Responses to Comments from Stakeholders On TEAM Analysis for PVD2

Set #2

Prepared by

California ISO
Department of Market Analysis & Grid Planning

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Stakeholder Questions & Responses

Jim Kritikson, Kritikson & Associates, Inc.

1. If there will also be an explanation of the bid adders before and after the new line, and how much of the annual benefit is due to this effect?

Response [Eric Toolson]:

The bid mark-ups can be substantial, however, their impact on PVD2 benefits is not as significant as some of the other variables such as gas or hydro. In the table below, we summarize the average annual mark-up for the SCE area for the three cases in 2008. The average annual bid mark-up in 2008 is approximately 30 percent for the high case, 17 percent for the base case, and 1 percent for the low case. The impact of these mark-ups on the benefits is an increase of $1.7 million for the high case, and a decrease of $2.8 million for the low case.

Mark-Up Input Variable	Case Description	SCE Average Annual Mark-Up	PVD2 Benefits (mil. $)
High	BBBL	30	$47.0
Base	BBBM	17	$45.3
Low	BBBH	1	$42.5

Perry Cole, SVP Trans-Elect New Transmission Development

2. How much of the change in economic value (since STEP studies) of the line is related to the assumption of the permanent gas price differential? I think you mentioned $2.39?

Response [Eric Toolson]:

Please see response to Question 3a in the "Response to Questions – Set #1 (Rev. 1). The gas price differential between California and the Southwest is about $0.37/mmbtu for both 2008 and 2013.

3. The $2.39 sounds like the SoCal Gas tariff. I have heard there may be an attempt for generators and others to be able to tap directly into the interstate pipelines and avoid SoCal gas like in many other states. What is the impact if that happens?

Response [Eric Toolson]:

We assume that generators will try to connect directly with the interstate pipeline and avoid additional natural gas distribution charges whenever possible. At this point, we are reflecting the avoidance of distribution costs primarily in the Southwest, where much of the new generation is being added in the Palo Verde region and can direct-connect to the interstate pipeline. The results of the valuation are fairly sensitive to the ultimate burner-tip gas price, and a significant shift in those costs and differentials, would likely have an impact on the resulting benefits.

4. Could you forward along the breakdown of the revenue requirement assumptions including cost of capital assumptions during and after construction. Also a breakdown of assumed construction costs with AFUDC.

Response [Eric Toolson]:

Southern California Edison (SCE) has estimated the capital cost of the proposed PVD2 upgrade to be $620 million at its online date at the beginning of 2009. SCE has also estimated the Allowance for Funds Used During Construction (AFUDC) costs to be approximately $60 million, for a total capital cost of $680 million at the 2009 online date.

For purposes of our analysis, we have deflated the capital costs one year so that they can be expressed in 2008 dollars (to be consistent with the benefits which are also expressed in 2008 dollars). The capital costs deflated to 2008 are $660 million using a 2.0 percent inflation rate.

These capital costs can be converted to an equivalent stream of annual revenue requirements. Although these revenue requirements change from year-to-year, for purposes of economic evaluations, we expressed this series of annual revenue requirements as an equal or "levelized" payment over the project life.

We estimate the levelized revenue requirement for the capital costs of the proposed PVD2 project is estimated to be $69 million per year for 50 years.1 If we assume that the operating costs of the line are approximately 0.25 percent of the capital costs per year, the total of capital and fixed operating costs was $71 million per year. Thus, for this analysis, we compared the computed levelized benefits to the $71 million levelized costs to determine the economic viability of the project.

The weighted cost of capital including debt, preferred stock, and common equity is approximately 10 percent. We have not received detailed information regarding the AFUDC rate at this point.

[1] The revenue requirements include the impact of federal and state income taxes, administrative and generation costs, insurance expenses, and ad valorem tax. SCE provided the CAISO with its computed "Real Economic Carrying Charge Rate for Transmission" of 10.43 percent. This rate is comparable to a Nominal Economic Carrying Charge Rate of 15.6 percent.

Cliff Rochlin, SOCAL Gas

5. What is the impact of marginal losses on the "Estimation of Capacity Value" and "Estimation of Value of Emission Reduction"? Stated differently, how much does marginal losses reduce the benefits of DPV2?

Response [Farrokh Rahimi]:

Impact of Marginal Losses on Estimation of Capacity Value:

Marginal losses have no direct impact on capacity benefits. This is because:

1) As currently contemplated in the resource adequacy requirement (RAR) proceedings, the capacity value of a "deliverable" resource would not be derated due to transmission losses (marginal or average) whether the resource is within or outside the control area. Thus, for system-wide RAR, a resource that meets deliverability requirements would count equally whether it is located within or outside the ISO control area). Since PVD2 enhances the deliverability of resources from outside the control area, its capacity benefits are due to increased transmission and unhampered by marginal losses.
2) Resources able to meet local RAR would have an advantage over system-wide RAR resources, but that has nothing to do with whether the system-wide RAR resource is within or outside the control area (and thus impacted positively by PVD2). Moreover, Local RAR, i.e., the MW volume of RAR capacity that **must** be within internal ISO control area load pockets, is expected to be small compared to the total (system-wide) RAR.
3) It is not necessary for a RAR contract to include a strike piece for energy; if no strike price is stipulated, the seller can bid any energy price (so there is no need to internalize energy price risks in the capacity price).

Impact of Marginal Losses on Estimation of Value of Emission Reduction:

It is not clear if the issue as stated pertains to marginal losses or average losses. With respect to average losses, it is true that to meet 1 MW of local load, a resource with an average loss factor of LF would have to generate (1+LF) MW. Thus for equal technology (same emission per MWh generated at the power plant), a local resource would have to generate less. But to the extent that the remote resource has a different generation technology, or can implement better emission abatement technology and still be competitive because of its lower generation plant construction costs, it may overcompensate for the impact of LF. Marginal losses would have no additional impact on emission reduction benefits beyond what was just stated for average losses.

Karen Griffin, California Energy Commission

6. What would be the impact of not maintaining a high reserve margin for the Southwest through time? Our analysis suggests that this assumption is highly uncertain, for 2 reasons.
    a. We have compared the WECC's 10 year resource plan with our own assessment of generation to be constructed in the Southwest. Both assessments confirm that there is a current "oversupply" of generation compared to load, with 2005 reserve margins of 26 * 27%. That level persists through 2007. In both analyses, the high reserve margin does not persist after 2007, but drops over time back to an amount of generation which can be absorbed by the load. I've attached a spreadsheet which shows an update of the status of generation units counted in the WECC 2003 analysis.
    b. There seems to be a bit of circular reasoning in assuming that the 26% reserve margin will persist through time. Economically, generation cannot survive without adequate revenues to cover costs and profits. A 26% reserve margin would drive prices below sustainable levels. Without the addition of a new export transmission line, either old generation would retire or new generation would not be built until native load increased enough to establish a new equilibrium. There seems to be a presumption of "if we build a transmission line, then new generation will be profitable." If this were true, it would be true only up to the transfer capacity of the line (i.e. 1200 MW). Lower gas transportation costs and possible lower construction costs might favor construction of new generation in the Southwest, but only if the electricity transmission costs did not wipe out the advantage or California in-state resources (such as renewables) were not given a preference.

For these reasons, the impact of the uncertainty of this assumption should be explicitly discussed.

The spreadsheet is attached as a table in the next page.

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 your expectations.

With respect to the extrapolation of benefits beyond 2013, we allow the reader to determine a real escalation rate and apply it to the energy benefits (see Table VII.2, p. 26 of draft CAISO Board Report). In the draft Report, we chose a 1 percent real escalation rate as a plausible outcome. Since most of the components driving the electric price are expected to escalate at a rate greater than inflation (i.e. capital, land, emissions, labor), and since fuel switching on the margin is expected to continue to occur from coal to gas (primarily in the off-peak), we believe that a 1 percent real escalation rate is a reasonable real escalation rate.

Southwest Load-Resource Balance 2005-2013
Richard Jensen Feb.1
Southwestern Resources

	2005	2006	2007	2008	2009	2010	2011	2012	2013
Existing	33,061	33,696	35,742	35,742	35,834	35,834	35,834	35,834	35,767
Additions	635	2517		92					
SW Retirements		471						67	
Total Resources	33,696	35,742	35,742	35,834	35,834	35,834	35,834	35,767	35,767
Summer Peak:									
Projected SW Loads	26,536	27,384	28,256	29,123	30,017	30,934	31,778	32,587	33,506
Excess Capacity	7,160	8,358	7,486	6,711	5,817	4,900	4,056	3,180	2,261
Reserve Margin %	**27.0%**	**30.5%**	**26.5%**	**23.0%**	**19.4%**	**15.8%**	**12.8%**	**9.8%**	**6.7%**
WECC 10-year plan estimate	**26.2%**	**26.5%**	**26.3%**	**25.2%**	**21.4%**	**18.9%**	**15.6%**	**13.0%**	**12.8%**

Notes:

Major capacity additions in CEC estimate include:

Plant:	**Owner:**
Bluffview	Farmington
Santan	S.R.P.
Palo Verde upgrad	APS
Springerville	Unisource
Charles Lenzie (Mo	NV Power
Luna**	PNM

**Not included in WECC estimate

Major capacity additions in WECC estimate NOT included in CEC setimate:

Plant:	**Owner:**
Bowie I & II	SWPG
Allen CC & GT	Sierra Pacific Resources
Welton Mowhawk	Dome Valley Energy
Copper Mountain	Sempra
Salton Sea VI	CalEnergy
Unidentified GT's	Unknown

7. In calculating congestion revenues, was there any netting of the costs of FTRs?

I think the way the economic benefit is calculated, it assumes that congestion revenues are paid to all IOU ratepayers (bundled, direct access and municipal customers) in proportion to their load. The reason they would be paid is because they bought FTRs in the first place. Thus, the congestion revenue reduces a risk investment they made. Is this correct? Was the FTR netted out? Is the congestion revenue that is distributed to all IOU ratepayers assumed to be proportional to load, or is it allocated based on history of FTRs purchases?

Response [Farrokh Rahimi]:

FTRs (or CRRs under MRTU) need not be considered explicitly in the analysis as explained below.

If there were no FTRs or CRRs (as the CAISO market operated from April 1, 1988 to January 31, 2000), all congestion revenues (indirectly paid by the transmission users) would be used to reduce the Transmission Revenue Requirements (TRR) of the Participating Transmission Owners (PTOs). This would mean lower Transmission Access Charge (TAC) for the load and lower Wheeling Access Charge (WAC) for other users of the transmission system (wheel through and wheel out).

In conjunction with FTRs and CRRs, in the TEAM methodology we have made the assumption that the prices paid in the FTR/CRR auction are unbiased estimates of the congestion revenues per MW of FTR/CRR (during the FTR/CRR life cycle). Moreover, we have assumed that the CRR allocations to the load serving entities exactly hedge their congestion exposure (i.e., do not create additional revenues or shortfalls). These are justifiable assumptions since they represent the objective of CRR allocations and FTR/CRR purchases by entities that are subject to transmission charges (and thus pay transmission rentals).

With these assumptions, it is clear that if all FTRs/CRRs were auctioned (no allocation), since the proceeds of the FTR/CRR auctions would go to the PTOs and reduce the TAC/WAC the end effect would be the same as when there was no FTR/CRR. To the extent some CRRs are allocated (rather than procured through the auction and paid for), they do not reduce the TAC/WAC, but they also eliminate the congestion payments by the entities that acquired them. Since CRRs are allocated only to the entities that pay the TAC/WAC, the end effect will be again the same as when there were no FTRs/CRRs.

With the above explanation, whatever cost shifts may already exist in the absence of FTRs/CRRs between congestion charges paid by a subset of transmission users and the reduction of TAC/WAC by the same or other transmission users, would not be changed by the assumed unbiased auction/allocation of FTRTs/CRRs.

8. This is a follow-up to questions 1 and 2 (not yet answered) on excess generation in the Southwest. The economic study seems to find that the lower cost of construction and operation of generation in the Southwest is offset by the costs of transmitting power to southern California. Therefore, new generation in the Southwest cannot compete with in-state generation on a competitive bid for energy. Given the higher total cost,

why would excess generation be built in the southwest? Is there something in the economics study which I have missed?

And, if there is no economic incentive for new generation to be built above what is needed in the Southwest to meet its own reserves, what is the impact on the value of DPV2 of holding reserves at a constant level through the West?

Response [Eric Toolson]:

We find that the cost of constructing and operating a combined-cycle (CC) facility is less in Arizona. If we add the levelized PVD2 costs ($/kw-year) to the cost of the Arizona CC (and do not consider any significant transmission or natural gas interconnection cost in California), the CC in California is less expensive at mid-range capacity factors. At high capacity factors where one might expect a CC unit to operate, the costs are comparable. To us, the issue is not so much of what a generic CC might cost in Arizona versus California, but how many California plants can be built in California urban areas, where they would have the maximum reliability benefit, without extensive interconnection costs.

9. Does the congestion exist in both the full LMP model and the managed in real time model, but the costs are paid out of different pockets? That is what the text of the Draft Technical Appendix M seems to say: in the LMP version it is paid for through congestion revenues which are reverted to ISO customers (because they paid for it in FTRs?). In the real time management system, payment is through the uplift charge which is paid by (whom)?

At first I thought you were saying that the congestion revenues were a phantom of the full LMP model. Now it appears that the costs are real, but paid for differently. Thanks for your help in understanding the logic.

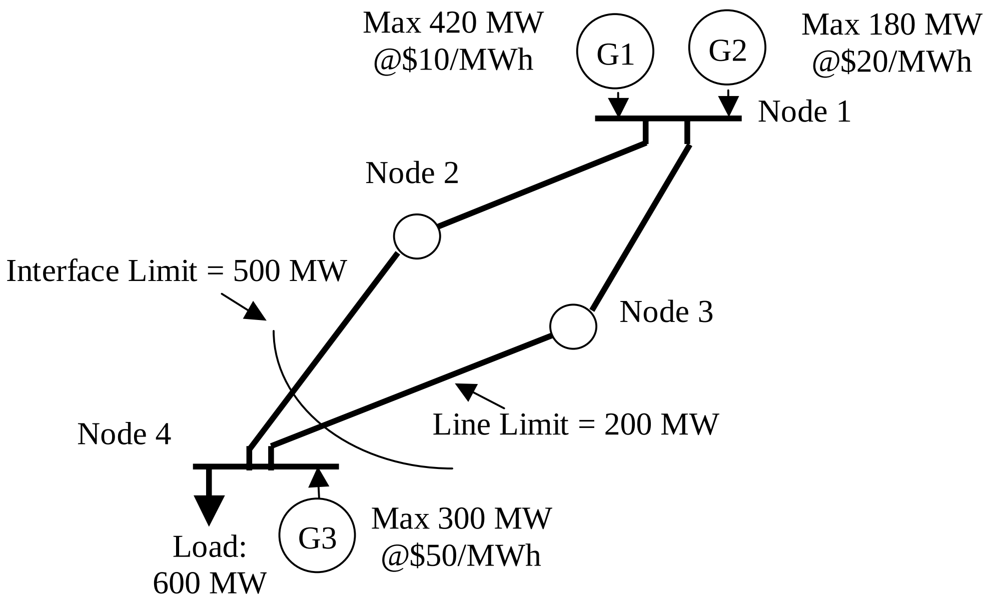
I'd really appreciate a simple graph or table of what congestion-related dollars are paid by whom in these 2 approaches.

Response [Farrokh Rahimi]:

It would be helpful to answer the question through an example as suggested:

Example:

Consider the following network with an interface limit of 500 MW and a transmission line limit of 200 MW on one of the lines comprising the interface. Assume all four transmission line segments shown have the same impedance. Nodes 2 and 3 are the boundary bodes between two control areas. The load is fixed at 600 MW (vertical demand), and generation capacities and prices are as shown. Assume supply is bid at cost (no market power).



Forward scheduling and real-time dispatch with the physical network model

The line limit of 200 MW is more constraining than the interface limit. The minimum cost solution is: G1 = 400 MW, G2 = 0 MW, and G3 = 200 MW. The relevant LMPs are LMP1 = $10/MWh and LMP4 = $50/MWh. The shadow prices are $0/MWh for the interface constraint and $80/MWh for the line constraint (a 1 MW increase in the line rating will allow displacement of 2 MW of G3 by 2 MW from G1 with a net dispatch cost reduction of ($50*2 - $10*2 = $80). The settlements are as follows:

- Cost to load: $50*600 = $30,000
- Generation revenues: $10*400 + $50*200 = $14,000
- Generation Cost: $10*400 + $50*200 = $14,000
- Producer surplus: $0
- Congestion rental: $80*200 = $16,000

These schedules will be feasible so there is no need for real-time re-dispatch.

Forward scheduling and real-time dispatch with the contract path external model

Day-ahead scheduling based on the contract path external network model would allow specifying import schedules at nodes 2 and 3 without considering the impact of transmission from node 1. An equivalent way of saying this is that the SCs can schedule up to the interface limit of 500 MW by limiting their schedule at node 3 below 200 MW, and scheduling the balance at node 2. In the day-ahead scheduling process, one may thus ignore the 200 MW line limit and enforce only the 500 MW interface limit. Accordingly, the minimum cost solution is: G1 = 420 MW, G2 = 80 MW, and G3 = 100 MW. The relevant LMPs are LMP1 = $20/MWh and LMP4 = $50/MWh. The shadow price of the interface constraint is $30/MWh. The day-ahead settlements are as follows:

- Cost to load: $50*600 = $30,000
- Generation revenues: $20*500 + $50*100 = $15,000
- Generation Cost: $10*420 + $20*80 + $50*100 = $10,800
- Producer surplus: $4,200
- Congestion rental: $30*500 = $15,000

The day-ahead schedules are not feasible in real-time since with 500 MW generated at node 1, there will be a flow of 250 MW on the line from node 3 to node 4. So, real-time re-dispatch will be required. It will involve DEC'ing G2 from 80 MW to 0 MW, and G1 from 420 MW to 400 MW, and INC'ing G3 from 100 MW to 200 MW. Depending on whether the settlement in real-time is as bid or based on LMPs. The settlement may be as follows:

a) With as-bid payments for real-time re-dispatch:

- Real-time generation revenue = Real-time re-dispatch cost charged to load: $50*100 - $20*80 - $10*20 = $3,200
- Re-dispatch re-dispatch cost to generation: $50*100 - $20*80 - $10*20 = $3,200
- Producer surplus from real-time re-dispatch: $0

Thus assuming as-bid settlement in real-time, the net result of the day-ahead and real-time settlement is:

- Cost to load: $30,000 + $3,200 = $33,200
- Generation revenues: $15,000 + $3,200 = $18,200
- Generation Cost: $10,800 + $3,200 = $14,000
- Producer surplus: $4,200
- Congestion rental: $15,000

b) With LMP settlement for real-time re-dispatch:

- Real-time generation revenue = Real-time re-dispatch cost charged to load: $50*100 - $10*100 = $4,000
- Re-dispatch re-dispatch cost to generation: $50*100 - $20*80 - $10*20 = $3,200
- Producer surplus from real-time re-dispatch: $4,000 – $3,200 = $800

Thus assuming LMP-based settlement in real-time, the net result of the day-ahead and real-time settlement is:

- Cost to load: $30,000 + $4,000 = $34,000
- Generation revenues: $15,000 + $4,000 = $19,000
- Generation Cost: $10,800 + $3,200 = $14,000
- Producer surplus: $4,200 + $800 = ($19,000 - $14,000) = $5,000
- Congestion rental: $15,000

Note: Comparing the results of the physical and contract path models, we see that the rental is lower in the contract path case, but the producer surplus and the cost to load are higher. Transmission upgrades are expected to reduce the rental and either reduce or leave intact the cost to load; this is why under a contract path paradigm, the benefit of the upgrade is expected to be higher (less loss of rental due to lower initial rental and higher consumer benefits due to higher initial cost to load).

Rich Lauckhart, Global Energy

10. I am a little confused with respect to whether the dollars described (e.g. for the natural gas price) are in nominal dollars or constant dollars. The text indicates that the prices are in "nominal 2003 dollars." I am not familiar with this terminology. I am used to saying that the prices are either:
    a. Nominal dollars (meaning that they have been adjusted to reflect both (a) increases in price due to fundamental changes and (b) increases caused by general inflation (loss in buying power of the dollar), or
    b. Constant dollars (e.g. constant 2005 dollars), meaning the prices have been adjusted to reflect increases in price due to fundamentals changes but not adjusted to reflect general inflation (loss in buying power from the dollars).

Can someone explain what is meant by "nominal 2003 dollars"? For example, if natural gas costs $5/mmbtu today (2005 dollars), but we think that supplies will grow even tighter in the future and new supplies will be more difficult (and costly to get), then the price might rise to $5.50 in the year 2010 in constant 2005 dollars. If we further assume that general inflation will decrease the buying power of the dollar, then the nominal price for gas in the year 2010 might actually require that $6 be paid in order to get the gas ($0.50 increase from fundamentals and $0.50 increase from general inflation).

I would appreciate any clarification on this matter that you can provide to me.

Response [Eric Toolson]:

The first sentence in the Technical Appendices, Appendix E, should read: "All of the fuel prices are in nominal dollars". The 2003 dollars refers to the CEC natural gas forecast that was used in the TEAM study. As you correctly note, "nominal" means including the impact of inflation, and "real" means including the impact of inflation to a specific year, and then excluding inflation after that point.

All of our market simulations with PLEXOS were performed with nominal dollars. For the most part, all of our summary results are in 2008 dollars (i.e. inflation is included up to and including 2008, and excluded after 2008). In all tables, figures, and text, we should be clear as to whether the dollars are in real (2008) or nominal dollars. If you or any other reader notices any areas of confusion, please point them out and we will clarify these instances.