Meeting Summary for the California Public Utilities Commission's Workshop on Pacific Gas & Electric Company's Application to Divest Three Power Plants
June 27, 1997, San Francisco.

The following is a summary of a technical workshop on the California Public Utilities Commission's (CPUC) Draft Initial Study regarding Pacific Gas & Electric (PG&E) Company's application to divest three of its fossil-fueled power plants. This document is not an official record of the event, which was not subject to the CPUC's recording rules. Wherever possible, speakers are identified by name. However, many participants did not identify themselves when speaking, or they submitted anonymous questions in writing. Many of the answers have been truncated and paraphrased, and clarifications have been added in brackets.

Daniella Hamilton of Public Affairs Management (PAM) opened the workshop at 10:05 a.m. She said the purpose of the workshop was to allow PG&E to respond to the Draft Initial Study (DIS) prepared by the CPUC for PG&E's application to divest the Morro Bay, Moss Landing and Oakland Power Plants.

Bruce Kaneshiro of the CPUC provided a brief explanation of the electric utility restructuring effort, stating that the CPUC's goal is to begin competitive retail sales of electric service on January 1, 1998. A possible barrier to a competitive market is the exercise of market power in the generation sector. As a way to remove this barrier, the Commission proposed that Edison and Pacific Gas & Electric Company (PG&E) voluntarily "divest" or sell a portion of their in-state fossil-fueled power generation capacity. As a result, PG&E applied to divest approximately 50 percent of its fossil-fueled generating capacity. Kaneshiro emphasized that restructuring will occur with or without divestiture.

Kaneshiro explained that the Draft Initial Studies conducted for the two divestiture applications are "decision point documents." The CPUC will use these studies to determine whether to conduct a full Environmental Impact Report (EIR), as defined in the California Environmental Quality Act (CEQA), or issue a Negative Declaration or a Mitigated Negative Declaration. He stated that the ultimate goal for CPUC staff, its consultants and subcontractors is to prepare the "appropriate document."

Hamilton then directed attention to Chris McManus, PG&E's case manager for divestiture, who introduced other members of the utility's panel: Leslie Everett, Vice President and Project Manager for divestiture; Joe Malkin, Outside Counsel; Sam Lovick, London Economics; Dave Farabee, Outside Counsel; and Cheryl Mason, outside counsel on CEQA matters.

McManus told participants about PG&E's announcement the previous day that it plans to sell not only the four power plants in its pending divestiture application, but all of its fossil-fueled and geothermal power plants in the state. McManus said PG&E amended its divestiture application to remove the Hunters Point Power Plant from consideration. It will file a second divestiture application later this year for authority to sell the Hunters Point, Pittsburg, Contra Costa and Potrero Power Plants, all fueled by natural gas, and the Geysers Geothermal Power Plant. PG&E would continue to own its nuclear and hydroelectric power plants.

Turning attention to the current DIS, McManus said PG&E's general objection was that the study relied on unrealistically high predictions of capacity factors for the plants targeted for divestiture. She added that even if the plants were operated at those high capacity factors, PG&E believes existing air quality regulation provides the necessary protection to ensure air quality.

McManus then gave the floor to Joe Malkin, who said that PG&E appreciated the extreme time constraints under which the CPUC staff and its consultants had to work, and that PG&E's criticism is not meant to question the competence and professionalism of the study team. He said the DIS presented an "outer bound" case of maximum possible environmental impact. As a result, the DIS predicts higher capacity factors at all 16 plants that both PG&E and Edison are selling. But, Malkin said, the study's conclusion that capacity factors at the plants would increase by as much as 616 times after divestiture is not realistic. He added that what was labelled in the DIS as "reasonably expected" is actually the theoretical worst case scenario for each individual plant, and that the study team agrees that it is not realistic that all 16 divested plants would actually experience this theoretical worst case.

Malkin attributed the unrealistic assessment of capacity factors to underlying assumptions in the study: that investor-owned utilities (IOUs) would illegally abuse their market power; and that new owners would operate the plants at a higher capacity factor than IOUs, because they would have more incentive to do so. The latter assumption, according to Malkin, reflects a lack of understanding of the operation and design of the Power Exchange (PX).

The assumption that utilities would exercise market power without divestiture is also unrealistic, Malkin continued, because to do so would violate state and federal law. Further, existing agencies will continue to monitor owners and enforce compliance with those laws. While abuse of market power is a legitimate concern, Malkin said, making it a base assumption in an environmental analysis ignores the state and federal legal responsibilities.

Malkin noted that PG&E cannot sell power into the PX at market-based rates unless the Federal Energy Regulatory Commission (FERC) concludes that PG&E either has no market power, or that the market power it possesses has been mitigated. The CPUC filed comments at FERC in support of the applications of the IOUs to sell power at market-based rates, believing that any market power is adequately mitigated, Malkin said.

Given that FERC has legal responsibility, and that the CPUC has concluded that FERC can authorize market-based rates, Malkin said, PG&E believes the assumption of exercise of market power contradicts both the law and the CPUC's position. PG&E also believes that the assumption of increased capacity factors contradicts the structure of the new market.

Malkin then introduced Sam Lovick, a consultant with London Economics contracted to PG&E who is involved with the design of the California PX and was involved in designing similar markets in the United Kingdom and Australia. Lovick made a presentation outlining his objections to the DIS comparison of divestiture and non-divestiture cases. Lovick pointed out that the new market structure will be radically different than the present structure. What the DIS did not recognize, he said, was that the new owners of the divested plants will not only sell power to the PX, other schedule coordinators (SCs), and the direct access market, they will also buy power from the PX and other SCs when the price is right in order to fulfill their supply obligations.

A basic principle of IOU operation in the new market is that IOUs will bid into the PX at their short-run marginal costs, which are essentially based on the spot price for natural gas, Lovick continued. If the IOUs have market power, they could bid above their short-run costs and restrict generation, whereas a divested plant would have incentives to bid at its short-run costs and increase generation. But there are good reasons to believe the IOUs will not restrict output to raise prices, he said.

The first reason is that the competition transition charge (CTC) removes any excess profits the IOUs would earn by bidding above costs. That would further remove incentive for bidding above costs. In fact, he added, many parties in FERC's market-based rates proceeding expressed concern that IOUs could deliberately bid below their costs in order to reduce the PX price, because the utilities will buy more power from the PX than they will sell.

The second reason is that the IOUs behavior will scrutinized by at least three sources: the CPUC, FERC, and a wide range of competitors and customers who have a great deal of interest in the outcome of these competitive markets.

Lovick said that because the IOUs will be prohibited from participating in the direct access market through 2001, the new owners of the divested plant will have trade opportunities that the IOUs won't have. So, the new owner could feasibly sell more power than the utility would be expected to generate in the restructured market. It is conceivable, for example, that a plant currently operating at a 30 percent capacity factor could increase sales that would equate to a 70 percent capacity factor because of direct access contracts. However, the fact that the new owner strikes a contract for increased sales does not mean it will generate the entire amount, Lovick asserted. The new owner could maximize its profit by buying low from the PX or other SCs and selling high to the direct access market.

Through buying elsewhere, and shutting down its plant, the owner could also increase profits by selling its contracted gas on the gas spot market. Even if they have long-term contracts for gas procurement, they will always base their bids on the spot price of gas. This is because of the option of selling the contracted gas on the spot market. Even if the PX or SC price is slightly higher than the price of power sold in the direct access market, the new owner could still make a profit by buying the power and selling the gas.

Lovick asserted that the early PX will be based on portfolios containing several power plants, rather than individual plants, although it will gradually become more diverse after divestiture. In effect, the PX will provide the same function as the portfolio, he said, in that the merit order of generation will essentially be unchanged -- cheaper resources will be used first.

The next important point is that the book value of the plant is irrelevant to bidding behavior, Lovick continued. If I pay $400 million for a power plant, I won't get a higher rate of return on my investment by bidding above my operating costs, I will just lose profits. So whatever the market pays for these plants does not have any material impact on operation in this market, he said.

Lovick acknowledged that new owners may make different investment decisions than PG&E. It is unlikely that there will be investment opportunities that would sufficiently improve their plants' thermal efficiencies to allow large changes in output to cross a sensible hurdle rate [10-16 percent]. He pointed to an illustration of a highly elastic supply curve to show that small changes in bid price could lead to dramatic reduction in profits. Plant short-run operating costs in the new market will be very, very flat, he said, at about $23/MWh.

Lovick concluded that: the bidding process in the new market will remain essentially unchanged between the IOUs and the new owners; the preferred bidding strategy will be based on spot price of gas; merit order will essentially be unchanged; and changes in generation patterns will be small, as they are driven largely by changes in maintenance practices and availability.

Lovick then answered several clarifying questions from the floor.
Q: (from DIS team member Bob Weatherwax, of Sierra Energy & Risk Assessment) Concerning your illustration, can you tell me how many hours in startup and ramping costs were allocated over? Was the number of hours the same regardless of the average incremental heat rate of the unit for which it is considered?
A: (Lovick) The illustration is a stylized example from an unconstrained simulation run, with allocation of start-up costs based on the operation regime of the plant, which changes depending on its place in merit order. Gas combustion turbines were assumed to bid fixed price. The numbers are in no way reliable; it's just a good indication of the shape of the supply curve.

Q: (DIS team member Bob Logan) Could you clarify the relationship between the $21 spot gas price and the $21 PX price [shown on Lovick's illustrative example]?
A: (Lovick) I did not attempt to link the two, in the sense that I did not try establish the arbitrage between the spot price of electricity and the spot price of gas. It's merely a numerical example that demonstrates bidding behavior. For example, at peak times I would not expect to see a huge differential between the spot price of gas and the spot price of electricity; I would expect to see that close because of the bidding behavior of participants in the market.

Dave Farabee, outside counsel for PG&E, then took the floor to discuss the DIS conclusion that divestiture could have a significant impact on air quality. He reiterated the earlier point that PG&E believes there will not be significant changes in capacity factor, and added that even if capacity factors do increase significantly, any potential environmental impact will be mitigated. Basically, there's a four-layer pie: at the base are the Federal and State Clean Air Acts; above that are the Clean Air Plans made by Air Quality Management Districts and Air Pollution Control Districts to achieve ambient air quality standards, then the rules and regulations adopted by various agencies to achieve the plans, and finally, enforcement of those rules and regulations.

Farabee then discussed the regulatory structure in place for each of the three power plants targeted for divestiture. Regarding the Moss Landing Power Plant: the Monterey Bay Unified Air Pollution Control District (MBAPCD) in 1991 adopted a Clean Air Plan, and in Sept 1993 adopted Rule 431, setting emission rate limits and mass emission limits to meet the goals of this plan. These emissions limits are included in the existing permits and will apply to the new owners, he said. The current rules apply only to "electric utilities," but the district has proposed to amend the Rule 431 such that the permit limits would apply to any owner. The district agrees that existing rule and permit limits are adequate to avoid significant air quality impacts, Farabee said.

Regarding the Morro Bay Power Plant: the San Luis Obispo Air Pollution Control District (SLOAPCD) in 1991 adopted its initial Clean Air Plan, Farabee continued. It established rate limits for the Morro Bay plant in 1993, and updated the Plan in 1995. Questions were raised in the DIS regarding whether or not the emission rate limits are adequate to mitigate potential air quality impacts after divestiture. But the utility and the district recently reached agreement to add mass emission limits to the existing rules and to incorporate these rule changes into the plant permits so they would apply to the new owners. Those agreements will ensure that divestiture will not result in significant adverse air quality impacts in San Luis Obispo County, he said. Farabee then introduced Larry Allen of SLOAPCD to confirm this agreement.

Allen said SLOAPCD personnel spent considerable time with PG&E discussing the district's concerns regarding divestiture impacts. PG&E has since agreed to include emissions caps in its permits for Morro Bay. In September, SLOAPCD will offer a rule change that will provide adequate mitigation of any potential impact from divestiture, Allen said.

Regarding the Oakland Power Plant: Farabee said the San Francisco Bay Air Quality Management District's (SFBAQMD) Rule 9 sets emission and operational limits for all combustion turbines, regardless of the owner, and the DIS itself concluded there would not be significant impact as a result of divestiture.

Farabee then took several questions from the floor.
Q: (unknown audience member) With respect to the Moss Landing plant, when will the rule [on emissions from utility boilers] be changed?
A: (Farabee) I'm not sure, sometime this fall.
Q: (same audience member) Will the permit limits incorporate all provisions of the rule for Moss Landing?
A: (Farabee) Those limits are in the permits now. All the emissions standards, with the possible exception of monitoring provisions, will be in the permit.

Q: (same audience member) Can we get a copy of the proposed rule?
A: (Farabee) You can probably get a copy from the district, or from us later on. [Chris McManus said PG&E would deliver copies of the proposed rule to anyone requesting a copy.]

Cheryl Mason, outside counsel working with PG&E on environmental and CEQA issues, then addressed environmental issues not related to air quality. She noted that most of the issues fall into a couple of categories: land use issues, such as current recreational uses, leases, impacts associated with remediating site contamination; and construction for subdividing power plant property. In most cases, PG&E believes it can alleviate the concerns expressed in the DIS simply by providing more information to study team. For example, some of the leases identified in the DIS have already expired; others have defined terms that allow PG&E to reevaluate over time whether or not it wants to continue the lease. The Purchase and Sale Agreement requires the buyer to assume existing leases, she added. Therefore, in many cases, Mason said, PG&E foresees little difference between its behavior and that of the new owners.

Mason also pointed out that the tanker delivery facilities at the Moss Landing Power Plant are in official "caretaker status." In order to use the facilities for oil deliveries, the new owner must renew the permit, which would trigger a full review of any impacts from oil deliveries. Therefore, the potential for oil spills identified in the DIS is speculative, she said, as is the inference that any financier behind the new owner would make the new owners restore oil facilities.

According to Mason, another inaccuracy in the DIS is a reference to a concern that increased generation at Moss Landing might increase thermal discharges into the Elkhorn Slough. Only Units 1-5 are cooled with water pumped into the slough, Mason asserted, and those units are permanently shut down. Increased thermal discharge into the slough would only occur if the new owner repowers; and any impact would be mitigated through the permit process required for the repower.

PG&E also disagrees with the DIS assumption that increased operations could also result in increased hazardous waste handling, and possibly accidents. PG&E does not believe the study team should correlate increased operations with an increased accident rate, and the buyer must still comply with existing regulations.

Mason continued by saying that PG&E disagrees with the DIS concern that revaluation and reassessment of taxes on the plant could lead to significant economic impacts that would result in significant physical impact. She said it's important to understand that under CEQA, purely social or economic impacts are not considered. A CEQA review examines whether or not those impacts might lead to a significant physical change to the environment, Mason said. PG&E thinks the study overlooks the fact that a change in plant value is not really the function of divestiture; rather, it's a function of the change in the market and restructuring. If CPUC were to deny PG&E's divestiture application, it is still obliged, under AB 1890, to undergo a market-valuation exercise and to release plants from CPUC regulation. At that point, you would get the same change in market value, and presumably a reassessment at the taxing authority level. So, PG&E does not think there would be any difference between divestiture and non-divestiture.

Mason acknowledged that in some cases, there are physical changes described in the DIS that PG&E finds feasible. For example, divestiture will undoubtedly accelerate construction and clean-up work that might have occurred later, she said. However, there are objective industry standards, as well as a host of permits and regulatory schemes that will prevent any significant impact from those kinds of activities.

The PG&E panel then took several clarifying questions from the floor.
Q: (the DIS team's Richard McCann of M.Cubed) Has PG&E received a ruling from the state Board of Equalization on property tax treatment of divestiture?
A: (Malkin) To the best of our knowledge, there is no ruling yet.

Q: (the DIS team's Donna Pittman of Pittman & Hames Associates) Are you saying there will be no changes in tax consequences under divestiture, even in terms of depreciation, or are you assigning all tax consequences to restructuring?
A: (Mason) We have not identified any significant changes associated exclusively with divestiture. The issue is that the tax consequences flow from market valuation, and that will occur regardless of divestiture. Divestiture is just one way to accomplish that. There are other ways.

Q: (from a representative of the Southeast Alliance for Environmental Justice (SAEJ)) When you said that remediation efforts will be sped up as opposed to done later, can you provide more background on that [in relation to your Proponents Environmental Assessment (PEA) for the Hunters Point plant]?
A: (Mason) The PEA was a document filed for this application just to describe the general conditions and operation of the plant. We concluded there wouldn't be any impact from divestiture alone. PG&E has decided to retain responsibilities for existing hazardous waste/contamination. PG&E will begin some of that cleanup work sooner than it might have otherwise in order to facilitate divestiture.

Mason then described PG&E's preferred timeline for completing the environmental review of the proposed divestiture and approving the auction process. She noted that divestiture on this scale is unprecedented. In this case, divestiture serves a multiple set of purposes: it satisfies the CPUC requirement to limit market power; it fulfills PG&E's desire for an objective basis for market-valuation of the plants; and it allows PG&E to participate on some level in the new market. PG&E's corporate decision was to divest in order to prepare for participating in the new market, Mason said.

Mason said PG&E is trying to find a way to divest within the time frames anticipated in the state law mandating restructuring, AB 1890. Its first step was to amend the divestiture application to withdraw the Hunters Point plant. The next step is to submit evidence that will convince the DIS team that the sale of the three plants will not have a cumulative impact.

If PG&E can provide sufficient information, she continued, the study team can produce a final Initial Study by August, and release a Mitigated Negative Declaration (MND) for circulation in September. The CPUC could approve the MND by November, Mason said, allowing the auction to begin in December. PG&E would return with a compliance filing in March, April or May of 1998, giving the CPUC the opportunity to review and approve the buyer and the sale under the terms of the rulings on the auction process and the MND, Mason said.

PG&E plans to file its second divestiture application in October, Mason continued, but the utility will submit much of the data needed for Initial Studies prior to that. After an application and a PEA are filed, CEQA generally provides for a very short time frame to decide whether a negative declaration or a full EIR is appropriate, Mason asserted. PG&E is hoping that by December, CPUC staff will be ready to circulate the appropriate CEQA document for the second Divestiture application, whether it is a Negative Declaration or an Environmental Impact Report, Mason said.

Mason said PG&E will propose that the CPUC address CEQA requirements before approving the auction process for either application. It would be very difficult to proceed with an auction without some regulatory certainty for the buyer regarding necessary mitigation. Under this scenario, PG&E could proceed with the auction of the first group of power plants in December, Mason said. Receiving CPUC approval for the transfer of ownership as early as possible in 1998 is important in order to complete the transfer by the end of 1998, she said. Completing the sale as soon as possible will minimize the CTC, which will benefit ratepayers, she added.

CEQA does permit a staged review of projects that are similar or are linked, Mason said, although cumulative impacts must be addressed. For the most part, she added, physical impacts at the plants are localized. PG&E does not think that looking at divestiture as a unified project is either necessary or accurate, in terms of CEQA; but, even with that kind of conceptual approach, CEQA allows a staged review so other stages of the project are not delayed while completing the environmental review.

For instance in the Bay Area, there may be issues of cumulative impact because four of the plants PG&E wants to divest are in the same basin; but that doesn't apply to Moss Landing or Morro Bay. We're proposing that during review of Moss Landing and Morro Bay, the staff confirm that there is not a cumulative issue that would affect approval of the sale. Authorizing the sale of the first three plants does not commit the CPUC to authorizing sale of the subsequent plants. As long as cumulative impacts have been considered, it is entirely appropriate to complete the detailed CEQA review of those other plants prior to authorizing their sale.

Jeanne Sole, representing the City and County of San Francisco, then made a comment regarding the process of divestiture. She expressed concern that the determination of environmental impact for the first divestiture application would apply largely to the second application, whereas CEQA expressly forbids any party from attempting to avoid an EIR process by breaking the project down into smaller parts. She said the City and County will more fully address this potentially illegal situation in its formal comments to the CPUC.

Mason answered several questions from the audience.
Q: (unknown audience member) Concerning your description for the second wave of divestiture, you allowed for the possibility of a Mitigated Negative Declaration or an EIR. Is there something different that you perceive about the second wave?
A: (Mason) We do not perceive a difference for the second wave as to whether divestiture would cause a significant change in the capacity factors or the way they operate. These four plants have a different set of air regulations and permitting, and we haven't completed our [Preliminary Environmental Assessment] of the site-specific issues. We don't anticipate that there could be impacts that could not be mitigated. But we have not completed our analysis. So we've opened the possibility that as we look at the project site-by-site in this next wave that we might find impacts that we have difficulty mitigating or it's not as clear to us what the impacts might be. But we don't expect to find that the economic analysis will be significantly different for these plants.

Q: (different unknown audience member) Is there a foregone conclusion that a Mitigated Negative Declaration will be prepared for the first application?
A: (Mason) It's not foregone by the CPUC or the staff. PG&E concludes that it is both legally permissible and should be the approach taken. We certainly think it remains an open possibility. But PG&E is very much interested in satisfying the CEQA requirements and developing responsible mitigation measures.

Q: (Marc Joseph) Did you mean to say that operation of the Bay Area plants doesn't affect the operation of other plants?
A; No, I said the way they operate under [APCD rules] I don't believe affects the other plants.

Q: (unknown audience member) What is the reason for deferring Hunters Point to the second application?
A: (Mason) Primarily because of the relationship between Hunters Point and the other Bay Area plants in terms of the air quality rules, and our desire to work with the [Bay Area Air Quality Management District] on all those plants at once.

After a lunch break, PG&E personnel addressed several written questions submitted by the study team and the audience. McManus said that because of time constraints and the complexity of the questions, PG&E felt it should answer many of the questions in writing. Those answers would be posted on the PG&E Divestiture Web page by July 2. The PG&E team did answer several questions orally.

Q: (anonymous) With the divestiture of the plants anticipated to occur at the earliest by December of 1998, do you hope or plan to rely on [a performance-based ratemaking (PBR)] mechanism from January 1, 1998, to the point of the sale?
A: (McManus) I don't think we believe divestiture will not happen until December 1998. For the first wave, we're planning on holding an auction in December of 1997, with the sale closing in the late spring or early summer. The CPUC held a prehearing conference about generation PBR this week, which resulted in an Assigned Commissioner Ruling saying the Commission is not going to proceed with a generation PBR at this time. Instead, PG&E will be working with the other parties to come up with an appropriate mechanism to determine the revenue requirements for the plants in the interim between January 1, 1998, and when the sale is closed.

Marc Joseph then clarified that PG&E did not ask for contingent ratemaking for fossil-fueled plants that have not been divested, Edison asked for it.
McManus then clarified that it is PG&E's intention to come up with negotiated resolution between parties about the revenue requirements for fossil-fueled plants in the interim between the onset of restructuring and the completion of divestiture.

Q: (Donna Pittman, Pittman & Hames) Could PG&E describe how a change in ownership from a utility to a non-utility under divestiture could affect the tax consequences to local jurisdictions?
A: (Mason) PG&E will address this in writing.

Q: (Joe O'Hagan, California Energy Commission) The DIS discussed the results of Phase 1 Site Assessment. PG&E today indicated that the Phase II Site Assessments have been completed. Will these results be incorporated into the revised Initial Study or EIR?
A: (Mason) Let me clarify: the Phase II assessments are not completed. They are underway at this time. Whether or not they are incorporated into the Final Initial Study depends on whether the CPUC feels they are relevant.

Q: (Anne Eng, Golden Gate University Environmental Law & Justice Department) Please clarify what is the "project" for purposes of CEQA review for the first application, as compared to the second application. Is PG&E treating this stage as a "programmatic" CEQA review, or limiting the review to only the three power plants? Would issues/findings/conclusions relating to capacity factors be addressed system-wide?
A: (Mason) This is a question that PG&E cannot answer by itself; ultimately, it depends on the CPUC's decision. PG&E, particular for the three plants in the present application, believe those can and should be treated as separate projects, and could be addressed in a Mitigated Negative Declaration. We do believe you have to look at cumulative impact issues enough to decide whether there is anything you have to address at these plants because of the cumulative analysis, before you complete your CEQA document on these plants. We do believe that analysis and the conclusion reached in arriving at a decision to issue a Negative Declaration could be incorporated in a subsequent CEQA document. We're not saying that the Negative Declaration precludes considering those issues when you look at the next plant. But we would be surprised if the CPUC, having done an adequate job, would reach completely inconsistent conclusions about their basic economic analysis. Our view of how divestiture might impact operations at individual plants suggests there would be no difference between system-wide analysis and analysis for the individual plants.

Q: (orally, from an audience member from a public interest law firm in San Francisco that is representing residents of Hunters Point) We are really struggling with this whole process. Do we participate and address these economic and environmental issues in the first application knowing they will have implications for the

second application? Or do we regroup here and say we're going to address the issues in the second application? We don't want to be put into compromising position by not participating now.
A: (Mason) What PG&E would look for, that we don't see in the DIS yet, is the identification of system-wide issues that would prevent the kind of analysis and mitigation that we're talking about. I think you should file comments on July 3rd about your concerns about those issues and interrelationships are. We don't see them; we will not take the position that we need to do a full-blown programmatic review, because we don't believe an EIR is necessary.
Q: (same person) You're inviting us to comment on the first application, without Hunters Point, and I am trying to explore the legal consequences of that.
A: (Mason) I would suggest a continued dialogue with the legal experts on that, and there are many of them here. The CPUC staff has taken the unusual step of releasing a DIS and seeking comment before releasing a final Initial Study. It's hard for me to tell you what all the implications would be to the way they're proceeding. All I can tell you is what PG&E's position is, based on what we have seen in the DIS and on what we believe we can demonstrate in terms of a factual analysis. We will have to see what others are arguing or are concerned about before we can give a full answer to does it need to be in this document, or another document? A continuing dialogue is the only way to deal with that.
Q: (same person) There are certain assumptions that will be expressed for this Phase 1 application that, even though we don't have a thorough understanding of the Phase 2 application, clearly there are going to be some direct or indirect consequences that will be addressed by the staff or the Commission. We need to have some understanding of the division between the two applications [to focus resources and ensure the cumulative impacts of both applications are addressed].
A: (Mason) Reaching a permanent understanding is in our interest as well. I do believe that the cumulative impact analysis that has to be done for the first application will have some relevance for the second application. We think there will be no impact, but there will be some need to agree on what should be properly included in a cumulative impact analysis--whether you call it a programmatic review or a project-by-project review.

Sam Lovick then answered one written question from the audience, and reiterated that PG&E would submit answers to other questions in writing.
Q: (anonymous) How does the London Economics analysis take into account must-run contracts?
A: (Lovick) There are two sorts of must-run contracts: one for reliability purposes, another for plants, such as Qualifying Facilities and nuclear plants, that for technical or legal reasons must remain running. Generally, the plants that are must-run for economic reasons would tend to bid them at zero into the PX. The reliability units also fall into two categories: those with permanent, long-term contracts, generally outside the PX; and those where the must-run process is decided later on in the auction process, which are run in the PX or, if they are not selected by the PX, by the ISO.

Hamilton then closed the workshop at 1:45 p.m., urging parties to submit formal comments in the proceeding to the CPUC by 5 p.m. on July 3rd.