Responses to Comments Received by the Market Surveillance Committee (MSC) On TEAM Analysis for PVD2

Prepared by

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Questions From
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1. There are 17 scenarios selected for Expected Benefits Calculations. Six scenarios (1,3,4,10,11,12) account for about 72% of the probability weight distribution. The remaining eleven scenarios seem to be heavily weighted with high outcome events for the driving variables. For example, demand has six high and one low outcomes, gas price has eight high and one low outcomes, Hydro has three dry and one wet outcomes, and Markup has seven high and no low outcomes. Will this selection of scenarios introduce a bias into the results of the economic evaluation?

   Response [Mingxia Zhang]: These seventeen scenarios should be considered all together in calculating the expected benefit. The six heavily weighted scenarios you noticed (1,3,4,10,11,12) should not be viewed separately from the other remaining eleven scenarios. The key feature of the entire collection of scenarios and probabilities is that the total probability (or "marginal probability") of each scenario for an individual variable (for instance, low demand) is consistent with the assumptions. For instance, low demand should have an overall probability of 15%, and it does. However, because some values of some variables occur only in a few scenarios, those scenarios must be assigned a relatively high probability to ensure that those values have the right marginal probability.

   In particular, the reason that these particular six scenarios are heavily-weighted is that these scenarios either contain combinations of more likely outcomes for all variables (e.g., scenario BBBM) or contain combinations of more likely outcomes for all but one variable, with this other variable having a value that occurs in very few scenarios (e.g., scenario BBDM, BBWM, BBBL, LBBM, and BLBM). Among all the 17 scenarios selected, demand is L in two, and H in six. However, the marginal probability of low demand is 15%, which is the same as the marginal probability of high demand, while base demand counts for 70% of the marginal probability. This means, the two scenarios with L demand must individually have higher probabilities than the individual H demand scenarios. The same marginal probability consistency also holds true for other variables. As a result, we do not expect that this selection of scenarios and probabilities will bias the economic evaluation results.

   Ideally, many more scenarios would have been run so that no individual scenario has a large probability; however, this is not practical given available computer capabilities and the computational requirements of the market simulation model.

2. Scenario (1), with probability weight 0.110, is used as the Base Case for the Expected Benefit Range Calculation. However, according to the probability weights assigned to the 17 scenarios, scenarios 10 and 11

have higher probability weights, 0.150 and 0.127, respectively. Why was scenario 1 used as the base case?

Response [Mingxia Zhang]: Scenario (1) is used as the Base Case for our market price based simulation because it is the combination of most-likely outcome for all variables. We do a thorough analysis using this base case to make sure all flows and prices do make sense for both the non-upgrade and upgrade case. Scenarios 10 and 11 have higher (joint) probability weights in the expected benefit calculation for the reason explained above. These two scenarios contain more likely outcomes for all but one variable, with this other variable having a value of a variable that occurs in very few scenarios. As a result, to ensure that this variable value has the right marginal probability, a relatively high probability needs to be assigned to those scenarios. If low demand occurred in more than two of the scenarios then it would have been possible for the (joint) probability for scenario LBBM to be less than 0.127. Similarly, if markup has more than one low outcome, we would expect the (joint) probability of scenario BBBL to go down. It is true that if more scenarios are selected and studied, the more accurate the (joint) probability estimates and the expected benefit calculation will be. However, we do have limitations on how many scenarios we can select and model. Nevertheless, the "Maximum Log-Likelihood" methodology used to assign weights to scenarios makes sure that a variable's low outcome has the same marginal probability as the high outcome. This gives us confidence that the expected benefit calculation has a minimum of bias.

The probability set for Expected Benefit Range calculation is different than the probability set reported for the expected benefit. For the expected benefit range calculation, additional scenarios are included to reflect possible generation/transmission outage contingencies and the "Max/Min LP" method is used to assign weights in order to find the most optimistic and pessimistic expected values consistent with the marginal probability constraints and the set of scenarios considered.

3. The operational gas cost differential between Arizona and California of 37 cents per MMBTU should be compared to the increase in marginal electric losses for units located in Arizona versus California. At $6.00 a MMBTU, 37 cents represents about 6.2% increase in the gas price. At $5.25 a MMBTU, it is about a 7% increase. Marginal losses can be much higher.

Response [**Farrokh Rahimi]:** It is correct that ignoring transmission losses in the optimization algorithm in PLEXOS (DC power flow optimization, DCOPF), could result in more generation being dispatched in Arizona (due to the fuel price differential with California) than would occur if we did include consideration of losses (AC power flow optimization, ACOPF). In the case stated here, marginal losses would contribute to LMP differential between Arizona and California if ACOPF were used. However, two points are important to consider: 1) The extent of the impact would depend on the amount (MW) and pattern (distribution on parallel paths) of power flow (during off peak hours the flows are expected to be smaller, and so will the marginal losses; during peak periods the impact of marginal losses would be higher). 2) After the upgrade the flows from Arizona to California could be higher than before the upgrade, but because they are distributed on parallel paths (because of new PVD2) the marginal losses could in fact decrease. Thus contrary to what the above comment/question may seem to imply, the ability of the cheaper resources in Arizona to compete with those in California would increase as a result of the PVD2 upgrade not only because of reduced congestion, but also because of reduced marginal losses.

4. Why are the congestion costs related to maintaining the SCIT considered to be in addition to the congestion savings related to the new line?

Response [**Jeff Miller]:** While the total SCIT limit was modeled in the simulations, the SCIT nomogram was not. We expect that the types of generation changes that are necessary to mitigate real- time congestion today whether due to SCIT, EOR, or individual line constraints, will continue to be necessary to mitigate the congestion problems identified in the studies.

5. Savings related to construction of new generation in California versus Arizona seem exaggerated. Why is water control technology more expensive in California than Arizona? Is it plausible to assume that Arizona units will not require some level of air emission technology? Many brown field sites already exist in California, reducing the land costs associated with new CTs. Is a two to one cost differential plausible?

Response [**Eric Toolson]:** The estimates of combined-cycle (CC) and combustion turbine (CT) costs in California versus Arizona are not derived from plant specific information, but are considered to be reasonable estimates. Lower permitting, land, emission credits, and labor costs drive the cost difference.

With respect to CC costs, we summarize these costs in Table VIII.1 of the draft CAISO Board Report. Excluding the PVD2 capital costs, we estimate the total annual fixed costs of a CC located in Arizona are 11 percent less than a similar one located in California.

With respect to CT costs, we estimate that the total annual fixed costs of a CT located in Arizona are 24 percent less than a similar one located in California. We have further discounted this value by one-third in an effort to be conservative. The net result is an assumption of a 16 percent reduction in costs.

We believe both of these estimates to be reasonable for a planning study. We understand that it is difficult to build or refurbish generating units on new or existing sites in urban areas. Hence, we expect that many of the future generating plants will need to be constructed outside of urban areas, potentially incurring gas and transmission interconnection costs which have not been reflected in the above estimates.

6. How much of an influence does the Southwest reserve margin of 27%, in 2013, have on the analysis? Is the Southwest reserve margin plausible?

Response [**Eric Toolson]:** We have recently enhanced our capability to compute planning reserve margins directly from the PLEXOS input data (instead of from the worksheets used to develop the input assumptions). This task is not as simple as one might expect, since the project dependable capacity (PDC) ratings, and not the nameplate ratings, need to be used for hydro and wind, and the issue of coincidental and non-coincidental loads needs to be addressed.

The Southwest planning reserve margins have recently been recomputed as 21 percent in 2008, and 19 percent in 2013. Although we originally intended for the Southwest reserve margins to be higher than 21 and 19 percent respectively, the 21 and 19 percent can be considered to be more conservative assumptions. We believe these recomputed figures are also more in line with the CEC's expectations.

7. It is my understanding that the TEAM analysis did a post processing analysis and determined that no new generation, other than Palomar, Mountain View, and Otay Mesa, would enter the market because new generation could not recover all of their costs from the CAISO energy market. With resource adequacy acting as a de facto capacity market, all costs need not be recovered from the energy market. Did the TEAM analysis look at the value of the PVD2 line if one, two, or three other new generators located in SP15?

Response [**Eric Toolson]:** We added 5,250 MW nameplate of renewables prior to 2008 (1,400 MW of dependable capacity). In addition, we added 6,020 MW of gas-fired generation in California and retired 2,410 MW, for a net gain of 3,610 MW. The Palomar, Mountain View, and Otay Mesa stations were part of the 6,020 MW of additional generation. Renewable resources were added to meet the state's renewable portfolio standard (RPS). Gas-fired generation was added after the renewables to ensure that a 16 percent capacity reserve margin was achieved.

After addition of the above-mentioned renewable and gas-fired resources, we did not find any additional gas-fired plants that could be justified on economics. Since the capacity reserve margin was achieved, capacity beyond the 16 percent reserve margin could not be credited with any capacity credit. Without the capacity credit, the net revenue from energy sales was insufficient to justify the development of additional plant. A similar approach was used in 2013.

Regarding the value of additional generation in Southern California, we are in the process of completing those cases. However, we have evaluated the impact of removing 1100 MW of generation located in Southern California from the generation mix. In 2008, the net value (difference in production costs without and with the 1100 MW of combined-cycle generation) is about $62 million (excluding PVD2 upgrade). In 2013, this value drops to $48 million in nominal dollars, or $43 million in 2008 dollars. The reduction in value can be a result of many factors including the increased amount of California renewables added between 2008 and 2013. As mentioned above, since we have already satisfied our reserve margin requirements, the net energy value from the 1100 MW facility is equal to $51/kw-year in 2008 and $36/kw-year in 2013 (both expressed in 2008 dollars). Neither of these amounts are sufficient to justify the economic entry of additional combined cycles with annual fixed costs estimated to be about $140/kw-year in 2008 dollars.

Questions from
John Burnett
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(LADWP)

LADWP appreciates the extensive work undertaken by the CAISO staff and other entities while evaluating the economic value to CAISO ratepayers of the proposed PVD2. LADWP technical staff has been in contact with CAISO staff and the Market Surveillance Committee (MSC) over the past several months as refinements to the economic study have been pursued. These comments are a continuation of this participation and provided in the spirit of regional planning coordination, and to assist the CAISO to reach the right and best conclusions.

There appears to be several assumptions in the CAISO's current economic study which overestimate the economic value of the PVD2. In the list below, the LADWP describes some of these assumptions, and provides brief reasons why these assumptions overestimate such value.

1. The CAISO has not recognized that the EOR 9000+ Project can increase the Palo Verde – West transmission (PV-West) capability: This has been discussed between the CAISO staff, the LADWP, and the Salt River Project in stakeholder meetings. LADWP and SRP think that PV-West can be increased by several hundred MW through relatively small scale and inexpensive upgrades to the Imperial Irrigation District (IID) transmission system. These upgrades are currently under study. SRP's studies show that these IID transmission upgrades would, in conjunction with EOR 9000+, increase the PV-West capability by around 600MW (increase from 3600MW to around 4200MW). (See ISO Feb. 2, 2005 Draft, footnote 1.) It appears that this increase in PV-West capability would provide some of the economic benefits attributed to PVD2 in the current economic study.

   Response (Johan Galleberg]: The Plan of Service for the EOR9000+ Project is to upgrade the series capacitors on Navajo-Crystal and Perkins – Mead 500 kV lines. Neither off these two lines is part of the PV West path. In fact they run from Arizona to Southern Nevada rather than from Arizona to Southern California. Based on this, and the ISO's extensive technical studies, the ISO does not believe that the EOR 9000 project would enable increased capability on the PV West Path.

   Several studies have shown that 3,600 MW is the right limit for PV West before the PVD2 project is placed in service. The dynamic stability studies for STEP identified 3,600 MW as the maximum capability on Palo Verde West. Also the WATS/WECC DPV2 Review Group approved simultaneous cases found 3,600 MW to be the maximum flow on this interface. In the opinion of the ISO and the primary owners of the lines in that path (SCE and SDG&E), a reasonable maximum capability for those two lines is 3600 MW.

With flow as high as 4,200 MW, significant reliability criteria violations have been identified in areas like MWD, IID, SDG&E and SCE. But maybe more importantly, the losses on the two lines compromising PV West are extremely high. For example, with flow on Palo Verde – Devers at 2,200 MW, a total of more than 100 MW and 1300 MVAR occur in losses on that line alone (100 MW is equal to the output of two LM6000 power plants).

2. Inaccuracies caused by the DC power flow used in the study add uncertainty to the economic results. For example, the flow patterns produced in the DC power flow are distorted because transmission line losses are not modeled on the transmission lines. Discussion now underway in the Seams Steering Group – Western Interconnection, Planning Work Group concerns the appropriateness of using the more accurate AC power flow in cases where losses and congestion are important; some hold that that WECC is such a case.

   Response [Jeff Miller]: We agree that more accurate simulations would be possible if we were to use an ac power flow rather than a dc power flow in the production cost simulations. As you mentioned, SSG-WI is investigating this possibility. However, SSG-WI is not planning to incorporate an ac power flow into the model. Instead, there are some ways that ABB has developed that would enable the modeling of losses using a DC power flow. This will hopefully avoid the pitfalls of using an AC power flow (substantial increases in computation time and non-convergence). As these improvements are developed and made available, the ISO will incorporate them. However, at this point, modeling losses within the production cost program is not available for the ISO to use as part of the methodology used to evaluate PVD2.

3. New generation near Devers has been underrepresented: The LADWP is concerned that the injection of this generation at Devers will cause overloads on the West-of-Devers system, limiting the usefulness of the PVD2 since PVD2 also drops off its energy in the West-of-Devers system. The $620M estimate for the PVD2 includes an upgrade of the West-of-Devers system, but this upgrade appears insufficient given that the following new generation near Devers was not represented:
   a. Only part of the 2000 MW of future Imperial Valley Geothermal generation appears to have been modeled. Because of the critical location of this generation, it appears that the economic study should reflect 600MW of new Imperial Valley Geothermal generation planned to be installed prior to PVD2, with 100MW additional generation planned to be installed each subsequent year.

      Response [Johan Galleberg]: The upgrade of the four 230 kV lines west of Devers includes a rebuild and a reconductor of the existing lines with 2B-1033 ACSR conductor. Preliminary studies performed by the ISO have shown that this will increase the limit from about 2,200 MW (estimated to be in place by 2006) to about 4,700 MW. The maximum flow West of Devers identified in the 2008 simulations with the DPV2 project in service is about 3,200 MW. This includes the modeling of 250 MW of geothermal generation from Imperial Valley and 520 MW from the Blythe 1 generator plant. 4,700 MW as a new West of Devers limit appears therefore to be sufficient to accommodate future generation from Blythe 2 and additional geothermal generation from Imperial Valley if this materializes.

b. New Blythe Generation and a new 500kV Transmission line from Blythe to Devers may add 1040 MW to West-of-Devers flows around the time when the PVD2 is in-service, according to the Colorado River Transmission presentation at the December 2004 STEP meeting.

Response: [Johan Galleberg]: We have not modeled them since these projects are still in conceptual stage. Both Blythe 2 and new Imperial Valley generation are only speculative projects at this point; Blythe 2 has not received AFC from CEC and the 2,000 MW of new generation from Imperial Valley is only at a conceptual planning level.

This under-representation of generation at Devers indicates that the cost of PVD2 is underestimated. In addition, the benefits from PVD2 are overestimated because the economic value of DPV2 decreases as more California generation is dispatched. **[See the above responses.]**

4. It is not clear whether or not volumetric compliance to the California Renewable Portfolio Standard has been met: While the CAISO has modeled the capacity they expect will be needed to allow compliance with the standard, they have not stated whether there were enough renewables dispatched to achieve volumetric compliance (kWh/yr) to the RPS. The more renewables dispatched in California, the lower the value of DPV2.

Response [**Eric Toolson]:** As an example of our approach, in 2008, we added sufficient renewables to provide 14,200 GWh/year of renewable energy in compliance of the volumetric requirements of the California RPS. The 14,200 new renewable generation is composed of the following resources:

- Wind – 9,240 GWh/year or 65 % of total
- Geothermal – 2,890 GWh/year or 20 % of total
- Digester Gas – 1,010 GWh/year or 7 % of total
- Biomass – 1,000 GWh/yr or 7 % of total

- Solar – 90 GWh/yr or 1 % of total

The wind and solar have hourly patterns which are directly utilized in the PLEXOS simulation so there is no dispatch, but rather a fixed amount of generation. Geothermal, digester gas, and biomass resources were all dispatched at their maximum capacity factor of 85 to 90 percent.

5. The study overestimates the value of imports to CAISO, thereby over estimating the value of the PVD2: From the viewpoint of a CAISO Load Serving Entity purchasing for its load, the cost of imported supply is underestimated because of the omission of losses and wheeling. This causes the cost of imports to be underestimated by roughly:

- Several percent because of losses (losses from Palo Verde to Southern California load);

  Response [Farrokh Rahimi]: It is true that the DC power flow used in PLEXOS does not take into account transmission losses, and thus may underestimate the locational marginal price (LMP) differences among locations in Arizona and California compared to what would have been computed under an AC Optimal Power Flow (ACOPF). However, as pointed out earlier, after the upgrade although the flows from Arizona to California could be higher than before the upgrade, because they are distributed on parallel paths (because of new PVD2) the marginal losses could in fact decrease. Thus the ability of the cheaper resources in Arizona to compete with those in California would increase as a result of the PVD2 upgrade not only because of reduced congestion, but also because of reduced marginal losses.

- A few percent because of wheeling (~=average transmission access charge / average energy bid).

  Response [Farrokh Rahimi]: We assume the issue of concern here is the wheeling charge associated with going across the transmission system to serve California load, and not the access charge paid by the California load (which does not depend on whether the energy it consumes is coming from Arizona or some resource in California). Please note that although there may be wheeling charges to get from the actual generation location in Arizona to the border point with California (CAISO market Scheduling Point), there are no wheeling charges for the part of the scheduled flow from the border point (CAISO Scheduling Point) to the load in California (only wheel through and wheel out pay wheeling charges to California ISO, which are used to reduce the Participating Transmission Owners' Transmission Revenue Requirements, and thus reduce the transmission and wheeling access charge rates.).

Several other factors appear to cause the value of imports to be overestimated:

- Bid mitigation of generation inside the CAISO lowers the price of CAISO generation in relation to import prices during high-price periods.

  Response [Farrokh Rahimi]: This statement is not correct. The bid mitigation within California would never bring the bid price below the levels of bids calculated in our market pricing scenarios. In fact the AMP Conduct Threshold is at present $100/MWh or 200% above the Reference Level (which itself is no less than the generation cost, and may be higher depending on how the Reference Price is set for the specific unit: based on successful market bids, negotiated with Potomac, etc.).

- Capacity contracts (e.g. resource adequacy capacity contracts (RACC)) lower the price of CAISO generation in relation to imports during high-price periods, unless the energy behind RACC is allowed to set the MCP. (The MCP would be lower unless energy being RACC can set the MCP.)

  Response [Farrokh Rahimi]: There may be some confusion reflected in this statement. First, under the current CPUC RAR ruling, as well as under MRTU, there is absolutely no requirement on RAR resources to self schedule as price takers in the ISO markets; they can satisfy their "must offer obligation" by bidding into the ISO market and can set the price. Second, in order to secure a resource in California as RAR resource, the Load Serving Entity would incur upfront costs (RAR contract payments). Unless there is a strike price in the contract that obligates the seller to bid at specific levels in the market, the RAR resource can bid any price for Energy as long as it does not trigger mitigation (AMP), which as stated above has generous trigger thresholds (if the RAR contract does have a strike price, then the lower the strike price, the higher the upfront payment by the LSE that the seller may require to sign the contract). Thus, it is not necessarily true that the RAR energy from internal RAR resources would be cheaper than imports. Third, RAR can be met from resources outside the control area provided there is adequate transmission; thus transmission expansion expanding inter-control area interchange can enhance RAR supply competition to the benefit of the CAISO rate payers. In sum, increasing competition by augmenting import capability is likely to enhance competition for RAR contracts and in the energy market.

CAISO appears to have already addressed similar price restraints caused by bilateral energy contracts (e.g. CERS contracts) and utility retained generation. (Page 19 of Feb 2, 2005 Draft report)

These factors indicate a bias toward an over-dispatch of import supply with respect to inside-CAISO supply, leading to an overestimation of the value of the PVD2.

[See the above responses.]

6. The Operational Benefits appear to be overstated because of the omission of the change to SCIT achieved by EOR 9000+ and the Short Term Upgrades. Further, it is not clear if the real time operational benefits achieved by MRTU have been taken into account.

- The addition of EOR 9000+ and the Short Term Upgrades changes the factor limiting the today's SCIT. Studies presented at STEP indicate that today's inertia-dependent limit (which requires a certain amount of Southern California generation to be on-line) will be largely or entirely replaced by new limits independent of inertia (such as a voltage dip at Devers). Because inertia will be largely or entirely removed from SCIT prior to PVD2, it appears that the Operational Benefits (i.e. $22M/yr in decreased SCIT related minimum load cost and redispatch cost) should be attributed to the EOR 9000+ and the Short Term Upgrades instead of PVD2.

  Response [Jeff Miller]: We agree that the addition of the EOR 9000 project and the short-term upgrades will provide substantial operational benefits, however, even after these upgrades, substantial congestion remains. Our estimate of the operational benefit is based on the ability of PVD2 to mitigate the congestions that remains after the addition of the other line.

- The CAISO staff has stated that the MRTU would remove real-time intra-zonal congestion by creating feasible forward schedules under LMP. Today's mitigation on the PVD1 for SCIT and loop flow is not done forward (except for the recent Transmission Reliability Margin (TRM)) and is called real-time intra-zonal congestion. Considering that MRTU will be in-service before PVD2, it appears that part of the real-time operational efficiency should be achieved by MRTU and TRM instead of PVD2.

  Response [Farrokh Rahimi]: This statement is incorrect. Under MRTU, the external network will remain radial (scissors cut) and unable to capture loop flows resulting from external (Import) schedules. Thus, regardless of whether the SCIT nomogram (in its present form or as potentially modified along with EOR 9000+) prevails, inter-tie constraints that presently require re-dispatch in real-time due to infeasible forward schedules will continue to require real-time re-dispatch under MRTU to mitigate such constraint violations in real time.

Given the above factors (a SCIT without inertia, and feasible forward schedules under MRTU and TRM), what part of today's' operating burdens (i.e. real-time intra-zonal congestion and MLCC) will be left for PVD2 to fix?

[See the above responses.]

7. LADWP would appreciate it if the CAISO indicates the economic study results for the CAISO's surrounding control areas.

Response [**Eric Toolson]:** In our analysis, we have focused on the Societal, Modified Societal, and CAISO Ratepayer perspectives. We have not focused on the non-CAISO areas other than to aggregate their benefits and costs as a single, non-CAISO entity. To provide the correct economic signals for the other areas, we would need to assign company ownership to all transmission lines, a fairly onerous process that we have not undertaken for this analysis.

Finally, LADWP emphasizes its desire and willingness to continue working with the CAISO, its members, and other planning organizations, to find common needs and goals, and determine regional solutions at the lowest cost for all. This has been done in the past and should continue to happen in the future.

The LADWP appreciates this opportunity to comment, and hopes that these comments help CAISO determine when the time is right to build PVD2. Please contact us if you have any technical questions: Tim Wu (213-367-0650) for transmission planning issues, and John Burnett (213-367-1744) for the other issues.