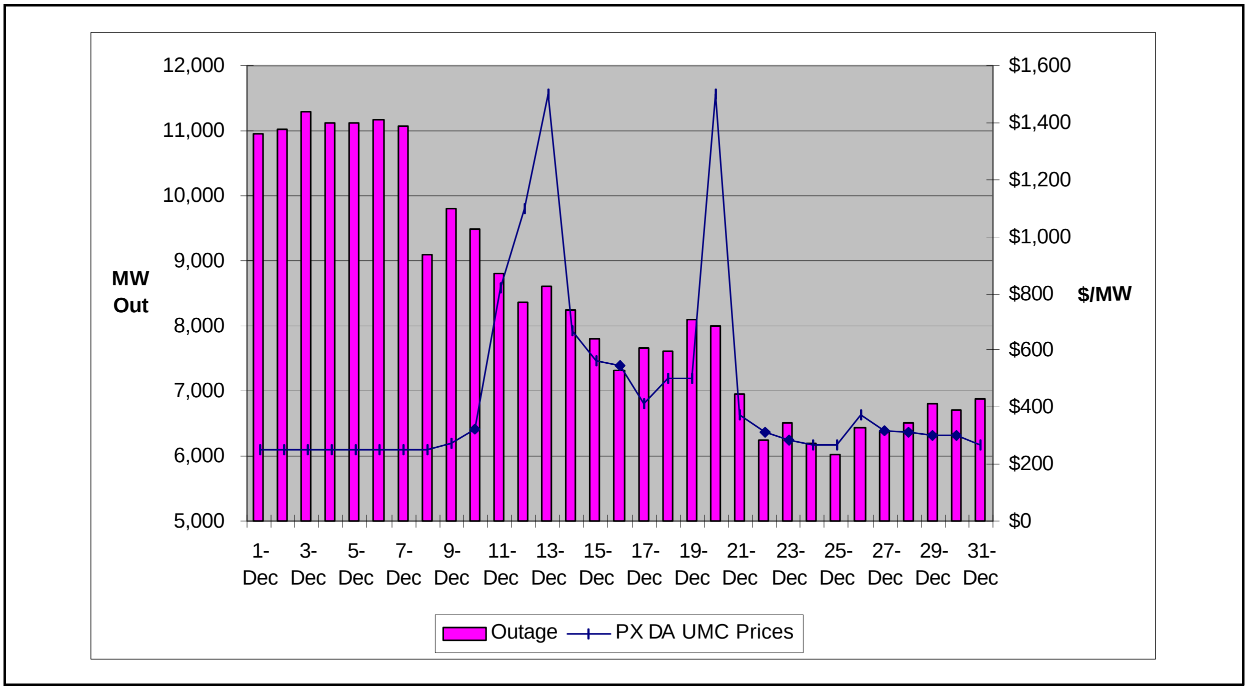
Figure 2 shows that after December 7, total outages declined until the last 6 days of the month, at which point they increased somewhat and then stabilized. Planned outages declined through the middle of the month and then rose slightly toward the end. The overall trend on forced outages was down with a slight increase at the end of the month. Force/planned outages were more erratic, increasing somewhat in the middle of the month and then decreasing at the end. The overall pattern appears to be a reduction in the number of forced and forced/planned outages over the course of the month, with a gradual increase in the number of planned outages at the end of the month.

Figure 2. Daily Plant Outages: December 2000



Turning to a comparison of the pattern of outages to wholesale electric price levels in California, figure 3 shows that the total outages were highest at the beginning of the month when prices were relatively stable. The outages, particularly planned outages, began to increase at the end of the month when prices were also relatively lower and stable. During a period of increasing, and then sharply higher prices between December 10 and 21, outages generally declined except for a small increase on December 19 and 20. Most significantly, the level of outages and prices did not always move in the same direction during the period of greatest price volatility. For example, on December 12, prices rose compared to December 11, but outages declined. Between the 17th and the 18th, prices were up and outages were down; between 18th and 19th prices were stable and outages were up, and between the 19th and the 20th prices rose dramatically, but outages dropped slightly. Both outages and prices declined on December 21. From December 21, prices were generally lower through the 25th; increased on the 26th, and were then somewhat lower and more stable through the end of the year. In this latter period of lower and stabler prices, outages were stable or increased somewhat.

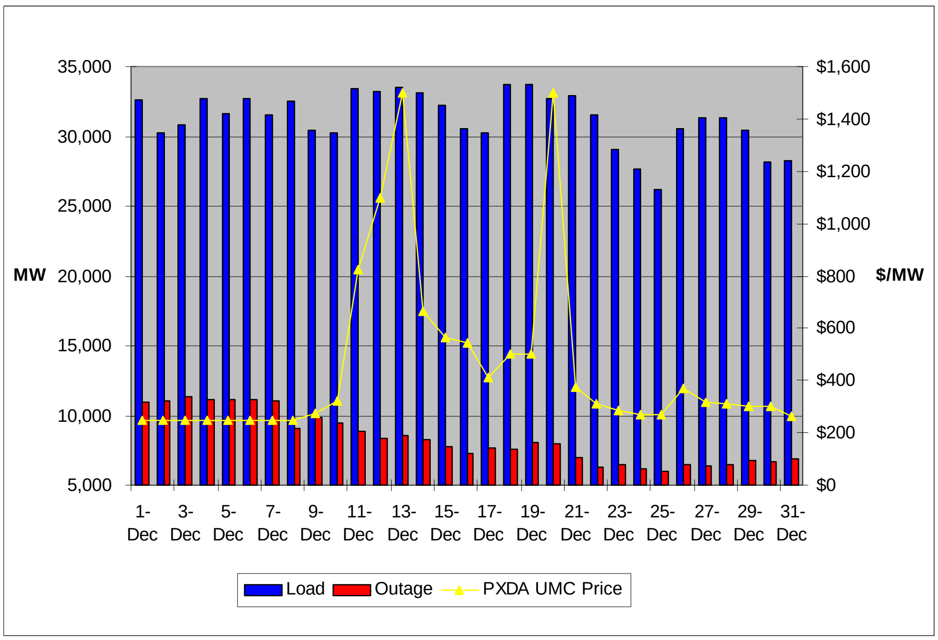
Figure 3. Daily Plant Outages and Cal PX Prices: December 2000



Of particular note, while prices moved sharply higher between the 9th and the 13th, outages moved generally downward in the same period, including forced outages. These were, as might be suspected, less consistent in their direction than planned outages, since the latter are to some degree subject to greater control by the plant operators in determining when the units should come on or off-line. However, the decline in all outages as prices increased is consistent with an expectation that periods of constrained demand and higher prices would encourage additional load to come forward, both because of a response to the ISO requirements and an opportunity to earn revenues that exceed the marginal cost of operating units that may have higher operating expenses or a greater risk of system failure. Thus, to the extent that maintenance of any type could be deferred, or more tightly controlled, to meet demand and increase revenues, this appears to have been what happened during December.

Figure 4 graphs the December outages against the PX day ahead unconstrained price and the actual daily ISO load for the same month. When figure 3 is compared to figure 4, price volatility appears to move much more consistently with increases and decreases in load than with outages, where as noted, the relation appears to be inverted.

Figure 4. Daily Plant Outages, Cal PX Prices, and Load: December 2000



II. The Telephone Audits

As noted, Staff discussed a number of outages listed in the ISO outage reports by means of a telephone audit. These included calls to West Coast (Dynegy) and Reliant that are subsumed under the separate analysis of those companies. Southern Energy California (Southern) operates 15 generating units located in California. During the audit period, many of those units were either shut down or operating at less than maximum capacity because of either scheduled maintenance or forced outage problems. The units included Contra Costa 6, Potrero Units 4, 5 and 6, and Pittsburg Units 1, 2, 3, 4 and 7. On December 13, 2000, staff spoke by telephone with Anne Cleary, Southern's President and Operations Manager, and Mark Gouveia, Southern's Director of Operations, concerning the status of Southern's generating units. On January 9, 2001, staff spoke with Gouveia, who updated the information Southern had given Staff in December. The information provided during these telephone conversations is as follows.

Since at least the summer of 2000, Southern has not taken any generating unit off-line as a forced outage unless it had concluded that running the unit posed an environmental or safety hazard. Most of Southern's California generating plants were constructed in the 1950s and 1960s with two in the early 70's and are suffering boiler and/or boiler tube problems. If a boiler tube leak becomes severe, it could damage the insulation in the boiler. The boiler insulation in a number of units contain asbestos. Although Southern told Staff that it is not sure if all of the boilers on its units have asbestos insulation, based on the construction practices during the time they were built, Southern treats a boiler as if it has asbestos insulation unless it definitively knows otherwise.

In order to keep its generating units in service during this time of high demand, Southern has run some of them at reduced capacity so as not to exacerbate the boiler tube leaks. If, in Southern's opinion, the leaks in a unit become severe enough to create an environmental or safety hazard, that unit is taken out of service until it can at least be temporarily repaired to operate safely. Southern told Staff that it is in Southern's economic interest during this time of high demand to keep units in service to sell power. The specific information that Southern gave Staff concerning its generating units that were either off-line or operating at less than full capacity during some of the audit period is as follows.

Contra Costa Unit 6 (339 MW) went off-line on November 29, 2000 for scheduled maintenance, under prior approval by the ISO, to meet 2002 NOx requirements. This unit was off-line during the entire audit period.

Southern's Pittsburg units, of which there are seven, and Potrero units, of which there are four operating, [4] have boiler problems due to age. As a result, some of the units were down in whole or in part during the audit period. In December, Potrero Units 4, 5 and 6 reached their maximum allowable operating unit limit for environmental emissions. However, Southern told Staff that the units were available for service had the ISO requested them. Southern told Staff that it had received a variance from the Bay Area Air Quality Management District to run the units if ordered by the ISO. Under the variance, the ISO could have directed the units to run between December 21 through 31, 2000 if the ISO declared a Stage 3 emergency and if they were the last resource

[4] Two of the units were retired by PG&E before the divestiture..

committed to satisfy San Francisco Operating Procedures to avert firm load shedding. Between January 1, 2001 and January 7, 2001, Southern ran Potrero Units 4, 5 and 6, but not more than 10 hours in all. However, during the initial interviews, Southern contended that Potrero Units 5 and 6 were available if the California ISO requested them, as Potrero Unit 4 would be after scheduled maintenance, which began on January 8, 2001, was completed.[5] In fact, after January 18, Units 5 and 6 began running 24 hours a day and on January 20 Unit 4 became available. On that date Unit 5 began a scheduled maintenance outage.

Four of Southern's Pittsburg units, units 1, 2, and 3 require major repair work to be done because of condenser tube leaks. Unit 4 first began its outage due to a boiler tube leak, and a chemical cleaning was scheduled at the same time. Throughout the entire audit period, Southern had Pittsburg Units 1 and 3 out of service. Southern took Pittsburg Unit 3 out-of-service on November 7, 2000 and Pittsburg Unit 1 out-of-service on November 10, 2000. Additionally, Pittsburg Unit 4 was out-of-service from November 16, 2000 through January 3, 2001 for condenser tube repair work. The repair work consists of acid cleaning the boilers, chopping out bad boiler tubes and retubing the condensers.

In general, throughout the audit period, Pittsburg Unit 2 has been operating approximately 13-18 MW short of its full capacity of 163 MW because of boiler tube leak concerns.[6] However, during the audit period, Pittsburg Unit 2 went completely off-line on several occasions, on December 11, 14-16 and 29, 2000 and January 2, 2001. Southern told us that these outages occurred when the unit tripped off-line because of an unknown electrical problem. Southern has placed additional monitoring equipment on the unit to hopefully locate the source of the problem if it happens again.

Pittsburg Unit 4 (154 MW) is currently available at full power. However, Pittsburg Unit 5 has been operating at 10-20 MW less than its maximum capacity (325 MW) during our entire audit period because of boiler tube leak concerns. For the same reason, during the audit period, Pittsburg Unit 7 has also consistently been running 18 MW short of its 700 MW capacity and has been effectively derated to 682 MW

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[5] The maintenance was scheduled to last two weeks.

[6] At the current time, Southern has pending with the Commission in Docket Nos. ER00-936-000 and ER00-937-000 an uncontested settlement with the ISO that would restate the operational capability of its Pittsburg units to more accurately reflect their current maximum dependable capacities as RMR units: 150 MW for Units 1 and 2, 154 MW for Unit 3, and 150 MW for Unit 4.

because of the condition of the unit. On January 8, 2001, Southern found evidence that boiler tube leaks in Pittsburg Unit 7 had become severe enough to cause a potential environmental and safety hazard and temporarily took the unit out-of-service to make a temporary fix. The unit returned to service on January 11, 2001. The CPUC had a representative on site monitoring the repair work.

III. The Reliant Energy Company Audit

A. The Plant Reviews

Staff visited two plants operated by Reliant, the Coolwater Plant in Daggett, California, and the Ormond Beach plant in Oxnard, California. The plant manager for the Coolwater Plant was also the plant manager for Reliant's Etiwanda plant and the plant manager for Ormond Beach was also the plant manager for Reliant's Mandalay plant. Therefore, Staff was able to discuss maintenance issues related to four of Reliant's plants. Staff met with Danny Ross, Manager of the Coolwater and Etiwanda plants on December 18, 2000, and Tom Snowdon, Manager of the Ormond Beach and Mandalay plants on December 19, 2000. Table 1 contains a list of all plants owned by Reliant serving the western and California markets, together with their unit type, net summer capacity, commercial operating date, and age. None of these plants was in a "reliable must run" (RMR) status with the ISO during calender year 2000.

Table 1. Power Plants Owned by Reliant Energy Company in the Southwest U.S.

Facility	Unit	Type	Net Summer Capacity (MW)	Commercial Operating Date	Age	Location
Ormond Beach	Unit 1	Thermal	750	1971	30	California
	Unit 2	Thermal	750	1973	28	
			1,500			
Etiwanda	Unit 1	Thermal	132	1953	48	California
	Unit 2	Thermal	132	1953	48	
	Unit 3	Thermal	320	1963	38	
	Unit 4	Thermal	320	1963	38	
	Unit 5	GT	126	1969	32	
			1,030			
Coolwater	Unit 1	Thermal	65	1961	40	California
	Unit 2	Thermal	81	1964	37	
	Unit 3	GT CC	241	1978	23	
	Unit 4	GT CC	241	1978	23	
			628			
Mandalay	Unit 1	Thermal	215	1959	42	California
	Unit 2	Thermal	215	1959	42	
	Unit 3	GT	130	1971	30	
			560			
Ellwood	Unit 1	GT	48	1974	27	California
El Dorado	Unit 1	GT CC	123	2000	1	Nevada
	Unit 2	GT CC	123	2000	1	
			246 *			
TOTAL MW			4,012			

* Represents Reliant's 50 percent share of a jointly-owned project.
GT - Gas Turbine
CC - Combined Cycle

1. Coolwater

Reliant's Coolwater Plant consists of four units. Units 1 and 2 each have one gas-fired boiler providing steam to a single turbine and generator. The two units have certain common facilities and are rated at 65 and 81 megawatts respectively. Units 3 and 4 consist of two gas-fired combustion turbines and one steam turbine, with the boiler for the steam turbine fired by the exhaust from the two gas turbines. The two combustion turbines can be operated together or if decoupled from the steam turbine, as independent units. The steam turbine is dependent on having at least one combustion turbine in operation. Each turbine is attached to a generator that has its own exciter and related elements. Both are rated at 241 megawatts Unit 1 was completed in 1961, Unit 2 in 1964, and Units 3 and 4 in 1978. Other details are listed in Table 1.

Because Coolwater is a relatively old facility, it was used with decreasing frequency by Southern California Edison (SCE) before it was sold to Reliant in April 1998. Figure 5 reflects the net output for the plant from 1996 through November 2000. These figures state the actual output of the plant available for distribution over the grid after consumption of power needed for plant operations. Figure 6 reflects the capacity factor for the various units, i.e., the percent of actual output for each unit measured against its total nominal capacity. Figure 7 displays the net output for each unit by month in 2000, the year of most intense usage. Figure 8 displays the performance for each unit by various service states, including when the unit was available to meet demand, was in reserve, or on forced or scheduled maintenance, measured against the total possible operating hours in a year.[7] Figure 9 displays the equivalent availability factor of each unit by month in 2000, i.e., the ratio of energy that the unit was actually available to provide measured against its total nominal capacity. If the unit is out for maintenance or has been derated, then the capacity actually available to meet demand is reduced below the unit's nominal capacity.

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[7] These include: on-line (the ability to meet all calls made on the unit); available (use of some of the unit capacity as a reserve to meet existing firm generating obligations); maintenance and planned outages; forced outage (when the unit is taken offline during operations due to unanticipated maintenance problems); and derated (when the unit's output is reduced, usually because mechanical limitations of different types require its output to be reduced).

Figure 5. Coolwater Net Generation: 1996-Nov 2000

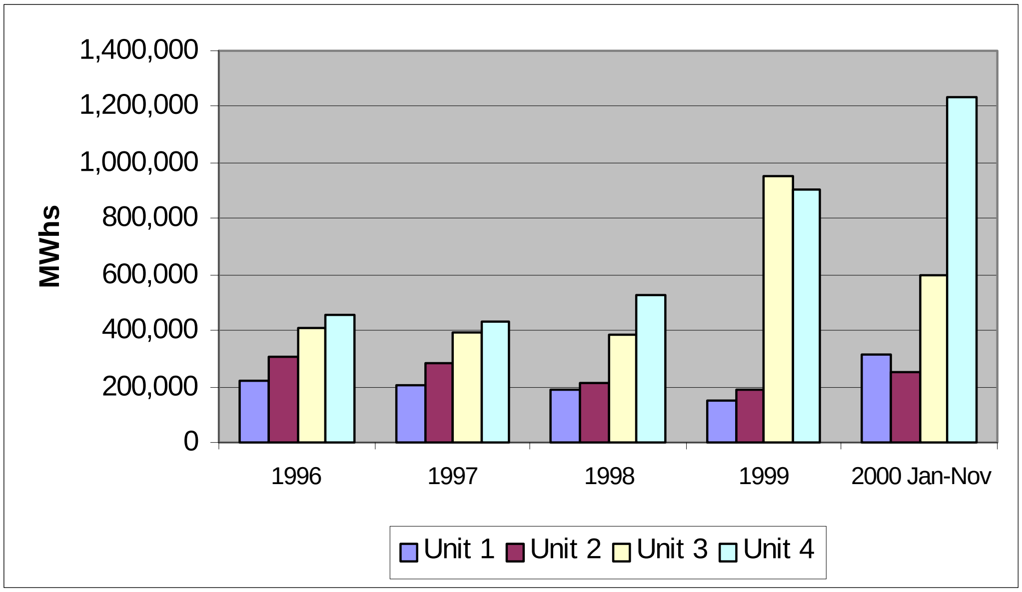


Figure 6. Coolwater Capacity Factors: 1996-Oct 2000

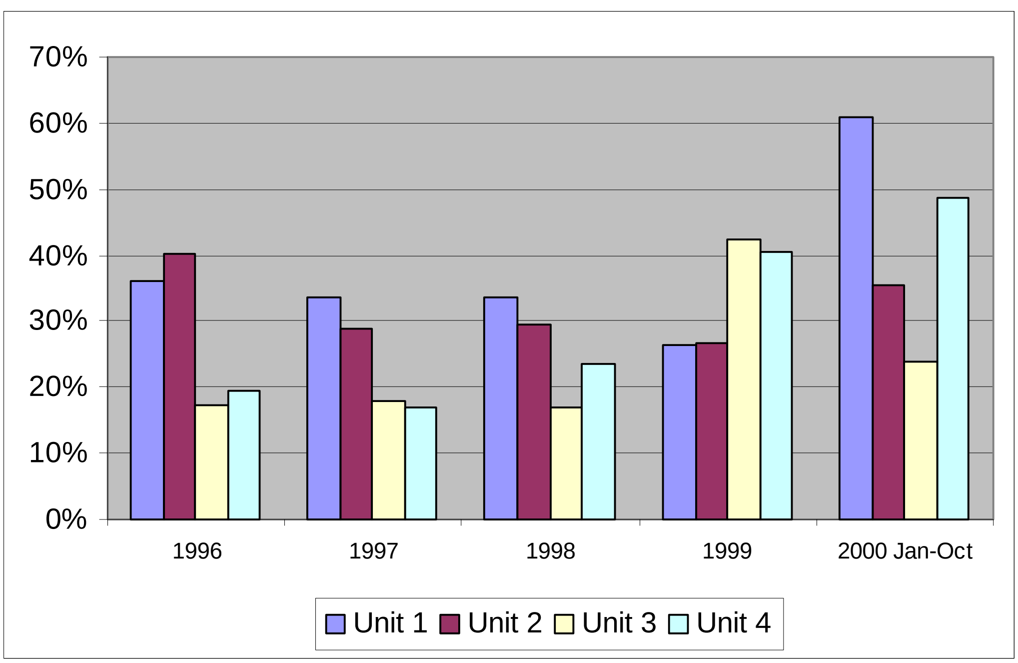


Figure 7. Coolwater Monthly Net Generation: Jan-Nov 2000

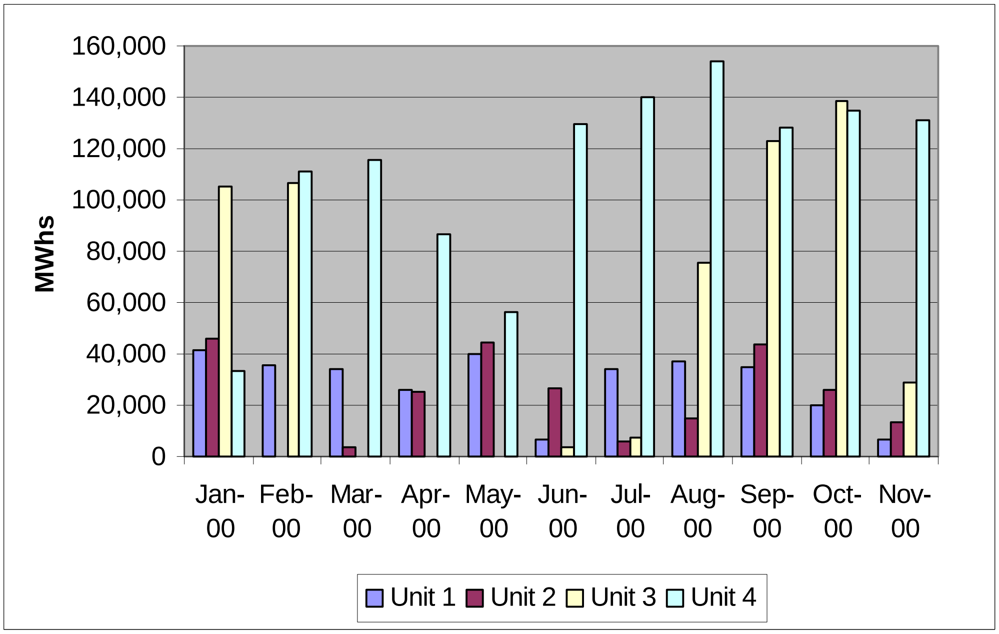


Figure 8. Coolwater Unit Performance: Jan-Nov 2000

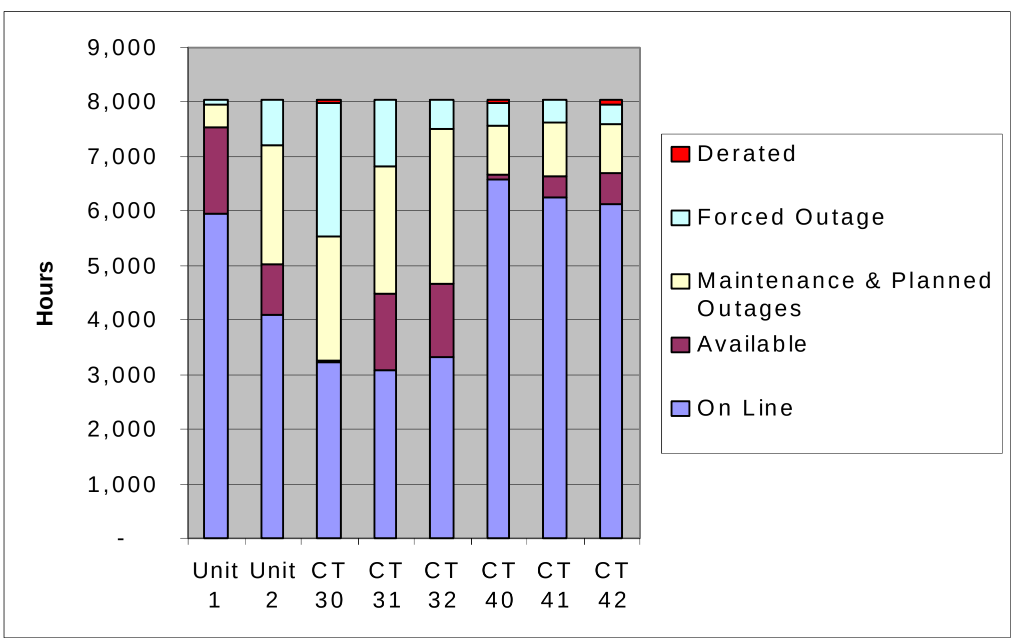
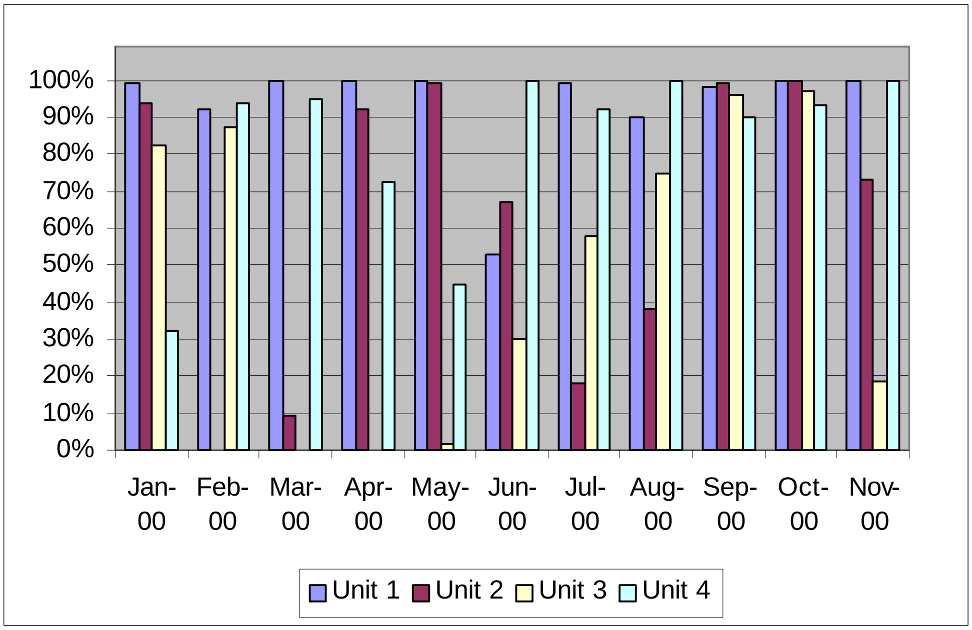


Figure 9. Coolwater Equivalent Availability Factors: Jan-Nov 2000



After relatively low usage in 1998, utilization increased substantially in the years 1999 and 2000 except for Unit 3, which suffered a major forced outage beginning in late May, as shown in figures 5 and 6. Output for the plant as a whole was high from June through November, as shown by figure 7. Figure 8 shows that Unit 4 (turbines 40, 41, and 42) performed particularly well, producing power or being available over 75 percent of the time, and Unit 3 performed less well, being on-line or available only 50 percent of the total annual hours the unit might have been in service. This is consistent with the history of this unit, as is discussed below. Figure 8 also shows that Units 1 and 2 had a high level of use and were available. Figure 9, the monthly availability factors, shows that, with the exception of Unit 3 and a four-week outage by Unit 1 and parts of Unit 4, maintenance was performed before the peak season began in June. Major maintenance expenditures at Coolwater have increased with demand: 1998, $1.0 million (a partial year); 1999, $1.2 million; and in 2000, $23.1 million to date. [8]

Representative maintenance items included: general maintenance and overhaul items on the steam turbines included; oil leaks on the front turbine standards, piping repairs, seals replacement, diaphragm rotor bore inspections, critical pipe inspections on the boiler steam piping, rotor analysis, complete inspection with repairs to the generators

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[8] Source: Summary of major maintenance expenditures provided by Reliant.

and exciters for the steam turbine 30 and combustion turbines 31 and 32, and historical alignment problems on steam turbine generator 30.

Mr. Ross provided a summary of the maintenance procedures at the Coolwater Plant and the relationship of these procedures to the scheduling and dispatching of the plant. Mr. Ross stated that he was the only Reliant employee at the Coolwater and Etiwanda sites. When Reliant Energy purchased Coolwater and Etiwanda from SCE in April 1998, Assembly Bill 1890 (AB 1890) required Reliant to utilize SCE employees to operate and maintain the plant for two years. The two-year Operations and Maintenance (O&M) contract between Reliant and SCE ended in April 2000, and was replaced with a new three-year agreement with stricter performance standards and incentives that could not be imposed with the two year AB 1890 mandatory operating contract. However, Reliant subsequently served notice in November 2000 that it was terminating the agreement, and effective April 1, 2001, Reliant will assume responsibility for all O&M at all plants it purchased from SCE.

Reliant uses the Conditioned Based Maintenance concept which analyzes problems and determines the "root cause" of the outage problem. Reliant then designs a maintenance plan for the outage to fix the "root cause," and get the unit back running. Reliant performs maintenance on a 24-hour day, 7 days a week (24/7) schedule. Previously, SCE performed most of the maintenance on an 8-hour day, 5 days a week (8/5) schedule, which was dictated by the use of the units. As the plant manager, Mr. Ross has the authority to take a unit off line for maintenance. Mr. Ross does not need any supervisory approval. His first job priority is to protect the assets and to keep the units available, up to the environmental limitations. Scheduled maintenance is coordinated with the California ISO. However, the ISO, Reliant scheduling coordinators, and plant managers are in daily contact with each other to discuss the plant's operating status. A more detailed discussion of the linkage between commercial and operating issues is included in the review of Staff's headquarters visit.

Related capital expenditures for the plant included: Installing on Units 1 and 2 automatic generation controls to be used in dispatching to the California ISO, rebuilding the forced draft fan on Unit 2 (which took four weeks), overhauling Unit 3's steam turbine, installing heat recovery stream generator (HRSG) upgrades to units 31 and 32 to replace the duct burners, installing a new combustion burner on turbine 31, clamshells, repairing the vanes on turbine transition rows 1 and 2, repair of turbine rows 3 and 4, and the compressor rotor blades. Reliant is now installing pneumatic controls on Unit 1, and in Spring 2001, it will perform a critical pipe inspection on Unit 1. Units 1 and 2 were induced flue gas recirculation (IFGR) fitted for NOx in 1998. Units 1 and 2 must have induced flue gas recirculation (IFGR) for NOx controls to operate at their current capacity, and Reliant has began a study to reduce the NOx at Coolwater to strengthen the output on this plant.

The capital expenditures are based on five-year O&M plan and a 25-year capital plan. Mr. Ross is responsible for adjusting the five and 25-year plans to operate the facility and to try to get ahead of maintenance. The five and 25-year plans are updated yearly in various detail, depending on the year and the maintenance to be performed on the units. Mr. Ross stressed the economic life of the unit is the measuring stick he uses for the viability of the asset to be fixed or replaced. Units 1 and 2 have been placed on the 25-year maintenance program because as long as economic life continues on the unit, Reliant keeps pushing out the economic life of the unit, even though the plants are 40 years old.

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Mr. Ross stated that Coolwater experienced an enormous amount of unexpected problems in year 2000, which is reflected in figure 9. He attributed the cause of these unexpected problems to SCE's delayed maintenance on the plant prior to its sale, and stated that Reliant is now paying for this catch-up maintenance. Mr. Ross also believed that SCE maintained the plant adequately for the amount of use the equipment experienced. More importantly, compared to 2000, the summer of 1999 was mild, so the units were not run as hard that year, and did not have the physical wear and tear as in 2000.

Because of the large number of outages at Coolwater in 2000, Staff reviewed other sources, including confidential internal engineering documents, and made a follow up call to Mr. Ross on January 16, 2001. The most significant problems were with Coolwater Unit No. 3, which had a major forced outage in late May of 2000. In late January 2000, Reliant scheduled maintenance for a complete inspection of Units 30, 31 and 32, the three turbines included in Unit 3. This outage had been planned with the concurrence of the ISO. The work began in late January and February with pretesting on the weekends which lasted 14 weeks. The maintenance included inspection of seals, oil leaks, critical pipes, and addressing historical alignment problems with the generator experienced by both SCE and Reliant. The work also included repairs to the blades, bearings and shells. An additional delay occurred during the scheduled outage when the rotor lift straps failed and the rotor was dropped on the ISO phase bus and duct. Although the rotor was not damaged, it had to be shipped back to the maintenance contractor for inspection. When Unit 3 was started up on May 26, 2000, the exciter on number 30 turbine failed because of a mechanical failure of the exciter.

The exciter had to be sent out for a total rebuild since it may have been causing some of the historical problems with the number 30 turbine. Since a rebuilt exciter would not be available until late September 2000, Reliant attempted to locate a replacement exciter, but was unable to locate a replacement because it needed the related collector ring and assembly. As an alternative strategy, Reliant worked with GE to design a temporary replacement static exciter for this Siemens Westinghouse unit. Reliant purchased, and did extensive modifications to retrofit this static exciter, including decoupling the two gas generators. Reliant initially expected to get the unit back on-line around July 5, 2000, but it took an additional four weeks to work through some design issues, and additional problems related to the configuration of the three turbines.

Reliant was eventually able to run combustion turbines 31 and 32 without steam by decoupling them from the steam unit. This required extensive modifications and in early August 2000, was able to get turbines 31 and 32 running, even though this was never done before to these units. This modification enabled Reliant to generate an additional 140 MW of power for seven additional weeks before the rebuilt exciter became available in late September. Turbine 30 is still running with the GE exciter. Additional problems were experienced with turbines 31 and 32 in late October and November due to additional damage that was caused to both units by the exciter failure. These turbines were again decoupled from turbine 30, and then recoupled after the repairs were made. Turbine 32 went back on-line on December 12, 2000, and turbine 31 came back into service on December 18, 2000. With the inclusion of turbines 30, 31, and 32, Unit 3 was scheduled to be completely back on-line by December 18, 2000. Reliant met the schedule.

Staff was advised that Coolwater has had a traditional alignment problem with the plant equipment. Reliant's review indicated that the problems with the alignments were traced to a faulty alignment wrench that came with the facility during the period of SCE's contract maintenance. The failure of SCE to detect the alignment problem and to perform a timely root cause analysis were among the reasons for the pending termination of the SCE contract and the move to greater control and operation of the facility by Reliant employees.

The principal maintenance efforts on the other units are as follows: Unit 1 was down in June and part of August for the installation of automatic generator controls designed to improve dispatching to the ISO. Unit 2 was down in February and March for scheduled maintenance involving a turbine overhaul. During this work, Reliant discovered problems with the unit's generator that extended the work through March. In June and July Unit 2 suffered a catastrophic fan failure which forced the unit down for 4 weeks. Unit 3 was discussed above. Unit 4 had a number of forced outages that derated this peaking unit. These included a gas-line break and burner outage on turbine 42 in July and also a problem with rubbing between the turbine and the generator which required the insertion of a spacer bar for part of April and approximately one half of May.

The capacity of Coolwater is directly impacted by environmental factors. During Staff's visit on December 18, 2000, Unit 2 was down since Reliant was replacing steam seals. This work was actually scheduled for 2001, but because of environmental restrictions, Units 1 and 2 cannot exceed 59 percent Capacity Factor in any given year. If they do exceed the 59 percent capacity factor, the units will be derated. When Unit 1 reached the 59 percent capacity factor cap, Reliant informed the ISO and Unit 1 was required to come off-line. However, on December 12, 2000, Reliant requested that the Mojave Air District grant a waiver of the Unit 1 and 2 site limit that permitted the two units to be averaged together to determine if the 59 percent capacity factor had been exceeded. This permitted Unit 1 to stay on-line and the ISO permitted Unit 2 to come down for annual maintenance. Thus, at the time of the site visit, Unit 1 was running on the Capacity Factor waiver and Unit 2 was down for scheduled maintenance. Unit 2 was expected to be and came back on-line December 21, 2000.

2. Etiwanda

Staff did not visit Reliant's Etiwanda plant near San Bernardino California. But since the plant is also managed by Mr. Ross, Staff was able to discuss its operations during the interview with Mr. Ross at the Coolwater plant. The plant has five units. Units 1 and 2 are identical steam units with a single generator each. Units 3 and 4 are also identical steam units with a single generator each. Unit 5 is a peaking unit consisting of 8 Pratt and Whitney aircraft engines and four turbines. Units 1 and 2 were completed in 1953 and have a rating of 132 megawatts. Units 3 and 4 were completed in 1963 and have a rating of 320 megawatts. Unit 5 was completed in 1969 and has a rating of 126 megawatts.

Figure 10 reflects the net output for the plant from 1996 through November 2000. These figures state the actual output of the plant available for distribution over the grid after consumption of power needed for plant operations. Figure 11 reflects the capacity factor for the various units, i.e., the percent of actual output for each unit measured against its total nominal capacity. Figure 12 displays the net output for each unit by month in 2000, the year of most intense usage. Figure 13 displays the performance for each unit by various service states, including when the unit was available to meet demand, was in reserve, or on forced or scheduled maintenance, measured against the total possible operating hours in a year. Figure 14 displays the equivalent availability factor of each unit by month in 2000, i.e., the ratio of energy that the unit was actually available to provide measured against its total nominal capacity. If the unit is out for maintenance or has been derated, then the capacity actually available to meet demand is reduced below the unit's nominal capacity. The fuel for all five units is natural gas.

Figure 10. Etiwanda Net Generation: 1996-Nov 2000

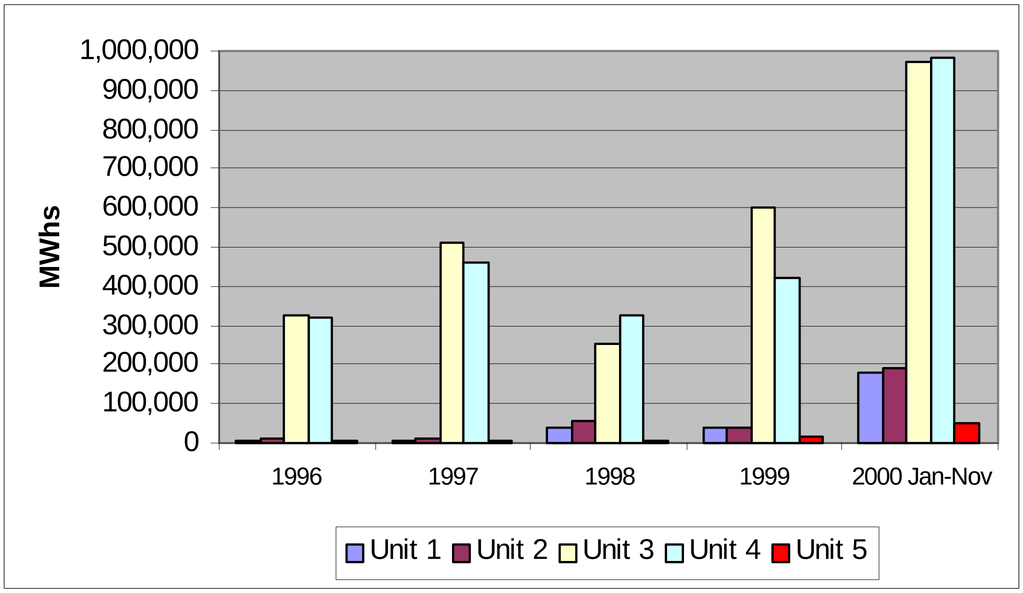


Figure 11. Etiwanda Capacity Factors: 1996-Oct 2000

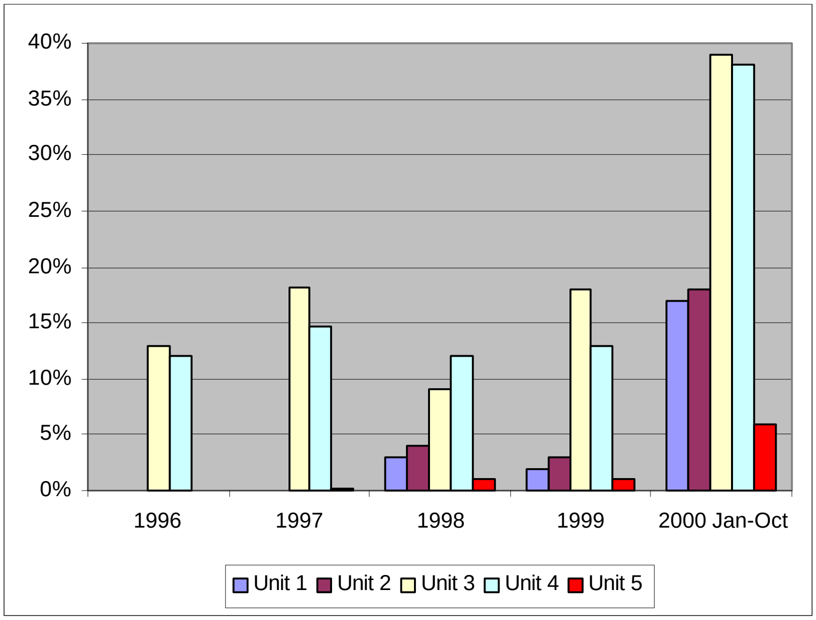


Figure 12. Etiwanda Monthly Net Generation: Jan-Nov 2000

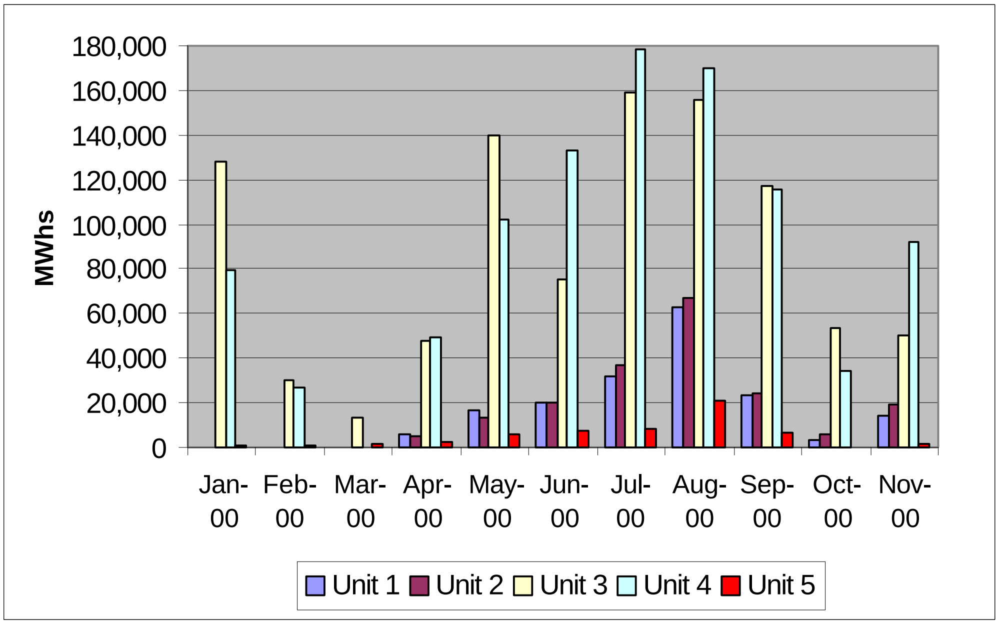


Figure 13. Etiwanda Unit Performance: Jan-Nov 2000

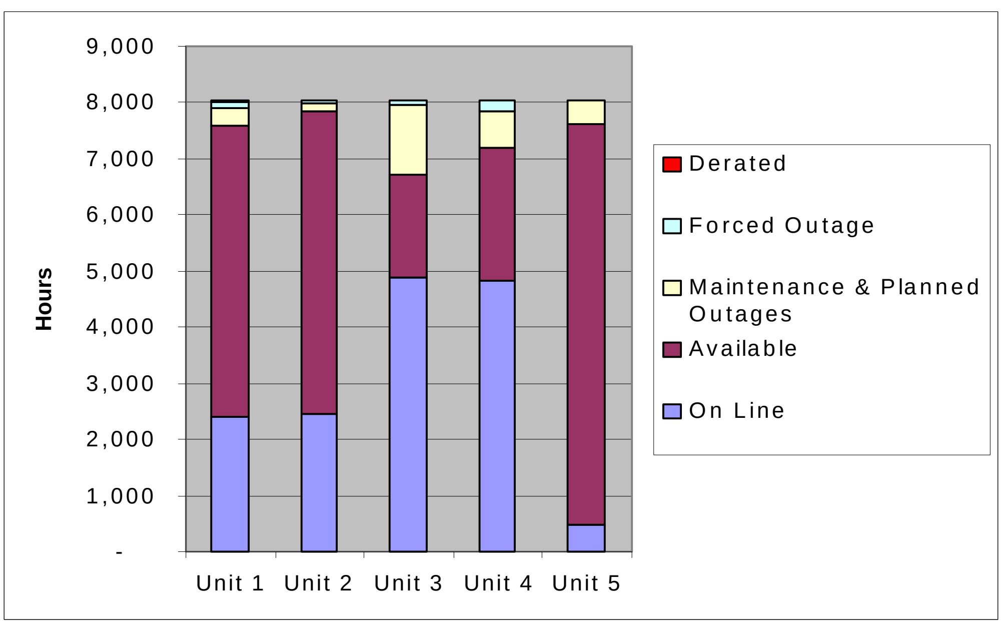
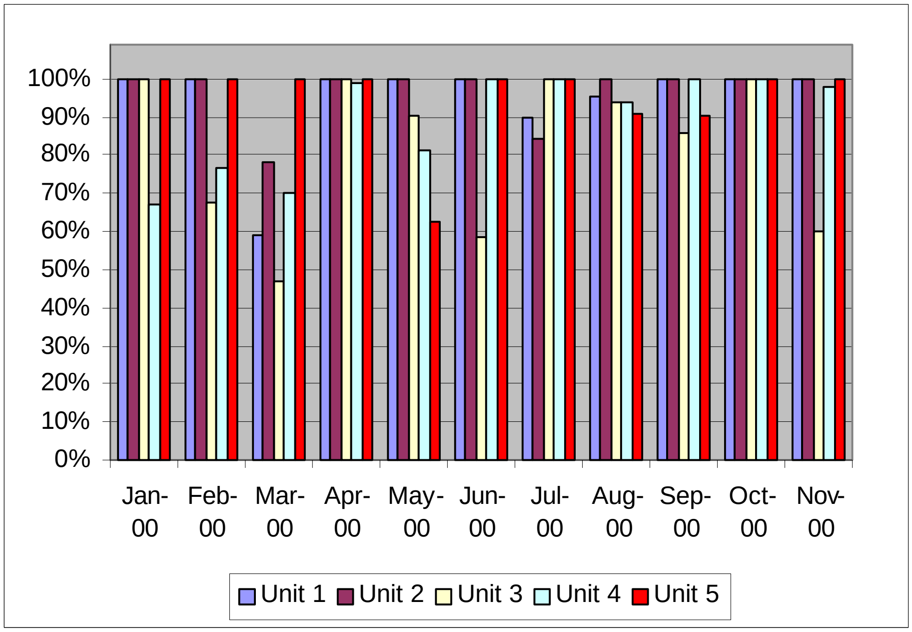


Figure 14. Etiwanda Equivalent Availability Factors: Jan-Nov 2000



Mr. Ross stated reliability at Etiwanda has been good, although the plant has had some minor forced outages, modest maintenance, and planned outages. Repairs are also being made to the cooling tower for Units 1 and 2, with the work to be completed by 2001. Mr. Ross stated that this was the only major thing done to Units 1 and 2. The major maintenance expenditures since Reliant took title to Etiwanda were $.5 million in 1998, $2.2 million in 1999 and $2.5 million in 2000.

Mr. Ross's assertions on the overall operating pattern and reliability of the Etiwanda plant are supported by the operating data shown in figures 10 through 11. Figures 10 and 11 show a sharp increase in the output in 2000 by all units compared to 1999. Figure 12 shows that there was substantial output in the peak months, and figure 13 shows that all the units were on-line or available some 87.5 percent of the year. Figure 14 shows that except for Unit 5, availability was close to 90 percent from June to November 2000. The maintenance problems with Unit 3 are discussed below.

On a unit basis, Unit 1 has tube leaks that forced the unit off-line twice, once in March and for a short period in July. Unit 2 had a problem with air pre-heater gear in March, as well as a short outage in July. Unit 3 was out-of-service for much of February and March for scheduled maintenance for boiler work and to repair a casing design flaw which resulted in breaches to the boiler. The maintenance was with ISO approval. This involved very extensive work and has been capitalized as a rebuild. Unit 3 also had other boiler casing and tube leaks in May and June, as well as November and portions of December, when there was a failure in the vestibule. After the last outage in November, Unit 3 came back on-line on December 15, 2000, and has performed adequately since. Unit 4 suffered deratings due to a turbine control valve problem beginning in May. This will be repaired during scheduled maintenance in January 2001.

Unit 4 suffers from the same boiler design flaw as Unit 3, and was down for maintenance for that problem during March and April. Unit 5 had two combustion engines fail in May resulting in a large derating of the unit. The engines were sent out for repair and one was replaced on a temporary basis by the use of a spare engine.

Units 1 and 2 present a graphic example of the impact of high demand on planned expenditures. Reliant stated that these 2 units were to be retired in 2000. However, the change in market conditions extended their useful economic life, and extensive repairs were made to their cooling towers to ensure reliability. Reliant also plans major improvements to Units 3 and 4 to increase their availability, including further work on the turbines and the installation of selective catalytic reductions (SCR's) to reduce NOx.

3. Ormond Beach

Reliant's Ormond Beach plant is located in Oxnard, California. It contains two gas- fired boilers, each with two turbines, one of which is a reheat turbine. Unit 1 was completed in 1971 and Unit 2 in 1973. Both are rated at 750 megawatts. Major maintenance figures for Ormond Beach were $5.9 million in 1999 and $11 million in 2000.

Figure 15 reflects the net output for the plant from 1996 through November 2000. This figures states the actual output of the plant available for distribution over the grid after consumption of power needed for plant operations. Figure 16 reflects the capacity factor for the various units, i.e., the percent of actual output for each unit measured against its total nominal capacity. Figure 17 displays the net output for each unit by month in 2000, the year of most intense usage. Figure 18 displays the performance for each unit by various service states, including when the unit was available to meet demand, was in reserve, or on forced or scheduled maintenance, measured against the total possible operating hours in a year. Figure 19 displays the equivalent availability factor of each unit by month in 2000, i.e., the ratio of energy that the unit was actually available to provide measured against its total nominal capacity. If the unit is out for maintenance or has been derated, then the actual capacity available to meet demand is reduced below the Unit's nominal capacity. The fuel is natural gas.

Figure 15. Ormond Beach Net Generation: 1996-Nov 2000

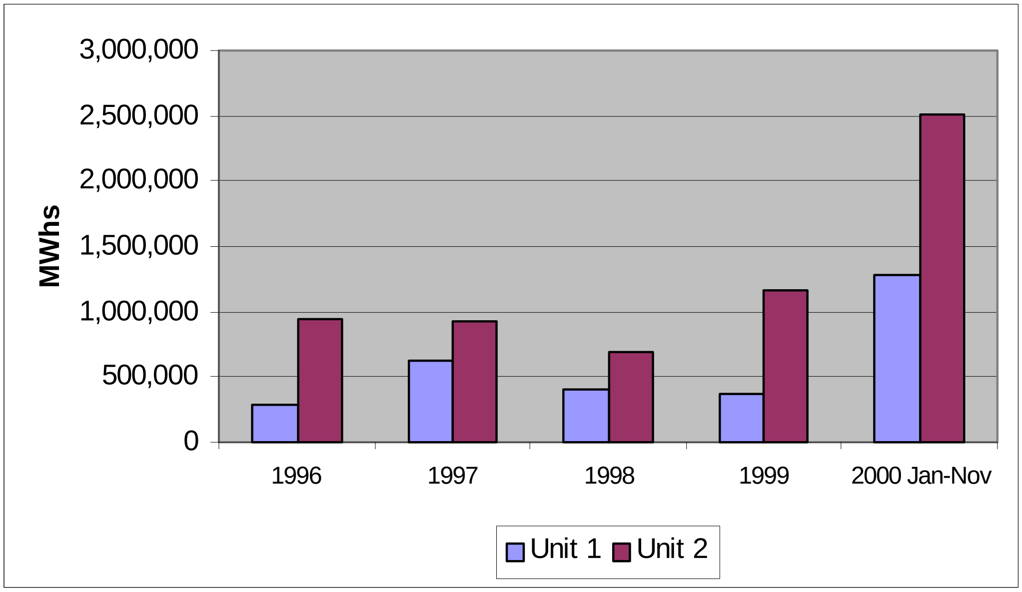


Figure 16. Ormond Beach Capacity Factors: 1996-Oct 2000

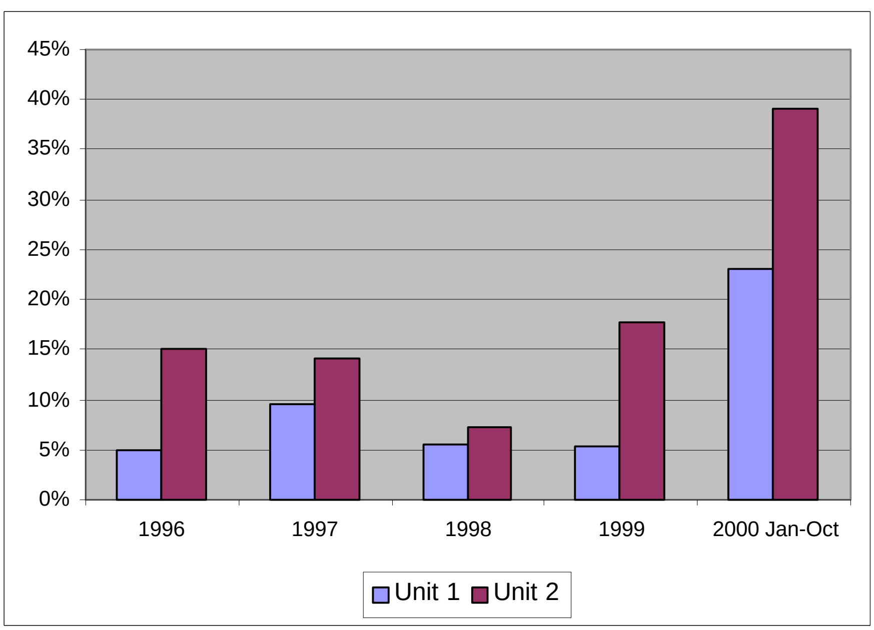


Figure 17. Ormond Beach Monthly Net Generation: Jan-Nov 2000

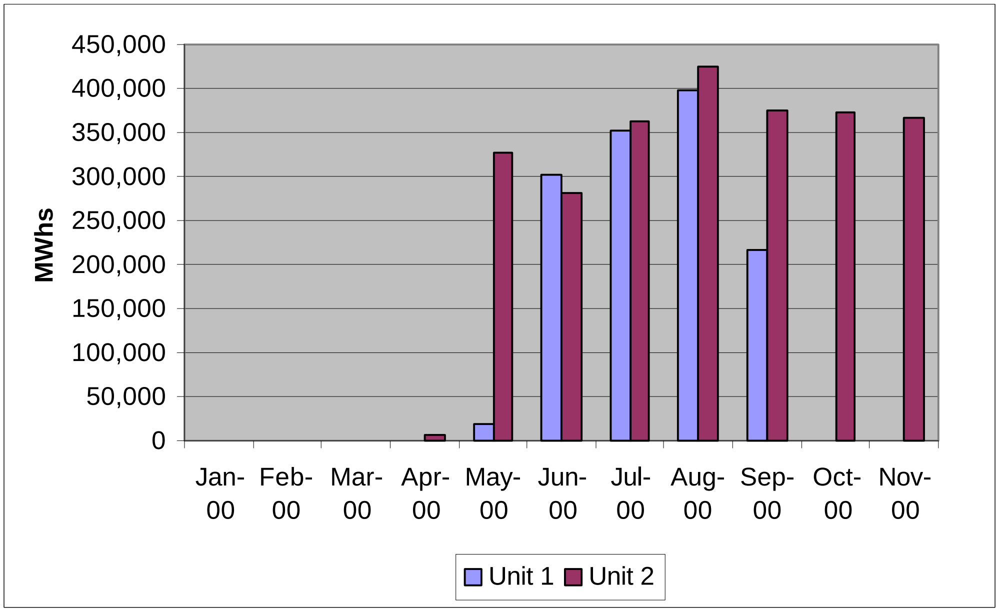


Figure 18. Ormond Beach Unit Performance: Jan-Nov 2000

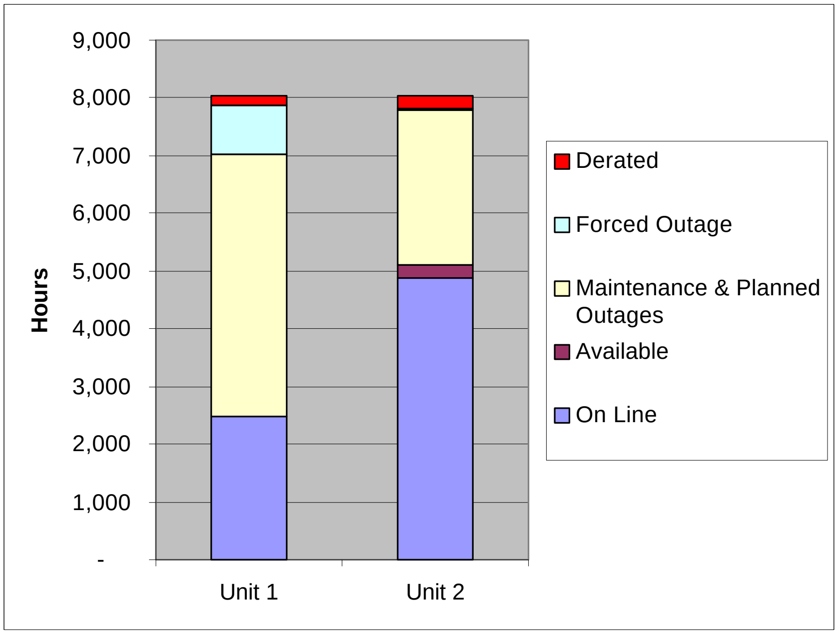
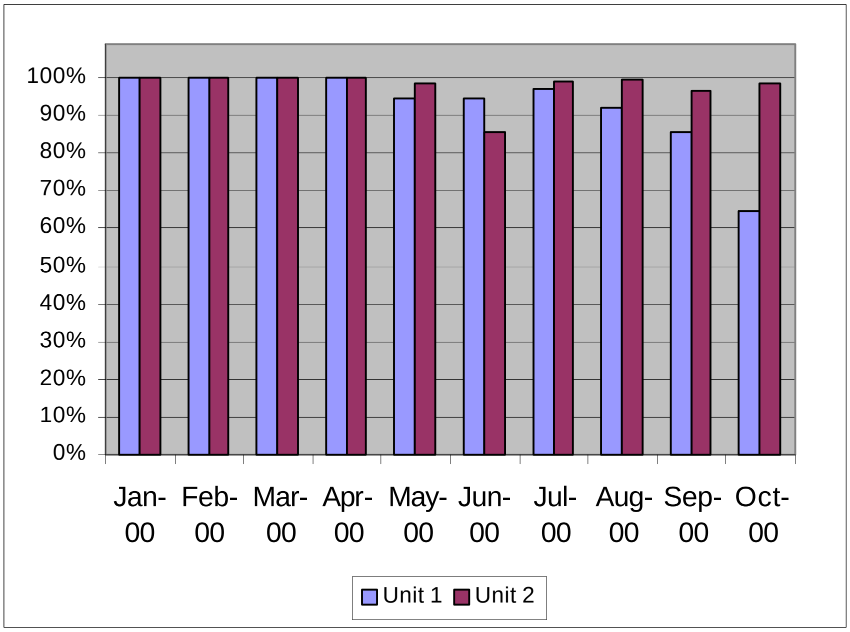


Figure 19. Ormond Beach Equivalent Availability Factors: Jan-Oct 2000



The Staff interviewed Mr. Tom Snowdon, plant manager, who is also the plant manager for Reliant's Mandalay Plant. As shown by figure 15, Ormond Beach has had a relatively low usage rate in recent years. This is in part because its large units are not particularly well suited for a load following function, even after improvements by SCE to Unit 2 to permit it to operate at a lower minimum load than Unit 1. SCE mothballed all of Ormond Beach during the winter months (November to May) and Reliant followed a similar plan during 1998/99 after acquiring the plant. However, figures 15 and 16 confirm that Reliant dramatically increased net generation and capacity in 2000 after it became apparent that demand would be higher for the entire year. Figure 17 reflects the seasonal nature of operation and in particular the amount of maintenance performed on Unit 1 at the beginning and end of the year. Figure 19 shows that despite the failure of Unit 1 in September, Reliant managed to keep the Unit on-line in service during the summer peak season. [9]

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[9] Figure 19 appears somewhat inconsistent with figure 18 because it shows Ormond Beach Units 1 and 2 having a high availability from January through May. This is because a unit that is mothballed but could be called on-line is considered available. During the same January to May period, the Units were also under maintenance, as reflected in the large amount of maintenance time shown by figure 18. The two figures are more consistent for the period after May when Ormond Beach came on-line, and then

During Staff's visit, Unit 1 was off-line for scheduled maintenance but is scheduled to return to service on January 28, 2001. This maintenance was planned for the Fall 2001, but during a spring 2000 inspection, Reliant found a serious problem with the generator. General Electric (GE) recommended at that time that the unit be taken down during the summer (mid-May through September) for a major overhaul to correct the generator problem. Normally, generators of the type at Ormond Beach should be inspected every 6-8 years, but it was 10 years since the last inspection. Mr. Snowdon commented that they could have performed the overhaul in the spring/summer 2000 based upon GE's recommendation, but Reliant did not take GE's recommendation and ran the plant during the summer 2000. This decision was made by consulting with senior management in Houston, the General Manager of Commercial Plant Operations, Matt Greek, and the Senior Vice President, John Stout, because the prospective need for the unit had become apparent, and the potential revenue gain exceeded the incremental risk of loss that would occur if the Unit 1 was kept on-line.

Unit 1 did make it through the summer 2000 and certain maintenance was deferred. However, Unit 1 was forced out on September 28, 2000, because the gas recirculating fan discharge expansion joint degraded to the point it could no longer keep gas in the boiler. This in turn began to melt the wires in the vestibule of the unit. Mr. Snowdon said Unit 1 was limited to 650 MW and repairing the damaged wiring created a 10-day outage. Unit 1 output was also declining, so Reliant decided to bring the unit down for repairs to fix major holes causing loss of heat. Reliant expected the unit to be down for 3 weeks. After the repairs were made, they tried to reconnect to the grid. The reconnect was out of sync with the grid frequency and the exciter was damaged on October 30, 2000. The root cause of the exciter damage was a relay in the synchronization relays that froze in position. [10] The damage was such that it provided an opportunity to perform a generator rewind and turbine overhaul at the same time. Both activities had been planned as scheduled maintenance for Fall 2001. However, when the exciter was damaged on October 30, 2000, Reliant decided to keep the unit down.

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suffered a forced outage on Unit 1 in late September.

[10] A small red light turns on a permissive to the synchronization process with the grid. The light was not on, but the operators (still operating under a contract with SCE) overrode the warning, with resulting damage. According to Reliant's Houston office, additional pre-existing damage was found in a switch yard still operated by SCE, to which Reliant has no access. It was Staff's impression that this was one of several factors that led to Reliant's dissatisfaction with the use of SCE employees and Reliant's decision to terminate the negotiated contract with SCE and to assume greater control over operations and maintenance at the plant.

Ormond Beach had experienced problems getting back on-line in spring 2000 after its turbine inspection. These 750 MW units had been previously run from mid June to end of Oct, then mothballed during winter months, and then run the next spring. Because Ormond Beach is on the ocean, the plant is susceptible to corrosion from the salt air/water. When starting up, the turbine heats up and must expand, and slide on keys and rails and if it does not slide properly, the turbine will vibrate when it spins. During the winter months, the keys and rails got frozen, the steel got a thin coat of corrosion, and the grease got hard. Reliant undertook a long process of heating up and cooling down the unit. Taking the unit apart and regrease would have taken longer. Reliant also had to unexpectedly rebuild the valves and pipes. Winter is the rainy season in California and when the units were shut down, rain gets in the insulation, which becomes soaked, and can rust completely through the thin-walled low pressure heater pipes. Reliant saw evidence of this problem in the winter 1998/99 and had to rebuild a significant number of these pipes to get equipment in service. However, Mr. Snowdon indicated that these problems are not unexpected for plants that were mothballed on a seasonal basis.

Mr. Snowdon discussed the relationship of the plant manager to the commercial units in Houston in somewhat greater detail than Mr. Ross. Mr. Snowdon does have the ability to make the decision to take a unit down to protect the plant assets. The criteria to determine if a unit should be taken off-line includes figuring the cost of the outage and failure modes, and figuring that against the lost opportunity cost in the marketplace. If there is a high price in the marketplace, he is inclined to take the risk to run the unit. Mr. Snowdon stated he makes the "economic decision" by comparing this criteria in conjunction with the demands of the ISO and his scheduling coordinator.

The decision to run/not run to recover the start up costs of bringing the units up from a cold start is made in Houston. During Staff's visit, Ormond Beach 2 was running. Reliant had not planned on running this unit during the winter based upon the market conditions in 1998 and 1999. Anticipating no opportunity in winter months, Reliant had planned to bring down the Ormond Beach units from November 1, 2000 through May 2001. The plan was to lay the units up during the winter, and reduce costs and staff during the winter, and then staff back up for the summer. However, about mid-June 2000, they foresaw the opportunity to run in winter 2000. Mr. Snowdon expects the market to become more competitive in the next couple of years, and their maintenance program is geared to meet this competition.

4. Mandalay

Mandalay consists of three natural gas-fired units. Units 1 and 2 are conventional steam-fired units completed in 1959, each rated at 215 megawatts. Unit 3 is a gas-fired turbine unit completed in 1971 and rated at 130 megawatts. Major maintenance was $7 million in 2000.

Figure 20 reflects the net output for the plant from 1996 through November 2000. This figures states the actual output of the plant available for distribution over the grid after consumption of power needed for plant operations. Figure 21 reflects the capacity factor for the various units, i.e., the percent of actual output for each unit measured against its total nominal capacity. Figure 22 displays the net output for each unit by month in 2000, the year of most intense usage. This demonstrates the productivity of individual units within the plants compared to the plant as a whole. Figure 23 displays the performance for each unit by various service states, including when the unit was available to meet demand, was in reserve, or on forced or scheduled maintenance, measured against the total possible operating hours in a year. Figure 24 displays the equivalent availability factor of each unit by month in 2000, i.e., the ratio of energy that the unit was actually available to provide measured against its total nominal capacity.

Figure 20. Mandalay Net Generation: 1996-Nov 2000

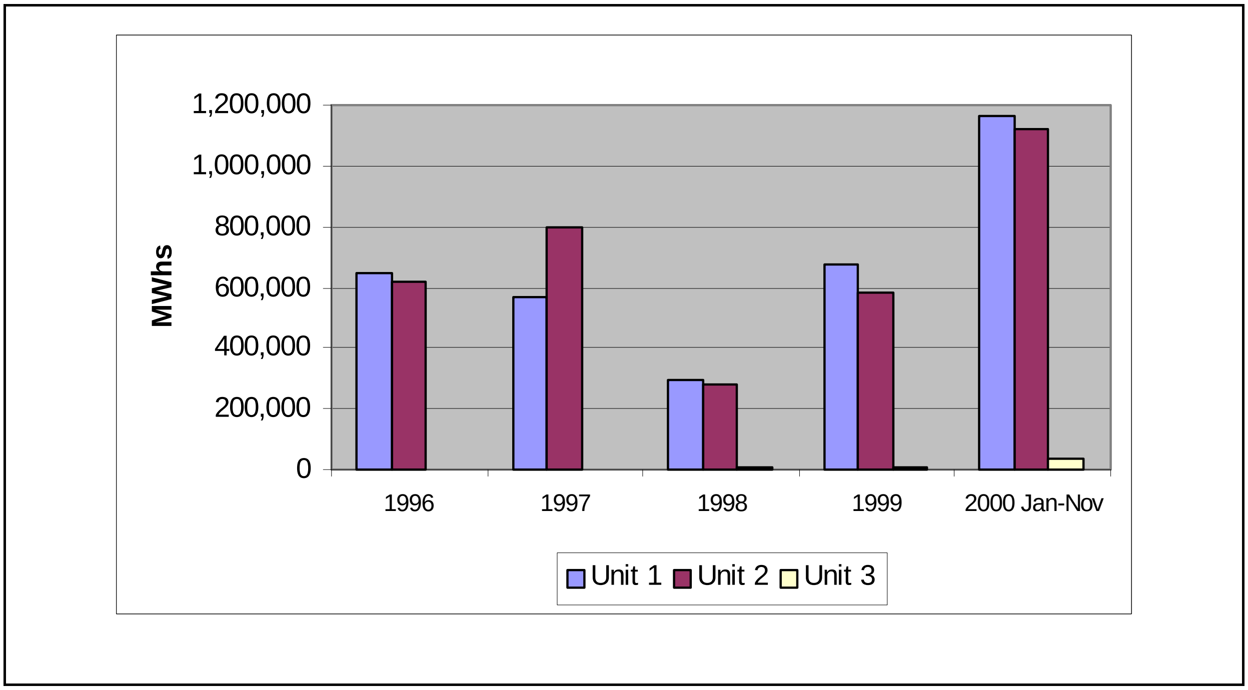


Figure 21. Mandalay Capacity Factors 1996-Oct 2000

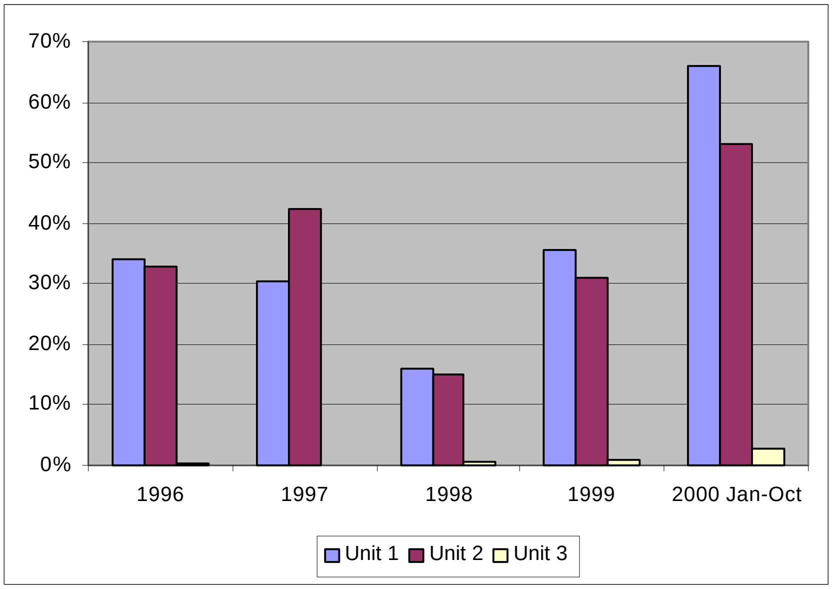


Figure 22. Mandalay Monthly Net Generation: Jan-Nov 2000

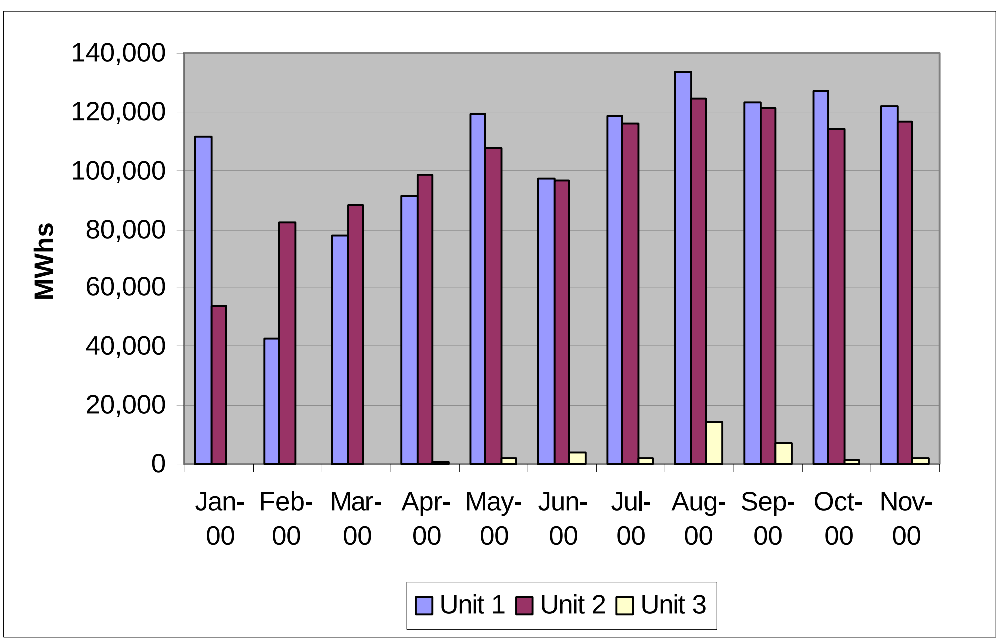


Figure 23. Mandalay Unit Performance: Jan-Nov 2000

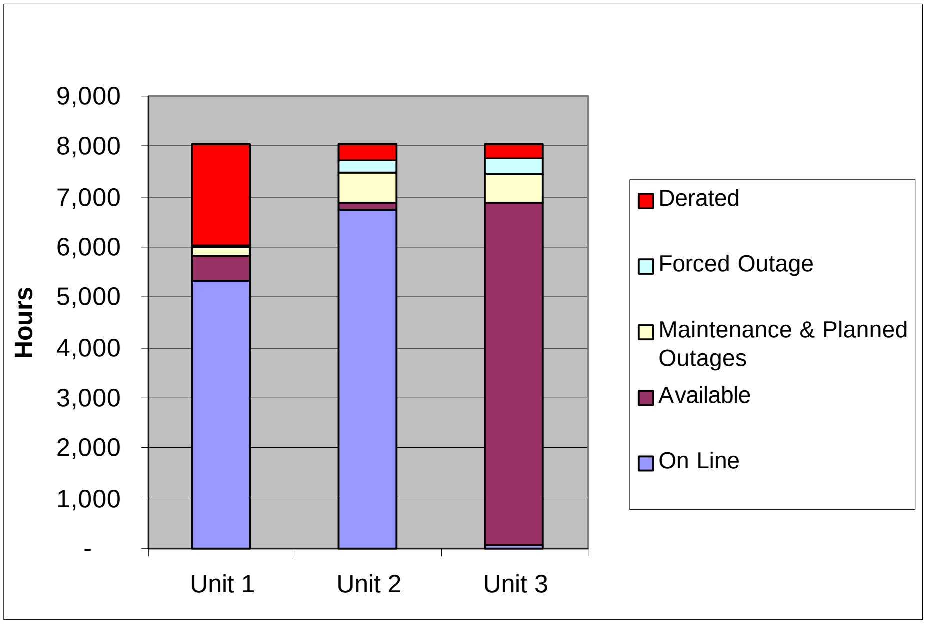
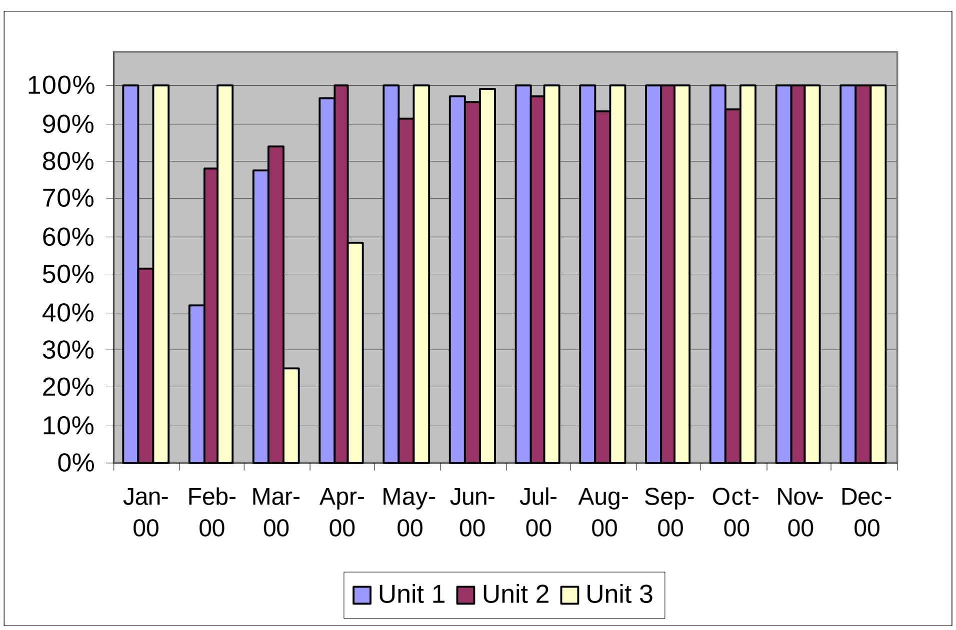


Figure 24. Mandalay Equivalent Availability Factors: Jan-Nov 2000



Mr. Snowdon explained that Reliant tends to dispatch Mandalay more frequently than Ormond Beach, and utilizes Mandalay longer during the year because Mandalay's units are smaller, more efficient and can be ramped up and down more frequently than Ormond Beach. A confidential engineering consultant report provided to Reliant concludes that maintenance appears to have been adequate and there have been few outages or operating problems with these units. Reliability for the units was high, in excess of 97 percent. Mr. Snowdon believes the reason for the difference in the availability of Units 1 and 2 in 1999 and 2000 was tube leaks.

Figures 20 and 21 show the large increase in output and utilization at Mandalay when comparing 1999 and 2000. Output was consistently high after June, as shown in figure 22. Figure 22 shows that availability was high after May despite the deratings and forced outages on Unit 1. In particular Figure 23 shows how environmental factors significantly impacts the operation of Mandalay Unit 3. Unit availability was high but the total output was low, even in a year of high demand. Reliant stated that this was because NOx emissions output restrictions established by the Ventura County Air Pollution Control District limit the operation of Mandalay Unit 3 to approximately 108 hours per year, or an annual capacity factor below 2 percent. Through July 1, 2000, Mandalay Unit 3 had generated approximately 6,500 MWh before it reached this 108-hour limitation.

However, Reliant and the Pollution Control District agreed to a Stipulated Conditional Order of Abatement whereby Reliant agreed to undergo District level new resource review, to evaluate and to install best available control technology (BACT), and pay a $4,000 mitigation fee to the Carl Moyer program for every hour it operated in excess of the current limit. Reliant's $4,000 fee was matched by $8,000 in Carl Moyer funds. The Carl Moyer Program supports reduction of air pollutants associated with heavy-duty diesel engines. The Stipulated Conditional Order of Abatement was not a waiver, but an agreement that Reliant pursue BACT. The agreement laid out a program to pursue, evaluate, then install control technology. Reliant is currently evaluating alternative control technologies to install and complete its obligation under the agreement. In exchange, the District permitted Reliant to run an additional 200 hours in the year 2000. Since July 1, 2000, Mandalay Unit 3 has generated more than 27,000 MWh under this agreement. When Staff interviewed Mr. Snowdon, Reliant had approximately 20 hours left under this agreement and only bid this unit on peak hours with the ISO. In the long run, Mr. Snowdon believes that this is a “win/win” deal with the generation issues in California.

B. The Visit to Reliant's Headquarters

Staff visited Reliant's corporate headquarters on January 3, 2001, and on the morning of January 5, 2001. The purpose of the visit was to obtain additional information on the relationship between commercial incentives and the decision to operate or not operate a plant. Staff determined in its visit to the plants that there appeared to be fairly close communication between the plant operators and the individuals making commercial decisions, but the nature of the decisions was sufficiently complex that a fuller understanding of those issues warranted a trip to Reliant's headquarters. In addition, there were numerous questions about the relationship between maintenance and capital budgeting, pricing, and accounting issues that could be most satisfactorily answered there.

Staff interviewed the following individuals at Reliant's headquarters: Jack Farley, President, West Region, Reliant Energy Wholesale Group; David Tess, Senior Vice President, Power Operations; Matt Greek, General Manager, Commercial Plant Operations; Michael Jines, Vice President and General Counsel, Wholesale Group; Bill Hamilton, Vice President, Risk Control, Wholesale Group; Reggie Howard, Vice President, West Power Trading; and Diana Diaz, Controller, Wholesale Service Company. In a series of meetings, Staff discussed with these individuals the factors Reliant uses to evaluate the proposed operations of its West Coast plants, the procedures used to dispatch a plant, and the evolution of the maintenance practices in its facilities. Much of the discussion focused on Ormond Beach because of the greater detail obtained about that unit. However, the general discussion of maintenance, capital, and commercial factors was relevant to all of the facilities that Staff reviewed.

Reliant operates its units on a portfolio basis so that units are scheduled according to their relative efficiency and the price Reliant will receive for the power. Based upon 1998 and 1999 market conditions, Reliant never expected to run Ormond Beach during the winter 2000/2001 and didn’t budget for the extra O&M operating costs to operate the unit. It had planned to mothball these units as it had done in previous years. But in the Fall 2000, market opportunities became available and management decided it was feasible to run Ormond Beach. Since Reliant had originally planned to mothball these units, it was necessary to maintain staffing levels beyond that level anticipated after November 1, 2000, in order to run Unit 2. [11] The staffing problems arise because the units are 28 and 30 years old and finding staff that knows how to operate them is

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[11] Ormond Beach has ample room in its NOx permit to allow for continuous full load operation and is not in the NOx reclaim credit program.

difficult. At the same time, the capital outlay for these plants to bring them more technically up to date (which would make the plants more efficient) is quite high and makes it difficult to operate the plants with individuals who are trained on new technology.

The relationship between maintenance, operations, and reliability is reflected in the operations of Ormond Beach in December. Reliant was asked by the ISO to run Ormond Beach at minimum load at night through December 2000 as a precautionary measure so the units could ramp up faster to meet demand quicker. Running these units at minimum load at night creates more wear and tear on the units and Reliant was forced to defer scheduled maintenance on these units because they were always kept running. To help hedge this loss, the ISO gave Ormond Beach "out of market calls." Reliant now plans to take Ormond Beach down in spring 2001 for scheduled maintenance and to prepare for summer.

Another earlier example of portfolio management was with Ormond Beach Unit 2. The ISO requested Reliant to run Ormond Beach 2 in July 2000 when this unit had a leaking gas fan. Reliant ran the unit an additional 5 days until it became too hazardous for the unit to run from a safety and damage standpoint. The decision was made by management to take the unit down for repairs. At the request of the ISO, Reliant has also kept El Dorado running this winter, and has deferred scheduled outage on this unit, but is concerned that if it continues running, the unit is headed for a forced outage. Reliant has been accommodating ISO requests but it will need to schedule the unit out, or risk unit failure and forced outages in the future.

The conversations at headquarters also confirmed that when Reliant acquired Etiwanda from SCE, Reliant planned to keep Etiwanda in service until its next major maintenance cycle or until the plant had no more profit margin based upon the company's financial model, then phase out Units 1 and 2. However, between the first of the year and by mid-May 2000 when the first price spikes occurred, Reliant began reevaluating this decision, then started planning and budgeting to make the major investment and perform the required maintenance on Etiwanda Units 1 and 2 to extend its economic life 6-8 years when the step-up in demand occurred. These conversations indicate the importance of price levels in determining whether maintenance budgets will be adequate to support the additional generation that may result if the useful life of the units is to be extended. Reliant stated that the risk of price caps has become an important factor in evaluating the benefits and costs of even short-term projects.

Reliant also explained the relationship between the daily decisions to schedule a plant and maintenance considerations. Reliant has an annual and 5-year projected budget for its plants and an internal control mechanism in place within the company that breaks decisions about the plants down into three levels. Level one is real-time decisions. This type of decision compares the market conditions to the cost and safety of running the plants. Level two are decisions that relate to the long range business plan and level three are intermediate type decisions. Real-time decisions are made by the plant manager based on the plant's ability to meet the commitments made by the traders and the needs of the ISO. The communication between the traders and plant manager varies depending on the traders' view of what the market is doing, what opportunities the market presents, and whether the plant managers' units will be needed. In making a real-time decision, the plant manager takes into consideration the status of the unit, the company's long-term business plan, and the need to avoid a catastrophic failure.

Intermediate decisions regarding the plant are in the nature of day-to-day maintenance. The plant manager will contact his superior, the west regional manager, who acts like a liaison between the plant and corporate, if the cost of a maintenance issue exceeds a certain amount or if an outage will cause a unit to be down longer than originally predicted. At that point, a return on investment (ROI) analysis is done for the project and the project is prioritized. These larger capital outlays are discussed with the vice president in charge of assets and the president of the West Region. These capital outlays also impact the budget for which the regional manager and plant manager are responsible, and the profitability of the plant. Budget constraints and materiality are the trigger to notify superiors. Most projects are considered as maintenance expenditures and expensed, including major maintenance which can extend the economic life of the units. These major maintenance expenditures are accounted for by the reserve or accrual method. NOx emission upgrades fall into this category.

Reliant described the trading function and its relationship to plant operations in the following terms: Some trades reflect daily cash trading in the real time market, and others are based on contracts for one to 10 years. There is also an asset group that evaluates the overall impact of these longer term commitments. On a daily basis, when bids come in, they are submitted to the real-time group, which calls the plant manager or his designate (i.e. the plant operator) to increase or decrease output as needed. Reliant also has a gas group that trades for the gas to be burned at the generation plants. The asset group works closely with the gas marketing group, always being aware of the cost of the gas to be burned, and how much must be burned to honor their commitments. Reliant also has NOx traders. If Reliant needs to go out onto the market to purchase more NOx credits, it generally can do so.

All these factors have to be analyzed as the traders look at the market and determine which market they need to be in. There are some 20 markets involved each day (each with up to 24 hourly blocks), or a potential total of some 500 discreet markets. The traders therefore talk with the plants daily and receive the physical limitations of the plant for the day, and the trader then decides if the plant will be brought up on-line or not. For example, as previously discussed, Reliant found a serious problem with the Unit 1 generator which could have caused the plant to be taken down all summer. However, Reliant's traders saw an opportunity to provide service and earn unanticipated revenue. The western regional plant manager, along with the plant manager at Ormond Beach, agreed to keep the unit running during the summer months. The trader has information before him or her that tells the cost-benefit of running the plant, but the plant manager has the final say in whether the unit will run in order to assure safety and to avoid serious damage to the equipment. Reliant's trader and the plant are in contact with each other 8-10 times a day.

The Staff interviews indicate that a substantial amount of discretion exists at the operating level to determine whether the units are kept on-line. There is considerable pressure to keep the units on-line since they are not RMR units, and revenues will be generated only when a bid is accepted or in response to an Out of Market (OOM) call. Except for longer term outages, there is little time for a review by more senior officers and the decisions are vested in the plant manager and the trading desk. If the ISO calls and requests the plant to run, Reliant asserted that it will honor the request. Reliant then stated that it has a long-term commitment to the California market, and that it must be willing to provide service in a reliable fashion on demand if it is to compete effectively in that market and in its other national markets. Reliant cited the following recent example of its commitment. In November 2000, a major transmission outage occurred and the ISO called and requested Reliant to put Etiwanda on-line. The plant fired up all 5 units as close to simultaneously as possible to meet the request. The ISO offered Reliant out-of-market pricing. Reliant was able to find the staffing to get the plant on-line after a short delay.

The financial analysis of an ISO request under these circumstances is based on a 24-hour analysis. Reliant stated that this is because it must go to minimum load during the low load times and will likely lose money during the off-peak hours because of the cost of fuel and operation. During the high load periods, the plants usually cover the hourly operating cost, but for overall operations to be profitable, the peak revenues must cover the shortfall that is incurred in the off-peak hours. Longer term investment and maintenance decisions are based on a series of forward price curves that match anticipated demand and revenues against the discounted cost of the investment. Reliant stated that regulatory uncertainty has become a major component in analyzing its long term investment decisions to be made in the California market.

Reliant noted that California statute AB 1890 required the new generation owner to contract with the previous owner for a two year period for the operation of the plant and use the predecessor company's employees. This contract with SCE expired in April 2000. Reliant then signed a new three-year contract. Reliant officers in Houston explained that when they extended the contract, SCE was in the process of establishing an O&M subsidiary, and there were certain issues of concern to Reliant which they felt were best handled by SCE. However, after extending the three-year contract, Reliant canceled the contract effective April 1 of 2001.[12] Reliant indicated that there were a number of factors that influenced this decision. For example, Reliant performed its own root cause analysis of the Ormond Beach Unit 1 Isophase synchronization because of concerns that SCE employees did not have the skill sets to complete these reports and were not always responsive to the root cause analysis concept.

IV. The West Coast Power LLC Audit

A. The Plant Reviews

Staff visited the West Coast's El Segundo plant located near Manhattan Beach, California on December 19, 2000. West Coast is a limited liability company jointly owned by NRG and Dynegy. Staff also discussed the operation of West Coast's Cabrillo I facilities in San Diego, California, and had previously interviewed the manager of those facilities in a telephone call on December 14, 2000. Staff also visited Dynegy's headquarters in Houston, where many of the day-to-day trading and commercial decisions are made regarding West Coast's assets. [13] The issues related to El Segundo are discussed in detail below. Those related to Cabrillo I are discussed in a more summary form based primarily on plant operating reports that were provided by Dynegy. El Segundo and Cabrillo I are the two facilities that form part of West Coast's generating portfolio. [14] Table 2 lists West Coast's generating units, their capacity, unit type, date in service, and age.

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[12] Reliant noted that other generators (NRG and AES) had terminated their O&M contracts with SCE when the mandatory two-year period carryover period expired under AB 1890. Reliant does plan to use SCE personnel for major outages and outside support.

[13] NRG's expertise lies more in plant operations and maintenance.

[14] Cabrillo II consists of 18 turbines in scattered in different locations throughout the San Diego area. However, they are operated as a single commercial unit and are therefore described in those terms.

Table 2. Power Plants Owned by West Coast Power LLC in the Southwest U.S.

Station	Unit	Type	Dependable or Summer Peak Capacity (MW)	Commercial Operating Date	Age	Location
Cabrillo Power I	Unit 1	Thermal	107	1954	47	California
	Unit 2	Thermal	104	1956	45	
	Unit 3	Thermal	110	1958	43	
	Unit 4	Thermal	300	1973	28	
	Unit 5	Thermal	330	1978	23	
			951			
El Segundo	Unit 1	Thermal	175	1955	46	California
	Unit 2	Thermal	175	1956	45	
	Unit 3	Thermal	335	1964	37	
	Unit 4	Thermal	335	1965	36	
			1,020			
Long Beach	Unit 1	GT	60	1976	25	California
	Unit 2	GT	60	1976	25	
	Unit 3	GT	60	1976	25	
	Unit 4	GT	60	1976	25	
	Unit 5	GT	60	1977	24	
	Unit 6	GT	60	1977	24	
	Unit 7	GT	60	1977	24	
	Unit 8R	ST CC	80	1976	25	
	Unit 9	ST CC	60	1977	24	
			560			
Cabrillo Power II	Division St	CT	16	1968	33	California
	El Cajon	CT	16	1968	33	
	Encina	CT	18	1968	33	
	Kearny 1	CT	17	1972	29	
	Kearny 2A	CT	17	1969	32	
	Kearny 2B	CT	17	1969	32	
	Kearny 2C	CT	16	1969	32	
	Kearny 2D	CT	16	1969	32	
	Kearny 3A	CT	17	1969	32	
	Kearny 3B	CT	17	1969	32	
	Kearny 3C	CT	16	1969	32	
	Kearny 3D	CT	16	1969	32	
	Miramar 1A	CT	19	1972	29	
	Miramar 1B	CT	19	1972	29	
	Naval Station	CT	26	1976	25	
	North Island 1	CT	19	1972	29	
	North Island 2	CT	18	1972	29	
	NTC	CT	16	1970	31	
			316			
	TOTAL MW		2,847			

CT - Combustion Turbine
ST CC - Steam Turbine Combined Cycle

1. El Segundo

West Coast's El Segundo plant is located near Manhattan Beach in the Los Angeles basin. The plant consists of four gas-fired power generating units. All four units are conventional steam-fired units with a single turbine, generator, and supporting units. El Segundo has been used as a peaking and load following unit and is operated on a seasonal basis, with Units 1 and 2 intended to run during the summer peak only. Units 1 and 2 were completed in 1955 and 1956 respectively and are both rated at 175 megawatts. Units 3 and 4, the more modern units, were designated as reliability must-run units in 2000. Units 3 and 4 were completed in 1964 and 1965 respectively and are both rated at 335 megawatts. Figure 25 reflects the net output for the plant from 1996 through 2000 and reflects the actual output of the plant available for distribution over the grid after consumption of power needed for plant operations. Figure 26 reflects the capacity factor for the various units, i.e., the percent of actual output for each unit measured against its total nominal capacity. Figure 27 displays the net output for each unit by month in 2000, the year of most intense usage.

Figure 25. El Segundo Net Generation: 1996-2000

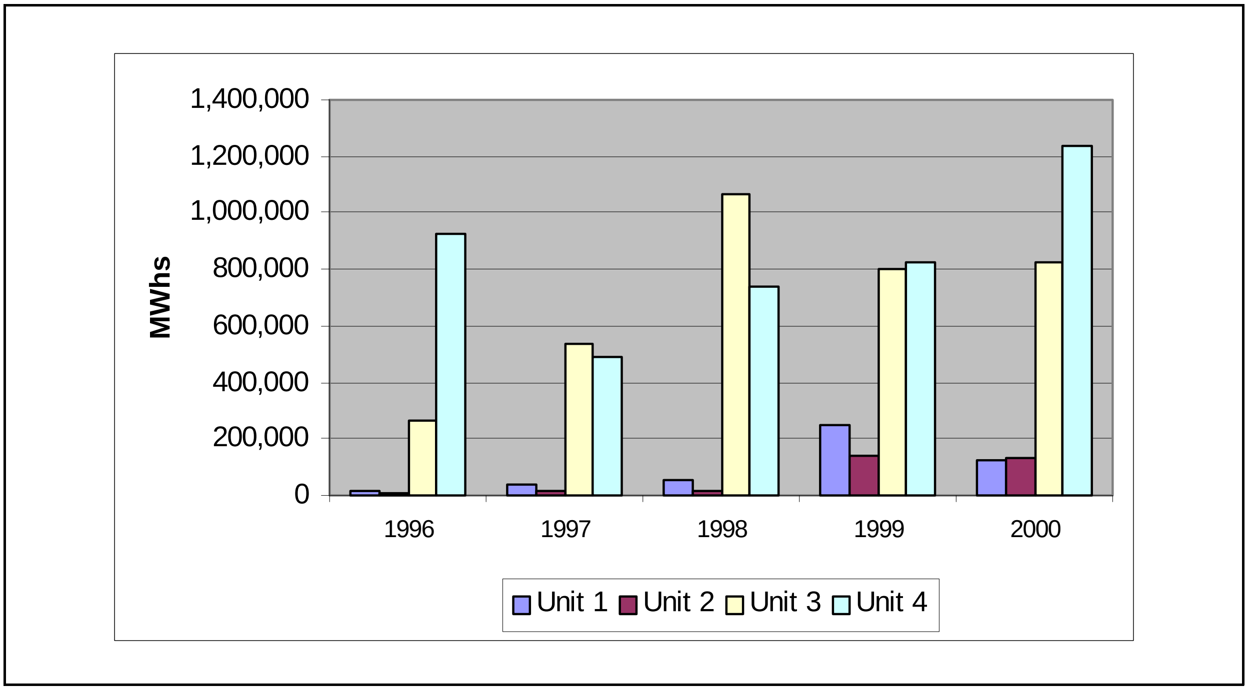


Figure 26. El Segundo Capacity Factors: 1996-2000

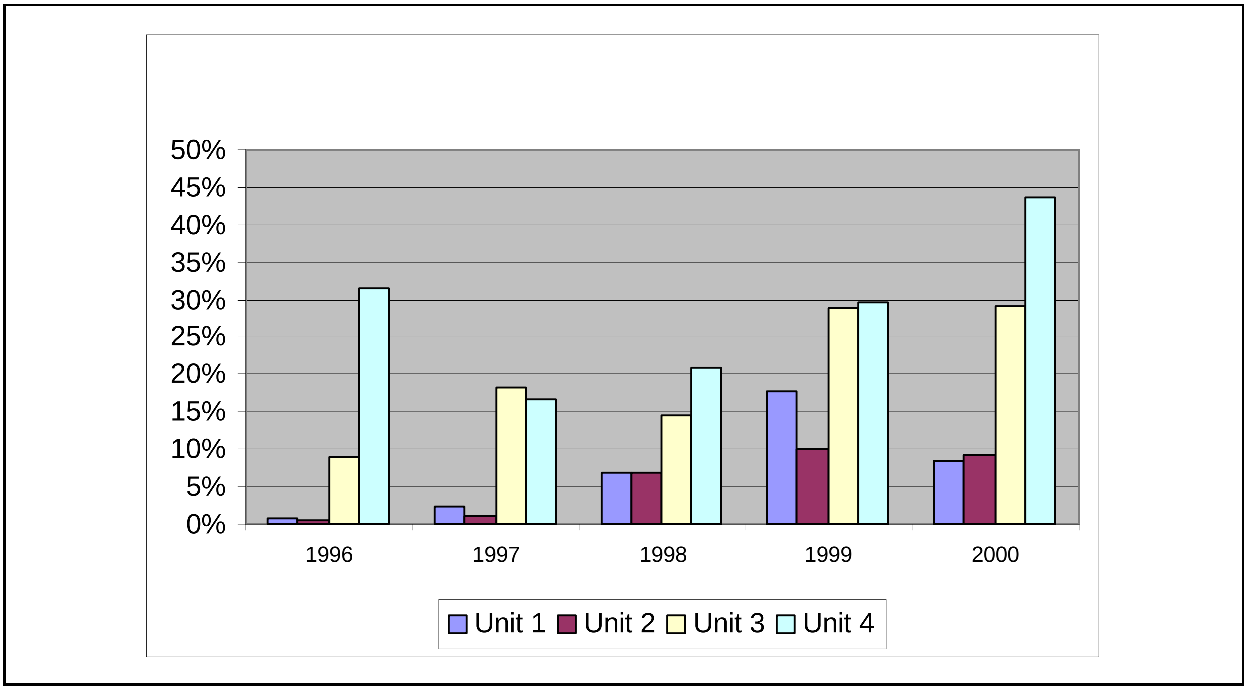
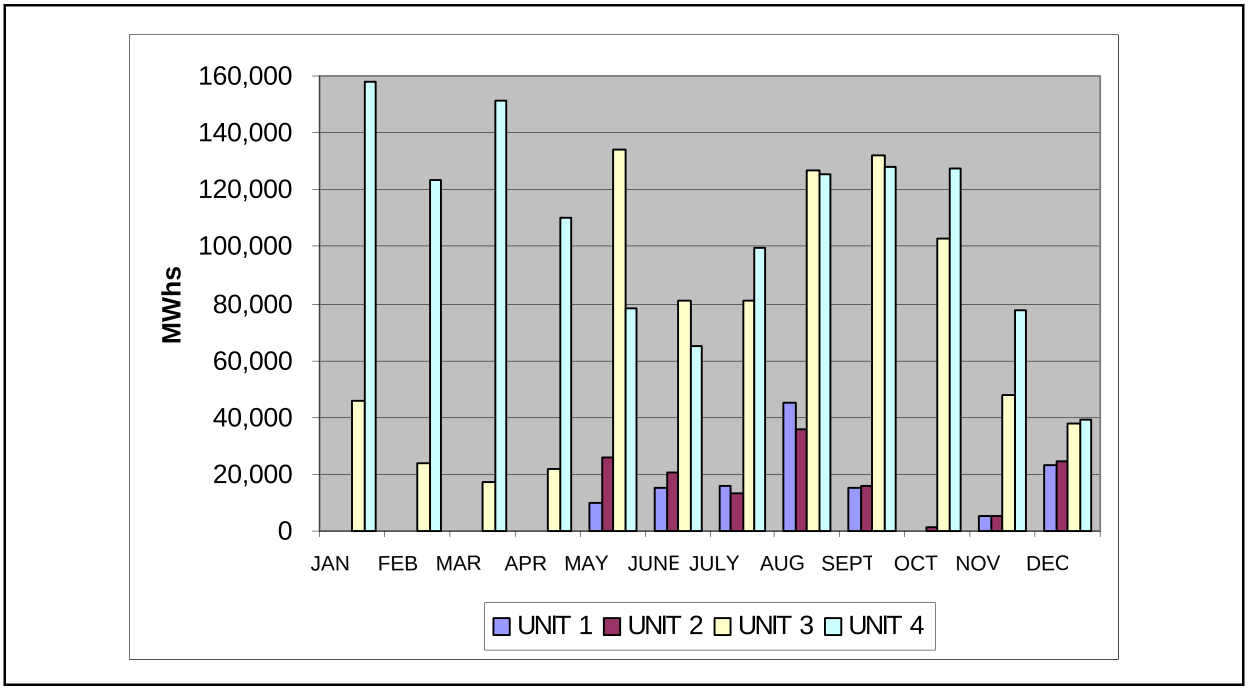


Figure 27. El Segundo Monthly Net Generation: Jan-Dec 2000



As previously discussed, West Coast, which owns El Segundo, is owned 50 percent by Dynegy and 50 percent by NRG. At El Segundo, Staff met with Audun Aaberg, Regional Plants Manager for NRG El Segundo Operations, Inc., Ernest Soczka, General Manager for El Segundo Power, LLC, and Augie King, Attorney. Approximately 70 percent of the employees at the plant site are on the NRG payroll, the other 30 percent are contract employees from SCE. The basic operational plan of the plant was to run Units 1 and 2 during the summer months, and Units 3 and 4 year round. Approximately six months ago, NRG made the decision to repower and replace Units 1 and 2, which are 45 years old. Units 1 and 2 were planned to be shut down in October 2000, but with the current situation in California, Units 1 and 2 continue to run. On December 19, 2000, NRG and Dynegy filed an Application for Certification (AFC) for the El Segundo Repowering (Modernization) Project with the California Energy Commission (00-AFC-14) . If they obtain the certification by August 2001, they expect to have the units operational in 2003. The repowered units will have 600 MW of capacity and the repowering cost was estimated to be less than $500 million.

The seasonal nature of the operation of Units 1 and 2 is reflected in Figure 27, which shows no generation of these units from January through April, then generation in May through September, minimal generation in October, and then a return to service to meet the crisis that began to develop in November and December. In contrast, Units 3 and 4 show high levels of output all year round except for the maintenance activities in November, which ended in a pump failure that shut down both units for much of December (discussed below in detail). However, despite the relative inefficiency of Units 1 and 2, and the problems with Units 3 and 4, overall output at the plant increased over the year 1999.

Mr. Aaberg stated there have been numerous additions as well as blown tubes at the El Segundo plant over the last year. Prior to the sale of the El Segundo units to West Coast, SCE performed minimal maintenance on these units. Mr. Aaberg indicated that SCE gave up maintaining the plant 10 years ago. In particular, SCE did not address the air leakage problems in the pipes or the corrosion problems from the salt air of the units because El Segundo is not enclosed. When Staff toured the Units 1 and 2 facilities, Staff observed considerable rust and corrosion in these units. NRG started overhauling the equipment upon its ownership.

El Segundo experienced unexpected failures in both the pumps and motors in Units 3 and 4 in the year 2000. In early 2000, Unit 3 had a forced outage because the Unit 3 boiler pump failed and it was repaired. The internal reports state these pumps continued to cause problems during the month of November and into December. On

November 28, Unit 3 was available for service, but suffered the failure of the sub feeder water pump (SUBFW pump) that provides feedwater to the unit's boilers when the plant attempted to bring the unit on-line. Such a pump is essential to start the unit. Previously, on November 24, Unit 4 had been taken off-line for annual maintenance with the ISO's concurrence. Units 3 and 4 are cross plumbed so the Unit 4 pump can be used to feed Unit 3 and the reverse. After the November 28 pump failure, the plant staff attempted to start Unit 3 using the Unit 4 pump, but the motor driving the Unit 4 pump failed. This shut down both units.

Auden Auberg, the plant manager, stated that West Coast made substantial efforts to bring both units back on-line. He stated that after the November 28 failure, the company sought a replacement pump but was unable to find one. The Unit 3 pump was sent out for rebuilding on an expedited basis. The company attempted to shift the Unit 3 pump motor to run Unit 4, and that motor failed also. The Unit 4 motor was sent out for repair at a total cost of $93,000. At the same time, the company also began searching for a replacement motor. A motor was purchased from a Colorado motor company and the motor was shipped from Texas and installed on an expedited basis at a cost of $61,178. The motor failed to start up. Another motor was purchased in California and its size was modified and retrofitted to permit its installation, at total cost of $81,290. The installation cost was $25,000 of the total purchase price.

Upon installation of the California motor, both Units were returned to service on December 14. The cost of repairing the two motors on Units 3 and 4 will exceed $193,000. Mr. Auberg stated that both the repair contractors and his staff worked on a 24 x 7 basis (two 12 hour shifts 7 days a week) to make the repairs to Units 3 and 4, and to bring them on-line to meet the December California grid crisis. They did not perform the scheduled chemical cleaning in order to bring Unit 4 back online more quickly and to meet energy demands of California in December. Mr. Aaberg stated that this shortcut will have a detrimental effect on future plant performance and increase future maintenance costs. The internal reports confirm this in writing, and plant staff vacations were canceled to deal with the grid crisis. Staff toured Units 3 and 4, and was able to see that pump 4 was not in-service and out for repairs. Staff also observed the modifications on the replacement motor.

Staff also reviewed the outage justifications for each day from July 1 through the end of the 2000. These reports indicated:

- July - Units 1 and 2 were generally not bid in and minor repairs were made to those Units. Units 3 and 4 suffered from tube leaks, turbine seal leaks, and steam valve seal leaks.

- August - Units 1 and 2 were derated for much of the month due to a turbine reheat limitation. Units 3 and 4 operated for the entire month of August except for 5 days that were lost to tube leaks.

- September - Unit 1 was off-line for one day due to a high thrush bearing failure, which the Unit also suffered in July. Unit 3 ran without incident and Unit 4 was out for four days with tube leaks.

- October - Units 1 and 2 reported no incidents. Unit 3 was restricted to 290 MW for 6 days due to tube leaks, was down again for one day due to an exciter failure, and down another day to repair an air pre-heater. Unit 4 went off-line for less than 3 hours on one day due to a generator exciter overload, which was repaired within 48 hours. This unit was not required to run on the third day. It was also off-line for a brief period due to an HP generator brush rigging failure.

- November - Units 1 and 2 were either on-line or were not required to be dispatched. Unit 3 suffered a boiler water contamination problem for the first 7 days of the month, then went on-line for 3 days, then had a superheater tube repair for one day. Unit 3 remained available or on-line until November 28, when it suffered the SUBFW pump failure. Unit 4 also suffered a boiler feedwater contamination problem the first 6 days of the month, then was on-line until taken off line for annual maintenance on November 24.

- December - Unit 3 was down due to the SUBFW pump failure until December 14. Since the pump failures prevented Unit 4 from being started, Unit 4 remained on annual maintenance until December 14. Both units came on-line on that date and operated without incident for the rest of the month. Unit 4 was brought up from annual maintenance ten days early to meet ISO demand.

The daily performance of Units 3 and 4 is reflected in Figures 28 and 29. These display when the units were on-line, when they were available, but not on-line, and when they were down for planned or forced outages for each 24-hour period. The units were clearly on-line or available for most times except for the pump failure of Units 3 and 4.

Figure 28. El Segundo Unit 3 Daily Performance: Oct-Dec 2000

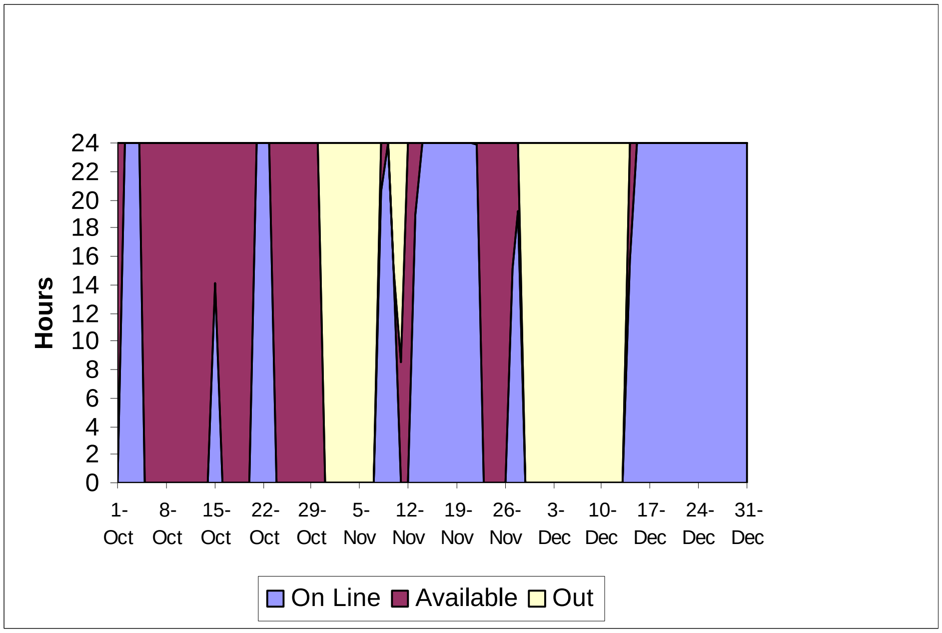
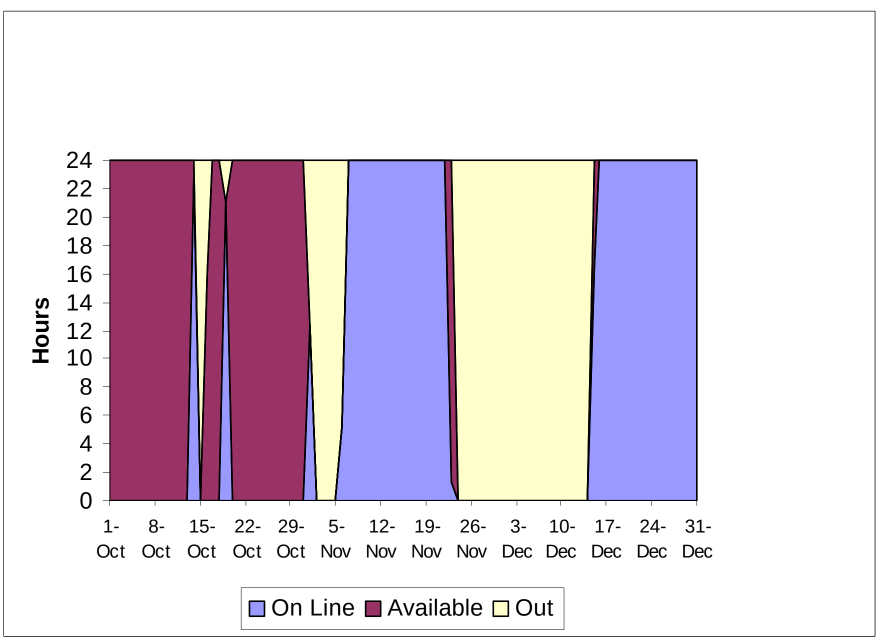


Figure 29. El Segundo Unit 4 Daily Performance: Oct-Dec 2000



2. Cabrillo I

Cabrillo I (formerly referred to as Encina under the previous owner) is located in Carlsbad, California, on the shoreline in the general vicinity of San Diego. The plant consists of five natural gas and residual units. Units 1 through 3 were designed for base load operation and Units 4 and 5 for cycling. Each Unit has a boiler, turbine, generator and related units. Unit 1 was completed in 1954 and is rated at 107 megawatts. Unit 2 was completed in 1956 and is rated at 104 megawatts. Unit 3 was completed in 1958 and is rated at 110 megawatts. Unit 4 was completed in 1973 and is rated at 300 megawatts. Unit 5 was completed in 1978 and is rated at 330 megawatts. Units 1 and 2 have historically been utilized only for the peak summer demand. SDG&E is currently operating Cabrillo I and NRG will assume operating control in May 2001.

Figure 30 reflects the net output for the plant from 1996 through 2000. This figures states the actual output of the plant available for distribution over the grid after consumption of power needed for plant operations. Figure 31 reflects the capacity factor for the various units, i.e., the percent of actual output for each unit measured against its total nominal capacity. Figure 32 displays the net output for each unit by month in 2000, the year of most intense usage. Figure 33 displays the performance for each unit by various service states, including when the unit was available to meet demand, was in reserve, or on forced or scheduled maintenance, measured against the total possible operating hours in a year. Figure 34 displays the equivalent availability factor of each unit by month in 2000, i.e., the ratio of energy that the unit was actually available to provide measured against its total nominal capacity.

Figure 30. Cabrillo I (Encina) Net Generation: 1996-2000

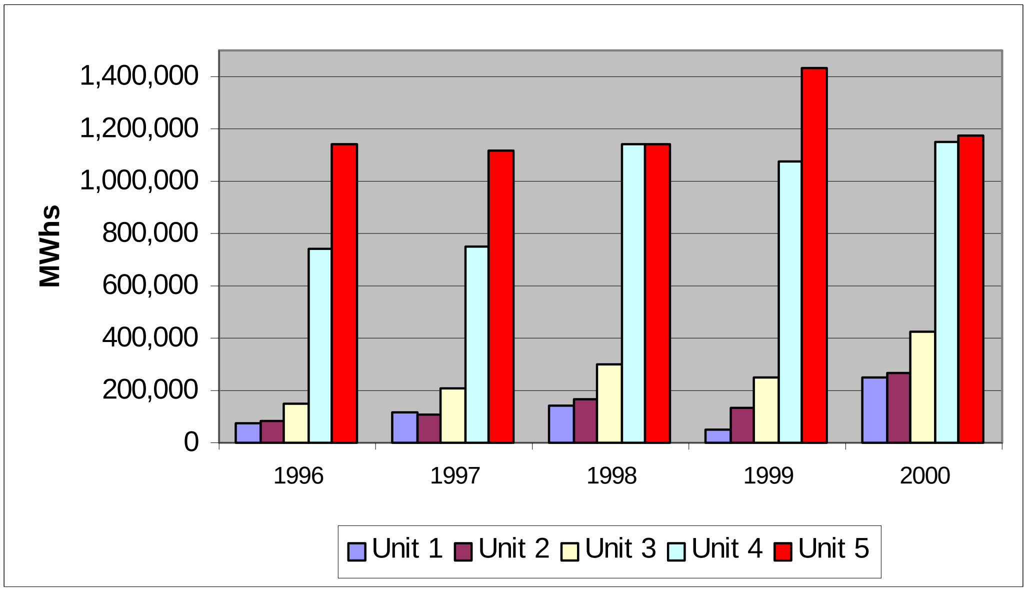


Figure reflects Units 4 and 5 low NOx burner installations in the year 2000.

Figure 31. Cabrillo I (Encina) Capacity Factors: 1996-2000

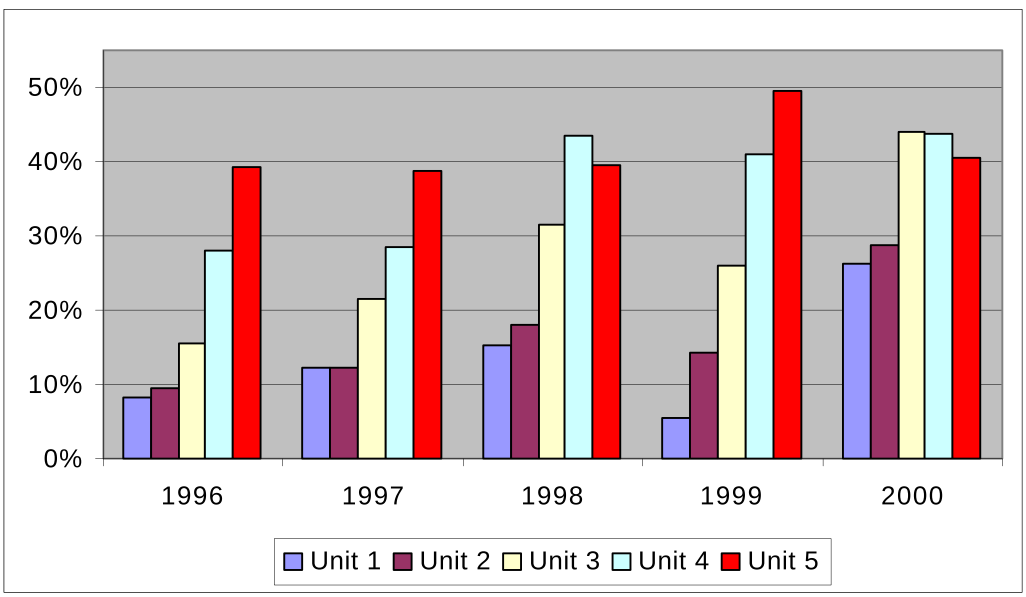


Figure reflects Units 4 and 5 low NOx burner installations in the year 2000.

Figure 32. Cabrillo I (Encina) Monthly Net Generation: Jan-Dec 2000

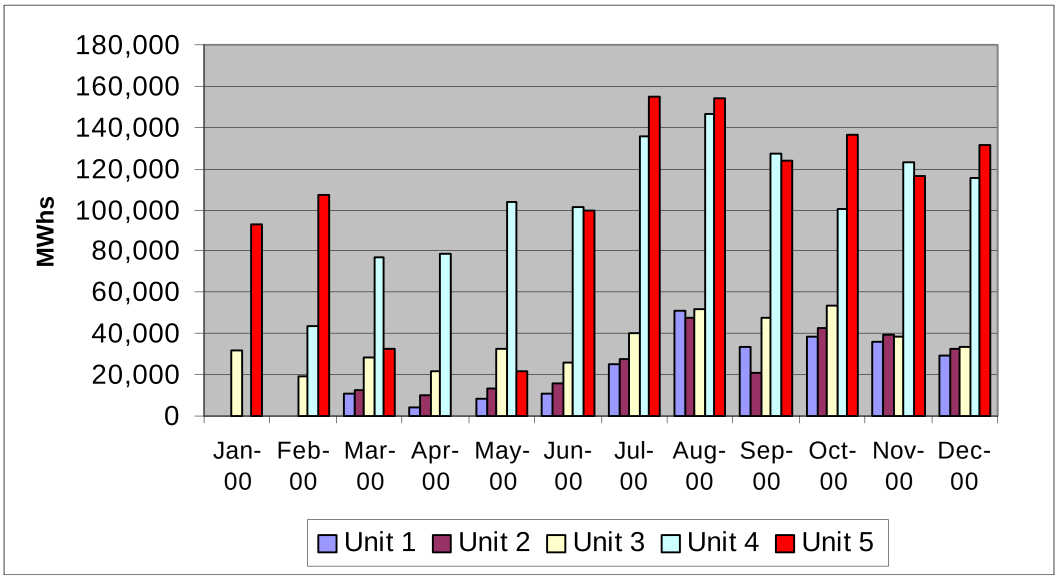


Figure reflects Units 4 and 5 low NOx burner installations in the year 2000.

Figure 33. Cabrillo I (Encina) Unit Performance: Jan-Sep 2000

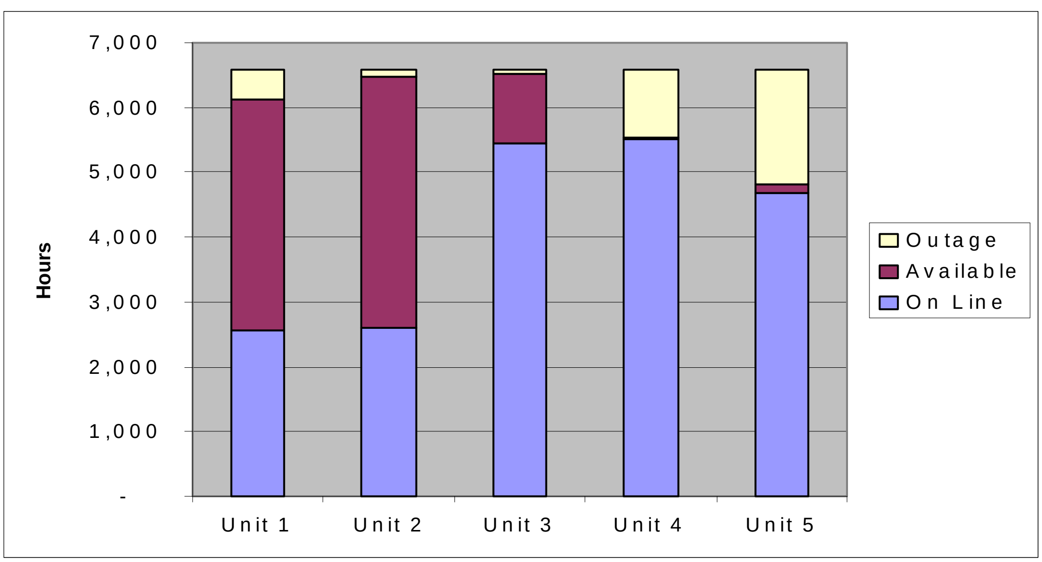


Figure reflects Units 4 and 5 low NOx burner installations in the year 2000.

Figure 34. Cabrillo I (Encina) Equivalent Availability Factors Jan-Dec 2000

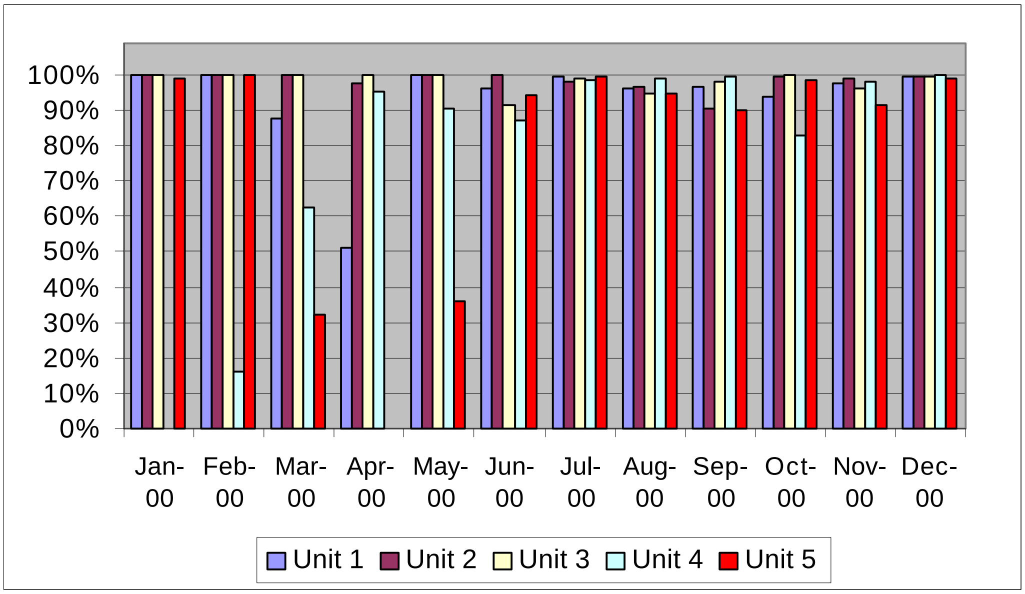


Figure reflects Units 4 and 5 low NOx burner installations in the year 2000.

Figures 30 and 31 show that Cabrillo I's output was about the same in 2000 as in 1999, but the plant was down for some time due to the installation of low NOx reduction equipment on Units 4 and 5. However, figures 33 and 34 indicates a high degree of availability for most of the Cabrillo I units during the year. During the spring months the unit's availability dropped due to the capital and maintenance activities being performed, but unit availability increased sharply beginning in June. [15] Mr. Hughes, the plant manager, provided detailed operating reports on the units. Because Cabrillo I is also a steam plant, like several of the other large units reviewed, Staff reviewed these reports to obtain an overview of the type of maintenance issues that might arise in such older units.

In January, the Plant performed long-term maintenance of various types on the units. There were minor outages on Unit 5 due to boiler pump feed controls. Unit 4 was out-of-service for long-term scheduled maintenance during the same month. In February, Unit 4 had a fan problem and some turbine valve management problems. Additional work was performed on the other units while they were not required to be dispatched. In March, Unit 1 had waterwall tube leaks and on March 21, Unit 4 had a pump leak followed by a bearing failure that severely derated the Unit. The unit returned

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[15] Staff's telephone interview on December 14, 2000 with Mr. Hughes, manager of the plant, focused on one outage in late November that involved a serious tube leak.

to service in 7 days. Considerable maintenance was performed on Units 1, 2, and 5 while they were not required to be dispatched, including accelerated repairs on tube leaks in Unit 1. The Unit was returned to service on April 14. Unit 4 had a short outage due to flame problems. Unit 5 had started a major overhaul in March, including turbine repairs, water tunnel cleaning, and a NOx burner project, which is reflected in the outage statistics of Figure 33.

In April, considerable maintenance was performed on Units 1, 2, and 5 at times when they were not required to be dispatched, including accelerated repairs on tube leaks in Unit 1. The Unit was returned to service on April 14. Unit 4 had a short outage due to flame problems in the same month. Unit 5 continued its extensive overhaul in April, which was completed on May 17 after extensive tests. Minor repairs continued, including NOx testing. Units 1 through 3 were continuously available except for minor tube problems on Unit 3. Unit 4 was continuously available but was derated for 8 days due to a boiler feed pump problem. [16] By early June, Unit 5 passed its NOx test, returned to service, but suffered a short forced outage on June 17 from a burner problem. Units 1 to 4 were available, but Unit 1 was derated for 11 days due to a circulating pump problem. Unit 4 had a similar problem and both pumps were repaired.

Demand was high in July as reflected in Figure 32. In July, Unit 5 had a burner problem on July 8 but continued operations. The repairs were not fully completed to permit continued operation of the Unit. Units 1 through 3 had various boiler leak and pump problems but the available time lost was minimal because of the timing of the repairs for periods when the Units were not dispatched. Unit 4 had a 5-hour down period on July 30, at which a number of repairs were performed. In August, also a period of high demand, Unit 1 performed without incident, Unit 2 was out for 13.5 hours due to two condenser problems, Unit 3 performed without incident, as did Unit 4. Unit 5 suffered a 7.5 hour outage due a gas system problem. As Figure 34 indicates, availability of the plant was excellent during June through August 2000, a period of intense demand despite a number of small maintenance problems.

Demand remained high in September. Units 3 and 4 performed without incident. Unit 2 was scheduled out-of-service for 2 days for boiler leaks in the first week and 2 days in the fourth week when the Unit was not on call for service. Unit 1 had a derate for leak checking for one day and for 15 hours on the 15th. Otherwise the Unit was available. Unit 5 had a less than one day outage to remove natural gas debris (tube leaks were simultaneously repaired), but the Unit experienced a boiler feed booster pump

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[16] Similar problems on older pumps were being encountered at El Segundo.

motor bearing failure on start-up. This limited the Unit's rating during repairs, which were completed in less than 40 hours. Unit 5 experienced other problems with its gas system, including some of its controls and generator circuits. However, despite these complications, Unit 5 still had a 90 percent availability factor and extensive net generation during the month. Extensive repairs continued on parts of the plant for which it was not necessary to cease operations.

In October, plant load continued heavy as demonstrated by Figure 32. Unit 1 experienced one forced outage and was scheduled out-of-service for two days due to problems with the closed water system, as was Unit 2. Unit 3 was in service for the entire month except for a one-hour outage on one day. Unit 4 was scheduled out of service for five days with fan blade problems. Unit 5 had four forced outages but the outages only totaled 9.5 hours and output was high. In November Units 1, 2 and 3 were available without incident except for one day involving a hydrogen leak on No. 3. Unit 4 was in service without incident. Unit 5 continued to experience a number of forced outages related to boiler valves, turbine control systems, safety valves, lubricating leaks, and a problem with a condensate pump. However, the outages only totaled 5.5 hours even given apparent operating limitations of this Unit. Figures 34 and 32 indicate that availability and output where high during the California grid crisis of that month, with availability approaching 100 percent for all units and output particularly high for Units 4 and 5. The December report was not available at the time of the Dynegy visit.

B. The Visit to Dynegy's Headquarters

Staff visited Dynegy's headquarters on January 4, 2001, and on the afternoon of the 5th. As previously noted, Dynegy is 50 percent partner with NRG in its ownership of the West Coast Power assets, the El Segundo, Long Beach, Cabrillo 1 and Cabrillo 2 generation plants in California. NRG is the operator of the plants while Dynegy does the scheduling, purchases fuel and NOx credits, and makes the commercial decisions about the dispatching of the plants. Staff interviewed Lynn Lednicky, Senior VP, Commercial Asset Management, Dynegy Marketing and Trade by phone because he was out of town on business. Interviewed in person were: Ed Ross, Senior Director and Regulatory Counsel, Dynegy Inc.; Betsy R. Carr, Director and Regulatory Counsel, Dynegy Inc.; J. Kent Williams, Sr. Director, Commercial Asset Management-West, Dynegy Marketing and Trade; Joseph M. Paul, Director and Regulatory Counsel, Dynegy Inc.; and Gina D. Ulbricht, CPA, Business Manager, Dynegy Marketing and Trade.

Dynegy explained the relationship between the scheduling and maintenance as follows. The plant manager has the responsibility to protect plants assets against serious damage. If an emergency occurs which results in a forced outage, the plant manager has the authority to immediately shut the plant down. If the plant becomes derated, the plant manager communicates the outage to Dynegy and Dynegy calls the ISO. With scheduled outages, the plant managers may exercise the discretion to defer the maintenance because of the needs of the ISO or commercial opportunity. As an example, El Segundo Unit 4 had a hydrogen leak this last summer, but the ISO needed the output from the unit. Maintenance was deferred and the unit was kept on-line. [17]

In daily practice, because of the real time nature of the market, the trading floor is considered the point of dispatch from an economic standpoint, but in the physical sense, the plants themselves are the dispatch points. When a unit first develops an operating problem, the decision is made by the plant manager as to the severity of the problem, when the unit can be taken down, how long the unit will be down, whether the unit can "limp along", and how the unit should be scheduled to minimize the company's financial exposure. This leeway allows the plant manager to assess the safety of the plants and increases reliability. The decision must ultimately be made at the plant level, but an asset manager is called into the decision process if the shutdown is likely to be protracted.

The risks involved in these decisions are one reason that the generation plants in the West Coast region are viewed as a portfolio. When Dynegy commits contractually to certain MWhs, the MWhs may come from two or three units instead of ramping one unit all the way up. For example, if Dynegy commits 600 MWhs to the California PX, that 600 MWhs may come from two or three units and not from just one unit. Dynegy stresses that they are not holding back the remaining power from the units; this practice allows for better reliability and the traders will be able to commit the rest of the unit's MWhs to the ISO for balancing or on an emergency basis. Staff was also given a tour of the trading floor to observe the communication and computer links between the plants and the trading staff and was given an explanation by a senior trader of the bid process in both the day ahead, hour ahead, and realtime market.

Staff and Dynegy also discussed the possible impact of regulation under AB 1890 on West Coast's ability to take control of its plants. Dynegy stated that upon purchasing the generation plants, in accordance to AB 1890, Dynegy and NRG became contractually bound for SCE to perform Operations and Maintenance (O&M) on the purchased plants. Dynegy made the decision prior to purchasing the plants that NRG

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[17] The plant manager must be careful in deciding on which units to defer maintenance because since the deferment of Unit 4, Unit 3 at El Segundo now has a problem and Unit 4 is has become more worn. Units 3 and 4 will need to be brought down for scheduled maintenance in February with the concurrence of the ISO.

could manage the O&M of the plants more effectively and more efficiently. Dynegy stated that it is no longer under contract with SCE for O&M on the purchased plants, and that the staffing transition from SCE to NRG for O&M went smoothly. The employees at the generation plants are now NRG employees. Dynegy believes that since NRG has taken the responsibility for O&M on the plants, there have not been as many outages per MW of capacity. Dynegy believes this has occurred for two reasons: (1) The units may have been running harder and longer, but maintenance practices are better; (2) much of the maintenance for the units has been deferred due to the market, ISO and PX requests. Dynegy stated that the maintenance employees have not had a vacation since summer.

V. Conclusion

This is a report on plant outages prepared in a short time frame in light of the ongoing power crisis in California. After reviewing the detailed materials provided by West Coast (Dynegy/NRG) and Reliant, it appears the older units owned by these companies have all experienced similar problems based on increased demand and the age of the units. Such problems included boiler tube leaks and casing problems, turbine seal leaks and turbine bladewear, valve failure, and pump motor failures. Similar problems were revealed in the telephone audit of the Southern units.

Staff did not discover any evidence suggesting that the companies reviewed in detail here, West Coast (Dynegy/NRG) and Reliant, were scheduling maintenance or incurring outages in an effort to influence prices or to obtain leverage in negotiations with the ISO. Rather, it appears that these companies accelerated maintenance and incurred additional expense to accommodate the ISO’s operating needs. They also reduced outages and deferred maintenance in December and preserved revenue opportunities by doing so. The detailed site reviews are therefore consistent with the results displayed by the aggregated time series data discussed in the introduction of this report, that prices and maintenance have generally moved in an inverted pattern and the prices are driven by demand, not the companies' maintenance practices.

The audit discussed in this report was not designed to determine whether the companies involved were withholding capacity from the market by refusing to bid or schedule the capacity, or by bids or prices at a level that would not be accepted by buyers.