Response to Questions from Public Workshop

Except where noted otherwise, Sam Lovick authored all responses.

Bob Weatherwax

Aren't the principal participants in English-Welsh pool under "intense scrutiny"? Do you deny that "Market Power" behavior has occurred in the English-Welsh pool? If you deny market power has occurred, why and how do you think that the many analyses that have found market power went wrong.

1. Generator behavior in the England and Wales Pool is scrutinized, as the question suggests.

2. There has been evidence of market power in the bidding behavior of the large generators. As a result, the E&W Regulator, Offer, has taken action to curb this market power including imposing a cap on average pool prices and requiring divestiture of plant by PowerGen and National Power.

3. Not applicable.

Wasn't the "Preferred Policy Decision" statement in which there is reference to "short run incremental electricity" bidding predicated upon assumed 2 part bidding also specified in the "Preferred Policy Decision"? Since current planning calls for a 1 part bid, won't bids by potentially marginal units such as the plants proposed for divestiture need to reflect both startup costs -- both fuel and operating costs?

1. The Preferred Policy Decision did not specify two-part bidding. The quoted statement was made in the context of the existing surplus of capacity in the West and the foreseeable reality of the market. Footnote 21 states: "Over time, as transition costs are eliminated and excess capacity diminishes, the clearing price for electricity will gradually reflect a value for capacity." Since the Draft Initial Study's worst case capacity factors are for 1998, the statement that the CPUC expects bidding to be based upon "short run incremental electricity costs" is clearly applicable to that analysis and for years to come. (Author: Joseph M. Malkin)

2. The terms 'two-part' and 'one-part' bid are not defined in the question, but I assume they mean respectively bids which have separate start-up ($/start), fixed running cost ($/h) and incremental ($/MWh) components versus bids that are solely incremental in nature ($/MWh). Furthermore, the term 'one-part bid' may be misleading to the extent that bidders can offer bids with more than one price/quantity pair.

   However, it is the case that some bidders will need to include an allocation of start cost and short-run (hourly) fixed running costs in their bids. Analysis by Professor Wilson, Professor Charles Plott and London Economics indicates that the iterative PX auction allows bidders to determine an efficient allocation.

   The term 'operating cost' in the question is imprecise. In a competitive market, bidders would not include their fixed operating costs such as labor costs in their bids; they would include any running related operating costs in their bids, to the extent that they can identify true running related (per hour or per MWh) avoidable costs.

Richard McCann

Are there cost for generators to participate in the PX? Would hourly or daily bid submission cost more than weekly bids?

1. There are costs involved in participation in the PX both in terms of the charges levied by the PX on participants for use of the PX services, and transaction costs for the participants. The extent of these costs is unknown, but I would expect the PX charges to be very small in comparison with the value of traded power. The extent of transaction costs are also unknown. However, they are to a degree avoidable since bidders can submit standardized bids if they see fit. These bids could be constructed on a weekly, daily or hourly basis.

   The question of whether weekly, daily or hourly bids would result in lower transaction costs cannot be unambiguously answered. If the market were based on weekly bids, but bidders subsequently wished to adjust their schedules, then low transaction costs of the initial auction could well be offset by transaction costs involved in unwinding an undesirable position.

   Finally, one of the advantages of competing exchanges (the PX and SCs) is that non-IOU bidders can select alternative SCs that offer lower transaction costs. One would expect these SCs to exploit all arbitrage opportunities available to them in order to maximize the profits for their member generators.

At full load operation, what % of the time would unit marginal costs (or avg. costs) be below the PX price? Doesn't a "highly elastic" supply curve imply that a small decrease in cost/bid could greatly increase output and total revenues?

2. This question comprises two parts:

   It is not possible to answer the first part of the question without some quantitative analysis, which I am unable to complete in the day available to answer the question. I would be happy to undertake the analysis at a future date if the results would inform the analysis of the CPUC's consultants. However, it should be noted that generators – whether IOUs or independent owners – may choose to run when the PX price is below their strict incremental rate when technical constraints occur, or when the cost of stopping and re-starting is greater than the loss from running for short periods when these conditions apply. One notes that the PX auction provides a mechanism for bidders to resolve when it is profitable to operate in this fashion.

   The implication of a small reduction in bid price under highly elastic conditions is, indeed, an increase in output and an increase in revenues. However, the increased output will occur at times when the wholesale [PX] prices are only marginally above the unit's operating costs (because the supply curve is elastic), so there will be little or no increase in profits. The low profitability from such improvements in merit order position implies that any significant capital investment needed to deliver the necessary improvement in *short-run* operating efficiency is unlikely to earn a reasonable return. Reducing bids without making the necessary improvements in short-run efficiency would result in losses.

Would a large generation holder submit bids based on an optimized portfolio? If not, what is the advantage of other scheduling coordinators other than the PX?

3. The term 'optimized portfolio' is unclear. Even with a portfolio, the profit maximizing strategy is to bid each plant at its short-run operating cost, just as if it were not in a portfolio. It would not be sensible to use a portfolio to meet a generation commitment if part of the portfolio is more

expensive than generation on the PX. Rather, the bidder would take into account opportunities to lower costs of provision by buying from the PX when it is cheaper than self-generation.

The pros and cons of separate exchanges is a complex issue, but is irrelevant to the question at hand since it is a required design element. However, SCs are free to trade in the PX so their existence does not change participants' ability or incentives to exploit arbitrage opportunities.

Without divestiture, would IOU plants also be "price takers"?

4. If they bid their marginal costs, as the Draft Initial Study indicates, then they will be behaving in exactly the same way as price taking plant. If the IOUs do not misuse any market power, then one would expect the operating regime for plant to be the same under IOU and divested ownership.

Should a generator consider the "opportunity cost" of gas in bidding? Could these include transportation to burner tip, gas storage, gas well shutdown, or maintaining steam? Would a portfolio operator be better able to adjust generation to take advantage of gas market arbitrage opportunities than a single-plant operator?

5. I would expect generators to consider all variable opportunity costs in their bids. Thus, if there are transport costs which are truly variable (i.e. charged on a per mbtu basis irrespective of the quantity burned) then these would be taken into account in the generator's bid. In this case, one would expect final output to be lower than an equivalent bidder that faces fixed transport costs.

Portfolio generators should be better able to manage such opportunities because they are less constrained by the technical capabilities of a single station. However, the difference are unlikely to translate into significant differences in overall output. Rather, the single station would still respond to price opportunities but with coarser output decisions. In exercising such coarse adjustments, one would expect the unit to have higher output in some periods and lower output in others.

To what degree are spot gas and bulk power market prices correlated?

6. In the absence of a PX trading history, it is not possible to answer this question categorically. But one would expect a strong degree of correlation with some divergence, for example, related to different storage properties for gas and electricity. However, the degree of correlation between prices does not change the underlying proposition that bidders would exploit any arbitrage opportunities that arise. Indeed, this is necessary behavior to close price differences.

How might a high cost for market entry on a daily basis (i.e., startup & commitment costs) affect the decision on how to bid with a single plant? With a portfolio of similar units? With a portfolio of dissimilar units?

7. The PX design allows individual and portfolio bidders to include their fixed daily running costs in their bids. The PX has been designed so that iterations reveal information necessary for bidders to make an efficient allocation, even when bidders have different underlying characteristics.

How will ancillary service be bid? Will a unit have to be operating (i.e., a "winner" in the energy auction) to bid in the ancillary service market? Will "winners" in the energy market have an advantage over "losers" in the ancillary services market?

8. The ISO will secure ancillary services (AS) through an auction process. There are also procedures for self-provision. There is no requirement for a unit to be committed in order to offer an AS bid, but if this occurred, I would expect the AS bidder to include the fixed costs of commitment in its AS bid. A "winner" in the energy market seeking to sell AS must reserve capacity in the energy market to do so. The opportunity costs of so doing would be traded against the costs of specific unit commitment in the AS auction — so there is no necessary advantage or disadvantage.

What alternative market power mitigation measures might be as effective as divestiture?

9. It depends what type of market power one is trying to mitigate. For example, divestiture does not mitigate local market power, such as that possessed by reliability must run units (e.g., Moss Landing and Oakland). Any owner of such a plant, whether an incumbent IOU or a new, independent owner, would possess market power when the unit is needed for reliability. Only a must run contract or some other regulatory mechanism could mitigate such market power. With respect to horizontal market power, in addition to various regulatory measures (e.g., bidding restrictions), other structural measures, such as eliminating transmission constraints or creating new transmission paths, would also mitigate market power. It is not clear which measures would be more or less effective than others under any given circumstances. (Author: Joseph M. Malkin.)

Does any other entity in the WSCC currently exercise market power in the bulk power market (e.g., BPA)?

10. We do not know of *any* entity in the WSCC that currently exercises market power in the bulk power market. (Author: Joseph M. Malkin.)

Bob Logan

Is it not true that increased fuel costs for start up and ramp up, increased maintenance cost due to start ups and cycling, increased maintenance and power replacement costs due to increased forced outages, increased transaction costs and fuel contract penalties will cause an independent owner to run its plant continuously unless the PX price is projected to be significantly lower for a significant block of time.

1. Do generators select their mode of operation to avoid the costs of starts, stops and ramps? Would they sustain losses in periods when PX prices were below fuel related running costs to avoid these costs? The answer to *these* questions is clearly yes. Generators trade off the costs of starts and stops against the losses from running. When start and stop costs predominate, then the unit will continue to run. When the losses from running in the PX are greater than the start costs, then the unit will incur a start.

   However, the question presented is whether change in ownership of the divested plant would result in a different pattern of operation. The answer, in the context of the Draft Initial Study, must be no. One would expect a different generation profile under new ownership only if there was a significant shift in the underlying short-run operating costs of the plant. No evidence has been presented which suggests that divestiture would change this aspect of the generator's costs.

Would you provide us with citations to documents prepared by your firm, which address the issue of portfolios. Particularly those prepared for the trustee.

2. The publicly available work by London Economics and others relating to the PX is available on the web at http://www.energyonline.com/wepex/.

Given the supply curve you showed, an independent owner will not have opportunities to gain by shutting down its plant and buying from the PX. Further you stated that the market will arbitrage away differences in gas and PX prices. Does this not limit your contention that independent owners will use the PX only during the spring runoff.

3. As discussed in the talk, the supply curve was illustrative only; it is not sensible to try and draw inferences about the specific running regime for individual plant from it. Nor do I contend that independent owners will only use the PX during the spring runoff. They could use the PX at any time that it is advantageous to do so. Furthermore, I have made no specific statements to the effect that the generators would trade directly through the PX. They could equally well trade into the other SCs. However, it is the case that the new owners would not maximize profits by generating when they can buy more cheaply from the PX, and if they adopt this axiom, their output will be the same as IOU-owned plant bidding short-run operating costs into the PX.

You state timing but not extent of maintenance may change. If maintenance and spares policies at Diablo Canyon did not change in response to the price per kWh incentive, what caused the significant increase in reliability and availability at Diablo Canyon.

4. I do not know the details of PG&E's maintenance policies at Diablo, nor whether these were changed in response to the change in tariff. I understand that refueling outage durations have been reduced substantially since 1988, and that this reduction has increased availability. However, many other nuclear plants throughout the country have also reduced their outage durations, even though they are still under traditional ratemaking. I also understand that the Diablo Canyon receives about $80/MWh for all energy generated provided water from hydro units is not being spilled. This figure is considerably higher than expected PX prices *and* much higher than Diablo's short-run operating costs and would give incentives for high availability. Since no one is suggesting that the divested plant will be able to earn such large operating surpluses, I do not think that Diablo provides a sensible comparator for the divested gas fired plant. In the restructured market, gas-fired plants will not have a comparable assurance that prices will be above their short-run operating costs; on the contrary, it is likely that for periods of time, energy prices will be below the short-run operating costs of these plants.

Paul Miller

Do the proposed rule/permit changes at the Morro Bay power plant take into consideration emissions other than NO_x. Could increased operations result in increases in other criteria pollutants such as CO or PM10. Would San Luis Air District consider these other pollutants potentially significant.

Assuming that a change in ownership of the Morro Bay Power Plant would increase the plant's capacity factor, such an increase in operations could increase CO and PM_{10} emissions on a mass basis. However, any such emission increases would not be a significant environmental impact. With regard to CO, the San Luis Obispo County area meets the federal and state ambient air quality standard. Rule 429 includes a CO emission limit intended to assure that the plant's CO emission rate does not increase. CO is primarily a problem at ground level in urban areas with a high density of automobiles. Thus, with the CO limit in place and plant emissions from an elevated stack, any increase in CO emissions from the plant is unlikely to affect the area's attainment status. As noted on page 4.5.32 of the Draft Initial Study, "additional modeling would be needed to determine whether the increased CO emissions would be a significant impact."

The Draft Initial Study notes that the PM_{10} emission rate stated for the plant in Table 4.5.4 is based on burning fuel oil. Rule 429 effectively prohibits use of oil as fuel for the plant except during a force majeure curtailment of natural gas supply. When burning gas, PM_{10} emissions from the plant are primarily secondary nitrate aerosols resulting from the plant's NO_x emissions. This secondary PM_{10} is controlled through the limits on NO_x emissions.

For the reasons expressed above, NO_x is the only pollutant for which plant emissions might be potentially significant. Accordingly, existing Rule 429, as well as the proposed rule and permit changes, focus on NO_x emissions, and assure that NO_x emissions from the plant will remain consistent with the air quality plan. Although PG&E cannot speak for the San Luis Obispo County Air Pollution Control District (SLO APCD), in light of the proposed daily mass emission limit for NO_x we believe that the district's statement that an EIR is not required for this divestiture application indicates that the District does not consider any possible divestiture-related emissions changes to be potentially significant. (Author: Dave Farabee and Cheryl Mason.)

I understand that the emission concentrations for Morro Bay for 2002 will be implemented sooner resulting in daily emission caps based on full capacity. Does the current Air Plan now assume that in the future year (2002) with the advanced emission controls assume the plants would and could operate at full capacity. Regardless of the answer, does the Air Plan need to be modified.

The NO_x mass emission cap of 3.5 tons per day proposed to be included in Rule 429 and the plant's operating permits, to become effective beginning December 31, 2000, would not allow the plant to operate at full capacity for 24 hours per day, at the 150 ppm and 10 ppm limits that apply to Units 1 and 2, and Units 3 and 4, respectively, beginning on December 31, 2000. The NO_x emission cap of 2.5 tons per day proposed to become effective beginning December 31, 2002 is based on emission limits of 30 ppm for Units 1 and 2 and 10 ppm for Units 3 and 4, operating at full capacity on any given day.

According to the SLO APCD, the assumption in the current Clean Air Plan (CAP) will change slightly. The emission projections in the 1995 CAP are made in five year increments. The year 2005 projection for PG&E NO_x emissions is 1.16 tons/day. This assumes a fully controlled facility operating at about 40% capacity. This was a reasonable assumption given expected operating conditions at the time the CAP was prepared. However, there was no requirement in the CAP or the District regulations that mandated this limit to be met. The 2.5 ton/day emissions cap agreed to by APCD and PG&E provides a firm limit on future emissions at the plant. Furthermore, the small increase in projected emissions is insignificant. With this change, the APCD still anticipates total NO_x reductions countywide in 2005 of nearly 43% compared to 1987 baseline emissions. These reductions are significantly greater than the 20% minimum reduction recommended by the Air Resources Board, and are expected to help the county achieve and maintain attainment of the state ozone standard in the near future. The next update of the CAP will include slightly revised emissions estimates for PG&E, as well as most other sources of emissions identified in the District's emissions inventory. (Author: Dave Farabee and Cheryl Mason.)

Richard McCann

1. If expected annual emissions increase with divestiture and an APCD is currently out of compliance, would the APCD be required to modify its AQMP to bring the plan in compliance with state/federal laws and regulations?

2. How would daily emission caps at Morro Bay affect market value/bids for the plant?

1. As indicated above, post-divestiture emissions from the Morro Bay Power Plant will remain consistent with the district's air quality plan. Consequently, the District need not revise its plan to account for any effects of divestiture of the Morro Bay Power Plant. Under existing California law, the district must update its air quality plan every three years to account for any changes in air quality and emissions trends.

2. PG&E does not expect the proposed daily emissions caps to affect the market value of the plant. (Author: Dave Farabee and Cheryl Mason.)