ATTACHMENT G

DIVESTITURE MODELING METHODOLOGIES AND ASSUMPTIONS

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1.0 INTRODUCTION

To support the economic and operational characterization of the operational and emission impacts of the proposed divestiture, the proprietary computer models SERASYM™ and the Surplus Energy Resource Assessment Model (SERAM II™)[1] were used to simulate the future operations of the California electric system and its interactions with the rest of the Western Systems Coordinating Council[2] after restructuring with and without the occurrence of divestiture of the four power plants as proposed by PG&E.

This attachment presents the case-specific sets of assumptions and modeling approaches on which the modeling analyses are predicated. In reading these sets of assumptions, the present system configuration with the ISO controlling the system should be assumed, with the listings below serving to call out especially significant continuations or interpretations of the status quo, indicate key assumed changes from present conditions, and/or delineate approaches and modifications to the modeling as appropriate for the scenarios under study.

2.0 NO-PROJECT CASES AND SENSITIVITY SCENARIOS

Two "no-project" cases postulating that the proposed divestiture project does not occur were modeled. The no-project case run for 1999 is the CEQA baseline case. Both the 1999 and 2005 no-project modeling assume the persistence of current utility generation ownership beyond the first phase of divestiture by PG&E and Southern California Edison (Edison). For consideration of divestiture effects and those of the numerous alternatives identified, these cases were used as starting points to produce further scenarios which incorporated additional assumptions and modeling stratagems to characterize the various alternatives and their operational and emissions impacts.

[1] SERASYM™ copyright © 1987-1995 Sierra Energy and Risk Assessment, Inc.: SERAM II™ copyright © 1989-1994 Sierra Energy and Risk Assessment, Inc.

[2] The WSCC comprises California; the Pacific northwest, Mountain and inland southwestern states extending as far as western Texas; the Mexican state of Baja California del Norte and the Canadian provinces of British Columbia and Alberta.

2.1 BASELINE

The 1999 baseline assumes that neither further divestiture nor market power manifestations occur. It provides a CEQA "no project" baseline which is to be used as the basis of comparison with all other cases and scenarios.

2.1.1 KEY COMMON ASSUMPTIONS WITH PHASE 1 DIVESTITURE MODELING

A myriad of assumptions and modeling methodologies go into every model forecast of electric system operations. For the baseline case, the same set of methods and assumptions were used, except as described below, as those employed in the baseline forecast reported in the Initial Study/Mitigated Negative Declaration for PG&E's first power plant auction in 1997 (Phase 1).[3] The assumptions from the first sale of particular importance to the proposed sale (Phase 2) include the following:

- Units continue to be bid into the ISO at minimum incremental cost and are dispatched per ISO/PX determination of minimum cost operations consistent with maintenance of system reliability.
- PG&E's SFOC are adopted by the ISO and continue to be observed during all hours of the year. No additional transmission serving San Francisco including those enhancements recently completed and just begun by PG&E are assumed or reflected in reductions to the amount of generation operated in San Francisco needed to comply with the SFOC.
- The ISO continues to hold agreements with its current list of "reliability must-run" (RMR) plants throughout the state, including all PG&E plants proposed for Phase 2 divestiture, in the interest of having generation, and other ancillary services such as voltage support, from units at these plants available to maintain the reliable operation of the state electric system.
- The ISO operated system is assumed to include all of the interconnected northern California Municipal Utilities and the Los Angeles Department of Water and Power.
- The state's (and the WSCC region's) transmission systems see no major changes or upgrades other than those already approved and under construction.
- Average water conditions and resulting hydroelectric generation both in California and in the Pacific Northwest were assumed in all future years.

2.1.2 NEW ASSUMPTIONS

As the baseline case is intended to simulate present or near-present operations, the year 1999 was chosen for simulation. New and updated assumptions for the baseline case and the entire set of modeled scenarios where appropriate include the following:

[3] Environmental Science Associates, *Mitigated Negative Declaration and Initial Study: Pacific Gas & Electric Company's Application No. 96-11-020, Proposal for Divestiture*, prepared for the California Public Utilities Commission, August 25, 1997, Attachment C, Section 2.

- San Francisco current and future loads were updated based upon a simple log-normal extrapolation of actual growth in peak loads from 1991 to 1997. The load shape and load factor was assumed to be identical to those observed in 1997.

- California statewide electricity peak demand and annual sendout were updated to reflect the latest California Energy Commission (CEC) forecast.[4] Hourly day load shapes for California utilities were updated to reflect the latest five years of Federal Energy Regulatory Commission (FERC) Form 715 data scaled to the CEC peak forecast.

- The new regional natural gas price forecasts just adopted by the CEC were employed, along with the corresponding updated inflation series forecast.[5]

- PG&E Geysers units were assumed to have the contractual authority and technical ability to be economically dispatched. Unit-specific Geysers peak dependable generation decline rate forecasts, and capacity increases resulting from the new Lake County wastewater pipeline supplying water for injection into Geysers steam fields (the Lake County Geysers Effluent Pipeline and Effluent Injection Project), were implemented.

- Selected operating characteristics of the PG&E units proposed for divestiture, and some aspects of San Diego Gas & Electric fossil-fueled power plants, were updated to reflect current knowledge gained during visits to those plants.

- Heat rates and other generation characteristics were updated for all PG&E fossil plants pursuant to amended Reliability Must-Run Agreement (RMRA) schedules between PG&E and the ISO.[6]

- Seventy megawatts of baseload generation from Edison's El Segundo plant were dispatched to satisfy an adjacent refinery's firm load.

- The special Mandalay natural gas supply contract between Edison and Southern California Gas Company was assumed to lapse, resulting in the Mandalay steam units receiving all natural gas at the same price as other Los Angeles Basin units.

- Pittsburg Power Plant Units 1 and 2 are operated to observe 115-kV voltage support requirements in PG&E's Delta Area during the summer peak period.

- Consistent with PG&E continued ownership of fossil plants, the BAAQMD "bubble" regulation of NOx emissions and future downward ratcheting of NOx emission limits under BAAQMD Regulation 9, Rule 11, and other current in-state air quality permit restrictions, continue to apply.

- New default emission rates for carbon monoxide and condensable and filterable particulate matter less than 10 microns in diameter from natural gas fired boilers are incorporated.[7]

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4 California Energy Commission, *Staff Report: 1998 Base Energy Outlook*, July 1998, Report No. P300-98-012 (draft).
5 California Energy Commission, Fuel and Transportation Committee, *California Natural Gas End Use Prices Forecast in Support of the 1997 Fuels Report*, February 25, 1998.
6 PG&E, *Amendments to the Must-Run Agreement Between PG&E and the California ISO and Schedules for Must-Run Facilities*, filed at FERC, Docket No. -98-1614-0000, January 29, 1998.
7 U.S. Environmental Protection Agency, AP-42 , Supplement D, March 1998 & May 1998.

2.1.3 ENHANCED MODELING METHODS AND APPROACHES

New requirements and questions became important in the process of performing the modeling for this phase of the divestiture. This necessitated applications of different and/or extended methodologies:

- A combination of Monte Carlo (MC) and probabilistic (i.e., cumulance) solution methods were employed in SERASYM™ to provide optimal results.[8] MC solutions with attendant long computer time simulations were used to more accurately predict combustion turbine usage in San Francisco, while more expedient probabilistic simulations were used for other studies and adjusted to reflect MC results where appropriate.

- The Bay Area Reliability Requirements (BARR) for unit commitment were installed and observed in the modeling pursuant to the assumed adoption and enforcement of these operational requirements by the ISO.

- The operations of the Delta plants (Pittsburg and Contra Costa Power Plants) were refined to more accurately reflect how PG&E operates the individual units to satisfy the existing water quality permit (NPDES) requirements for the May through mid-July period.

- Transmission modeling representations among utility members of the ISO were refined and enforcement of line rating limits enhanced.

2.1.4 BASELINE CASE RESULTS

The tabulated results for the baseline are presented in Table G-1, which exemplifies the standard presentation form used in this Attachment to present modeling results. Unit and plant specific results are presented for each of the fossil and geothermal units proposed for divestiture. Results are also presented for the remainder of the generation employed to serve California ISO load. The table shows, for instance, that the unit with the highest expected capacity factor (given normal hydro conditions) of the fossil units proposed for divestiture is Potrero 3.[9] At a capacity factor of 41 percent, Potrero 3 is operated mostly in support of the SFOC as established in a separate analysis (see Section 3.1 below).

Air emissions for each of five pollutants are reported both in pounds per MWh and pounds per million Btu. For fossil-fueled plants, emissions of nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), respirable particulate matter (PM-10) and reactive organic gases (ROG) are reported; for example, Hunters Point 4 is shown with total 1999 NOx emissions of 141 tons (36 pounds per billion BTUs). Similar information is provided for the four other pollutants for this unit and similar information is shown for the other Bay Area fossil units as well. The same applies for the geothermal plants except that sulfur emissions are in the form of hydrogen sulfide gas (H_2S) instead of SOx and, using the industry convention, emissions were computed based

8 Monte Carlo methods utilized variance convergence techniques to minimize needed sampling.
9 While Table G1 shows Hunters Point Unit 4 with a larger capacity factor of 53 percent, Hunters Point is not part of the proposed divestiture, having been withdrawn from the sale by PG&E in July 1998.

upon pounds per kWh of generation and not pounds per million BTUs.[10] Since SOx is strictly a fuel-based pollutant, it is clear from looking at the emission rate for Hunters Point 4 and comparing it with one of the combustion turbines (CTs), all of which burn only distillate fuel, that natural gas has about 1/100th the sulfur emissions, on a generation rate basis, of any of the four oil-fired CTs.

The row second from the bottom ("Non-BAAQMD California Load-Related") describes the operations of the remaining plants. For comparison, it indicates that all the other sources of generation used to satisfy ISO load in California emitted over 200 thousand tons of NOx at a rate of about 1.78 lb per MWh.[11] The bottom row incorporates the results for the plants proposed for divestiture, presenting overall results for the state.

2.2 THE 2005 NO-PROJECT CASE

The 2005 no-project case depicts post-1999 cumulative impacts upon PG&E-built Bay Area electric generation of electric industry restructuring, changing air quality regulatory requirements, load growth in San Francisco and the remainder of California, resource additions to meet growth requirements, and resource retirements according to current and pending regulatory agreements. The year 2005 was chosen to ensure capture of all effects of the existing air quality regulations yet be sufficiently within the restructured period. The BAAQMD air quality rules currently call for increasingly stringent emission limits in the region over the next few years, reaching a steady state before 2005.

2.2.1 NO-PROJECT CASE, 2005: NEW ASSUMPTIONS

- All units at the Hunters Point plant in San Francisco are assumed to be retired pursuant to the July 9, 1998 agreement between PG&E and the City and County of San Francisco (although the agreement has no set retirement date).

- Transmission enhancements currently under construction on the San Francisco transmission supply corridor to permit more electricity imports are assumed completed and the SFOC modified accordingly to require a lesser amount of generation within the San Francisco area consonant with this improved import capability. It is assumed that the new shunt capacitors recently installed at the Metcalf Substation are operational, the transmission changes currently underway at San Mateo are completed, and additional distribution system changes are made in San Francisco to permit shedding of additional network load. In total these transmission changes will increase transfer capacity into the City by about 50 MW. The assumed distribution changes would result in an additional 50 MW reduction in the SFOC. Note that this does not eliminate the need for new generation and/or transmission in or near San Francisco in the face of load growth and the retirement of Hunters Point.

[10] For ease of modeling a heat rate of 10,000 Btu/kWh was used for the geothermal units instead of the more technically correct 22,000+ Btu/kWh. This simplification affected neither total potential generation from the Geysers Plants nor the economic dispatch position of individual plants.

[11] This rate is a simple average and includes, for example, California hydro, with no emissions, and Edison and LADWP's out-of-state coal production, with relatively high emission rates.

- To meet load and reliability requirements in the face of local load growth, native power generation in the city is supplemented by the construction of a 480-MW natural gas-fired resource patterned after the CPUC's "Identified Deferrable Resource" (IDR) with selective catalytic reduction,[12] thereby continuing to satisfy the SFOC while obeying emission limits.

- Pittsburg Units 3 and 4 are retired consistent with an emission control plan evaluated by PG&E and with an emission control case evaluated in PG&E's PEA for this proposed divestiture.[13] Units 1 and 2, slated for shutdown under the same plan, were retained to provide needed local system support including voltage support via their connection to the local 115-kV transmission system.[14]

- All postulated emission control improvements listed in Appendix B, Table B-2 of PG&E's Fossil Plant PEA were incorporated into modeling, as well as the retirement of Pittsburg 3 and 4;[15] however, Pittsburg 1 and 2 were assumed retained for voltage support, with selective catalytic reduction (SCR) added to Pittsburg 2 to permit observance of the Bay Area air quality bubble standards in 2005.

- Resource modifications were made to areas not local to the plants being divested. Existing Los Angeles-area generation at High Grove and San Bernardino was repowered, and new generation added near the California border in Boulder City Nevada, consistent with CEC siting proceedings, Mojave Desert Air Quality Management District permit filings, and the best professional judgment of the EIR team. Additionally, new generation was added in San Diego to satisfy a capacity shortage caused by expected regional transmission import constraints and demand growth in San Diego County.

2.2.2 RESULTS FOR 2005 NO-PROJECT CASE

Tabulated results for the 2005 no-project case are presented in Table G-2. Probably the most interesting results from this case are the very high capacity factor seen for the new 480-MW station in San Francisco, as befits such an efficient plant, and the reduction in generation from Potrero Unit 3 due to the presence of the new 480-MW station and its individual capability, except under very high San Francisco loads, to meet the SFOC. It is also obvious from reviewing the results to see that Pittsburg Unit 1, absent major emission controls, is the least "clean" of any of the fossil-fueled boiler units analyzed.

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12 Beginning in 1989 the CPUC's Biennial Resource Plan Update or BRPU (Investigation No. 89-07-004) formulated a process through which state utilities would obtain new generation to meet forecast resource needs by means of an auction. An alternate "default" new resource, the Identified Deferred Resource (IDR), was defined, representing the most cost-effective new resource the utilities would be expected to construct themselves, which "competed" with private bidders to build the generation and provided a cost comparison. The IDR was defined as a natural gas fired combined cycle plant with twin 240-MW units and the latest emission control technologies. The IDR resource is hereafter referred to as the new "480-MW station" or "two 240-MW units" in San Francisco.

13 PG&E, *Proponent's Environmental Assessment: Pacific Gas & Electric Company's Proposed Sale of Four Bay Area Electric Generating Plants*, before the Public Utilities Commission of the State of California, January 14, 1998 ["Fossil Plant PEA"], pp. 5-13 to 5-21.

14 Units 1 and 2 are the only Pittsburg units connected to the 115-kV system.

15 PG&E, *Proposed Sale of Four Bay Area Electric Generating Plants, Op. Cit.*, Appendix B, page B-20.

2.3 ANALYTICAL MAXIMUM GENERATION

2.3.1 PROCEDURES FOR RUNNING ANALYTICAL MAXIMUM GENERATION CASES

The analytical maximum generation cases are intended to study the potential impacts of selling the plants to private parties with incentives greater than those of PG&E to maximize generation sales from the plants they own.[16] Reasons a new owner might have incentive to run its units more than PG&E are comprehensively discussed in Attachment C and include, among others, having a smaller generation portfolio and thus relying more on this unit's income; reduced operating costs from such actions as staff cuts, new equipment, refurbishments, or acquiring cheaper fuel supplies; and signing direct access contracts.

In order to investigate these potential effects, both the baseline and cumulative impact cases were used as starting points for a series of sensitivity scenarios to test the environmental impacts of running these plants at their maximum credible levels of generation consistent with the market into which they sell. This market features some unavoidable limits that absolutely preclude *all* of these plants from simultaneously running full out. These constraints include the availability of the individual units; transmission limits; limited hourly demand net of ISO obligated must-run and must-take generation; existing take-or-pay contracts with out-of-state utilities; and competition from negligible or very low variable cost of generation sources including California hydro, lower cost coal generation and imports. In addition, there is sufficient generation being offered under this phase of divestiture that postulated generation from one unit can be displaced during some hours of lower load by postulated generation from another of the units being offered for sale.

To implement these scenarios we chose to reduce their fuel costs in order to preserve relative economic dispatch order between the units. In the "analytical maximum" cases for the fossil plants, the natural gas prices seen by the natural gas-fired boiler units were replaced with the cheapest natural gas supply utilized in the baseline and cumulative impact case modeling, that of the Coolwater plant in southern California, reduced by a further twenty-five percent and provided in unlimited quantities.[17]

The Geysers geothermal plants supplied by Calpine wells (Nos. 13 and 16) are already running at their steam-limited maximum levels; the remainder, supplied by UNT, are not. Geothermal units have fewer options than natural gas units for reducing fuel costs due to the fuel's very nature as a product of local geothermal heating of the water table, but UNT could nevertheless run the units baseloaded to employ all available steam if so inclined. Consequently, for the geothermal case we reduced the price of the geothermal steam for the UNT plants to the level provided by Calpine for Geysers Plants 13 and 16.

16 *Cf.* Attachment C of this EIR.
17 Gas price forecast for Coolwater supplied by the CEC.

This “analytical maximum” concept is not applicable to peaking units such as the combustion turbines to be divested, although it does apply and was employed with the new 480 MW combined-cycle (CC) resource addition in the 2005 no-project case. A CC can be a highly cost effective baseload or intermediate resource, while CTs are unavoidably high cost, normally reserved for transmission disturbances or generator outages, and cannot operate more than ten percent of the hours in a year, in any event, due to BAAQMD rules.

2.3.2 RESULTS FOR ANALYTICAL MAXIMUM GENERATION CASES

To take account of the mutual displacement effect among the plants being operated at their analytical maximum levels, we chose to run each of the three natural gas plant packages[18] and the geothermal plants in separate simulations at their maximum levels. A case featuring simultaneous analytical maximum operations of all the natural gas plants was also run to investigate their joint maximum in case a single owner were to purchase all of them, as happened in the first phase of PG&E divestiture.

2.3.2.1 Analytical Maximum Generation - Delta Plants

Table G-3 represents the analytical maximum of the baseline for the Contra Costa and Pittsburg units, which are assumed to be sold together to a single buyer. The 1999 analytical maximum change in generation from these plants is quite large. Capacity factors at both plants doubled in the 1999 case and total generation rose by 9,026 GWh, equivalent to approximately 3.5 percent of the entire California load. Pollutants emitted by the plants increased apace, though the resulting average NOx emission rate actually declined due to these units being cleaner than the average for the Bubble. There was some reduction in San Francisco boiler generation but it was very modest (only 29 GWh).

No separate analytical maximum case was run for the Delta units for 2005; see Section 2.3.2.3 and Table G-6.

2.3.2.2 Analytical Maximum Generation - Potrero Unit 3

Table G-4 is the analytical maximum version of the baseline case for Potrero 3, the only steam boiler unit at the Potrero Power Plant. In 1999 much of Potrero’s analytical maximum increase in generation displaces generation from the Hunters Point Plant due to Potrero satisfying the SFOC in lieu of the Hunters Point units, whereas the increase in Potrero 3 generation has essentially no impact on CT generation at Potrero or at Hunters Point 1. This is to be expected since the CTs are used almost exclusively to satisfy reliability needs which do not vary with level of operation of boiler units, all of which are found relative early in the commitment order.

2.3.2.3 Analytical Maximum Generation - All Natural Gas-Fired Steam Boilers

Table G-5 shows the 1999 baseline with all the natural gas-fired steam boilers proposed for divestiture and at the Hunters Point Plant run at analytical maximum. This run inspects the

[18] It was assumed that the Delta plants would be purchased and operated similarly, by a single owner.

degree of joint backout attributable to the simultaneous running of all the area natural gas units at these maximal levels. Each natural gas boiler increases its capacity factor significantly compared to the 1999 baseline (Table G-1); however, the level of operation is reduced slightly at each plant in the joint maximum case from that found in the individual maximum cases (Tables G-3 and G-4). Interestingly, in spite of the reduced generation at each plant, individual units may operate more in the joint maximum case. For example, Hunters Point 2 and 3 increase their total generation while generation from Hunters Point 4 drops by a greater total amount, and Potrero 3, also in the City, drops the most of any unit. Overall, these differences are fairly minor.

Table G-6 shows the analytical maximum version of the 2005 no-project case for all area natural gas boilers. No individual cases were run for 2005 for the Potrero or Delta analytical maximum because the reductions in generation, minor in 1999, were expected to be even less significant in 2005 since the overall greater capacity factors were anticipated in 2005 to meet increased load requirements. Additionally, the change in overall system resources and particularly the retirement of Pittsburg 3 and 4 change the overall commitment and reduces the total amount of generation from the Delta units. Note that the analytical maximum change in generation from the new 480-MW station was minimal in any event, since it was already sufficiently cheap and would reduce generation at the other fossil-fueled plants being divested.

2.3.2.4 Analytical Maximum Generation - The Geysers Geothermal Plants

Table G-7 shows the analytical maximum baseline for operations of the Geysers at maximum steam usage. Here, generation increased for all the UNT plants, while it remained unchanged at maximum output for Geysers 13 and 16, the two Calpine-supplied units with the very low priced steam.

Table G-8 shows the 2005 no-project case with the Geysers at analytical maximum. Interestingly, the increase in generation in 1999 is much larger than in 2005 because, by then, the UNT steam price has escalated less than the price of natural gas so that most of the steam available is used in the no-project case.

2.4 SENSITIVITY SCENARIOS

Numerous alternative possibilities for the future, of varying likelihood, may be identified, characterized, and investigated as to potential impacts. Besides the range of reasonably conceivable impacts of divestiture, these potentials include sales of varying facilities to parties with varying operating incentives and sales and operating policies, resource changes in the local areas of the plants, revisions to operating criteria, revisions to fuels used by units, and levels of air quality regulation.

For analyzing the sensitivity of the system to these alternatives, one or both of the cases above were modified to reflect each of the sets of possibilities and the differential impacts analyzed.

2.4.1 ANALYTICAL MAXIMUM CASE WITH ALTERNATIVE SAN FRANCISCO GENERATION, TRANSMISSION

This scenario studied a variant to the 2005 no-project arrangement case with less reliance on new in-city generation while still meeting emission limits and the SFOC, through a combination of increasing transmission import capability into the City and further reducing the level of in-city load covered by in-city generation for the SFOC. No consideration is given to costs or to determining cost effective actions. All that are considered are the technical changes necessary to support the scenario and the time to implement the change. Further, these actions will tend to reduce overall reliability in the City to the degree additional elements of the network load are not sustainable from indigenous generation.

To eliminate some of this new generation while maintaining the SFOC, even the relaxed SFOC following the transmission improvements prior to 1999, at 2005 load levels does not appear feasible; additional transmission into the city, with concurrent further relaxation of the SFOC, is required. The 2005 no-project case was run with all Bay Area natural gas-fired generation at analytical maximum, and two additional changes. First, further transmission enhancements to the San Francisco import corridor were assumed to add an additional 250 MW of import capability over the 2005 no-project case. These additional changes are necessary to account for future load growth in the City, replace the capacity from the other new 480-MW station (two new 240-MW units) no longer assumed, and keep the capacity factors of each of the CTs well below ten percent in spite of increased use for the modified SFOC and to help support the overall ISO system. Transmission upgrades might involve reconductoring the 1000 foot segment of the “overhead” 115 kV lines between San Mateo and Martin substations that is actually a subterranean cable and increasing the amount of transformation at the Martin Substation, and/or building a second, buried 230 kV cable from San Mateo to Martin. Other improvements north of Martin would also be required including possibly a 115 kV cable from Martin to Hunters Point and a buried cable from Hunters Point to Potrero. Second, this additional transmission allowed the SFOC’s native on-line generation requirements to be relaxed enough to allow one of the two new 240-MW units in the City previously assumed in the no-project case to be eliminated, leaving one new 240-MW unit equipped with SCR added in San Francisco.

Table G-9 presents the results of this scenario. The new 240-MW station is seen to run at the same high capacity factor as the full 480-MW station because it is assumed to have the same economics on a per MW basis. Potrero generation rises only slightly at the CTs. Generation also rises noticeably at the Delta Plants and even increases slightly for the geothermal plants, even under analytical maximum conditions. Given the assumptions regarding load growth and new and remaining resources available to serve system load, no problem is detected in satisfying the remaining lost generation from the postulated new 240-MW station though the variable cost of serving the load is significantly increased.

2.4.2 SUSPENDED NATURAL GAS FIRED EMISSION CONTROL TECHNOLOGY

Over the next few years, BAAQMD air quality rules are set to require gradually lower emission rates for utility electric steam boiler generation. Also, load growth in San Francisco will cause PG&E to run both its steam and combustion units progressively more to meet load and reliability requirements, causing these units to approach current BAAQMD emission and operation limits they had previously remained comfortably below.

PG&E has contemplated installing numerous emission control technology measures between now and 2005 at its natural gas-fired generating units in order to maintain compliance with its BAAQMD regulations.[19] These regulations (specifically Regulation 9, Rule 11) would not, in their current form, apply to new non-utility owners. BAAQMD has stated its intent to modify Regulation 9, Rule 11 to ensure its continued applicability to all of the steam boilers at the four Bay Area power plants, regardless to whether they are utility owned.

To study the maximum possible emissions impacts of the sales from a regulatory perspective, these scenarios postulate for the no-project cases that the new owners (of the PG&E electric generating plants being divested) install none of the PG&E-planned NOx emission controls between now and 2005, consistent with BAAQMD not modifying Regulation 9, Rule 11 to apply to the new ownership.

2.4.2.1 Suspended Natural Gas-Fired Emission Controls - Normal Dispatch

The tabulated results for the cases with emission controls frozen at 1998 levels are presented in Tables G-10 and G-11. In 1999, total NOx emissions from Pittsburg, for example, increase from 3,000 (see Table G-1) to 3,685 tons and the emission rate increases by 22 lb/BBtu. In 2005, Pittsburg emissions increase from (see Table G-2) 661 to 3,034 tons and the rate goes up by 74 lb/BBtu.

2.4.2.2 Suspended Natural Gas-Fired Emission Controls - Analytical Maximum Operation

Tabulated results for the analytical maximum generation cases for 1999 and 2005 with emission controls frozen at 1998 levels are presented in Tables G-12 and G-13. Here, in 1999 total Pittsburg NOx emissions increase from 3,000 tons in the 1999 baseline case (see Table G-1) to 7,444 tons, and the emission rate increases by 22 lb/BBtu. In 2005, at analytical maximum dispatch Pittsburg NOx emissions increase by 4,261 tons (see Table G-2) due to the freeze in emission controls *ceteris paribus*, and the emission rate goes up by 79 lb/BBtu.

[19] PG&E, *Proposed Sale of Four Bay Area Electric Generating Plants, Op. Cit*, Appendix B and current PG&E-BAAQMD regulatory compliance plans.

2.4.3 PROPOSED ENRON POWER PLANT

In April 1998, ENRON Corporation announced that it plans to partner with the City of Pittsburg and a steel producer to build a natural gas-fired combined-cycle plant of about 500 MW in or near the city. The partners expect to file a siting application with the CEC and hope to begin operations by 2001. Part of the plant's capacity would be reserved for an "over-the-fence" steel producer with an existing 50 MW boiler that would be retired.

A 2005 case was added with a new 450-MW combined-cycle (CC) natural gas-fired plant in Pittsburg, based on the new 480-MW station in San Francisco (described earlier) and with the same natural gas supply prices as adjacent PG&E plants. The new plant was incorporated into, and made subject to, the BARR, and the existing Pittsburg Plant Units 1 and 2 were retired as PG&E had previously planned, under the assumption that the local voltage support function they would otherwise have provided could be handled by ENRON. Lastly, all Bay Area steam units were dispatched at their analytical maximums.

The tabulated 2005 results for the case with the ENRON plant are presented in Table G-14. The major impact of the presence of the ENRON facility is that generation from remaining boilers declines by 1,830 GWh and total NOx emissions from the boilers and CCs decline by 484 tons, while total Bay Area generation rises by 1,696 GWh. Along with increased total generation associated with the proposed new 450-MW CC comes increases in other pollutants: e.g., annual PM-10 emissions increase by 21 tons.

2.4.4 EXTENDED DELTA PLANT FISH ENTRAINMENT LIMITS

The National Pollution Discharge Elimination System (NPDES) permits for the Contra Costa and Pittsburg plants, among other operational restrictions, require limits to cooling water intake to protect striped bass spawning in the Sacramento and San Joaquin River delta.[20] These rules, which restrict generation and capacities for the units in question, take effect about May 1 of each year and end on July 15 or when the California Department of Fish and Game advises that striped bass levels in the river warrant ending the restrictions.

The U.S. Fish and Wildlife Service and state authorities have been in negotiations with PG&E about applying similar but more extensive restrictions than these in order to protect endangered native species.[21] The new restrictions, which would protect endangered and threatened species from entrainment as well as temperature increases from cooling water, are tentatively planned to shift the beginning of the special operations season from May to February with the ending remaining in July.

The baseline case for 1999 was modified to extend the Delta plant fish entrainment limitation periods and associated operational restrictions to be in effect from the beginning of February to mid-July. These conditions, without predicted retirements or necessary concomitant

[20] NPDES Permits Nos. CA0004863 and CA0004880.
[21] The striped bass is not a native species to California waters.

transmission upgrades, were carried into 2005 for purposes of comparison. The tabulated results for the runs with extended Delta protect periods are presented in Tables G-15 and G-16. The impact of this change appears very modest; the generation at Contra Costa declines slightly while the generation at Pittsburg increases more than enough to make up for the decline at Contra Costa. However, in all instances the increase in generation occurs primarily at Pittsburg 7, which has a cooling pond, and declines in generation occur at units with once-through cooling where the detriment to the fish population occurs.

2.4.5 GAS CONVERSION OF SAN FRANCISCO COMBUSTION TURBINES

Natural gas-fueled combustion turbines are, for certain pollutants, cleaner burning than those burning residual or distillate petroleum products. The Potrero and Hunters Point CTs, which burn distillate, are the only commonly used utility electrical generation units being controlled by the ISO whose primary fuel is not natural gas.[22] Conversion of these units to natural gas burning would reduce NOx and other emissions in the local area, all other things being equal. However, by converting to natural gas all other things would not remain equal. This fuel conversion would have the effect of reducing each unit's marginal operating costs due to expected continuing significant differences in fuel prices, and thus increase their frequency of usage.

This case studies the net operational benefits that might arise from fuel conversion of the CTs. No estimate was made of the cost effectiveness of such a procedure though PG&E has studied the possibility and it appears to be feasible from an engineering perspective.

The analytical maximum case for all Bay Area natural gas generation in 2005 (1999 not providing sufficient lead time for the conversion) was modified to convert Potrero Units 4 through 6 to burn natural gas, available at the typical northern California price. The tabulated results are presented in Table G-17. The impact of this change was as expected in terms of operations: the CTs were called on much more often when converted to natural gas. In fact, their usage exceeded slightly the ten percent operational ceiling now imposed upon these units while they burn distillate. The key question is whether or not the pollutant emission declined with the conversion in spite of increased operation. The answer appears to be mixed, depending upon the pollutant. SOx emissions decline drastically while PM-10 remain basically unchanged. NOx, on the other hand, increases but is insignificant as compared to the overall emissions of the boiler units.

3.0 SPECIAL ANALYSES

Several analyses were made of special possible circumstances that were not based on the no-project case because they either involved no actual modeling or a significant modification to the system modeling to employ a modeling "trick" or stratagem to isolate an effect.

[22] SDG&E has three CTs that burn diesel or jet fuel but they are seldom called upon to operate.

3.1 SAN FRANCISCO STAND-ALONE WITH ALTERNATE IN-CITY GENERATION AND DISPLACEMENT GENERATION REQUIREMENTS

The electricity generated by the Hunters Point and Potrero plants in San Francisco is normally used only to supply local loads and satisfy the SFOC. Since even at full output these plants cannot regularly support San Francisco's entire load without resorting to several of the CTs as well as all the boilers, the city is usually a net importer of electricity over its transmission link with the rest of the PG&E system. However, occasional conditions exist under which the City units operate at greater than the level dictated by the SFOC, thereby reducing electricity imports into the City and helping to support overall, and not just in-city, PG&E loads. For example, at times of high summer peak loads, as available capacity outside San Francisco becomes scarcer and dearer, the generation in San Francisco, which is strategically located in the heart of the Bay Area Reliability Area, will be called upon to increase its level of generation to reduce imports into the City, freeing up other generation to serve overall system loads.[23]

To analyze the extent to which the generation in San Francisco operates to support only in-city load and system requirements versus out-of-city needs, the San Francisco system forming part of the total system was severed from the rest of the system and run by itself. Local loads were unchanged; the transmission link into and out of the City was connected to a firm source of generation which served only to supply San Francisco loads at inframarginal cost; i.e., a cost level sufficiently below those of any of the City's generators so that it was always economic to completely fill the transmission line. The total generation from the San Francisco units under these conditions constitutes the minimum needed beyond that required to satisfy the SFOC and/or supplement the full import capability available. This amount of total in-city generation was then subtracted from the corresponding in-city generation levels found in the cases, and the difference taken to represent the amount of in-city generation that ran to serve purposes outside the City.

Because the City is such a small region and the individual generators are such large percentages of this load, we employed the Monte Carlo solution technique in SERASYM™ to permit accurate results.

The tabulated results for 1999 for the San Francisco stand-alone cases are presented in Table G-18, which differs in form from the tables presented heretofore. This table only reports generation from the in-city plants and reports both the stand-alone and full-system cases and the differences between them. Examination of these results show that very little San Francisco generation is used to displace non-city generation. It totals 122 GWh for an 8.0 percent increase over the minimum amount of generation needed to observe the SFOC, given the assumed level of import capability. The majority of the increase occurs in Hunters Point Unit 4 although the largest increase arises in the CTs, which are presumably needed to help serve system peak load

[23] PG&E, *Dispatching Instructions O-49: Unit Commitment Requirements for Bay Area Reliability*, June 23, 1997, p. 14, Figure 2 and *passim*.

conditions. Annual emission increases are also quite modest averaging just about ten per cent for each of the pollutants.

3.2 PITTSBURG POWER PLANT PEAK DAILY PM-10 EMISSIONS

In each year of electrical system operations each plant has a peak day when the specific plant sees and must meet its highest level of generation. That day is unlikely to be the peak load day of the year due to the impacts of availability of other, cheaper sources of generation. Also, that day may or may not be the same day as when selected emissions also peak for that plant. Further, emissions of NOx which are driven by the control technology on a given set of units may not peak the same day that other pollutants such as ROG, CO or PM-10 peak, since those pollutants all peak on the day of maximum fuel burn which is not necessarily the day of maximum generation or NOx outputs.

Special analyses were undertaken to identify the hourly emissions from the Pittsburg Plant on the day of its maximum-modeled PM-10 emissions. For Pittsburg, the day of maximum-modeled PM-10 emissions is the second to the last Monday in September. The hourly tabulated results for the Pittsburg Power Plant for the no-project case in 1999 are presented in Table G-19. The hourly tabulated results for the analytical maximum case in 2005 are presented in Table G-20. Hourly generation and emissions are shown on the tables by unit**.** The results show that all of the units are committed at all times of the day and that the peak operations and peak PM-10 emissions occur from hours 14 and 17; i.e., 1:00 p.m. and 5:00 p.m. in 1999. Due to the high demand, all units are operating at their peak outputs during that afternoon except for Pittsburg 7, which has a very expensive incremental cost of operations at peak output due to its closed cycle cooling so it was not fully dispatched even though the remainders of the units were. For 2005, with a higher demand level throughout the system and Pittsburg 3 and 4 retired, the peak emissions occur in hours 8 and 11 through 22: that is, through most of the afternoon and evening.

4.0 INVESTIGATION OF RESULTS

From comparison of the results of the cases, the various scenarios, and the special analyses of alternatives, observations can be made that provide guidance in the divestiture EIR process. Observations evident from the results to date include:

- Overall emissions throughout the WSCC (including California) attributable to meeting California electric load decline substantially for NOx, SOx, and PM-10 and increase modestly for CO if the plants to be divested are assumed to run at their full analytical maximum outputs.

- Modeling of analytical maximum operations of steam plants to be divested, based on existing physical and contractual limitations and intentionally optimistic natural gas supply price assumptions, results in increased operations of the plants by about 25 to 50 percent depending upon the year considered, which is substantially less than a simple extrapolation of plant availability would conclude and might not be much greater than the impact of a dry hydroelectric production season.

- The plants being divested that are not slated for retirement will increase their levels of production without divestiture in future years due to net growth in future statewide load after retirements and new plants are considered, so the maximum potential increase in generation associated with divestiture declines substantially between 1999 and 2005.

- Bay Area electric generation could increase to analytical maximum levels and still comply with BAAQMD NOx emissions "bubble" limits (in Regulation 9, Rule 11) in both 1999 and 2005 (although the bubble regulation in its existing form should not be presumed for 2005 with new owners).

- The greatest potential increase in NOx emissions due to divestiture, represented by the difference between baseline conditions and analytical maximum operations, declines very rapidly between 1999 and 2005 assuming future installation of emission control equipment on the Bay Area plants to meet BAAQMD Reg. 9, Rule 11 limits.

- The revised AP-42 standards just issued by the U.S. EPA substantially increase the predicted level of emissions from CO and PM-10 from the natural gas fired boilers.

- In an average hydroelectric generation year, generation in San Francisco occurs almost exclusively to support the SFOC and the existing units are not sufficiently economic to be otherwise used to support system load except in the highest system load conditions.

- Current transmission into San Francisco is optimized with the indigenous generation requirements imposed by the SFOC so as to support City load not satisfied by the SFOC. A reduction in the SFOC coupled within an increase in transmission capability would result in a one-for-one reduction in in-city generation.

- Reducing the incremental heat rate for Potrero 3 at higher output levels significantly influences its output and the output of the Hunters Point steam units.

- Given average hydro conditions, the expansion of the season during which Delta plant operations are modified to reduce fish take has relatively little effect on total Delta plant generation, although generation shifts significantly between units and the two plants.

Table G-1

1999 Baseline

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS														
							NO_X			SO_X/H_2S			PM10			CO			ROG		
							Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu
Hunters Point	1	CT	DF	52	4	0.9	7	3.31	0.167	4	1.98	0.100	1	0.68	0.035	4	2.22	0.112	1	0.69	0.035
	2	ST	NG	107	89	9.5	112	2.51	0.155	1	0.02	0.001	6	0.13	0.008	62	1.39	0.086	6	0.14	0.009
	3	ST	NG	107	55	5.9	74	2.69	0.156	0	0.02	0.001	4	0.14	0.008	41	1.49	0.087	4	0.15	0.009
	4	ST	NG	163	756	53.0	141	0.37	0.036	4	0.01	0.001	30	0.08	0.008	326	0.86	0.084	33	0.09	0.008
	Σ			429	905	24.1	334	0.74	0.065	9	0.02	0.002	40	0.09	0.008	434	0.96	0.085	44	0.10	0.009
Potrero	3	ST	NG	207	752	41.4	347	0.92	0.091	4	0.01	0.001	29	0.08	0.008	321	0.85	0.084	32	0.09	0.008
	4	CT	DF	52	15	3.4	20	2.61	0.164	12	1.59	0.100	4	0.55	0.034	14	1.77	0.111	4	0.55	0.035
	5	CT	DF	52	9	1.9	12	2.81	0.165	7	1.70	0.100	3	0.59	0.034	8	1.90	0.111	3	0.59	0.035
	6	CT	DF	52	6	1.4	9	3.01	0.166	6	1.81	0.100	2	0.62	0.035	6	2.02	0.112	2	0.63	0.035
	Σ			363	782	24.6	389	0.99	0.095	29	0.07	0.007	38	0.10	0.009	349	0.89	0.086	41	0.10	0.010
Contra Costa	6	ST	NG	340	961	32.3	533	1.11	0.109	5	0.01	0.001	37	0.08	0.008	400	0.83	0.082	41	0.09	0.008
	7	ST	NG	340	1204	40.4	178	0.30	0.029	6	0.01	0.001	47	0.08	0.008	501	0.83	0.082	51	0.09	0.008
	Σ			680	2166	36.4	711	0.66	0.064	11	0.01	0.001	84	0.08	0.008	902	0.83	0.082	93	0.09	0.008
Pittsburg	1	ST	NG	163	322	22.5	276	1.71	0.138	2	0.01	0.001	15	0.09	0.008	168	1.05	0.084	17	0.10	0.008
	2	ST	NG	163	332	23.2	330	1.99	0.152	2	0.01	0.001	17	0.10	0.008	184	1.11	0.084	18	0.11	0.008
	3	ST	NG	163	464	32.5	404	1.74	0.142	3	0.01	0.001	22	0.09	0.008	240	1.04	0.084	24	0.10	0.008
	4	ST	NG	163	399	28.0	355	1.78	0.141	3	0.01	0.001	19	0.10	0.008	214	1.07	0.085	21	0.11	0.008
	5	ST	NG	325	1116	39.2	546	0.98	0.091	6	0.01	0.001	46	0.08	0.008	505	0.91	0.084	51	0.09	0.008
	6	ST	NG	325	1150	40.4	582	1.01	0.091	6	0.01	0.001	49	0.08	0.008	538	0.94	0.084	54	0.09	0.008
	7	ST	NG	682	1601	26.8	507	0.63	0.060	8	0.01	0.001	64	0.08	0.008	704	0.88	0.084	70	0.09	0.008
	Σ			1984	5384	31.0	3000	1.11	0.099	30	0.01	0.001	231	0.09	0.008	2554	0.95	0.084	255	0.09	0.008
Geysers	5	G	GS	39	232	68.0	0	0.00		58	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	233	68.3	0	0.00		48	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	240	72.1	0	0.00		64	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	238	71.5	0	0.00		50	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	152	54.1	1	0.01		26	0.34		0	0.01		0	0.00		1	0.01	
	10	G	GS	32	151	53.9	1	0.01		36	0.47		0	0.01		0	0.00		1	0.01	
	11	G	GS	56	227	46.2	0	0.00		65	0.57		1	0.01		0	0.00		1	0.01	
	12	G	GS	39	259	75.8	1	0.01		65	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	604	94.5	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	432	80.8	0	0.00		22	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	601	94.0	0	0.00		5	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	320	77.7	0	0.00		9	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	58	418	82.4	0	0.00		28	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	302	78.3	0	0.00		17	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	4409	75.2	4	0.00		521	0.24		13	0.01		1	0.00		18	0.01	
Non-BAAQMD Calif. Load-Related					243620		216867	1.78		117565	0.97		N/A	N/A		N/A	N/A		24475	0.20	
Total Calif. Load-Related					252856		221300	1.75		117645	0.93		N/A	N/A		N/A	N/A		24908	0.20	

UNIT TYPES: CT combustion turbine; ST steam turbine; G geothermal steam; CC combined cycle

FUELS: NG natural gas w/ residual oil backup; DF distillate fuel oil; GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects 1998 AP42 updates

Table G-2

2005 - No Project, Hunters Point Shut Down; Increased Transmission to Serve SF Load, Reduce BARR

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS: NO_X Tons	NO_X #/MWh	NO_X #/MMBtu	SO_X/H_2S Tons	SO_X/H_2S #/MWh	SO_X/H_2S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point plant retired																					
Potrero	3	ST	NG	207	622	34.3	38	0.12	0.012	3	0.01	0.001	23	0.08	0.008	257	0.83	0.082	26	0.08	0.008
	4	CT	DF	52	43	9.5	46	2.12	0.164	28	1.29	0.100	3	0.15	0.012	4	0.18	0.014	10	0.45	0.035
	5	CT	DF	52	37	8.1	39	2.13	0.164	24	1.29	0.100	3	0.15	0.011	3	0.18	0.014	8	0.44	0.034
	6	CT	DF	52	34	7.5	37	2.13	0.165	22	1.30	0.100	3	0.15	0.011	3	0.18	0.014	8	0.44	0.034
	Σ			363	736	23.1	159	0.43	0.041	77	0.21	0.020	32	0.09	0.008	267	0.73	0.069	52	0.14	0.013
Contra Costa	6	ST	NG	340	1348	45.3	81	0.12	0.012	7	0.01	0.001	50	0.07	0.008	549	0.81	0.082	56	0.08	0.008
	7	ST	NG	340	1379	46.3	83	0.12	0.012	7	0.01	0.001	51	0.07	0.008	560	0.81	0.082	57	0.08	0.008
	Σ			680	2728	45.8	164	0.12	0.012	14	0.01	0.001	101	0.07	0.008	1109	0.81	0.082	114	0.08	0.008
Pittsburg	1	ST	NG	163	299	21.0	280	1.87	0.152	2	0.01	0.001	14	0.09	0.008	151	1.01	0.082	15	0.10	0.008
	2	ST	NG	163	520	36.4	40	0.15	0.013	3	0.01	0.001	23	0.09	0.007	253	0.97	0.082	26	0.10	0.008
#3 retired																					
#4 retired																					
	5	ST	NG	325	1200	42.2	75	0.12	0.012	6	0.01	0.001	46	0.08	0.007	508	0.85	0.082	52	0.09	0.008
	6	ST	NG	325	1344	47.2	87	0.13	0.012	7	0.01	0.001	54	0.08	0.007	589	0.88	0.082	60	0.09	0.008
	7	ST	NG	682	2938	49.2	180	0.12	0.012	15	0.01	0.001	112	0.08	0.007	1221	0.83	0.082	125	0.09	0.008
	Σ			1658	6302	43.4	661	0.21	0.020	33	0.01	0.001	249	0.08	0.007	2721	0.86	0.082	279	0.09	0.008
New 480 MW		CC	NG	480	3806	90.5	184	0.10	0.014	12	0.01	0.001	101	0.05	0.008	150	0.08	0.011	80	0.04	0.006
Geysers	5	G	GS	39	297	86.8	0	0.00		75	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	294	86.0	0	0.00		61	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	288	88.9	0	0.00		77	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	290	89.4	0	0.00		61	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	224	80.0	1	0.01		39	0.34		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	223	79.5	1	0.01		52	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	463	94.4	0	0.00		133	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	304	89.1	1	0.00		77	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	576	95.3	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	480	89.8	0	0.00		24	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	571	94.4	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	378	91.7	0	0.00		11	0.06		1	0.01		0	0.00		2	0.01	
	18	G	GS	62	494	91.0	0	0.00		34	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	360	89.4	0	0.00		20	0.11		1	0.01		0	0.00		1	0.01	
	Σ			665	5241	90.0	5	0.00		693	0.26		16	0.01		1	0.00		21	0.01	
Non-BAAQMD California Load-Related					268880		200232	1.49		102084	0.76		12208	0.09		48410	0.36		25140	0.19	
Total Calif. Load-Related					282452		201400	1.43		102220	0.72		12692	0.09		52657	0.37		25664	0.18	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
- -115/230 kV transmission into SF assumed to be increased to about 550 MW

Table G-3

1999 Baseline & Contra Costa and Pittsburg at Analytical Maximum

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS														
							NO_X			SO_X/H_2S			PM10			CO			ROG		
							Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu
Hunters Point	1	CT	DF	52	4	0.9	7	3.33	0.169	4	1.98	0.100	1	0.68	0.035	5	2.22	0.112	1	0.69	0.035
	2	ST	NG	107	89	9.5	112	2.51	0.155	1	0.02	0.001	6	0.13	0.008	62	1.39	0.086	6	0.14	0.009
	3	ST	NG	107	53	5.6	71	2.70	0.157	0	0.02	0.001	4	0.14	0.008	40	1.50	0.087	4	0.15	0.009
	4	ST	NG	163	737	51.6	137	0.37	0.036	4	0.01	0.001	29	0.08	0.008	318	0.86	0.084	32	0.09	0.008
	Σ			429	883	23.5	328	0.74	0.066	9	0.02	0.002	39	0.09	0.008	424	0.96	0.085	43	0.10	0.009
Potrero	3	ST	NG	207	744	41.0	344	0.92	0.091	4	0.01	0.001	29	0.08	0.008	318	0.85	0.084	32	0.09	0.008
	4	CT	DF	52	16	3.4	21	2.63	0.164	13	1.60	0.100	4	0.55	0.034	14	1.78	0.111	4	0.55	0.035
	5	CT	DF	52	9	1.9	12	2.81	0.166	7	1.70	0.100	3	0.59	0.034	8	1.89	0.112	3	0.59	0.035
	6	CT	DF	52	6	1.3	9	3.02	0.167	6	1.81	0.100	2	0.63	0.035	6	2.03	0.112	2	0.63	0.035
	Σ			363	775	24.4	386	1.00	0.095	29	0.08	0.007	38	0.10	0.009	347	0.89	0.086	41	0.10	0.010
Contra Costa	6	ST	NG	340	2110	70.8	1118	1.06	0.109	10	0.01	0.001	78	0.07	0.008	840	0.80	0.082	86	0.08	0.008
	7	ST	NG	340	2618	87.9	370	0.28	0.029	13	0.01	0.001	97	0.07	0.008	1042	0.80	0.082	107	0.08	0.008
	Σ			680	4728	79.4	1488	0.63	0.065	23	0.01	0.001	175	0.07	0.008	1883	0.80	0.082	193	0.08	0.008
Pittsburg	1	ST	NG	163	617	43.2	483	1.57	0.141	3	0.01	0.001	26	0.08	0.008	288	0.94	0.084	29	0.09	0.008
	2	ST	NG	163	985	69.0	874	1.78	0.163	5	0.01	0.001	41	0.08	0.008	451	0.92	0.084	45	0.09	0.008
	3	ST	NG	163	1088	76.2	961	1.77	0.162	6	0.01	0.001	45	0.08	0.008	498	0.92	0.084	50	0.09	0.008
	4	ST	NG	163	940	65.8	841	1.79	0.162	5	0.01	0.001	40	0.08	0.008	438	0.93	0.084	44	0.09	0.008
	5	ST	NG	325	2277	80.0	1038	0.91	0.091	11	0.01	0.001	87	0.08	0.008	961	0.84	0.084	96	0.08	0.008
	6	ST	NG	325	2474	86.9	1147	0.93	0.091	13	0.01	0.001	96	0.08	0.008	1062	0.86	0.084	106	0.09	0.008
	7	ST	NG	682	3468	58.0	1061	0.61	0.061	18	0.01	0.001	133	0.08	0.008	1473	0.85	0.084	147	0.08	0.008
	Σ			1984	11848	68.2	6406	1.08	0.104	62	0.01	0.001	468	0.08	0.008	5171	0.87	0.084	517	0.09	0.008
Geysers	5	G	GS	39	200	58.5	0	0.00		50	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	199	58.4	0	0.00		41	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	216	65.0	0	0.00		58	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	216	64.9	0	0.00		45	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	138	49.4	1	0.02		24	0.35		0	0.01		0	0.01		1	0.01	
	10	G	GS	32	137	49.0	2	0.02		33	0.48		0	0.01		0	0.01		1	0.01	
	11	G	GS	56	184	37.6	0	0.00		53	0.57		1	0.01		0	0.00		1	0.01	
	12	G	GS	39	230	67.5	2	0.01		58	0.51		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	603	94.3	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	391	73.2	1	0.00		20	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	601	94.0	0	0.00		5	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	292	71.0	0	0.00		8	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	58	380	74.9	1	0.00		26	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	268	69.7	1	0.01		15	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	4059	69.3	7	0.00		464	0.23		12	0.01		2	0.00		17	0.01	
Non-BAAQMD Calif. Load-Related					234625		207805	1.77		109942	0.94		N/A	N/A		N/A	N/A		24209	0.21	
Total Calif. Load-Related					252859		216412	1.71		110065	0.87		N/A	N/A		N/A	N/A		25003	0.20	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Analytical Maximum does not apply to CTs
- Reflects 1998 AP42 updates

Table G-4

1999 Baseline & Potrero 3 at Analytical Maximum

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO$_X$ Tons	NO$_X$ #/MWh	NO$_X$ #/MMBtu	SO$_X$/H$_2$S Tons	SO$_X$/H$_2$S #/MWh	SO$_X$/H$_2$S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point	1	CT	DF	52	4	0.9	7	3.34	0.168	4	1.99	0.100	1	0.69	0.035	4	2.23	0.112	1	0.69	0.035
	2	ST	NG	107	53	5.6	82	3.11	0.159	1	0.02	0.001	4	0.16	0.008	46	1.72	0.088	5	0.17	0.009
	3	ST	NG	107	35	3.7	59	3.35	0.159	0	0.02	0.001	3	0.17	0.008	33	1.86	0.088	3	0.19	0.009
	4	ST	NG	163	648	45.4	122	0.38	0.036	3	0.01	0.001	25	0.08	0.008	282	0.87	0.084	28	0.09	0.008
	Σ			429	740	19.7	269	0.73	0.063	8	0.02	0.002	34	0.09	0.008	364	0.98	0.085	37	0.10	0.009
Potrero	3	ST	NG	207	1371	75.6	658	0.96	0.091	7	0.01	0.001	55	0.08	0.008	609	0.89	0.084	61	0.09	0.008
	4	CT	DF	52	15	3.4	20	2.62	0.164	12	1.60	0.100	4	0.55	0.034	14	1.77	0.111	4	0.55	0.035
	5	CT	DF	52	9	1.9	12	2.82	0.165	7	1.70	0.100	3	0.59	0.035	8	1.90	0.111	3	0.59	0.035
	6	CT	DF	52	6	1.3	9	3.02	0.167	5	1.81	0.100	2	0.63	0.035	6	2.03	0.112	2	0.63	0.035
	Σ			363	1401	44.1	699	1.00	0.093	32	0.05	0.004	64	0.09	0.008	637	0.91	0.085	70	0.10	0.009
Contra Costa	6	ST	NG	340	963	32.3	534	1.11	0.109	5	0.01	0.001	37	0.08	0.008	402	0.83	0.082	41	0.09	0.008
	7	ST	NG	340	1191	40.0	176	0.30	0.029	6	0.01	0.001	46	0.08	0.008	496	0.83	0.082	51	0.09	0.008
	Σ			680	2154	36.2	710	0.66	0.065	11	0.01	0.001	83	0.08	0.008	898	0.83	0.082	92	0.09	0.008
Pittsburg	1	ST	NG	163	321	22.5	276	1.72	0.138	2	0.01	0.001	15	0.10	0.008	169	1.05	0.084	17	0.11	0.008
	2	ST	NG	163	330	23.1	331	2.00	0.151	2	0.01	0.001	17	0.10	0.008	185	1.12	0.085	18	0.11	0.008
	3	ST	NG	163	468	32.8	405	1.73	0.141	3	0.01	0.001	22	0.09	0.008	243	1.04	0.084	24	0.10	0.008
	4	ST	NG	163	396	27.8	355	1.79	0.141	3	0.01	0.001	19	0.10	0.008	214	1.08	0.085	21	0.11	0.008
	5	ST	NG	325	1110	39.0	543	0.98	0.091	6	0.01	0.001	45	0.08	0.008	503	0.91	0.084	50	0.09	0.008
	6	ST	NG	325	1138	40.0	576	1.01	0.091	6	0.01	0.001	48	0.08	0.008	533	0.94	0.084	53	0.09	0.008
	7	ST	NG	682	1600	26.8	507	0.63	0.061	8	0.01	0.001	64	0.08	0.008	705	0.88	0.084	70	0.09	0.008
	Σ			1984	5363	30.9	2993	1.12	0.099	30	0.01	0.001	231	0.09	0.008	2550	0.95	0.084	255	0.10	0.008
Geysers	5	G	GS	39	231	67.7	0	0.00		58	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	230	67.4	0	0.00		48	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	236	70.8	0	0.00		63	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	236	70.8	0	0.00		49	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	151	53.9	1	0.01		26	0.35		0	0.01		0	0.00		1	0.01	
	10	G	GS	32	150	53.6	1	0.02		36	0.47		0	0.01		0	0.00		1	0.01	
	11	G	GS	56	221	45.0	0	0.00		63	0.57		1	0.01		0	0.00		1	0.01	
	12	G	GS	39	264	77.2	1	0.01		66	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	604	94.4	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	432	80.9	0	0.00		22	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	601	94.0	0	0.00		5	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	318	77.3	0	0.00		9	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	58	419	82.5	0	0.00		29	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	301	78.2	0	0.00		17	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	4395	75.0	4	0.00		518	0.24		13	0.01		1	0.00		18	0.01	
Non-BAAQMD Calif. Load-Related					243201		215980	1.78		116472	0.96		N/A	N/A		N/A	N/A		24474	0.20	
Total Calif. Load-Related					252859		220652	1.75		116554	0.92		N/A	N/A		N/A	N/A		24928	0.20	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Analytical Maximum does not apply to CTs
- Reflects 1998 AP42 updates

Table G-5

1999 Baseline & All Divestiture Steam Units at Analytical Maximum

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	ENERGY OUTPUT (billion Btu)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO_X Tons	#/MWh	#/MMBtu	SO_X/H_2S Tons	#/MWh	#/MMBtu	PM10 Tons	#/MWh	#/MMBtu	CO Tons	#/MWh	#/MMBtu	ROG Tons	#/MWh	#/MMBtu
Hunters Point	1	CT	DF	52	77	4	0.9	6	3.29	0.167	4	1.97	0.100	1	0.68	0.035	4	2.20	0.112	1	0.69	0.035
	2	ST	NG	107	5324	422	45.0	403	1.91	0.151	3	0.01	0.001	20	0.10	0.008	224	1.06	0.084	22	0.11	0.008
	3	ST	NG	107	4960	391	41.7	375	1.92	0.151	2	0.01	0.001	19	0.10	0.008	208	1.06	0.084	21	0.11	0.008
	4	ST	NG	163	12306	1219	85.4	223	0.37	0.036	6	0.01	0.001	47	0.08	0.008	517	0.85	0.084	52	0.08	0.008
	Σ			429	22666	2036	54.2	1008	0.99	0.089	15	0.01	0.001	87	0.09	0.008	953	0.94	0.084	96	0.09	0.008
Potrero	3	ST	NG	207	12548	1224	67.5	569	0.93	0.091	6	0.01	0.001	48	0.08	0.008	527	0.86	0.084	53	0.09	0.008
	4	CT	DF	52	242	15	3.4	20	2.60	0.164	12	1.59	0.100	4	0.55	0.034	13	1.76	0.111	4	0.55	0.035
	5	CT	DF	52	146	9	1.9	12	2.79	0.165	7	1.69	0.100	3	0.58	0.034	8	1.88	0.111	3	0.59	0.035
	6	CT	DF	52	110	6	1.3	9	2.98	0.166	6	1.80	0.100	2	0.62	0.034	6	2.01	0.112	2	0.62	0.035
	Σ			363	13045	1254	39.4	610	0.97	0.094	31	0.05	0.005	56	0.09	0.009	555	0.88	0.085	61	0.10	0.009
Contra Costa	6	ST	NG	340	20461	2104	70.6	1114	1.06	0.109	10	0.01	0.001	78	0.07	0.008	837	0.80	0.082	86	0.08	0.008
	7	ST	NG	340	25584	2631	88.3	371	0.28	0.029	13	0.01	0.001	97	0.07	0.008	1047	0.80	0.082	107	0.08	0.008
	Σ			680	46046	4734	79.5	1486	0.63	0.065	23	0.01	0.001	175	0.07	0.008	1884	0.80	0.082	193	0.08	0.008
Pittsburg	1	ST	NG	163	6845	615	43.1	481	1.56	0.141	3	0.01	0.001	26	0.08	0.008	288	0.93	0.084	29	0.09	0.008
	2	ST	NG	163	10622	974	68.2	864	1.77	0.163	5	0.01	0.001	40	0.08	0.008	446	0.92	0.084	45	0.09	0.008
	3	ST	NG	163	11768	1080	75.6	954	1.77	0.162	6	0.01	0.001	45	0.08	0.008	494	0.92	0.084	49	0.09	0.008
	4	ST	NG	163	10488	947	66.3	845	1.79	0.161	5	0.01	0.001	40	0.08	0.008	441	0.93	0.084	44	0.09	0.008
	5	ST	NG	325	23068	2297	80.7	1047	0.91	0.091	12	0.01	0.001	88	0.08	0.008	969	0.84	0.084	97	0.08	0.008
	6	ST	NG	325	25504	2497	87.7	1157	0.93	0.091	13	0.01	0.001	97	0.08	0.008	1071	0.86	0.084	107	0.09	0.008
	7	ST	NG	682	34557	3424	57.3	1045	0.61	0.060	17	0.01	0.001	131	0.08	0.008	1451	0.85	0.084	145	0.08	0.008
	Σ			1984	122853	11834	68.1	6393	1.08	0.104	61	0.01	0.001	467	0.08	0.008	5161	0.87	0.084	516	0.09	0.008
BAAQMD Bubble		ST only		3248	204036	19825	69.7	9449	0.95	0.093	102	0.01	0.001	775	0.08	0.008	8521	0.86	0.084	857	0.09	0.008
Geysers	5	G	GS	39	1973	197	57.7	0	0.00		50	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	1981	198	58.0	0	0.00		41	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	2163	216	65.0	0	0.00		58	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	2145	214	64.4	0	0.00		45	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	1350	133	47.4	2	0.02		23	0.35		0	0.01		0	0.01		1	0.01	
	10	G	GS	32	1343	132	47.1	2	0.03		31	0.48		0	0.01		0	0.01		1	0.01	
	11	G	GS	56	1786	179	36.4	0	0.00		51	0.57		1	0.01		0	0.00		1	0.01	
	12	G	GS	39	2238	222	64.9	2	0.01		56	0.51		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	6024	602	94.2	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	3771	376	70.4	1	0.00		19	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	5992	599	93.7	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	2876	288	69.8	0	0.00		8	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	58	3702	369	72.7	1	0.00		25	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	2605	259	67.3	1	0.01		14	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	39949	3985	68.0	7	0.00		454	0.23		12	0.01		2	0.00		16	0.01	
Non-BAAQMD Calif. Load-Related						233000		207059	1.78		109337	0.94		N/A	N/A		N/A	N/A		24133	0.21	
Total Calif. Load-Related						252859		216556	1.71		109468	0.87		N/A	N/A		N/A	N/A		25000	0.20	

UNIT TYPES: CT combustion turbine; ST steam turbine; G geothermal steam; CC combined cycle

FUELS: NG natural gas w/ residual oil backup; DF distillate fuel oil; GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Analytical Maximum does not apply to CTs

Table G-6

2005 - Bay Area Steam Units at Analytical Maximum; Hunters Point Shut Down; Increased Transmission to Serve SF Load, Reduce BARR

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS														
							NO_X			SO_X/H_2S			PM10			CO			ROG		
							Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu
Hunters Point plant retired																					
Potrero	3	ST	NG	207	1151	63.5	71	0.12	0.012	6	0.01	0.001	44	0.08	0.008	478	0.83	0.082	49	0.09	0.008
	4	CT	DF	52	42	9.2	44	2.12	0.164	27	1.29	0.100	3	0.15	0.012	4	0.18	0.014	9	0.45	0.035
	5	CT	DF	52	36	7.8	38	2.13	0.164	23	1.30	0.100	3	0.15	0.012	3	0.18	0.014	8	0.44	0.034
	6	CT	DF	52	33	7.2	35	2.13	0.165	21	1.30	0.100	2	0.15	0.012	3	0.18	0.014	7	0.44	0.034
	Σ			363	1261	39.7	188	0.30	0.029	77	0.12	0.012	52	0.08	0.008	488	0.77	0.075	73	0.12	0.011
Contra Costa	6	ST	NG	340	2096	70.4	123	0.12	0.012	10	0.01	0.001	76	0.07	0.008	836	0.80	0.082	86	0.08	0.008
	7	ST	NG	340	2055	69.0	121	0.12	0.012	10	0.01	0.001	75	0.07	0.007	819	0.80	0.082	84	0.08	0.008
	Σ			680	4151	69.7	244	0.12	0.012	20	0.01	0.001	151	0.07	0.008	1655	0.80	0.082	170	0.08	0.008
Pittsburg	1	ST	NG	163	648	45.4	579	1.79	0.164	4	0.01	0.001	27	0.08	0.008	290	0.90	0.082	30	0.09	0.008
	2	ST	NG	163	992	69.5	66	0.13	0.012	5	0.01	0.001	40	0.08	0.007	442	0.89	0.082	45	0.09	0.008
#3 retired																					
#4 retired																					
	5	ST	NG	325	1699	59.7	103	0.12	0.012	9	0.01	0.001	64	0.08	0.008	699	0.82	0.082	72	0.08	0.008
	6	ST	NG	325	2157	75.8	133	0.12	0.012	11	0.01	0.001	83	0.08	0.007	903	0.84	0.082	93	0.09	0.008
	7	ST	NG	682	4260	71.3	261	0.12	0.012	22	0.01	0.001	162	0.08	0.008	1768	0.83	0.082	181	0.09	0.008
	Σ			1658	9756	67.2	1142	0.23	0.023	50	0.01	0.001	375	0.08	0.007	4103	0.84	0.082	420	0.09	0.008
New 480 MW		CC	NG	480	3806	90.5	184	0.10	0.014	12	0.01	0.001	101	0.05	0.008	150	0.08	0.011	80	0.04	0.006
Geysers	5	G	GS	39	280	81.8	1	0.00		71	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	277	81.0	1	0.01		57	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	275	85.0	0	0.00		73	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	277	85.5	0	0.00		58	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	205	73.3	1	0.01		35	0.35		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	203	72.6	1	0.01		48	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	463	94.4	0	0.00		133	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	291	85.1	1	0.01		73	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	576	95.3	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	462	86.5	1	0.00		23	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	571	94.4	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	368	89.3	0	0.00		10	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	62	477	87.8	1	0.00		32	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	345	85.7	1	0.00		19	0.11		1	0.01		0	0.00		1	0.01	
	Σ			665	5070	87.0	7	0.00		665	0.26		15	0.01		2	0.00		21	0.01	
Non-BAAQMD California Load-Related					263479		196419	1.49		98344	0.75		11848	0.09		46970	0.36		24952	0.19	
Total Calif. Load-Related					282453		198177	1.40		98504	0.70		12528	0.09		53365	0.38		25695	0.18	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
- 115/230 kV transmission into SF assumed to be increased to about 550 MW

Table G-7

1999 Baseline & UNT Geysers at Analytical Maximum Geothermal Steam Usage

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO_X Tons	NO_X #/MWh	NO_X #/MMBtu	SO_X/H_2S Tons	SO_X/H_2S #/MWh	SO_X/H_2S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point	1	CT	DF	52	4	0.9	7	3.31	0.167	4	1.98	0.100	1	0.68	0.035	4	2.22	0.112	1	0.69	0.035
	2	ST	NG	107	89	9.5	112	2.52	0.156	1	0.02	0.001	6	0.13	0.008	73	1.65	0.102	6	0.14	0.009
	3	ST	NG	107	56	5.9	75	2.70	0.156	0	0.02	0.001	4	0.14	0.008	49	1.76	0.102	4	0.15	0.009
	4	ST	NG	163	754	52.8	140	0.37	0.036	4	0.01	0.001	29	0.08	0.008	382	1.01	0.099	33	0.09	0.008
	Σ			429	903	24.0	335	0.74	0.065	9	0.02	0.002	40	0.09	0.008	509	1.13	0.100	44	0.10	0.009
Potrero	3	ST	NG	207	752	41.4	347	0.92	0.091	4	0.01	0.001	29	0.08	0.008	378	1.00	0.099	32	0.09	0.008
	4	CT	DF	52	16	3.4	20	2.62	0.164	12	1.59	0.100	4	0.55	0.034	14	1.77	0.111	4	0.55	0.035
	5	CT	DF	52	9	2.0	13	2.81	0.165	8	1.70	0.100	3	0.59	0.034	8	1.90	0.111	3	0.59	0.035
	6	CT	DF	52	6	1.4	9	3.01	0.166	6	1.81	0.100	2	0.62	0.035	6	2.02	0.112	2	0.63	0.035
	Σ			363	782	24.6	389	0.99	0.095	29	0.08	0.007	38	0.10	0.009	406	1.04	0.100	41	0.10	0.010
Contra Costa	6	ST	NG	340	963	32.3	534	1.11	0.109	5	0.01	0.001	37	0.08	0.008	472	0.98	0.096	41	0.09	0.008
	7	ST	NG	340	1190	40.0	176	0.30	0.029	6	0.01	0.001	46	0.08	0.008	584	0.98	0.096	51	0.09	0.008
	Σ			680	2153	36.2	710	0.66	0.065	11	0.01	0.001	83	0.08	0.008	1056	0.98	0.096	92	0.09	0.008
Pittsburg	1	ST	NG	163	322	22.6	277	1.72	0.138	2	0.01	0.001	15	0.10	0.008	199	1.24	0.099	17	0.11	0.008
	2	ST	NG	163	331	23.2	332	2.01	0.152	2	0.01	0.001	17	0.10	0.008	218	1.32	0.100	19	0.11	0.008
	3	ST	NG	163	469	32.8	407	1.74	0.141	3	0.01	0.001	22	0.09	0.008	286	1.22	0.099	24	0.10	0.008
	4	ST	NG	163	400	28.0	358	1.79	0.141	3	0.01	0.001	20	0.10	0.008	254	1.27	0.100	22	0.11	0.008
	5	ST	NG	325	1107	38.9	542	0.98	0.091	6	0.01	0.001	45	0.08	0.008	590	1.07	0.099	50	0.09	0.008
	6	ST	NG	325	1135	39.9	575	1.01	0.091	6	0.01	0.001	48	0.08	0.008	626	1.10	0.099	53	0.09	0.008
	7	ST	NG	682	1595	26.7	506	0.63	0.061	8	0.01	0.001	64	0.08	0.008	826	1.04	0.099	70	0.09	0.008
	Σ			1984	5359	30.8	2997	1.12	0.099	30	0.01	0.001	231	0.09	0.008	2999	1.12	0.099	255	0.10	0.008
Geysers	5	G	GS	39	319	93.5	0	0.00		80	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	319	93.5	0	0.00		66	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	304	91.3	0	0.00		81	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	304	91.3	0	0.00		64	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	246	87.7	1	0.01		42	0.34		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	243	86.8	1	0.01		57	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	455	92.7	0	0.00		130	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	308	90.2	1	0.01		78	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	604	94.4	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	490	91.7	0	0.00		25	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	600	93.9	0	0.00		5	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	387	93.9	0	0.00		11	0.06		1	0.01		0	0.00		2	0.01	
	18	G	GS	58	468	92.1	0	0.00		32	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	352	91.2	0	0.00		20	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	5400	92.1	4	0.00		718	0.27		16	0.01		1	0.00		22	0.01	
Non-BAAQMD Calif. Load-Related					243661		215259	1.77		116386	0.96		N/A	N/A		N/A	N/A		24462	0.20	
Total Calif. Load-Related					252859		219690	1.74		116466	0.92		N/A	N/A		N/A	N/A		24894	0.20	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- UNT = Geysers steam suppliers Union, NEC and Thermal
- Geothermal units emit H_2S but basically no SO_X
- Analytical Maximum does not apply to CTs
- Reflects 1998 AP42 updates

Table G-8

2005 - Geysers Geothermal at Analytical Maximum; Hunters Point Shut Down; Increased Transmission to Serve SF Load, Reduce BARR

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS														
							NO_X			SO_X/H_2S			PM10			CO			ROG		
							Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu
Hunters Point																					
plant retired																					
Potrero	3	ST	NG	207	613	33.8	37	0.12	0.012	3	0.01	0.001	23	0.08	0.008	254	0.83	0.082	26	0.08	0.008
	4	CT	DF	52	42	9.3	45	2.13	0.164	27	1.29	0.100	3	0.15	0.012	4	0.18	0.014	9	0.45	0.035
	5	CT	DF	52	35	7.8	38	2.14	0.165	23	1.30	0.100	3	0.15	0.011	3	0.18	0.014	8	0.44	0.034
	6	CT	DF	52	33	7.3	36	2.14	0.165	22	1.30	0.100	2	0.15	0.011	3	0.18	0.014	7	0.44	0.034
	Σ			363	725	22.8	156	0.43	0.041	75	0.21	0.020	32	0.09	0.008	264	0.73	0.069	51	0.14	0.013
Contra Costa	6	ST	NG	340	1344	45.1	81	0.12	0.012	7	0.01	0.001	50	0.07	0.008	548	0.81	0.082	56	0.08	0.008
	7	ST	NG	340	1371	46.0	82	0.12	0.012	7	0.01	0.001	51	0.07	0.007	557	0.81	0.082	57	0.08	0.008
	Σ			680	2716	45.6	163	0.12	0.012	13	0.01	0.001	101	0.07	0.008	1105	0.81	0.082	113	0.08	0.008
Pittsburg	1	ST	NG	163	293	20.5	276	1.88	0.153	2	0.01	0.001	14	0.09	0.008	149	1.01	0.082	15	0.10	0.008
	2	ST	NG	163	520	36.4	41	0.16	0.013	3	0.01	0.001	23	0.09	0.008	254	0.98	0.082	26	0.10	0.008
#3 retired																					
#4 retired																					
	5	ST	NG	325	1190	41.8	74	0.12	0.012	6	0.01	0.001	46	0.08	0.007	504	0.85	0.082	52	0.09	0.008
	6	ST	NG	325	1344	47.2	87	0.13	0.012	7	0.01	0.001	54	0.08	0.007	589	0.88	0.082	60	0.09	0.008
	7	ST	NG	682	2965	49.6	182	0.12	0.012	15	0.01	0.001	113	0.08	0.007	1233	0.83	0.082	126	0.09	0.008
	Σ			1658	6312	43.5	660	0.21	0.020	33	0.01	0.001	250	0.08	0.008	2728	0.86	0.082	279	0.09	0.008
New 480 MW		CC	NG	480	3795	90.3	183	0.10	0.014	12	0.01	0.001	101	0.05	0.008	149	0.08	0.011	80	0.04	0.006
Geysers	5	G	GS	39	317	92.8	0	0.00		80	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	313	91.7	0	0.00		65	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	308	94.9	0	0.00		82	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	308	94.9	0	0.00		64	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	251	89.4	1	0.01		43	0.34		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	250	89.0	1	0.01		59	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	466	95.0	0	0.00		134	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	314	92.0	1	0.00		79	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	574	95.0	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	496	92.8	0	0.00		25	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	572	94.6	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	391	94.9	0	0.00		11	0.06		1	0.01		0	0.00		2	0.01	
	18	G	GS	62	505	92.9	0	0.00		34	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	373	92.5	0	0.00		21	0.11		1	0.01		0	0.00		2	0.01	
	Σ			665	5436	93.3	4	0.00		728	0.27		16	0.01		1	0.00		22	0.01	
Non-BAAQMD California Load-Related					268907		200310	1.49		101511	0.75		12197	0.09		48607	0.36		25234	0.19	
Total Calif. Load-Related					282454		201472	1.43		101645	0.72		12680	0.09		52853	0.37		25757	0.18	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
- -115/230 kV transmission into SF assumed to be increased to about 550 MW

Table G-9

2005 - Bay Area Steam Units at Analytical Maximum; Hunters Point Shut Down; New 240 MW in San Francisco; Transmission Increased to Serve SF Load and Reduce BARR without full New 480 MW

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO$_X$ Tons	NO$_X$ #/MWh	NO$_X$ #/MMBtu	SO$_X$/H$_2$S Tons	SO$_X$/H$_2$S #/MWh	SO$_X$/H$_2$S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point plant retired																					
Potrero	3	ST	NG	207	1148	63.3	70	0.12	0.012	6	0.01	0.001	44	0.08	0.007	477	0.83	0.082	49	0.09	0.008
	4	CT	DF	52	45	9.9	48	2.12	0.164	29	1.29	0.100	3	0.15	0.012	4	0.18	0.014	10	0.45	0.035
	5	CT	DF	52	43	9.5	46	2.12	0.164	28	1.29	0.100	3	0.15	0.012	4	0.18	0.014	10	0.44	0.034
	6	CT	DF	52	38	8.4	41	2.13	0.165	25	1.29	0.100	3	0.15	0.012	3	0.18	0.014	8	0.44	0.034
	Σ			363	1275	40.1	204	0.32	0.031	87	0.14	0.013	53	0.08	0.008	488	0.77	0.074	77	0.12	0.012
Contra Costa	6	ST	NG	340	2114	71.0	124	0.12	0.012	10	0.01	0.001	77	0.07	0.008	843	0.80	0.082	86	0.08	0.008
	7	ST	NG	340	2066	69.4	122	0.12	0.012	10	0.01	0.001	75	0.07	0.007	823	0.80	0.082	84	0.08	0.008
	Σ			680	4179	70.2	246	0.12	0.012	20	0.01	0.001	152	0.07	0.008	1666	0.80	0.082	171	0.08	0.008
Pittsburg	1	ST	NG	163	647	45.3	578	1.79	0.164	4	0.01	0.001	27	0.08	0.008	290	0.90	0.082	30	0.09	0.008
	2	ST	NG	163	1023	71.7	68	0.13	0.012	6	0.01	0.001	42	0.08	0.007	456	0.89	0.082	47	0.09	0.008
#3 retired																					
#4 retired																					
	5	ST	NG	325	1718	60.3	104	0.12	0.012	9	0.01	0.001	65	0.08	0.007	707	0.82	0.082	72	0.08	0.008
	6	ST	NG	325	2167	76.1	134	0.12	0.012	11	0.01	0.001	83	0.08	0.007	907	0.84	0.082	93	0.09	0.008
	7	ST	NG	682	4334	72.5	266	0.12	0.012	22	0.01	0.001	165	0.08	0.008	1800	0.83	0.082	184	0.09	0.008
	Σ			1658	9890	68.1	1150	0.23	0.023	51	0.01	0.001	380	0.08	0.007	4160	0.84	0.082	426	0.09	0.008
New 240 MW		CC	NG	240	1905	90.6	92	0.10	0.014	6	0.01	0.001	51	0.05	0.008	75	0.08	0.011	40	0.04	0.006
Geysers	5	G	GS	39	284	83.0	1	0.00		72	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	285	83.3	1	0.00		59	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	279	86.0	0	0.00		74	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	278	85.8	0	0.00		58	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	210	74.9	1	0.01		36	0.34		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	208	74.2	1	0.01		49	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	463	94.5	0	0.00		133	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	291	85.2	1	0.01		73	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	573	94.8	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	473	88.5	0	0.00		24	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	574	94.9	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	366	88.8	0	0.00		10	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	62	482	88.7	1	0.00		33	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	350	86.9	1	0.00		19	0.11		1	0.01		0	0.00		1	0.01	
	Σ			665	5115	87.8	7	0.00		672	0.26		15	0.01		2	0.00		21	0.01	
Non-BAAQMD California Load-Related					265203		198172	1.49		99373	0.75		11966	0.09		47536	0.36		25163	0.19	
Total Calif. Load-Related					282452		199864	1.42		99538	0.70		12603	0.09		53925	0.38		25877	0.18	

UNIT TYPES: CT combustion turbine; ST steam turbine; G geothermal steam; CC combined cycle

FUELS: NG natural gas w/ residual oil backup; DF distillate fuel oil; GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
-115/230 kV transmission into SF assumed to be increased to about 800 MW

Table G-10

1998 - Baseline & Emission Controls Frozen at 1998 Levels

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NOx			SOx/H2S			PM10			CO			ROG		
							Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu
Hunters Point	1	CT	DF	52	4	0.9	7	3.31	0.167	4	1.98	0.100	1	0.68	0.035	4	2.22	0.112	1	0.69	0.035
	2	ST	NG	107	89	9.5	112	2.51	0.155	1	0.02	0.001	6	0.13	0.008	62	1.39	0.086	6	0.14	0.009
	3	ST	NG	107	55	5.9	74	2.69	0.156	0	0.02	0.001	4	0.14	0.008	41	1.49	0.087	4	0.15	0.009
	4	ST	NG	163	756	53.0	493	1.30	0.127	4	0.01	0.001	30	0.08	0.008	326	0.86	0.084	33	0.09	0.008
	Σ			429	905	24.1	686	1.52	0.134	9	0.02	0.002	40	0.09	0.008	434	0.96	0.085	44	0.10	0.009
Potrero	3	ST	NG	207	752	41.4	532	1.42	0.139	4	0.01	0.001	29	0.08	0.008	321	0.85	0.084	32	0.09	0.008
	4	CT	DF	52	15	3.4	20	2.61	0.164	12	1.59	0.100	4	0.55	0.034	14	1.77	0.111	4	0.55	0.035
	5	CT	DF	52	9	1.9	12	2.81	0.165	7	1.70	0.100	3	0.59	0.034	8	1.90	0.111	3	0.59	0.035
	6	CT	DF	52	6	1.4	9	3.01	0.166	6	1.81	0.100	2	0.62	0.035	6	2.02	0.112	2	0.63	0.035
	Σ			363	782	24.6	574	1.47	0.141	29	0.07	0.007	38	0.10	0.009	349	0.89	0.086	41	0.10	0.010
Contra Costa	6	ST	NG	340	970	32.6	538	1.11	0.109	5	0.01	0.001	38	0.08	0.008	404	0.83	0.082	41	0.09	0.008
	7	ST	NG	340	1198	40.2	177	0.30	0.029	6	0.01	0.001	46	0.08	0.008	499	0.83	0.082	51	0.09	0.008
	Σ			680	2169	36.4	715	0.66	0.065	11	0.01	0.001	84	0.08	0.008	903	0.83	0.082	93	0.09	0.008
Pittsburg	1	ST	NG	163	323	22.6	427	2.64	0.212	2	0.01	0.001	15	0.09	0.008	169	1.05	0.084	17	0.10	0.008
	2	ST	NG	163	332	23.3	468	2.81	0.213	2	0.01	0.001	17	0.10	0.008	186	1.12	0.085	19	0.11	0.008
	3	ST	NG	163	473	33.1	617	2.61	0.212	3	0.01	0.001	22	0.09	0.008	245	1.04	0.084	24	0.10	0.008
	4	ST	NG	163	397	27.8	539	2.71	0.214	3	0.01	0.001	19	0.10	0.008	215	1.08	0.085	21	0.11	0.008
	5	ST	NG	325	1114	39.1	545	0.98	0.091	6	0.01	0.001	46	0.08	0.008	504	0.91	0.084	50	0.09	0.008
	6	ST	NG	325	1144	40.2	579	1.01	0.091	6	0.01	0.001	48	0.08	0.008	536	0.94	0.084	54	0.09	0.008
	7	ST	NG	682	1609	26.9	510	0.63	0.060	8	0.01	0.001	64	0.08	0.008	708	0.88	0.084	71	0.09	0.008
	Σ			1984	5394	31.0	3685	1.37	0.121	31	0.01	0.001	232	0.09	0.008	2563	0.95	0.084	256	0.10	0.008
Geysers	5	G	GS	39	232	67.9	0	0.00		58	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	231	67.7	0	0.00		48	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	237	71.1	0	0.00		63	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	236	71.0	0	0.00		50	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	153	54.6	1	0.01		26	0.35		0	0.01		0	0.00		1	0.01	
	10	G	GS	32	152	54.1	1	0.02		36	0.47		0	0.01		0	0.00		1	0.01	
	11	G	GS	56	222	45.3	0	0.00		64	0.57		1	0.01		0	0.00		1	0.01	
	12	G	GS	39	264	77.4	1	0.01		67	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	604	94.4	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	434	81.1	0	0.00		22	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	600	93.9	0	0.00		5	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	319	77.5	0	0.00		9	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	58	418	82.3	0	0.00		28	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	302	78.4	0	0.00		17	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	4404	75.2	4	0.00		520	0.24		13	0.01		1	0.00		18	0.01	
Non-BAAQMD Calif. Load-Related					243609		216353	1.78		117040	0.96		N/A	N/A		N/A	N/A		24484	0.20	
Total Calif. Load-Related					252859		222012	1.76		117120	0.93		N/A	N/A		N/A	N/A		24918	0.20	

UNIT TYPES: CT combustion turbine
ST steam turbine
G geothermal steam
CC combined cycle

FUELS: NG natural gas w/ residual oil backup
DF distillate fuel oil
GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects 1998 AP42 updates

Table G-11

2005 - Hunters Point Shut Down; NOx Emission at 1998 Rates

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO$_X$ Tons	NO$_X$ #/MWh	NO$_X$ #/MMBtu	SO$_X$/H$_2$S Tons	SO$_X$/H$_2$S #/MWh	SO$_X$/H$_2$S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point plant retired																					
Potrero	3	ST	NG	207	582	32.1	408	1.40	0.139	3	0.01	0.001	22	0.08	0.007	241	0.83	0.082	25	0.08	0.008
	4	CT	DF	52	42	9.3	45	2.13	0.164	27	1.30	0.100	3	0.15	0.012	4	0.18	0.014	10	0.45	0.035
	5	CT	DF	52	36	7.8	38	2.14	0.165	23	1.30	0.100	3	0.15	0.012	3	0.18	0.014	8	0.44	0.034
	6	CT	DF	52	33	7.4	36	2.14	0.165	22	1.30	0.100	2	0.15	0.011	3	0.18	0.014	7	0.44	0.034
	Σ			363	693	21.8	527	1.52	0.144	75	0.22	0.021	30	0.09	0.008	251	0.72	0.069	49	0.14	0.014
Contra Costa	6	ST	NG	340	1282	43.1	696	1.09	0.109	6	0.01	0.001	48	0.07	0.008	524	0.82	0.082	54	0.08	0.008
	7	ST	NG	340	1378	46.3	198	0.29	0.029	7	0.01	0.001	51	0.07	0.008	560	0.81	0.082	57	0.08	0.008
	Σ			680	2661	44.7	894	0.67	0.068	13	0.01	0.001	99	0.07	0.008	1084	0.81	0.082	111	0.08	0.008
Pittsburg	1	ST	NG	163	281	19.7	370	2.64	0.212	2	0.01	0.001	13	0.09	0.008	143	1.02	0.082	15	0.10	0.008
	2	ST	NG	163	454	31.8	591	2.60	0.213	3	0.01	0.001	21	0.09	0.008	228	1.00	0.082	23	0.10	0.008
#3 retired																					
#4 retired																					
	5	ST	NG	325	1162	40.8	546	0.94	0.091	6	0.01	0.001	45	0.08	0.007	493	0.85	0.082	51	0.09	0.008
	6	ST	NG	325	1278	44.9	623	0.98	0.091	7	0.01	0.001	52	0.08	0.007	563	0.88	0.082	58	0.09	0.008
	7	ST	NG	682	2947	49.3	904	0.61	0.061	15	0.01	0.001	112	0.08	0.008	1225	0.83	0.082	126	0.09	0.008
	Σ			1658	6121	42.1	3034	0.99	0.094	32	0.01	0.001	243	0.08	0.008	2653	0.87	0.082	272	0.09	0.008
New 480 MW		CC	NG	480	3795	90.3	183	0.10	0.014	12	0.01	0.001	101	0.05	0.008	149	0.08	0.011	80	0.04	0.006
Geysers	5	G	GS	39	296	86.8	0	0.00		75	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	295	86.3	0	0.00		61	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	287	88.5	0	0.00		76	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	287	88.6	0	0.00		60	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	220	78.5	1	0.01		38	0.34		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	219	78.0	1	0.01		52	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	466	95.0	0	0.00		134	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	303	88.7	1	0.00		76	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	574	95.0	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	485	90.7	0	0.00		25	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	571	94.5	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	374	90.9	0	0.00		10	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	62	494	90.9	0	0.00		34	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	362	89.8	0	0.00		20	0.11		1	0.01		0	0.00		1	0.01	
	Σ			665	5233	89.8	5	0.00		691	0.26		16	0.01		1	0.00		21	0.01	
Non-BAAQMD California Load-Related					269184		196834	1.46		101512	0.75		12207	0.09		48717	0.36		25245	0.19	
Total Calif. Load-Related					282454		201472	1.43		101645	0.72		12680	0.09		52853	0.37		25757	0.18	

UNIT TYPES: CT combustion turbine; ST steam turbine; G geothermal steam; CC combined cycle

FUELS: NG natural gas w/ residual oil backup; DF distillate fuel oil; GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
-115/230 kV transmission into SF assumed to be increased to about 550 MW

Table G-12

1999 - Baseline & Emission Controls Frozen at 1998 Levels & All Divestiture - Bound Steam at Analytical Maximum

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO$_X$ Tons	NO$_X$ #/MWh	NO$_X$ #/MMBtu	SO$_X$/H$_2$S Tons	SO$_X$/H$_2$S #/MWh	SO$_X$/H$_2$S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point	1	CT	DF	52	1	0.2	2	3.89	0.168	1	2.31	0.100	0	0.80	0.035	1	2.59	0.112	0	0.81	0.035
	2	ST	NG	107	421	45.0	403	1.91	0.151	3	0.01	0.001	20	0.10	0.008	224	1.06	0.084	22	0.11	0.008
	3	ST	NG	107	385	41.1	370	1.92	0.151	2	0.01	0.001	19	0.10	0.008	205	1.07	0.084	21	0.11	0.008
	4	ST	NG	163	1213	84.9	778	1.28	0.127	6	0.01	0.001	47	0.08	0.008	514	0.85	0.084	51	0.08	0.008
	Σ			429	2020	53.7	1552	1.54	0.138	12	0.01	0.001	86	0.08	0.008	945	0.94	0.084	95	0.09	0.008
Potrero	3	ST	NG	207	1217	67.1	867	1.42	0.139	6	0.01	0.001	47	0.08	0.008	523	0.86	0.084	52	0.09	0.008
	4	CT	DF	52	3	0.6	5	3.36	0.167	3	2.01	0.100	1	0.69	0.035	3	2.25	0.112	1	0.70	0.035
	5	CT	DF	52	1	0.3	3	3.82	0.169	2	2.26	0.100	1	0.78	0.035	2	2.54	0.113	1	0.79	0.035
	6	CT	DF	52	1	0.3	2	3.87	0.169	1	2.29	0.100	0	0.79	0.035	1	2.58	0.113	0	0.80	0.035
	Σ			363	1222	38.4	877	1.43	0.139	12	0.02	0.002	49	0.08	0.008	530	0.87	0.084	54	0.09	0.009
Contra Costa	6	ST	NG	340	2107	70.7	1116	1.06	0.109	10	0.01	0.001	78	0.07	0.008	839	0.80	0.082	86	0.08	0.008
	7	ST	NG	340	2616	87.8	369	0.28	0.029	13	0.01	0.001	97	0.07	0.008	1041	0.80	0.082	107	0.08	0.008
	Σ			680	4723	79.3	1486	0.63	0.065	23	0.01	0.001	175	0.07	0.008	1880	0.80	0.082	193	0.08	0.008
Pittsburg	1	ST	NG	163	616	43.1	726	2.36	0.212	3	0.01	0.001	26	0.08	0.008	288	0.94	0.084	29	0.09	0.008
	2	ST	NG	163	981	68.7	1134	2.31	0.212	5	0.01	0.001	41	0.08	0.008	450	0.92	0.084	45	0.09	0.008
	3	ST	NG	163	1083	75.8	1250	2.31	0.212	6	0.01	0.001	45	0.08	0.008	496	0.92	0.084	50	0.09	0.008
	4	ST	NG	163	939	65.8	1103	2.35	0.212	5	0.01	0.001	40	0.08	0.008	438	0.93	0.084	44	0.09	0.008
	5	ST	NG	325	2276	79.9	1037	0.91	0.091	11	0.01	0.001	87	0.08	0.008	960	0.84	0.084	96	0.08	0.008
	6	ST	NG	325	2473	86.9	1147	0.93	0.091	13	0.01	0.001	96	0.08	0.008	1062	0.86	0.084	106	0.09	0.008
	7	ST	NG	682	3425	57.3	1047	0.61	0.060	17	0.01	0.001	132	0.08	0.008	1454	0.85	0.084	145	0.08	0.008
	Σ			1984	11793	67.9	7444	1.26	0.121	61	0.01	0.001	466	0.08	0.008	5147	0.87	0.084	515	0.09	0.008
Geysers	5	G	GS	39	196	57.4	0	0.00		49	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	196	57.3	0	0.00		40	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	214	64.1	0	0.00		57	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	213	64.1	0	0.00		45	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	135	48.2	2	0.02		23	0.35		0	0.01		0	0.01		1	0.01	
	10	G	GS	32	134	47.7	2	0.03		32	0.48		0	0.01		0	0.01		1	0.01	
	11	G	GS	56	178	36.3	0	0.00		51	0.57		1	0.01		0	0.00		1	0.01	
	12	G	GS	39	226	66.3	2	0.02		57	0.51		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	603	94.4	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	378	70.7	1	0.00		19	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	601	94.0	0	0.00		5	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	289	70.2	0	0.00		8	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	58	371	73.0	1	0.00		25	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	259	67.3	1	0.01		14	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	3993	68.1	8	0.00		455	0.23		12	0.01		2	0.00		16	0.01	
Non-BAAQMD Calif. Load-Related					233101		206517	1.77		108877	0.93		N/A	N/A		N/A	N/A		24157	0.21	
Total Calif. Load-Related					252859		217876	1.72		108986	0.86		N/A	N/A		N/A	N/A		25014	0.20	

UNIT TYPES: CT combustion turbine; ST steam turbine; G geothermal steam; CC combined cycle

FUELS: NG natural gas w/ residual oil backup; DF distillate fuel oil; GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Analytical Maximum does not apply to CTs
- Reflects 1998 AP42 updates

Table G-13

2005 - Bay Area Steam Units at Analytical Maximum; Hunters Point Shut Down; NOx Emissions at 1998 Rates

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS: NO_X Tons	NO_X #/MWh	NO_X #/MMBtu	SO_X/H_2S Tons	SO_X/H_2S #/MWh	SO_X/H_2S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point plant retired																					
Potrero	3	ST	NG	207	1122	61.9	790	1.41	0.139	6	0.01	0.001	43	0.08	0.008	466	0.83	0.082	48	0.09	0.008
	4	CT	DF	52	41	9.1	44	2.13	0.164	27	1.29	0.100	3	0.15	0.012	4	0.18	0.014	9	0.45	0.035
	5	CT	DF	52	35	7.6	37	2.14	0.165	22	1.30	0.100	3	0.15	0.012	3	0.18	0.014	8	0.44	0.034
	6	CT	DF	52	32	7.1	35	2.14	0.165	21	1.30	0.100	2	0.15	0.012	3	0.18	0.014	7	0.44	0.034
	Σ			363	1230	38.7	906	1.47	0.142	76	0.12	0.012	51	0.08	0.008	476	0.77	0.075	72	0.12	0.011
Contra Costa	6	ST	NG	340	2075	69.7	1099	1.06	0.109	10	0.01	0.001	76	0.07	0.007	828	0.80	0.082	85	0.08	0.008
	7	ST	NG	340	2052	68.9	290	0.28	0.029	10	0.01	0.001	75	0.07	0.007	818	0.80	0.082	84	0.08	0.008
	Σ			680	4127	69.3	1389	0.67	0.069	20	0.01	0.001	151	0.07	0.007	1646	0.80	0.082	169	0.08	0.008
Pittsburg	1	ST	NG	163	635	44.5	736	2.32	0.212	3	0.01	0.001	26	0.08	0.007	285	0.90	0.082	29	0.09	0.008
	2	ST	NG	163	974	68.2	1124	2.31	0.212	5	0.01	0.001	40	0.08	0.008	435	0.89	0.082	45	0.09	0.008
#3 retired																					
#4 retired																					
	5	ST	NG	325	1683	59.1	767	0.91	0.091	8	0.01	0.001	63	0.08	0.008	693	0.82	0.082	71	0.08	0.008
	6	ST	NG	325	2141	75.2	993	0.93	0.091	11	0.01	0.001	82	0.08	0.008	897	0.84	0.082	92	0.09	0.008
	7	ST	NG	682	4248	71.1	1302	0.61	0.060	22	0.01	0.001	161	0.08	0.007	1765	0.83	0.082	181	0.09	0.008
	Σ			1658	9681	66.7	4922	1.02	0.099	50	0.01	0.001	373	0.08	0.008	4075	0.84	0.082	417	0.09	0.008
New 480 MW		CC	NG	480	3795	90.3	183	0.10	0.014	12	0.01	0.001	101	0.05	0.008	149	0.08	0.011	80	0.04	0.006
Geysers	5	G	GS	39	278	81.3	1	0.00		70	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	276	80.7	1	0.01		57	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	272	84.0	0	0.00		72	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	273	84.3	0	0.00		57	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	203	72.6	2	0.02		35	0.35		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	202	71.9	2	0.02		48	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	466	95.0	0	0.00		134	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	290	84.8	1	0.01		73	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	574	95.0	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	468	87.5	1	0.00		24	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	572	94.6	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	361	87.6	0	0.00		10	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	62	480	88.3	0	0.00		33	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	347	86.1	1	0.00		19	0.11		1	0.01		0	0.00		1	0.01	
	Σ			665	5060	86.9	7	0.00		663	0.26		15	0.01		2	0.00		21	0.01	
Non-BAAQMD California Load-Related					263621		194072	1.47		101487	0.77		12005	0.09		46507	0.35		25019	0.19	
Total Calif. Load-Related					282454		201472	1.43		101645	0.72		12680	0.09		52853	0.37		25757	0.18	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
-115/230 kV transmission into SF assumed to be increased to about 550 MW

Table G-14

2005 - Bay Area Steam Units at Analytical Maximum; Hunters Point Shut Down; Transmission Increased to Serve SF Load, Reduced BARR; ENRON Merchant Plant in Pittsburg

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS														
							NO_X			SO_X/H_2S			PM10			CO			ROG		
							Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu
Hunters Point plant retired																					
Potrero	3	ST	NG	207	1123	61.9	69	0.12	0.012	6	0.01	0.001	43	0.08	0.008	466	0.83	0.082	48	0.09	0.008
	4	CT	DF	52	36	7.9	38	2.13	0.164	23	1.30	0.100	3	0.15	0.012	3	0.18	0.014	8	0.45	0.035
	5	CT	DF	52	30	6.5	32	2.14	0.165	19	1.30	0.100	2	0.15	0.012	3	0.18	0.014	7	0.44	0.034
	6	CT	DF	52	28	6.1	30	2.14	0.165	18	1.30	0.100	2	0.15	0.012	3	0.18	0.014	6	0.44	0.034
	Σ			363	1217	38.3	168	0.28	0.027	66	0.11	0.011	50	0.08	0.008	475	0.78	0.075	69	0.11	0.011
Contra Costa	6	ST	NG	340	2067	69.4	122	0.12	0.012	10	0.01	0.001	75	0.07	0.008	825	0.80	0.082	84	0.08	0.008
	7	ST	NG	340	2021	67.8	119	0.12	0.012	10	0.01	0.001	74	0.07	0.007	806	0.80	0.082	83	0.08	0.008
	Σ			680	4087	68.6	241	0.12	0.012	20	0.01	0.001	149	0.07	0.007	1631	0.80	0.082	167	0.08	0.008
Pittsburg #1-4 retired																					
	5	ST	NG	325	1668	58.6	101	0.12	0.012	8	0.01	0.001	63	0.08	0.007	687	0.82	0.082	70	0.08	0.008
	6	ST	NG	325	2121	74.5	131	0.12	0.012	11	0.01	0.001	81	0.08	0.007	889	0.84	0.082	91	0.09	0.008
	7	ST	NG	682	4226	70.7	259	0.12	0.012	21	0.01	0.001	161	0.08	0.008	1756	0.83	0.082	180	0.09	0.008
	Σ			1332	8016	68.7	492	0.12	0.012	41	0.01	0.001	305	0.08	0.007	3333	0.83	0.082	341	0.09	0.008
New 480 MW		CC	NG	480	3795	90.2	183	0.10	0.014	12	0.01	0.001	101	0.05	0.008	149	0.08	0.011	80	0.04	0.006
ENRON		CC	NG	450	3554	90.2	172	0.10	0.014	11	0.01	0.001	95	0.05	0.008	140	0.08	0.011	75	0.04	0.006
Geysers	5	G	GS	39	272	79.6	1	0.01		69	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	271	79.3	1	0.01		56	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	269	83.0	0	0.00		72	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	270	83.3	0	0.00		57	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	199	70.8	2	0.02		34	0.35		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	196	70.0	2	0.02		46	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	466	95.0	0	0.00		134	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	283	82.9	1	0.01		72	0.51		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	574	95.0	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	457	85.6	1	0.00		23	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	569	94.1	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	357	86.8	0	0.00		10	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	62	469	86.3	1	0.00		32	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	339	84.2	1	0.00		19	0.11		1	0.01		0	0.00		1	0.01	
	Σ			665	4992	85.7	9	0.00		654	0.26		15	0.01		2	0.00		21	0.01	
Non-BAAQMD California Load-Related					265339		195513	1.47		96787	0.73		11823	0.09		46866	0.35		25083	0.19	
Total Calif. Load-Related					282454		196597	1.39		96926	0.69		12428	0.09		52454	0.37		25740	0.18	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
- 115/230 kV transmission into SF assumed to be increased to about 550 MW

Table G-15

1999 - Extended Delta Fish Entrainment Restrictions Case - 1999 Baseline & Delta Restrictions in Effect 2/15 through 7/15

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO$_X$ Tons	NO$_X$ #/MWh	NO$_X$ #/MMBtu	SO$_X$/H$_2$S Tons	SO$_X$/H$_2$S #/MWh	SO$_X$/H$_2$S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point	1	CT	DF	52	4	0.9	7	3.31	0.167	4	1.98	0.100	1	0.68	0.035	4	2.22	0.112	1	0.69	0.035
	2	ST	NG	107	89	9.5	112	2.51	0.155	1	0.02	0.001	6	0.13	0.008	62	1.39	0.086	6	0.14	0.009
	3	ST	NG	107	55	5.9	74	2.69	0.156	0	0.02	0.001	4	0.14	0.008	41	1.49	0.087	4	0.15	0.009
	4	ST	NG	163	756	53.0	141	0.37	0.036	4	0.01	0.001	30	0.08	0.008	326	0.86	0.084	33	0.09	0.008
	Σ			429	905	24.1	334	0.74	0.065	9	0.02	0.002	40	0.09	0.008	434	0.96	0.085	44	0.10	0.009
Potrero	3	ST	NG	207	752	41.4	347	0.92	0.091	4	0.01	0.001	29	0.08	0.008	321	0.85	0.084	32	0.09	0.008
	4	CT	DF	52	15	3.4	20	2.61	0.164	12	1.59	0.100	4	0.55	0.034	14	1.77	0.111	4	0.55	0.035
	5	CT	DF	52	9	1.9	12	2.81	0.165	7	1.70	0.100	3	0.59	0.034	8	1.90	0.111	3	0.59	0.035
	6	CT	DF	52	6	1.4	9	3.01	0.166	6	1.81	0.100	2	0.62	0.035	6	2.02	0.112	2	0.63	0.035
	Σ			363	782	24.6	389	0.99	0.095	29	0.07	0.007	38	0.10	0.009	349	0.89	0.086	41	0.10	0.010
Contra Costa	6	ST	NG	340	963	32.3	534	1.11	0.109	5	0.01	0.001	37	0.08	0.008	401	0.83	0.082	41	0.09	0.008
	7	ST	NG	340	1190	39.9	176	0.30	0.029	6	0.01	0.001	46	0.08	0.008	496	0.83	0.082	51	0.09	0.008
	Σ			680	2153	36.1	710	0.66	0.065	11	0.01	0.001	83	0.08	0.008	898	0.83	0.082	92	0.09	0.008
Pittsburg	1	ST	NG	163	323	22.6	277	1.72	0.138	2	0.01	0.001	15	0.09	0.008	169	1.05	0.084	17	0.10	0.008
	2	ST	NG	163	332	23.3	333	2.01	0.152	2	0.01	0.001	17	0.10	0.008	186	1.12	0.085	19	0.11	0.008
	3	ST	NG	163	473	33.1	410	1.73	0.141	3	0.01	0.001	22	0.09	0.008	245	1.04	0.084	24	0.10	0.008
	4	ST	NG	163	397	27.8	356	1.79	0.141	3	0.01	0.001	19	0.10	0.008	215	1.08	0.085	21	0.11	0.008
	5	ST	NG	325	1110	39.0	543	0.98	0.091	6	0.01	0.001	45	0.08	0.008	503	0.91	0.084	50	0.09	0.008
	6	ST	NG	325	1142	40.1	578	1.01	0.091	6	0.01	0.001	48	0.08	0.008	535	0.94	0.084	53	0.09	0.008
	7	ST	NG	682	1812	30.3	569	0.63	0.060	9	0.01	0.001	71	0.08	0.008	790	0.87	0.084	79	0.09	0.008
	Σ			1984	5590	32.2	3067	1.10	0.098	31	0.01	0.001	239	0.09	0.008	2643	0.95	0.084	264	0.09	0.008
Geysers	5	G	GS	39	231	67.7	0	0.00		58	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	231	67.6	0	0.00		48	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	38	236	70.9	0	0.00		63	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	38	236	70.8	0	0.00		49	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	152	54.2	1	0.01		26	0.35		0	0.01		0	0.00		1	0.01	
	10	G	GS	32	151	53.8	1	0.02		36	0.47		0	0.01		0	0.00		1	0.01	
	11	G	GS	56	220	44.9	0	0.00		63	0.57		1	0.01		0	0.00		1	0.01	
	12	G	GS	39	264	77.2	1	0.01		67	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	73	604	94.4	0	0.00		28	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	433	81.0	0	0.00		22	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	73	600	93.9	0	0.00		5	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	319	77.5	0	0.00		9	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	58	417	82.1	0	0.00		28	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	44	301	78.2	0	0.00		17	0.11		1	0.01		0	0.00		1	0.01	
	Σ			669	4395	75.0	5	0.00		518	0.24		13	0.01		1	0.00		18	0.01	
Non-BAAQMD Calif. Load-Related					243430		216240	1.78		116925	0.96		N/A	N/A		N/A	N/A		24477	0.20	
Total Calif. Load-Related					252859		220739	1.75		117006	0.93		N/A	N/A		N/A	N/A		24919	0.20	

UNIT TYPES: CT combustion turbine
ST steam turbine
G geothermal steam
CC combined cycle

FUELS: NG natural gas w/ residual oil backup
DF distillate fuel oil
GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects 1998 AP42 updates

Table G-16

2005 - Extended Delta Fish Entrainment Restrictions Case - 2005 Cumulative Impacts & Delta Restrictions in Effect 2/15 through 7/15

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS															
							NO_X			SO_X/H_2S			PM10			CO			ROG			
							Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	Tons	#/MWh	#/MMBtu	
Hunters Point plant retired																						
Potrero	3	ST	NG	207	549	30.3	34	0.12	0.012	3	0.01	0.001	21	0.08	0.008	233	0.85	0.084	23	0.08	0.008	
	4	CT	DF	52	16	3.4	26	3.29	0.166	15	1.98	0.100	5	0.68	0.035	17	2.21	0.112	5	0.69	0.035	
	5	CT	DF	52	13	2.9	23	3.51	0.167	14	2.10	0.100	5	0.73	0.035	15	2.35	0.112	5	0.73	0.035	
	6	CT	DF	52	12	2.6	21	3.65	0.167	13	2.18	0.100	4	0.75	0.035	14	2.44	0.112	4	0.76	0.035	
	Σ			363	589	18.5	104	0.35	0.032	45	0.15	0.014	36	0.12	0.011	280	0.95	0.088	38	0.13	0.012	
Contra Costa	6	ST	NG	340	1348	45.3	81	0.12	0.012	7	0.01	0.001	51	0.08	0.008	548	0.81	0.082	56	0.08	0.008	
	7	ST	NG	340	1376	46.2	82	0.12	0.012	7	0.01	0.001	52	0.08	0.008	558	0.81	0.082	57	0.08	0.008	
	Σ			680	2724	45.7	163	0.12	0.012	14	0.01	0.001	103	0.08	0.008	1106	0.81	0.082	113	0.08	0.008	
Pittsburg	1	ST	NG	163	316	22.1	263	1.66	0.138	2	0.01	0.001	15	0.09	0.008	161	1.02	0.084	16	0.10	0.008	
	2	ST	NG	163	525	36.8	40	0.15	0.013	3	0.01	0.001	24	0.09	0.008	264	1.00	0.084	26	0.10	0.008	
#3 retired																						
#4 retired																						
	5	ST	NG	325	1198	42.1	75	0.12	0.012	6	0.01	0.001	47	0.08	0.008	519	0.87	0.084	52	0.09	0.008	
	6	ST	NG	325	1353	47.5	87	0.13	0.012	7	0.01	0.001	55	0.08	0.008	607	0.90	0.084	61	0.09	0.008	
	7	ST	NG	682	2907	48.7	178	0.12	0.012	15	0.01	0.001	112	0.08	0.008	1239	0.85	0.084	124	0.09	0.008	
	Σ			1658	6299	43.4	644	0.20	0.019	33	0.01	0.001	252	0.08	0.008	2789	0.89	0.084	279	0.09	0.008	
Geysers	5	G	GS	33	261	90.1	0	0.00		66	0.50		1	0.01		0	0.00		1	0.01		
	6	G	GS	33	261	90.2	0	0.00		54	0.41		1	0.01		0	0.00		1	0.01		
	7	G	GS	31	243	89.6	0	0.00		65	0.53		1	0.01		0	0.00		1	0.01		
	8	G	GS	31	244	89.9	0	0.00		51	0.42		1	0.01		0	0.00		1	0.01		
	9	G	GS	27	191	80.8	1	0.01		33	0.34		1	0.01		0	0.00		1	0.01		
	10	G	GS	27	189	80.0	1	0.01		45	0.47		1	0.01		0	0.00		1	0.01		
	11	G	GS	48	353	83.9	0	0.00		101	0.57		1	0.01		0	0.00		1	0.01		
	12	G	GS	32	249	88.7	1	0.01		63	0.50		1	0.01		0	0.00		1	0.01		
	13	G	GS	61	508	95.0	0	0.00		24	0.09		1	0.01		0	0.00		2	0.01		
	14	G	GS	53	422	90.9	0	0.00		21	0.10		1	0.01		0	0.00		2	0.01		
	16	G	GS	61	504	94.2	0	0.00		4	0.02		1	0.01		0	0.00		2	0.01		
	17	G	GS	39	314	91.9	0	0.00		9	0.06		1	0.01		0	0.00		1	0.01		
	18	G	GS	49	389	90.5	0	0.00		26	0.14		1	0.01		0	0.00		2	0.01		
	20	G	GS	37	290	89.5	0	0.00		16	0.11		1	0.01		0	0.00		1	0.01		
	Σ			562	4417	89.7	4	0.00		577	0.26		13	0.01		1	0.00		18	0.01		
Non-BAAQMD ST California Load-Related					272842		201341	1.48		102125	0.75		N/A	N/A		N/A	N/A		25406	0.19		
Total Calif. Load-Related					282454		202252	1.43		102216	0.72		N/A	N/A		N/A	N/A		25836	0.18		

UNIT TYPES: CT combustion turbine
ST steam turbine
G geothermal steam
CC combined cycle

FUELS: NG natural gas w/ residual oil backup
DF distillate fuel oil
GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects 1998 AP42 updates

Table G-17

2005 - Bay Area Steam Units at Analytical Maximum; Hunters Point Shut Down; SF CTs Burning Cheap Natural Gas; Increased Transmission to Serve SF Load, Reduce BARR

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NOx Tons	NOx #/MWh	NOx #/MMBtu	SOx/H2S Tons	SOx/H2S #/MWh	SOx/H2S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point plant retired																					
Potrero	3	ST	NG	207	1150	63.4	70	0.12	0.012	6	0.01	0.001	44	0.08	0.007	477	0.83	0.082	49	0.09	0.008
	4	CT	NG	52	63	13.9	55	1.74	0.135	1	0.03	0.002	3	0.09	0.007	35	1.11	0.086	17	0.54	0.042
	5	CT	NG	52	57	12.5	50	1.74	0.135	1	0.03	0.002	3	0.09	0.007	32	1.11	0.086	15	0.54	0.042
	6	CT	NG	52	54	11.8	47	1.74	0.135	1	0.03	0.002	3	0.09	0.007	30	1.11	0.086	15	0.54	0.042
	Σ			363	1324	41.6	222	0.34	0.032	8	0.01	0.001	52	0.08	0.007	574	0.87	0.083	96	0.15	0.014
Contra Costa	6	ST	NG	340	2095	70.3	123	0.12	0.012	10	0.01	0.001	76	0.07	0.008	835	0.80	0.082	86	0.08	0.008
	7	ST	NG	340	2054	68.9	121	0.12	0.012	10	0.01	0.001	75	0.07	0.007	819	0.80	0.082	84	0.08	0.008
	Σ			680	4149	69.6	244	0.12	0.012	20	0.01	0.001	151	0.07	0.008	1654	0.80	0.082	169	0.08	0.008
Pittsburg	1	ST	NG	163	648	45.4	579	1.79	0.163	4	0.01	0.001	27	0.08	0.008	290	0.90	0.082	30	0.09	0.008
	2	ST	NG	163	991	69.4	66	0.13	0.012	5	0.01	0.001	40	0.08	0.007	442	0.89	0.082	45	0.09	0.008
#3 retired																					
#4 retired																					
	5	ST	NG	325	1699	59.7	103	0.12	0.012	9	0.01	0.001	64	0.08	0.008	699	0.82	0.082	72	0.08	0.008
	6	ST	NG	325	2156	75.7	133	0.12	0.012	11	0.01	0.001	83	0.08	0.007	903	0.84	0.082	92	0.09	0.008
	7	ST	NG	682	4255	71.2	261	0.12	0.012	22	0.01	0.001	162	0.08	0.008	1766	0.83	0.082	181	0.09	0.008
	Σ			1658	9749	67.1	1141	0.23	0.023	50	0.01	0.001	375	0.08	0.007	4100	0.84	0.082	420	0.09	0.008
New 480 MW		CC	NG	480	3806	90.5	184	0.10	0.014	12	0.01	0.001	101	0.05	0.008	150	0.08	0.011	80	0.04	0.006
Geysers	5	G	GS	39	279	81.7	1	0.00		70	0.50		1	0.01		0	0.00		1	0.01	
	6	G	GS	39	276	80.9	1	0.01		57	0.41		1	0.01		0	0.00		1	0.01	
	7	G	GS	37	275	84.8	0	0.00		73	0.53		1	0.01		0	0.00		1	0.01	
	8	G	GS	37	277	85.4	0	0.00		58	0.42		1	0.01		0	0.00		1	0.01	
	9	G	GS	32	205	73.2	1	0.01		35	0.35		1	0.01		0	0.00		1	0.01	
	10	G	GS	32	203	72.5	1	0.01		48	0.47		1	0.01		0	0.00		1	0.01	
	11	G	GS	56	463	94.4	0	0.00		133	0.57		1	0.01		0	0.00		2	0.01	
	12	G	GS	39	290	85.0	1	0.01		73	0.50		1	0.01		0	0.00		1	0.01	
	13	G	GS	69	576	95.3	0	0.00		27	0.09		2	0.01		0	0.00		2	0.01	
	14	G	GS	61	462	86.5	1	0.00		23	0.10		1	0.01		0	0.00		2	0.01	
	16	G	GS	69	570	94.4	0	0.00		4	0.02		2	0.01		0	0.00		2	0.01	
	17	G	GS	47	367	89.2	0	0.00		10	0.06		1	0.01		0	0.00		1	0.01	
	18	G	GS	62	477	87.8	1	0.00		32	0.14		1	0.01		0	0.00		2	0.01	
	20	G	GS	46	345	85.6	1	0.00		19	0.11		1	0.01		0	0.00		1	0.01	
	Σ			665	5066	87.0	8	0.00		665	0.26		15	0.01		2	0.00		21	0.01	
Non-BAAQMD California Load-Related					263425		199556	1.52		102031	0.77		12006	0.09		46234	0.35		24908	0.19	
Total Calif. Load-Related					282453		201347	1.43		102121	0.72		12686	0.09		52712	0.37		25674	0.18	

UNIT TYPES:
- CT combustion turbine
- ST steam turbine
- G geothermal steam
- CC combined cycle

FUELS:
- NG natural gas w/ residual oil backup
- DF distillate fuel oil
- GS geothermal steam

NOTES:
- All units assumed to use their primary fuels exclusively (but note change to CTs)
- Geothermal units dispatched economically per existing steam supply contracts
- Geothermal units emit H_2S but basically no SO_X
- Reflects latest 1998 AP42 updates
- 115/230 kV transmission into SF assumed to be increased to about 550 MW

Table G-18

1999 - SF Stand-Alone Case - SF Peninsula Only

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	ENERGY OUTPUT (billion Btu)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO_X Tons	NO_X #/MWh	NO_X #/MMBtu	SO_X Tons	SO_X #/MWh	SO_X #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point	1	CT	DF	52	23	2	0.3	2	2.44	0.163	1	1.50	0.100	0	0.52	0.034	1	1.66	0.111	0	0.52	0.034
	2	ST	NG	107	1049	73	7.8	88	2.40	0.167	1	0.02	0.001	4	0.12	0.008	49	1.33	0.093	5	0.13	0.009
	3	ST	NG	107	455	32	3.5	37	2.32	0.165	0	0.02	0.001	2	0.12	0.008	21	1.29	0.091	2	0.13	0.009
	4	ST	NG	163	6347	618	43.2	115	0.37	0.036	3	0.01	0.001	24	0.08	0.008	269	0.87	0.085	27	0.09	0.008
	Σ			429	7875	725	19.3	242	0.67	0.062	5	0.01	0.001	31	0.09	0.008	339	0.94	0.086	34	0.09	0.009
Potrero	3	ST	NG	207	8240	807	44.5	374	0.93	0.091	4	0.01	0.001	31	0.08	0.008	346	0.86	0.084	35	0.09	0.008
	4	CT	DF	52	173	12	2.7	14	2.33	0.163	9	1.43	0.100	3	0.49	0.034	10	1.59	0.111	3	0.49	0.034
	5	CT	DF	52	82	6	1.2	7	2.41	0.163	4	1.48	0.100	1	0.51	0.034	5	1.64	0.111	1	0.51	0.034
	6	CT	DF	52	49	3	0.7	4	2.39	0.163	2	1.47	0.100	1	0.51	0.034	3	1.63	0.111	1	0.51	0.034
	Σ			363	8545	828	26.0	399	0.96	0.093	19	0.05	0.005	37	0.09	0.009	363	0.88	0.085	40	0.10	0.009
SF Peninsula		ST only		584	16092	1530	29.9	614	0.80	0.076	8	0.01	0.001	62	0.08	0.008	684	0.89	0.085	68	0.09	0.009

1999 - SF Stand-Alone Case - 1999 Basecase

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	ENERGY OUTPUT (billion Btu)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO_X Tons	NO_X #/MWh	NO_X #/MMBtu	SO_X/H_2S Tons	SO_X/H_2S #/MWh	SO_X/H_2S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point	1	CT	DF	52	80	4	0.9	7	3.31	0.167	4	1.98	0.100	1	0.68	0.035	4	2.22	0.112	1	0.69	0.035
	2	ST	NG	107	1440	89	9.5	112	2.51	0.155	1	0.02	0.001	6	0.13	0.008	62	1.39	0.086	6	0.14	0.009
	3	ST	NG	107	953	55	5.9	74	2.69	0.156	0	0.02	0.001	4	0.14	0.008	41	1.49	0.087	4	0.15	0.009
	4	ST	NG	163	7759	756	53.0	141	0.37	0.036	4	0.01	0.001	30	0.08	0.008	326	0.86	0.084	33	0.09	0.008
	Σ			429	10233	905	24.1	334	0.74	0.065	9	0.02	0.002	40	0.09	0.008	434	0.96	0.085	44	0.10	0.009
Potrero	3	ST	NG	207	7642	752	41.4	347	0.92	0.091	4	0.01	0.001	29	0.08	0.008	321	0.85	0.084	32	0.09	0.008
	4	CT	DF	52	245	15	3.4	20	2.61	0.164	12	1.59	0.100	4	0.55	0.034	14	1.77	0.111	4	0.55	0.035
	5	CT	DF	52	149	9	1.9	12	2.81	0.165	7	1.70	0.100	3	0.59	0.034	8	1.90	0.111	3	0.59	0.035
	6	CT	DF	52	114	6	1.4	9	3.01	0.166	6	1.81	0.100	2	0.62	0.035	6	2.02	0.112	2	0.63	0.035
	Σ			363	8149	782	24.6	389	0.99	0.095	29	0.07	0.007	38	0.10	0.009	349	0.89	0.086	41	0.10	0.010
SF Peninsula		ST only		584	17795	1652	32.3	674	0.82	0.076	9	0.01	0.001	68	0.08	0.008	750	0.91	0.084	75	0.09	0.008

1999 - SF Stand-Alone Case - Exceedance of Full-System Modeling over SF Peninsula-Only Modeling

PLANT/UNIT		TYPE	FUEL	NET CAPACITY (MW)	ENERGY OUTPUT (billion Btu)	GENERATION (GWh)	CAPACITY FACTOR (percent)	EMISSIONS NO_X Tons	NO_X #/MWh	NO_X #/MMBtu	SO_X/H_2S Tons	SO_X/H_2S #/MWh	SO_X/H_2S #/MMBtu	PM10 Tons	PM10 #/MWh	PM10 #/MMBtu	CO Tons	CO #/MWh	CO #/MMBtu	ROG Tons	ROG #/MWh	ROG #/MMBtu
Hunters Point	1	CT	DF	same	57	3	0.6	5	0.87	0.005	3	0.48	0.000	1	0.17	0.000	3	0.56	0.001	1	0.17	0.000
	2	ST	NG	same	391	16	1.7	24	0.11	-0.012	0	0.00	0.000	1	0.01	-0.001	13	0.06	-0.007	1	0.01	-0.001
	3	ST	NG	same	498	23	2.5	37	0.37	-0.009	0	0.00	0.000	2	0.02	0.000	20	0.21	-0.005	2	0.02	0.000
	4	ST	NG	same	1412	139	9.7	26	0.00	0.000	1	0.00	0.000	5	0.00	0.000	57	-0.01	-0.001	6	0.00	0.000
	Σ			same	2359	180	4.8	91	0.07	0.004	4	0.01	0.000	9	0.00	0.000	95	0.02	-0.001	10	0.00	0.000
Potrero	3	ST	NG	same	-598	-55	-3.1	-27	0.00	0.000	0	0.00	0.000	-2	0.00	0.000	-25	0.00	0.000	-3	0.00	0.000
	4	CT	DF	same	71	3	0.7	6	0.28	0.002	4	0.16	0.000	1	0.05	0.000	4	0.18	0.000	1	0.06	0.000
	5	CT	DF	same	67	3	0.7	6	0.40	0.002	3	0.22	0.000	1	0.08	0.000	4	0.26	0.001	1	0.08	0.000
	6	CT	DF	same	65	3	0.6	5	0.62	0.003	3	0.34	0.000	1	0.12	0.000	4	0.40	0.001	1	0.12	0.000
	Σ			same	-395	-46	-1.4	-10	0.03	0.002	10	0.03	0.003	1	0.01	0.001	-14	0.02	0.001	1	0.01	0.001
SF Peninsula		ST only		same	1703	122	2.4	59	0.01	-0.001	1	0.00	0.000	6	0.00	0.000	66	0.01	-0.001	7	0.00	0.000

UNIT TYPES: CT combustion turbine; ST steam turbine

FUELS: NG natural gas; DF distillate fuel oil

NOTES:
- All units assumed to use their primary fuels exclusively
- SF Peninsula Only: modeled as existing by itself, save for single incoming transmission corridor
- Reflects 1998 AP42 updates

Table G-19

1999 - Baseline - Peak Day of PM10 Emissions from Pittsburg Power Plant

UNIT	HOUR																								FULL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DAY
	STATION OPERATING LEVEL (MW)																								
1	41	28	28	28	28	41	82	163	130	130	163	163	163	163	163	163	163	163	163	163	163	163	163	41	2860
2	41	28	28	28	28	41	82	163	130	130	163	163	163	163	163	163	163	163	163	163	163	163	163	41	2859
3	41	28	28	28	28	41	82	163	130	130	163	163	163	163	163	163	163	163	163	163	163	163	163	41	2859
4	28	28	28	28	28	82	130	163	130	130	130	130	163	163	163	163	163	163	163	163	130	130	163	82	2844
5	163	163	60	60	60	260	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	260	6551
6	163	60	60	60	60	261	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	261	6462
7	200	200	200	200	200	200	200	360	360	360	360	360	563	576	576	576	576	360	576	360	360	360	360	200	8643
Σ	677	535	432	432	432	926	1227	1663	1531	1531	1630	1630	1866	1879	1879	1879	1879	1663	1879	1663	1630	1630	1663	926	33078
	PM10 EMISSIONS (lbs)																								
1	7	3	3	3	3	4	7	13	11	11	13	13	13	13	13	13	13	13	13	13	13	13	13	4	244
2	4	3	3	3	3	4	7	13	11	11	13	13	13	13	13	13	13	13	13	13	13	13	13	4	240
3	4	3	3	3	3	4	7	13	11	11	13	13	13	13	13	13	13	13	13	13	13	13	13	4	240
4	4	4	4	4	4	7	11	13	11	11	11	11	13	13	13	13	13	13	13	13	11	11	13	7	242
5	13	13	6	6	6	20	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	20	498
6	13	6	6	6	6	20	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	20	501
7	16	16	16	16	16	16	16	27	27	27	27	27	42	43	43	43	43	27	43	27	27	27	27	16	655
Σ	62	49	42	42	42	76	98	129	119	119	127	127	144	145	145	145	145	129	145	129	127	127	129	76	2620

NOTES: Peak Day of Pittsburg 7 PM10 Emissions was Thursday, Week 35
Reflects 1998 AP42 updates

Table G-20

2005 - Analytical Max. w/o HPPP - Peak Day of PM10 Emissions from Pittsburg Power Plant

UNIT	HOUR																								FULL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DAY
	STATION OPERATING LEVEL (MW)																								
1	163	163	130	130	130	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	3814
2	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	3913
3	RETIRED																								
4	RETIRED																								
5	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	7800
6	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	326	7816
7	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682	16367
Σ	1659	1659	1626	1626	1626	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	1659	39710
	PM10 EMISSIONS (lbs)																								
1	13	13	11	11	11	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	311
2	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	317
3	RETIRED																								
4	RETIRED																								
5	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	586
6	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	597
7	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	1259
Σ	128	128	126	126	126	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	3070

NOTES: Peak Day of Pittsburg 7 PM10 Emissions was Friday, Week 27
Pittsburg 3, 4 assumed no longer operating
Reflects 1998 AP42 updates