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UNITED STATES BANKRUPTCY COURT

NORTHERN DISTRICT OF CALIFORNIA

(SAN FRANCISCO DIVISION)

In re PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, Debtor. Federal I.D. Number 94-0742640	CASE NO. 01-30923-DM Chapter 11 Case **Expert Declaration of Andrew J. Van Horn, Ph. D.** **REDACTED VERSION**

I, ANDREW J. VAN HORN, declare:

1. All opinions in this declaration are based on my personal knowledge, except where expressly stated otherwise, or on publicly available information from sources of good reputation and on exhibits exchanged between Pacific Gas and Electric Company ("PG&E") and Puget Sound Energy, Inc. ("Puget").

2. The purpose of this declaration is to provide my expert opinion regarding:

- PG&E's ability to provide up to 300 Megawatts (MW) and 413,000 Megawatt-hours (MWh) of power in winter months to Puget as required under the Capacity and Energy Exchange Agreement Between Puget Sound Power and Light Company and Pacific Gas and Electric Company (Agreement), dated October 4, 1991,
- the functioning of the electricity market and the role of the Control Area operator, particularly in curtailing schedules under the Agreement,
- causes of the declared system emergencies in California and curtailments of scheduled deliveries to Puget in January and February 2001,
- changes in market conditions and the future likelihood of system emergencies in California, particularly during the November 2001 through February 2002 period, and
- the strong incentive PG&E has to meet fully its obligations under the Agreement, as measured by the value of the Agreement to PG&E over the next year.

3. <u>Principal Conclusions</u>:

Based on changes that have already occurred after February 2001 or are likely to occur by next November that will affect California and Western energy markets, and based on my analysis of factors affecting power transactions, including results from a detailed simulation of the WSCC power market, and my review of the Agreement, I conclude that:

a. Puget's claims that PG&E will be unable to reliably produce 300 MW of power for delivery to Puget next winter are unfounded. PG&E's own fossil, nuclear, hydroelectric and pumped storage power plants total about 5,800 MW and are expected to generate about 8,900,000 MWh during November 2001 through February 2002. PG&E's contracts provide over 3,000 MW of additional capacity

and 8,464,000 MWh of additional energy expected to be available during November 2001 through February 2002.

b. **Market and regulatory conditions in California during January and February 2001 were unique and extreme compared to conditions in the past. More normal conditions can reasonably be expected to occur in future winters, bringing supply and demand into balance and increasing the reliability of the western power grid over that experienced this past winter.**

c. **Specific measures now being undertaken in California and the West, including increased energy conservation to reduce demand, higher prices that will reduce demand, and the addition of new generating capacity to increase electricity supply will act to increase electric system reliability by November 2001. The measures being instituted to bring supply and demand into balance this summer will also reduce the likelihood of shortfalls next winter. These actions will reduce the likelihood of Stage 1, 2 or 3 emergencies that might cause the ISO to curtail power transactions next winter. As more new power plants are added in 2002, and beyond, the reliability of supply in California and the West will increase further from what it was in January and February 2001.**

d. **The Agreement between Puget and PG&E has always assumed there is a risk that scheduled transactions will be curtailed by or at the request of the control area operator acting in accord with established WSCC operating criteria and good utility practice.**

e. **There is considerable value to PG&E of continuing the Agreement. Between June 1, 2001 and September 30, the value of Puget's deliveries to PG&E would be in excess**

of $192 million.[1] Between June 1 and December 31, 2001 the approximate value of the power deliveries to PG&E from Puget less the value of power PG&E will deliver to Puget is in excess of $118 million, and between June 1, 2001 and the end of February 2002, the approximate net value of the power to PG&E is $72 million.

4. I am a Principal and the Managing Director of the Van Horn Consulting Group, located in Orinda, California. I earned a B. S. degree in Physics from Harvey Mudd College in 1967 and a Ph. D. degree in Physics from the University of California at Berkeley in 1972. Prior to founding the Van Horn Consulting Group in 1987, I was a Principal and Director of Putnam, Hayes & Bartlett, Inc, an economic and management consulting firm. My resume attached to this declaration contains additional details of my qualifications, including a list of all publications I have authored in the last ten years. I expect to be compensated at my normal hourly rate of $200 for my work on this case.

5. My opinions are based on over 23 years' examination and analysis of electricity and fuel markets and the conditions that affect their operation, including economic, technical, regulatory, managerial and political factors. My declaration in this matter is based primarily on:

- my examination and analysis of western (and other) electricity and fuel markets,
- the terms of the Agreement , and
- the conditions likely to prevail during 2001 and 2002 and in subsequent winter seasons.

6. **PG&E owns and operates power plants with sufficient capacity to generate more than 300 MW of power. These generation resources are more than sufficient to generate and deliver the energy required under the Agreement. PG&E also controls more than 300 MW by contract that can be delivered on the interconnected western power transmission grid to satisfy**

[1] This value could be higher due to the pattern of PG&E's scheduled deliveries, higher hourly prices than those used in the calculation and high price volatility anticipated for this summer.

the Agreement.[2] The Agreement does not specify or require particular facilities to be dedicated to generating the power to be supplied under the Agreement.

7. Tables I and II below show the energy from PG&E-owned resources and contracts anticipated to be produced under dry rainfall conditions (i.e., a "dry hydro year") during the period from November 2001 through February 2002 and the capacities of these resources.[3]

Table I

Projected PG&E-owned and Contracted Generation November 2001 to February 2002

Dry Hydro Year Estimate (MWh per month) --Redacted

Resource	November	December	January	February	TOTALS
Hydro					
Pumped Storage					
Fossil					
Nuclear					
SUB-TOTALS					
Irrigation District					
Qualifying Facility					
Bilaterals					
TOTALS					

[2] The western power grid operates as an interconnected system. Power injected at one location can be withdrawn at another, subject to the laws of physics and the rules under which the electric transmission grid is operated.

[3] PGE Exhibit D (PG&E 01195 and PG&E 01192).

Table II

PG&E-owned and Contracted Generating Capacity

During November 2001 to February 2002 -- Redacted

(MW)

Resource	November	December	January	February
Hydro				
Pumped Storage				
Fossil				
Nuclear				
SUB-TOTALS				
Irrigation District				
Qualifying Facility				
Bilaterals				
TOTALS				

8. Higher amounts of power than shown in Table I would be generated from PG&E's hydroelectric power plants under less adverse rainfall and snowfall conditions (e.g., a normal hydro year).

9. Because PG&E has already delivered 178,000 MWh to Puget during January and February 2001, the remaining amount of energy PG&E is obligated to deliver during November and December 2001 is 235,000 MWh. This 235,000 MWh is only about 2.6 percent of the amounts that PG&E would have available for those two months in a low hydro year, as shown in Table I. During the 1997 to 2000 period, PG&E delivered on average 245,000 MWh to Puget during the months of November and December, so the maximum amount to be delivered by PG&E later this year is less than the average amount delivered in recent years.

10. The total net capacity of PG&E resources, owned and under contract, is expected to be 9,422 MW or more during the November 2001 to February 2002 period. The 300 MW maximum hourly delivery under the Agreement is 3.2 percent, or less, of the capacity of

PG&E's available generating resources.[4] **Clearly, PG&E has sufficient capacity and expected energy from its generation resources to meet its obligations under the Agreement.**

11. PG&E has been a net purchaser rather than a net generator for many years, including the period before the Agreement was entered into. For example, in 1991, PG&E generated 51,406,980 MWh, whereas its sales plus PG&E's internal uses, losses and unaccounted for energy totaled 81,380,137 MWh.[5] While PG&E has sold some of its generating plants and the energy from and capacities of sold plants are not included in Tables I and II, these plants remain in business and are either operational or temporarily shut down for refurbishments. Most of these plants are expected to be available to generate power next winter.

12. Puget is also a net purchaser of energy and reports that it purchases 65% of its electricity, primarily from plants on the mid-Columbia River.[6] This is a higher percentage of purchased power than PG&E's percentage of purchased power at the time the Agreement was entered into and is about the same percentage as PG&E expects to purchase in years with normal year hydro conditions. Despite loads that are higher than their own respective generating capacities and energy outputs, both Puget and PG&E have managed to deliver their annual obligations each year under the Agreement.

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[4] In addition, PG&E will either restore its 170 MW Kern power plant to operational status as soon as reasonably possible or sell the plant to a firm that would restore the facility and supply power into the western electricity market. PG&E's Kern power plant was placed in cold stand-by in 1984 and was retired from PG&E's books in 1994. PG&E conducted an auction for the sale of the plant and identified a winning bidder. PG&E then filed applications with the CPUC for authority to establish a market value and to sell the plant to the winning bidder. After these applications were filed, the Governor approved ABx1-6, amending Public Utilities Code Section 377 to prohibit, prior to January 1, 2006, the disposal of generation facilities owned by public utilities. The CPUC found it was precluded by Code Section 377 from allowing PG&E to sell the Kern facility. On April 3, 2001, the CPUC ordered PG&E to restore the Kern plant to operational status as soon as reasonably possible. Moreover, Assembly member Dean Florenz (D-Shaftner) has sponsored ABx1-63 to allow PG&E to sell the plant to the high bidder.

[5] Pacific Gas and Electric Company, 1991 Financial and Statistical Report. PG&E Exhibit L.

[6] http://www.pse.com/about/electric_supply.html, May 9, 2001. A utility that is dependent largely on supplies from hydro facilities is likely to experience significant variations in the availability of its generation due to variations in water conditions. Puget is more dependent on hydro generation than PG&E and is particularly dependent on hydro generation it does not own.

13. The western power transmission system is governed by the rules and criteria of the Western Systems Coordinating Council (WSCC).[7] Within the WSCC, control area operators, including the California Independent Systems Operator (ISO) and the Bonneville Power Administration (BPA) or its successor RTO West,[8] operate the western transmission grid in accord with WSCC rules and the laws of physics. These rules are designed to assure reliable interconnected system operation and are intended to keep transmission flows within specified limits, while maintaining system frequency, controlling scheduled interchanges of power with other control areas and minimizing loop flow. When it is necessary to maintain operations within the parameters established by the WSCC, the control area operator may curtail or interrupt scheduled energy transactions. This risk of non-delivery of scheduled energy transfers has always existed throughout the term of the Agreement.[9]

14. Electricity market participants buying, selling or delivering power to or from PG&E, including electricity sellers, buyers and Scheduling Coordinators, are expected to comply with the California ISO's procedures and protocols. During its existence, the California ISO has instituted various alerts, warnings and Stage 1, 2 and 3 emergencies to preserve and maintain the reliable operation of the transmission grid and protect electric system facilities and the public from hazard.

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[7] WSCC is an alliance of power systems in the 14 western states, two Canadian provinces and the northern portion of one Mexican state. Its interconnected transmission system integrates the great hydroelectric facilities of the Pacific Northwest with the large coal-fired and nuclear generating stations in the Southwest and Rocky Mountain area and the natural gas-fired, nuclear, hydro and renewable power plants in California.

[8] A control area operator can also be referred to as an Independent System Operator (ISO) or a Regional Transmission Organization (RTO). In general, RTOs will consolidate a number of control areas. RTO West will be the ISO for an 8 state Regional Transmission Operator (RTO) that includes both a for-profit transmission company and transmission assets owned by PacifiCorp, Idaho Power and BPA. The for-profit company TransConnect will own and operate the transmission facilities in the area served by Avista, Montana Power, Nevada Power, Sierra Pacific Power, Portland General, and Puget Sound Energy. RTO West includes all of these applicants, including BPA, which controls 75% of the transmission facilities in the region. The Federal Energy Regulatory Commission recently approved TransConnect. Puget is a member of TransConnect and was an active participant in the design and development of RTO West, which received its initial approval by FERC on April 25, 2001 [RTO1-35-000].

[9] A Control Area is a geographic area within which a system operator regulates electric power generation and transmission in order to maintain scheduled interchanges of power with other Control Areas and to maintain system frequency and other system characteristics as specified in the North American Electric Reliability Council (NERC) Operating Guidelines. Regional electric reliability councils, such as the Western States

(footnote continued...)

The California ISO has filed its Dispatch Protocols (covering Emergency Operations and Obligations of Participating Generators Relating to System Emergencies) with the Federal Energy Regulatory Commission (FERC) and also has an Operating Procedure. A summary of relevant parts of the California ISO's Emergency Procedures, Dispatch Protocol and Operating Procedure is presented in Attachment I.

15. The RTO West is developing its operating protocols, including those for system emergencies. RTO West plans to file a Tariff with FERC that includes an Appendix C covering Dispatch and Emergency Operations.[10] A draft of this Appendix states: "RTO West shall have the full authority to …. alter scheduled deliveries of Energy and/or Ancillary Services into or out of the RTO West Grid, if such actions are reasonably necessary to prevent the imminent loss of operational control or to retain operational control over the RTO West Grid…." As an applicant of RTO West and member of TransConnect, Puget has presumably developed, or at least reviewed, the protocols for RTO West. All control area operators within the WSCC interconnected region, as well as throughout the nation, have similar protocols for maintaining grid operations and protecting the grid and other interconnected facilities. These protocols, when instituted by control area operators, take precedence over contracted power flows, and in emergency situations may be applied to interrupt or curtail firm power flows.[11]

16. Control area operators give a high priority to maintaining system reliability. For example, in April 2001, BPA publicly stated in its monthly Journal that "BPA has sold no power to California that was needed in the Northwest. BPA's Policy is to do **nothing** for California that will adversely affect the reliability of the Northwest's electrical system, the Northwest's environment or BPA's financial health."[12]

(continued from previous page)
Coordinating Council, WSCC, develop particular rules and protocols.

[10] Appendix C: RTO West Dispatch and Emergency Operations, 3/21/01 Draft PG&E Exhibit N.

[11] Because of the laws of physics, the actual paths by which electricity flows and are delivered in a transmission system are not the same as the contractual paths used to represent the origination and delivery of power.

[12] Keeping Current, A Publication of the Bonneville Power Administration, April 2001. PG&E Exhibit U.

17. The rules and operating criteria for control area operators, which previously included PG&E and Southern California Edison (SCE), and the laws of physics governing the delivery of electric energy over transmission lines are very much the same as they were from 1991 to 1998, before the partial deregulation and restructuring of the California electricity market. As a result, the risk of non-delivery of scheduled energy transfers has existed throughout the term of the Agreement.

a. The curtailments of PG&E's deliveries to Puget that occurred during January 2001 and three hours in February 2001 were not failures of PG&E supply. They derived from the California ISO's operation of its control area. The ISO operated in accord with operating criteria that are designed to protect the grid and interconnected facilities, while maintaining reliable service. The cause was a temporary imbalance in supply and demand, as determined by the operating criteria, due to a shortfall in available supplies. The emergency declarations were the ISO's, not PG&E's. The power that otherwise would have been delivered to Puget was, instead, delivered within California to keep the system in instantaneous balance. As described in Attachment I, the California ISO can declare an emergency and take actions if there is a danger of imminent collapse of the system. The purpose of this preventive action is to prevent actual system collapse and to minimize the scope of any collapse.

b. There is always a risk that power will not be delivered due to a variety of potential causes. For example, the blackouts caused by outages on the transmission facilities that link California and the Pacific Northwest (the "Intertie") during the 1990s resulted in curtailment of otherwise firm power flows across the Intertie.

c. The control area operator's reliability rules and protocols during a system emergency supersede contractual delivery schedules of market participants. The electric system within a control area could not work effectively without the ability of a system operator to take actions necessary to prevent the collapse of the system.

18. The Agreement permits interruptions due to Uncontrollable Forces and good faith actions taken to "prevent, reduce, or eliminate: (i) hazard to life or property or (ii) unsatisfactory, or jeopardy to continuity of, electric service within that Party's Service Area."[13]

19. In its Complaint, Puget discusses the "firm energy" it can generate from its own facilities and from firm contractual commitments.[14] However, the Agreement differs in some respects from other power sales agreements in its treatment of firm power. Unlike firm purchase power contracts for the electric power output of a specific generating unit (called Unit Commitment Service) or a firm wholesale power transaction conducted under WSPP Agreement Service Schedule C,[15] the Exchange Agreement does not provide for damages for failure to deliver nor does it dedicate particular facilities or each utility's system resources to providing the energy to be delivered under the Agreement. In the Agreement, there is no provision for damages spelled out in the event of interruption by the Control Area operator. Indirect and consequential damages are prohibited. There are also no liquidated damages for interruptions, as is common in "firm" power sales contracts.

20. Although Puget claims that it has every reason to believe that wintertime curtailments will recur, the energy market and electric system conditions that occurred during January and February 2001 were extreme in comparison to past experience. They were also extreme in comparison to the conditions likely to occur after summer 2001. Improved market and electric system conditions will reduce the likelihood of curtailments next winter.

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[13] The Agreement, PG&E Exhibit A, pages 16-17.

[14] The Complaint No. C01-0417C, March 20, 2001, filed in U.S. District Court, Western District at Seattle, pages 13-14.

[15] WSPP Agreement Service Schedule C: FIRM CAPACITY/ENERGY SALE OR EXCHANGE SERVICE,

(footnote continued...)

21. During January and February 2001, extreme conditions required the California ISO to declare system emergencies. A list of the Stage 1, Stage 2 and Stage 3 emergencies declared by the California ISO in 2000 and through March 20, 2001, is contained in a report prepared by LCG Consulting.[16] Table III, below, contains information from announcements made by the California ISO on selected days during January and February 2001. The California ISO declared an unprecedented number of Stage 3 electrical emergencies during those two months due to the very low reserve margins in California. Furthermore, these emergencies often lasted the entire day. The total capacity of the plants that had planned and unplanned outages was unusually high on the days of the emergencies.

Table III

Selected Announcements by the California Independent System Operator

During January and February 2001[17]

Date	Key Points
1/11/01	Stage Three Electrical Emergency Declared. The total amount of generation offline is now at 15,000 megawatts or more than one-third of all the available power in the state. The Stage Three is in effect until 10 p.m.
1/17/01	Stage Three Emergency Again Today. The total number of units offline due to planned and unplanned outages is more than 11,000 megawatts. The Stage Three declaration enables the California ISO to receive additional emergency assistance from federal and state agencies.
1/18/01	Northern California Blackouts Ordered at 9:50 a.m. Electricity supply remains very limited throughout the Western Region. Conservation efforts will help lessen the severity and duration of outages. All Californians are urged to rededicate their efforts to save as much energy as possible during this emergency situation.
1/19/01	Rotating blackouts have not been ordered but they cannot be ruled out. Yesterday's Stage Three Electrical Emergency was extended at midnight and remains in effect until midnight tonight.

(continued from previous page)
PG&E Exhibit AA.

[16] Analysis of reserves for the California System Operator Area, March 20, 2001, prepared by LCG Consulting, March 20, 2001. PG&E Exhibit M.

[17] News Releases from the California Independent Operator, www.caiso.com, PG&E Exhibit X.

Date	Key Points
1/22/01	State remains under Stage Three Electrical Emergency.
1/23/01	Stage Three Emergency Extended.
1/26/01	Stage Three Electrical Emergency Declared. The Stage Three declaration allows the California ISO to access emergency assistance from federal and state agencies in order to make up for the generation loss.
2/5/01	Tomorrow is 22nd Day Under Stage Three Emergency.
2/13/01	Stage Three Extended for Day 30. A total of 10,000 megawatts is offline throughout the state due to maintenance issues.

22. The insufficiency of generating capacity experienced in California during January and February 2001 occurred, at times, in other parts of the western interconnected system. For example, see ISO's January 18, 2001 announcement in Table III. According to BPA, three factors are contributing to this year's extraordinary circumstances.[18] Each factor alone poses challenges for BPA, but the combination is particularly difficult. The three factors are:

- "a near record low-water year" with Columbia Basin water runoff for 2001 at "only 55 percent of normal, the second-lowest runoff in the 72-year history of this measurement."
- "a tight West Coast power supply" with frequent power emergencies in California, and
- "an extreme market" with prices in the range of $200 to $300 per megawatt-hour, compared to historic Northwest wholesale prices that have rarely been above $30 per megawatt-hour.

A lack of available supply, along with the drought, led BPA to declare power system emergencies on two occasions this past winter. BPA was able to keep the lights on by using water it normally would have stored for fish migration during the spring.

23. This shortfall of generating capacity was caused by the confluence of numerous extreme weather, market and regulatory conditions that are unlikely to recur together in the future. Among the factors that contributed to the curtailments are:

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[18] Communication from Bonneville Power Administration to BPA Customers and Citizens of the Pacific Northwest, March 29, 2001. PG&E Exhibit DD.

– Low hydro conditions in California and the Pacific Northwest,

– Very high natural gas prices throughout the U.S. and in California,

– Insufficient natural gas transmission line capacity into California,[19]

– Numerous unplanned electric generator outages, including an accident at the San Onofre nuclear plant on February 5, 2001, putting 1100 MW out of service,[20]

– Qualifying Facilities (QFs) and other generators withholding power due to lack of payments and cash flow difficulties,

– Electric transmission constraints, and

– Shortage of air emission credits for NOx.[21]

24. Each of the above factors should return to more favorable conditions later this year. More normal precipitation and snowfall in California and the Pacific Northwest should increase next winter's water runoff over this year's very low values, which were projected in February to be only 55 percent of normal in the Columbia Basin.[22] Natural gas prices should come down somewhat, and California gas prices should move closer to national averages than they were this past winter.[23] This past winter both the price of natural gas in California and its basis differential relative to national average gas prices reached unprecedented high levels. Generator forced outages resulting from equipment malfunctions should also move back towards historical norms. Already Qualifying Facilities have begun generating more power than in January and February, since they are now being paid fully for their current generation, while this past winter many were receiving only partial

[19] Partially caused by the explosion on the El Paso pipeline on August 19, 2000, that removed 500-600 MMcf/day of natural gas pipeline capacity entering California.

[20] The anticipated date of return to service is in June 2001.

[21] Many factors have contributed to the unusual market conditions that occurred this past winter. A number of these are discussed in an article: "Was Gas to Blame? Exploring the Cause of California's High Prices." Edward N. Krapels, Public Utilities Fortnightly, February 15, 2001, p. 28. PG&E Exhibit Y.

[22] Communication from Bonneville Power Administration to BPA Customers and Citizens of the Pacific Northwest, March 29, 2001. PG&E Exhibit DD. The graph for January-July runoff at The Dalles (1929-2000) shows that only 1977 runoff was lower than this year's.

[23] Natural gas prices were unusually high last winter, in part due to relatively low storage inventories and low drilling activity brought about by low oil prices two years ago. Increased drilling activities will help reduce natural gas prices.

payments. On March 27, 2001, the California Public Utilities Commission ordered PG&E, SCE and San Diego Gas & Electric Company (SDG&E) to pay for energy deliveries from a Qualifying Facility within 15 days of receipt of an invoice. On May 9, 2001, PG&E reported that only eight of the more than 300 Qualifying Facilities under contract to PG&E were shut down for payment-related reasons.[24] Overall, as discussed below, many factors and actions now being undertaken will reduce the likelihood of California supply shortfalls next winter and in winters thereafter.

25. Taken together, the very likely improvements in market conditions and electric system reliability should enable PG&E to deliver power reliably to Puget. Among these factors are:

- new power plants coming on line and enhancements to other supply sources,
- transmission upgrades, which will improve power flows,
- increased voluntary conservation by energy consumers that reduces demand,
- responses by consumers to price increases that will lower demand,
- programs to shift demand to non-peak periods, including time-of-use meters,
- more typical occurrences of plant outages, which were abnormally high during winter 2001,
- increased operating hours at some plants through the acquisition of emission offsets,
- expected increases in hydroelectric production due to more normal rainfall, and
- various legislative and regulatory actions.

Also, it is likely that there will be improved generator responses to ISO dispatch instructions during emergency situations.[25] Many of these factors have been widely reported in the press.[26] Some information on them is presented below.

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[24] http://www.pge.com/006a_news_rel/010509ashtml

[25] In January and February there was some turmoil about the California ISO's authority to order generators to dispatch their plants in emergencies. As a result the ISO sued the generators on February 6, 2001, in federal court in Sacramento. The complaint and other papers are on the ISO website and may be found at: http://www.caiso.com/docs/09003a6080/0b/81/09003a60800b8126.pdf. The lawsuit was rendered moot and the issue resolved by FERC Order dated April 25, 2001 (EL00-95-012), which confirmed ISO's emergency dispatch powers. One of the ISO's chief complaints in the case was that generators were interfering with ISO's proper functioning by debating the need to turn on their plants and resisting the orders, unless they were assured of payment from a creditworthy buyer. This turmoil has settled down and should not recur in future Stage 3 emergencies.

26. ***New Power Plants***. Many power plant projects are under construction, seeking financing or are being developed through California's emergency procedures and should be on-line in 2001, 2002 and 2003. Data on projects from a list prepared by the California Energy Commission (CEC) are shown in Table IV.

TABLE IV

Status of Approved and Emergency Projects to Add Generating Capacity in California[27]

	Capacity (MW)	Location	Decision Date	On-line Date
2001 Construction				
Sutter	500	Sutter Co.	Apr-99	Jul-01
Los Medanos	559	Contra Costa	Aug-99	Jul-01
Sunrise	320	Kern Co.	Dec-00	Aug-01
Wildflower Larkspur	90	San Diego Co.	Apr-01	Jul-01
Wildflower Indigo	135	Riverside Co.	Apr-01	Jul-01
Alliance Century	40	San Bernardino	Apr-01	Aug-01
Alliance Drews	40	San Bernardino	Apr-01	Aug-01
Calpine King City	50	Monterey Co.	May-01	Sep-01
Subtotal	1,734			
2001 Financing				
Huntington Beach	450	Orange Co.	May-01	Aug-01
United Golden Gate	51	San Mateo Co.	Mar-01	Aug-01
Subtotal	501			
2001 Emergency				

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[26] For example, see Wall Street Journal, Page B1, May 9, 2001: "The Big Power Crunch – California Braces for the Heat With Programs to Expand Supplies and Cut Demand." The article cites some of the "steps California is taking to conserve energy and prevent rolling blackouts: ~ Proposing to add 5,000 megawatts of new generating capacity, ~ Appointing an 'energy construction czar,' ~ Offering rebates for energy-efficient consumer appliances, ~ Paying businesses for using less electricity during peak demand periods, ~ Installing thousands of sophisticated electric meters to track usage, ~ Urging people to conserve through widespread publicity campaigns." PG&E Exhibit K.

[27] Table shows projects listed by the California Energy Commission with on-line dates in 2001, 2002 and 2003. Information as of May 2, 2001 from www.energy.ca.gov. The Huntington Beach project has recently been approved. PG&E Exhibits O, W.

	Capacity (MW)	Location	Decision Date	On-line Date
GWF Hanford	95	Kings Co.	May-01	Aug-01
Ramco Chula Vista	57	San Diego Co.	May-01	Aug-01
Calpine Gilroy	150	Santa Clara Co.	May-01	Sep-01
Pegasus Energy	180	San Bernardino Co.	May-01	Sep-01
Simple Cycle	100	Fresno Co.	May-01	Aug-01
Simple Cycle	50	Sutter Co.	May-01	Aug-01
Simple Cycle	49	San Diego Co.	May-01	Sep-01
Simple Cycle	50	Kern	May-01	Sep-01
Simple Cycle	80	Sacramento	May-01	Aug-01
Simple Cycle	60	San Mateo Co.	May-01	Aug-01
Simple Cycle	150	Los Angeles Co.	May-01	Sep-01
Simple Cycle	65	Los Angeles Co.	May-01	Sep-01
Subtotal	1,086			
2001 TOTAL	**3,321**			
2002 Construction				
La Paloma	1,048	Kern Co.	Oct-99	Dec-01 - Mar-02
Delta	880	Contra Costa	Feb-00	Apr-02
Moss Landing	1,060	Monterey Co.	Oct-00	Jun-02
Subtotal	2,988			
2002 Financing				
Mountainview	1,056	San Bernardino	Mar-01	Dec-02
2002 TOTAL	**4,044**			
2003 Construction				
Elk Hills	500	Kern Co.	Dec-00	Mar-03
High Desert	720	San Bernardino	May-00	Jul-03
Subtotal	1,220			
2003 Financing				
Pastoria	750	Kern Co.	Dec-00	Jan-03
Midway-Sunset	500	Kern Co.	Mar-01	Mar-03
Blythe	520	Riverside Co.	Mar-01	Mar-03
Otay Mesa	510	San Diego Co.	Apr-01	Apr-03
Subtotal	2,280			
2003 TOTAL	**3,500**			

27. The totals for the annual capacity additions in California as a result of these projects are 3,321 MW in 2001, 4,044 MW in 2002 and 3,500 MW in 2003. In addition to these projects, there are numerous projects seeking or planning to seek approval from the CEC. Furthermore, the list of projects does not include small plants and upgrades that do not require CEC approval. The governor has appointed an "energy construction czar" to oversee the building of new plants.[28] There will also be new power plants coming on-line in 2001 in other parts of the WSCC. For example, the report by LCG Consulting shows 7,331 MW of capacity additions in 2001 in the WSCC region.[29]

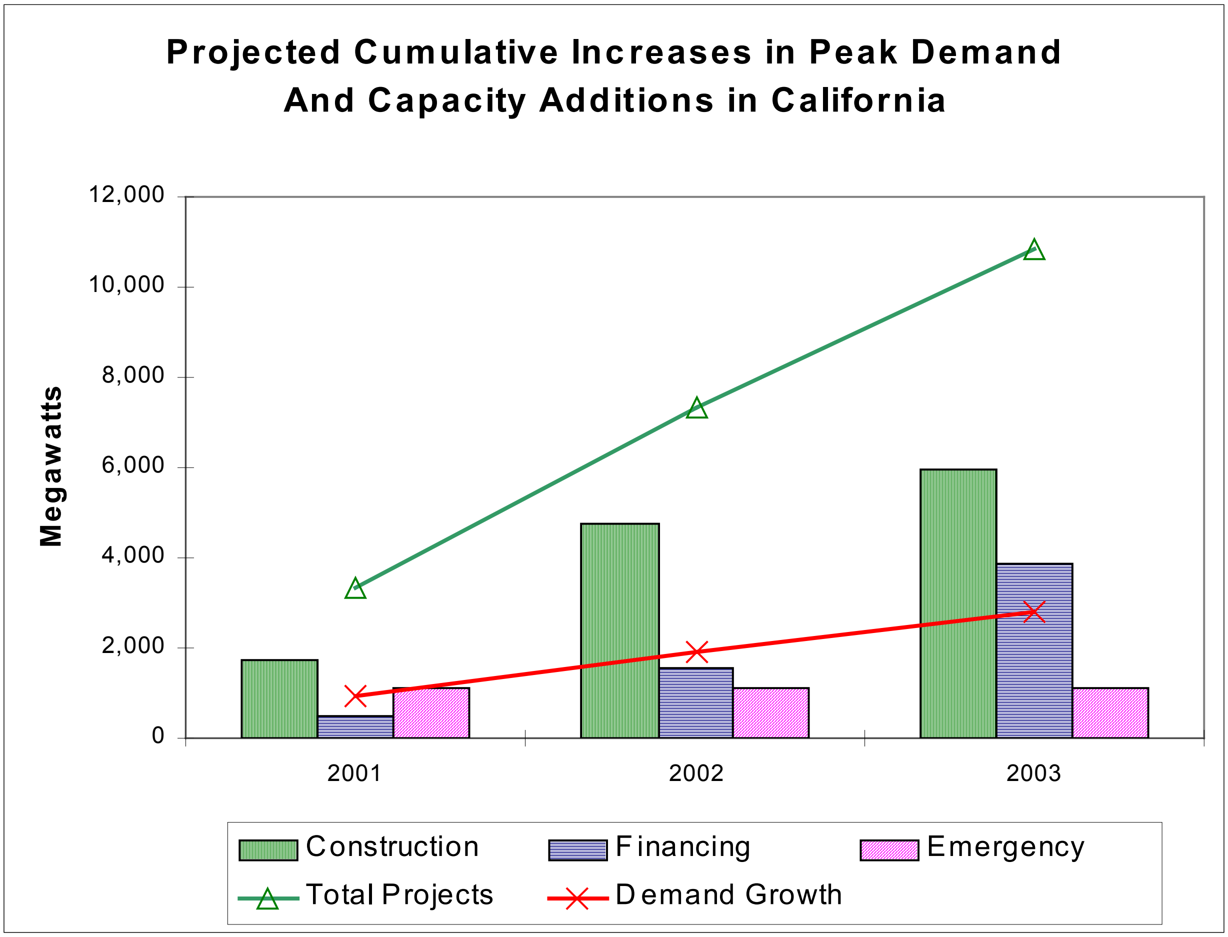
28. The CEC forecasts that the coincident peak demand in 2001 could be as high as 51,267 MW for the California ISO load and 58,648 MW for the state.[30]

[28] Wall Street Journal, Page B1, May 9, 2001. PG&E Exhibit K.

[29] Analysis of reserves for the California System Operator Area, March 20, 2001, prepared by LCG Consulting, March 20, 2001. PG&E Exhibit M.

[30] California Energy Demand, Staff Report, California Energy Commission, June 2000. PG&E Exhibit EE.

29. Figure 1



30. In its forecast, the CEC shows annual increases in projected peak demand in the range of 900 to 1,000 MW. Figure 1 above shows a comparison of the cumulative increases in demand to the cumulative capacity increases from the projects in California that are under construction or have been approved and have received or are seeking financing or are being developed under expedited emergency procedures. The figure clearly shows that there should be significant improvements in the electric market conditions and, hence, increased reserve margins in California later this year and over the next two years.

31. ***Transmission Upgrades***. The California government and the CPUC have taken several recent actions to assure that constraints on California's transmission system are alleviated. California Assembly Bill 970 requires the CPUC to "identify and undertake those actions necessary to reduce or remove constraints on the state's electric transmission and distribution system." And, in addition to transmission upgrades in California, many projects are being undertaken in other areas of the WSCC region.[31]

32. On March 27, 2001, the CPUC directed the utilities to undertake 33 transmission projects to relieve system congestion by this summer. The CPUC intends to address longer-term transmission planning issues and the appropriate role of utilities in the development of generation in a second phase of this proceeding.

33. PG&E plans to construct a transmission interconnection with a generating plant being constructed by Dynegy, Inc./NEO. The 49-megawatt plant is not included in Table IV but is expected to start operation by the summer of 2001.

34. On April 3, 2001, the CPUC ordered PG&E to conduct studies of biological resources along the transmission corridor commonly referred to as "Path 15."[32] PG&E must initiate the studies immediately in order to assure that PG&E is able to begin construction of improvements to Path 15 as soon as possible, in the event the Commission so orders.

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[31] See project listing at http://www.wcif.org/cgi-bin/w2rSum.asp

[32] Path 15 is the main transmission interconnection between Southern California and Northern California. Congestion on Path 15 prohibits, at times, access to economic supply sources in Southern California or the desert Southwest.

35. The director of Mexico's Federal Electricity Commission recently stressed the importance of building up electric connections between the countries from 400 MW possibly to 2,000 MW by next year.[33]

36. ***Increased Conservation.*** Senate Bill 5X and Assembly Bill 29X signed by Governor Davis on April 11 provide more than $850 million for energy conservation and distributed generation programs.[34] On May 3, 2001, the CPUC approved a decision ordering PG&E, SDG&E, SCE and SoCalGas to implement a "rapid deployment strategy" for those programs with currently authorized funding, plus carryover funding and the new funding from the state. Governor Davis announced on April 16 that Californians have slashed their electricity use by 9 percent in March, and according to the CEC state businesses and residents reduced electricity demand by 2,967 MW in March compared to last year. President Bush sent a memorandum to the Heads of Executive Departments and Agencies, directing them to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities.[35] Conservation efforts are also underway in other parts of the WSCC region. For example, Washington State regulators recently approved an innovative energy conservation plan from Puget.[36] Puget projects a load reduction of 3 percent from conservation.[37]

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[33] EFE via COMTEX, May 4, 2001. PG&E Exhibit FF.

[34] SB 5X and AB 29X provide more than $850 million for energy conservation and distributed generation programs, including $35 million for time-of-use meters, $50 million for innovative peak load reduction programs, $90 million for agricultural load reduction and energy efficiency, $50 million for energy-efficient household appliances, $60 million for high efficiency lighting in commercial buildings, $20 million for the low-income energy efficiency program, and $20 million for high efficiency lighting to low-income residences. CCH Law Reports, No. 1302, p. 4. PG&E Exhibit CC.

[35] News Release, Office of the Press Secretary, The White House, May 3, 2001. PG&E Exhibit P.

[36] http://www.pse.com/fastfind/news_flash.html, dated April 25, 2001.

[37] PSE 2144, PG&E Exhibit GG.

37. Consumer Responses to Price Increases. On March 27, 2001, the Commission approved the continuation of an interim increase in electric rates of one cent per kWh (authorized on January 4, 2001) and an additional increase of three cents per kWh for PG&E and SCE customers. The three-cent increase is equal to an increase of about 27 percent in electric rates. The CPUC is to decide tomorrow how the increase will be allocated among customer classes.

38. The University of California Energy Institute studied the impact of increases in electric prices on electric energy consumption in the service territory of SDG&E.[38] Retail rates more than doubled for customers of SDG&E during the period examined by this study (the summer of 2000), while they remained frozen for customers of PG&E and SCE. The study found that average electricity consumption decreased by 1.6% between mid-July and the end of August. Consumption was reduced by over 6% in the late afternoon and late evening. The authors noted that, because of the uncertainty about the duration and the credibility of the rate increase, these results should be viewed as a lower bound on the demand reductions that could be achieved through pricing incentives. Other studies have also shown that significant reductions in demand will occur as a result of price increases. For example, the Department of Energy's Energy Information Administration forecasts the behavior of the U.S. energy system by applying its National Energy Modeling System (NEMS). NEMS uses a short-term demand elasticity for electricity of about -0.2, i.e., initially demand will decline by 0.2% for every 1% increase in price. A reduction of demand in a particular hour essentially avoids the need to generate power equal to the MW demand reduction occurring in that hour. Residential consumers in California will be offered a 20% reduction in their bills, if they conserve at least 20% during the summer months compared to their usage in the previous year.

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[38] "The Impact of Retail Rate Deregulation on Electricity Consumption in San Diego," James Bushnell and Erin Mansur, University of California Energy Institute, PWP-082, April 2001. PG&E Exhibit Q.

39. Programs to shift demand to non-peak periods. On April 3, 2001, the CPUC ordered PG&E, SCE and SDG&E to each file revised tariffs to implement changes to current interruptible demand programs.[39] In this interim order, the CPUC described the changes to the programs and the incentives that are being offered to participants in the programs. The new programs increase the times that participants can be called upon to reduce load.

40. More typical occurrences of plant outages. Plant outages in recent months have been unusually high when compared to historical averages. For example, on January 11, 2001, the ISO reported that the total amount of generation off-line was 15,000 MW or more than one-third of all the available power in the state.[40] Some of the plants have been off-line for refurbishments. These refurbishments should increase the capacity and/or improve the future reliability of the plants. For example, in Table IV above, the existing Moss Landing power plant has units under construction to provide a capacity increase of 1,060 MW with an on-line date of June 2002.

41. Increased operating hours of some plants through acquisition of emission offsets. Several power plants in the Los Angeles air basin exceeded their allowable air emissions and were forced to cut back generation or pay substantial penalties. Efforts are underway to alleviate this situation.

42. Expected increases in hydroelectric production. The Pacific Northwest has had one of its worst years on record for hydroelectric production. Simply based on historical production, it is probable that the hydro conditions in the Pacific Northwest for the next rainy season will improve.

43. Various other regulatory and legislative actions. In addition to the actions discussed above there are numerous actions now being considered. For example: (i) AB 569 requires the CEC

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[39] Interruptible programs offer reduced rates to customers who agree to lower their electric consumption when called upon by the utility.

to resolve permit appeals in 30 days and exempts repowering projects from Environmental Impact Report Requirements, (ii) AB 944 authorizes simple cycle power plants certified prior to January 1, 2001 and operational prior to August 1, 2001 to convert the facility to a combined-cycle plant, (iii) AB 1529 requires CEC to establish a procedure for expedited review of transmission lines, natural gas pipelines, and (iv) SB 55 (1st Extraordinary Session) exempts electrical corporations from penalties incurred due to air emissions during a Stage 2 or greater emergency. These and other bills related to the electric market situation are pending in the state legislature.

44. All of these factors are likely to act to reduce any potential supply and demand imbalances next winter and allow PG&E to deliver power on schedule to Puget. The demand during winter months in California and in the WSCC as a whole is lower than in summer months. Hence, actions to improve reliability in California for the summer months should enhance reliability during winter months.

45. Detailed physical and economic simulations of the WSCC power market demonstrate that the addition of power plants during 2001 will improve market conditions and system reliability by winter 2001-2002. The improved reliability will decrease the likelihood of Stage 2 and 3 emergencies and should enable PG&E to reliably deliver power to Puget next winter.

46. An independent quantitative study performed by LCG Consulting in February 2001 evaluated the expected reserves and reliability of the California ISO's control area by simulating the operation of the western electricity market. The study was not commissioned by PG&E for this case. The study estimates the probabilities of Stage 2 emergencies for each month from May 2001 through February 2002. The quantitative analysis was performed by applying the UPLAN-Network Power

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(continued from previous page)
[40] News release, California ISO, January 11, 2001. PG&E Exhibit X.

Model, which produces results used by utilities, merchant power plant owners, the CPUC and others. This large-scale hourly simulation model is a large-scale multi-commodity, multi-area regional electricity model.[41] The UPLAN-NPM simulates physical market operations in response to supplier bids for energy and ancillary services, and it performs hourly chronological production costing with Monte-Carlo methodology to simulate the system reliability and uncertainty associated with generators and loads. It is among the most sophisticated and highly regarded models to simulate electric market conditions. The results cited here are for the WSCC region. The WSCC region is the appropriate region to examine, since the generators within the WSCC are interconnected. UPLAN divides the region into major areas or zones, which reflect distinct geographic and climatic conditions and recognize transmission constraints.

47. UPLAN contains data on the electric transmission lines, electric energy and peak demand, electric generating plants and fuel prices. With this information, the model evaluates by hour which plants will supply each market zone, the costs of operating those plants, bidding strategies and the resulting market clearing prices. The market clearing price in a zone for a particular hour is the price of electricity delivered to the zone from the marginal generator for that hour. The hourly market clearing prices can be aggregated to provide average market clearing prices during on-peak periods and off-peak periods, as well as annual average prices. The model also balances hourly electric energy flows over the transmission lines, so that flows satisfy the laws of physics and

[41] Results from independent UPLAN simulations conducted in February 2001 were added to the calendar year 2001 results to extend the reported study results into 2002, in order to demonstrate the projected occurrences of Stage 2 and 3 emergencies during January and February 2002. UPLAN is owned by LCG Consulting of Los Altos, California. The model simulates the WSCC using approximately 330 power plants and a network equivalent circuit with 15 demand areas, 87 nodes and 219 transmission lines. The transmission emulation is actual AC load flow, run with typical weeks for each month in an hourly chronological mode, with generating units applying various bidding procedures to simulate expected market behavior. Analysis of Reserves for the California Independent System Operator Area, LCG Consulting, Los Altos, CA. March 20, 2001. PG&E Exhibit M.

electrical constraints.

48. The LCG analysis forecasts hourly reserves in California using the UPLAN volatility model. Probability distributions were developed to measure the uncertainty range for future electric loads, hydro conditions and transmission interface limits. The model's calculations incorporate specific generating units expected to be installed during the remainder of 2001, but do not include some of the other measures being instituted that will additionally improve the operation and reliability of California's power grid by next winter. Some assumptions in the simulations are conservative (e.g., capacity additions in 2001 are below the amount the CEC currently lists, as shown in Table IV). As shown in Table V below, the LCG report concludes that conditions within the ISO's control area will lead to an expected 980 hours when reserves will fall below 5% (a Stage 2 emergency condition) during the months of June through September 2001.

Table V

Projected Number of Hours with Less Than 5% Reserves
In the California ISO Control Area

Month	Most Likely	Mean	Deviation
May 2001	312	307.3	102.2
June	340	301.4	67.6
July	367	324.0	61.6
August	258	262.5	90.9
September	60	92.2	62.7
October	0	3.9	10.5
November	0	0.5	3.6
December	0	0	0
January 2002	0	0	0
February	0	0	0

49. However, during November 2001 through February 2002, the UPLAN-NPM calculations show on average that there will be only 0.5 hour when the ISO's reserves fall below 5%, leading to a

Stage 2 emergency.[42] The estimated average number of Stage 3 emergencies during November 2001 - February 2002 is zero. This highly detailed simulation of the western power grid demonstrates that summer 2001 will be a difficult period with unreliable electric supplies in California. However, by the winter of 2001-2002 the reliability of the California electricity grid should improve significantly. Hence, the ability to export power supplies out of California reliably in the wintertime will also improve in the future. Furthermore, deliveries to Puget were never curtailed in Stage 2 emergencies, and even in Stage 3s Puget received full or partial deliveries.

50. Current forecasts of power prices indicate PG&E has a strong incentive to perform its Exchange Agreement obligations during 2001 and in future years, as the summer energy PG&E will receive from Puget will most likely be more valuable than the energy PG&E must deliver to Puget next winter. During 2001, PG&E has already delivered 178,000 MWh of its 413,000 MWh annual obligation to Puget. Puget's failure to deliver its power obligation to PG&E this summer would decrease the reliability of the California power system and contribute to higher market prices for power in California.

51. During the remainder of 2001, the Agreement has a positive monetary value to PG&E, its creditors, and all Californians. I have roughly estimated this value as follows, using data presented by Puget. In an April 16, 2001 Declaration for Puget, Mr. Gaines presents forward electricity market prices.[43, 44] Mr. Gaines' Declaration says the value to PG&E to receive contract deliveries from Puget

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[42] These estimates of the number of hours with stage 2 emergencies are mean estimates from a detailed Monte Carlo simulation of the power system that analyzes the probabilities of numerous events and market conditions. PG&E Exhibit M.

[43] Puget's April 16, 2001 Gaines' Declaration, paragraphs 18-19 and Exhibit E.

[44] While an analysis using forward prices does give estimates of values of the Agreement, there are additional benefits to the Agreement. These include the flexibility of scheduling power and the opportunity to take advantage of price differentials between COB and mid-Columbia.

this Summer 2001 is $192 million.[45] Applying the same logic based on the quarterly prices shown in Gaines' Exhibit E, the value of PG&E's deliveries to Puget for the full remaining contract quantities in November and December 2001, would be approximately $74,000,000 (235,000 MWh x Forward Price at COB during Q4 2001of $315/MWh). The difference is the approximate value to PG&E's estate to keep the contract in place for the balance of 2001 alone. This 2001 value to PG&E is $118,000,000. Therefore, for the remainder of calendar year 2001, the continued performance of the Agreement favors PG&E economically by about $118 million. This value and the values shown in the next paragraph are illustrative only since they do not account for the hourly pattern of Puget's or PG&E's likely purchases and other factors.

52. The following simple calculation also illustrates the overall value of the Agreement to PG&E between now and the end of February 2002. Based on prices in Gaines' Exhibit E, if Puget did not deliver power to PG&E this summer under the Agreement, and PG&E was able to replace that power at COB, which is not assured by any means, the cost to PG&E would exceed $192 million. Subtracting the value of the power to be delivered to Puget during the four months, November 2001 through February 2002, which is about $120 million,[46] the approximate net value of the Agreement to PG&E is about $72 million through February 2002.

53. Because it was concerned about the relative value of the Agreement in 1999, Puget asked Enron to bid to take over Puget's responsibilities under the Agreement, and Enron bid to do so.[47] Enron's bid would have required Puget to make substantial payments. Because of the positive value of the Agreement to PG&E during the remainder of calendar year 2001 and into 2002, bidders would

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[45] Puget's April 16, 2001 Gaines' Declaration, paragraphs 18-19 and Exhibit F.

[46] $120 million equals (235,000 MWh x $315/MWh Q4 2001 forward price at COB + 178,000 MWh x $260/MWh Q1 2002 forward price at COB). This illustrative value assumes that Puget would receive 178,000 MWh in January and February 2002, the same amount it received this year.

be likely to pay PG&E for the opportunity to take over its performance for the rest of 2001, provided that Puget is required to uphold its side of the Agreement.

54. Importantly, Puget's deliveries into California this summer could make the difference in whether or not rolling blackouts occur on any particular day. For example, on May 7, 2001, emergency power imports of about 300 MW from the Northwest into California might have averted rolling blackouts. Reuters news (9:17 p.m. ET, May 7) stated: "Voluntary conservation and emergency power imports from the Northwest led ISO officials to declare earlier in the day that California would likely make it through the hot afternoon hours without going to a top level 'Stage Three' power alert, which raises the possibility of blackouts…The ISO ordered utilities to cut about 300 megawatts of electricity from the grid, or roughly enough power to serve 300,000 homes."[48] If such a situation happened this summer, as is anticipated, Puget's delivery of 300 MW could make the difference between a Stage 3 Emergency and rolling blackouts.

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[47] PG&E Exhibit HH (PSE 304-305).

[48] Reuters news (9:17 p.m. ET, May 7). PG&E Exhibit V.

ATTACHMENT I

SUMMARY OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR'S (ISO's) EMERGENCY PROCEDURES, DISPATCH PROTOCOL AND OPERATING PROCEDURE [49, 50, 51]

The timing and severity of a forecasted shortfall in Operating Reserves determines whether an Alert, Warning, or Emergency is declared.[52] To indicate the severity of an Emergency, which is declared for Operating Reserve shortfalls, these Emergency declarations are further classified into three stages. A Stage 3 Emergency may be declared at any time it is clear that a critical Operating Reserve shortfall (i.e., less than one and one half percent) is unavoidable, or is forecast to occur within the next two hours. **Stage 3 is the most severe Stage of Emergency and indicates that, without significant ISO intervention, the electric system is in danger of imminent collapse.** Involuntary curtailment of service to consumers (i.e., "rolling blackouts") is required during a Stage 3 Emergency in amounts as needed to maintain Operating Reserve above one and one half percent. The Stage 3 Emergency Declaration is sent to all Market Participants, to appropriate state regulatory, oversight, and response agencies, and is broadcast to the General Public in a coordinated effort between the ISO and Utility Distribution Companies.

All Generating Units are subject to control by the ISO during a System Emergency. The ISO has the authority to instruct the alteration of scheduled deliveries of Energy and/or Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency, and provided that the ISO has, where reasonably practicable, utilized Ancillary Services which it has the contractual right to instruct and which are capable of contributing

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[49] ISO Alerts, Warnings, and Emergencies, February 1999 PG&E Exhibit R.

[50] ISO Dispatch Protocol. PG&E Exhibit S.

[51] ISO Operating Procedure, No. G-201. PG&E Exhibit T.

[52] Operating Reserve is the margin of generating resource above that required to meet consumer demand. This margin is necessary to maintain reliability and as protection against the sudden loss of a generation resource.

to or containing or correcting actual, imminent or threatened System Emergencies prior to issuing such instructions.

The ISO's Operating Procedure contains a list of options that the ISO will exhaust prior to the issuance of the "System Emergency" notification. The last of nine options to be executed is to "curtail out-of-area exports from all in area entities."

I declare under penalty of perjury that the foregoing is true and correct.

Executed on May 14, 2001, at ____________________, California.

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Andrew J. Van Horn, Ph.D.