Stakeholder Comments Template

Subject: Exceptional Dispatch – Straw Proposal

Submitted by	Company	Date Submitted
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This template has been created for submission of stakeholder comments on the topic of Exceptional Dispatch and specifically the straw proposal paper related to this topic as posted on April 14, 2008 (at: http://www.caiso.com/1f91/1f91cdbd12f0.pdf) and discussed at the stakeholder meeting on April 15, 2008. Upon completion of this template please submit (in MS Word) to mailto:jmcclain@caiso.com. Submissions are requested by close of business on April 24, 2008.

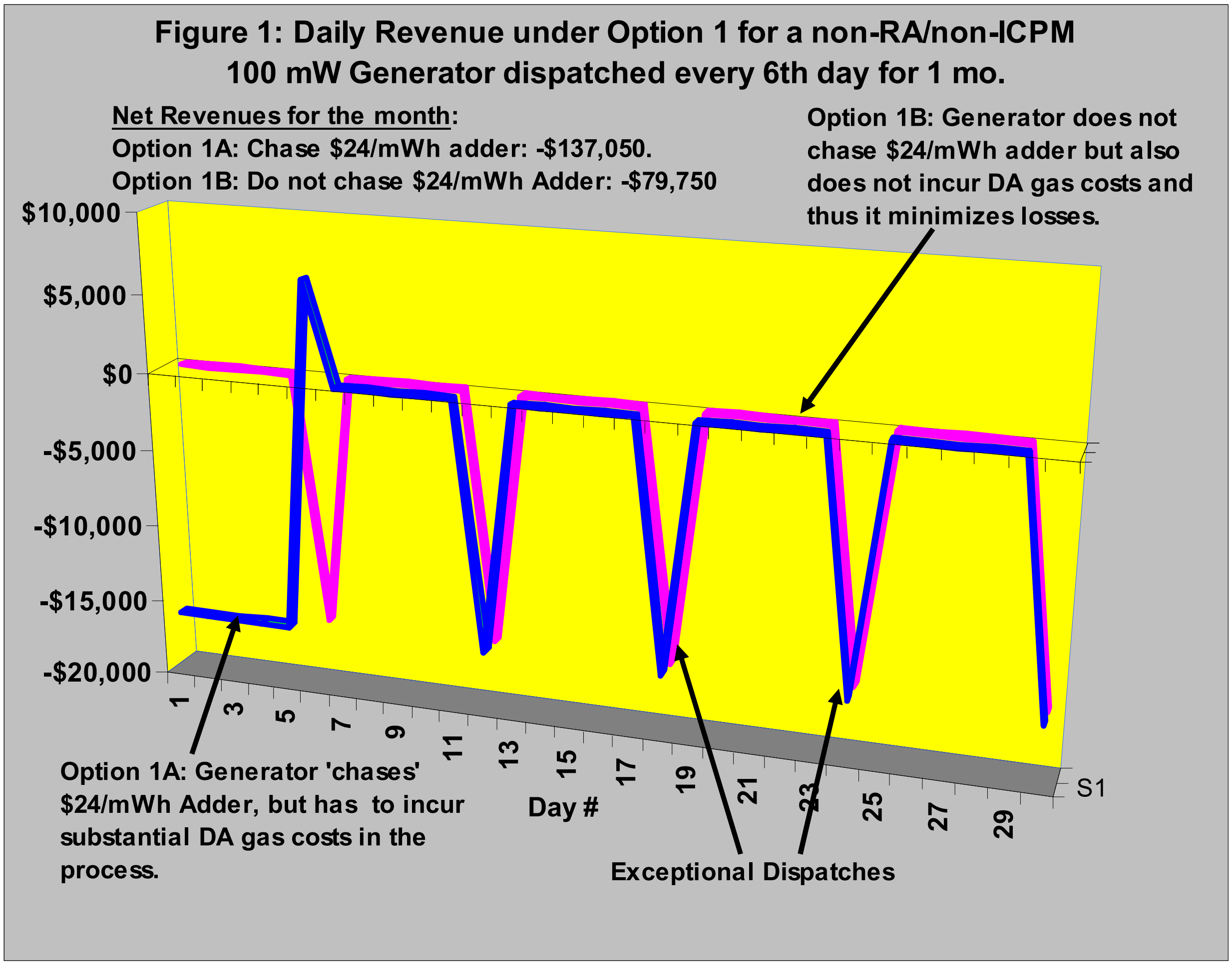
Please provide your comments to the areas below related to the two straw proposals and aspects of the proposals that you do or do not support in the space below. There is also a general comments section for any other comments you would like to provide.

1. Option 1 – Bid Adder Option

As Reliant has previously indicated in its Stakeholder Comments[1], mitigation of Exceptional Dispatches creates an operating cost compensation gap, and Option 1 does not resolve this issue. In Option 1, the CAISO proposes a $24/mWh bid adder that would be added to the otherwise mitigated bids (the maximum of LMP or the DEB) of a non-RA/non-ICPM resource that is Exceptionally Dispatched. A generating resource would have to bid into day-ahead CAISO energy markets in order to be eligible for receiving the $24/mWh supplemental payment.

Option 1 is not likely to be compensatory for an Exceptionally Dispatched generator because a generating resource will have to "chase" the $24/mWh supplemental payment by making day-ahead offers into the day-ahead CAISO energy market, which typically requires the purchase and nomination for timely transportation of gas on a day-ahead basis. This is illustrated in Option 1A in Figure 1, below, in which a 100 MW non-RA/non-ICPM generating resource that observes that SP26 30-minute Dispatchable Energy Requirements[2] are low makes day-ahead offers into CAISO markets in order to be eligible for the $24/mWh supplemental payment.

[1] See Reliant's Exceptional Dispatch Comments, April 4, 2008, at http://www.caiso.com/1fa3/1fa39bf140a00.pdf
[2] CAISO, Exceptional Dispatch: Options for Market Power Mitigation and Supplemental Pricing, 04/14/08 Straw Proposal, page 8 (hereafter "CAISO Straw Proposal").



In Option 1A, after five consecutive days of making offers, the resource is Exceptionally Dispatched on Day 6, receiving a $24/mWh bid adder that is compensatory, when added to the DEB, for *only that day's* operational costs. However, the resource, recognizing that during the previous 5 days it incurred losses on day-ahead gas purchases that turned out not to be needed (resulting in the possible loss on the resale of gas and the loss of unrecoverable transportation costs, such as Firm Access Rights[3], that will be necessary for units served by SoCalGas in *advance* of nomination and scheduling) because it was neither taken in the day-ahead market or Exceptionally Dispatched, the generator does not put in a bid for the remaining days of the month, even though it still observes a shortages in reserves capable of providing SP26 30-minute reserves. However, due to this reserves shortage, this generating resource is Exceptionally Dispatched on days 12, 18, 24 and 30, incurring operating costs losses for each dispatch, culminating in a monthly operating cost loss of $137,050.

Contrast this with Option 1B in Figure 1, in which the same resource does not put a bid for any of the 30 days in the month and does not chase the $24/mWh bid adder. Thus, in a perverse twist, this non-bidding generating resource experiences fewer losses than the resource that chases

[3] See: www.socalgas.com/business/firmaccess/ and the timeline for implementation of Firm Access Rights (scheduled to being in October 1, 2008) at www.socalgas.com/business/firmaccess/docs/timeline.ppt

the $24/mWh bid adder. As is clearly seen, the CAISO Option 1 is not compensatory, and as shown above, it causes a generator to incur more losses. The market and the customer are better served and reliability is enhanced when incentives are in place to encourage – not discourage – greater supply.

2. Option 2 – Relaxed Mitigation Option

Option 2, while an improvement over Option 1, is still not a preferred resolution to the problems created by mitigation of Exceptional Dispatch bids. The premise of Option 2 is that it is not worth the CAISO's effort to try to impose mitigation on non-RA/non-ICPM Exceptionally Dispatched generating units because the CAISO believes that Exceptional Dispatch will be rare and because Exceptional Dispatches of a non-RA/non-ICPM generating units are envisioned to be even less frequent. Thus, for administrative simplicity, in Option 2 the CAISO proposes to relax mitigation for non-RA/non-ICPM units.

To evaluate Option 2, consider a 100 MW (the same type of resources that the CAISO models in its Straw Proposal) non-RA/non-ICPM generating unit that must choose whether to (A) pursue the relaxed mitigation available to non-RA/non-ICPM resources that have submitted a bid into CAISO day-ahead energy markets or (B) whether to not pursue this supplemental payment.

There are two basic options available to such a generating resource. In Option 2A, a generating resource submits a bid each day in the CAISO day-ahead energy market in order to be eligible for the relaxed mitigation thus allowing it a supplemental payment of as much as $341,667 (equal to 1/12th of CAISO's proposed ICPM payment amount for a 100 MW generator)[4] if it was Exceptionally Dispatched. Some generating units might purchase and nominate gas for transportation scheduling prior to the operating day. If generating unit's bid is neither taken in CAISO's day-ahead market nor Exceptionally Dispatched on a day-ahead basis, this unit must then attempt to sell the gas that it purchased on a day-ahead basis, and may at times sell this fuel at a loss[5]. If this generating resource, however, is ultimately Exceptionally Dispatched on an intra-day basis on Day 6, it will have had to repurchase gas on an intra-day basis the gas it previously sold, leading to even higher operating costs. However, because it had a bid in, and assuming that this was the first such Exceptional Dispatch for the 30-day period, in just 8 hours the resource will reach its revenue cap under this "Relaxed Mitigation" supplemental payment option, and it cannot earn any more revenues from supplemental payments. As the CAISO Straw Proposal states:

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[4] *Id.*, at page 15. Note that the Straw Proposal does not use a gas cost or heat rate in their example, but it is easily shown that an 11 heat rate unit operating at a $ 7.25/MMBTU gas price would reach CAISO's proposed ICPM-based relaxed mitigation payment cap of $3.42/KW-month in just over 8 hours if, in this instance of exceptional dispatch, its bid was set at $500/MWH.

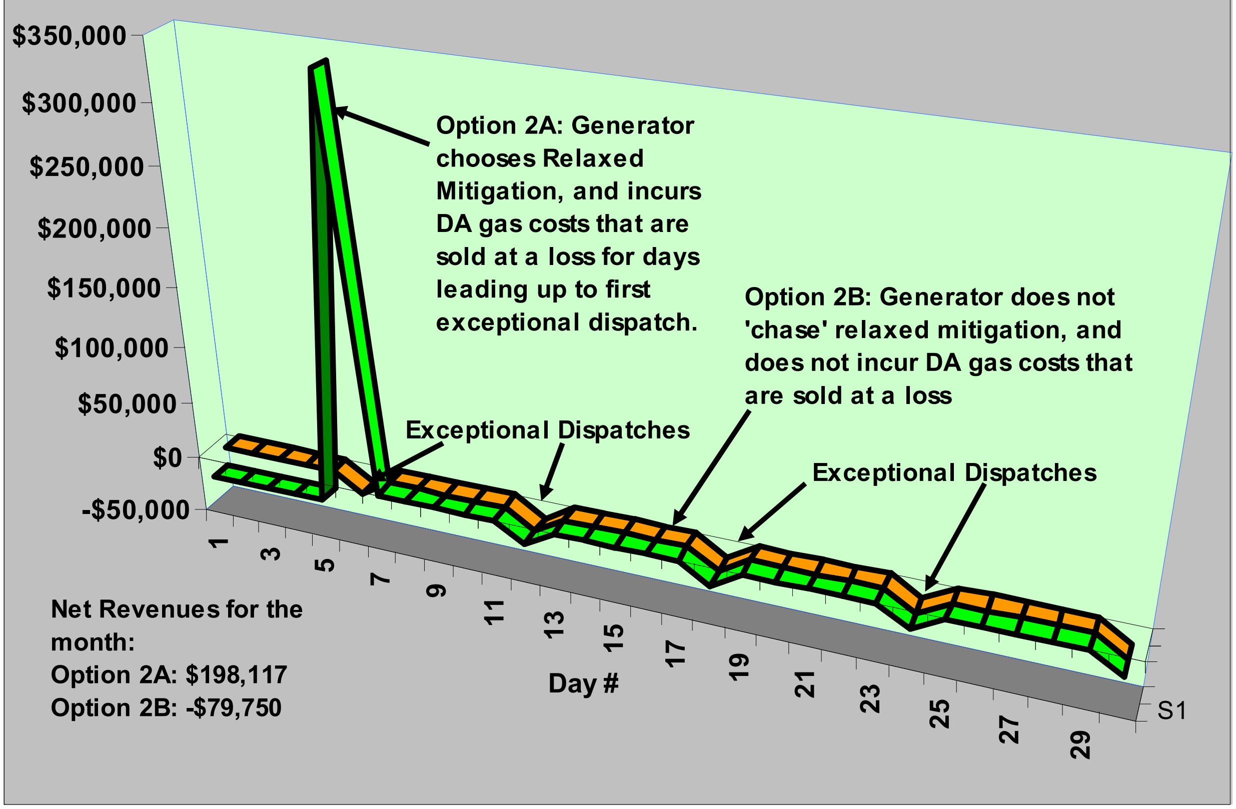
[5] Natural gas prices are a reflection of supply and demand. When the generator is in demand – particularly on short notice – the spot price of gas can rise sharply. When the generator is not needed – again, particularly on short notice – spot gas prices can fall sharply as supply swamps demand. A Gas Price Index is a reflection of the range of reported gas transactions. This range can be quite broad. The lower end or the upper end of the range can be significantly lower or higher, respectively than the resulting Index, which is frequently a rough average of the range. A generator fueled by natural gas can and does define the lower and upper ends of the range when they are either selling or buying late, respectively. Hence, fuel cost compensation that is based merely on a Gas Price Index can result in material losses.

> When a supplier hits the revenue cap, it would be subject subsequently, for the remainder of the 30 day period beginning with the first Exceptional Dispatch, to full mitigation (i.e., higher of LMP or DEB).[6]

In Option 2B, the generator does not 'chase' the relaxed mitigation pricing that it did in Option 2A. While in Option 2B this generator risks being mitigated if there is an Exceptional Dispatch, it also does not purchase day-ahead gas that it is forced to sell at a loss on the intra-day market.

Option 2A and 2B and the associated revenue streams are illustrated in Figure 2:

Figure 2: Daily Revenue for non-RA/non-ICPM 100 mW Generator dispatched for 8 hours every 6th day for 1 month, under CAISO Pricing Option #2.



As shown in Figure 2, inasmuch as net revenues under Option 2A are $198,117, participating in CAISO's proposed Option 2 is preferred to net revenues of -$79,750 from not participating (Option 2B). In addition, CAISO's relaxed mitigation pricing option is preferred over Option 1, discussed above. However, Option 2 does not ameliorate the need for CAISO to reconsider its Exceptional Dispatch mitigation proposal, because neither Option 1 or Option 2 will automatically trigger an ICPM designation for the use of capacity of a non-RA/non-ICPM resource and neither Option 1 or Option 2 addresses operational costs shortfalls incurred when either a RA/ICAPM or a non-RA/non-ICPM resources respond to an Exceptional Dispatch.

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[6] CAISO Straw Proposal at page 15.

In response to Reliant's earlier comments urging CAISO to address operational cost compensation issues, CAISO states:

> [t]he proposal to use the DEB as the mitigated price was discussed and addressed by FERC in the September 21, 2006 Order. FERC stated that the variable cost plus 10% option would be sufficient to cover the various operating costs and "While this option accounts for a supplier's operating cost, we note that a supplier whose bid is mitigated to cost plus ten percent will also have an opportunity to recover its fixed costs during times when it is not the marginal unit that sets the market clearing price in the market." FERC also cited lack of evidence presented for the argument that the 10% adder would be insufficient. The FERC order can be found at: http://caiso.com/1878/1878f9725ef80.pdf with specific reference to paragraph 1045 for the FERC Determination.[7]

However, the Commission order cited by CAISO[8] for support of the DEB and the 10% adder is clearly discussed in a local market power context[9] where a unit may run each day and each day gas costs are similar to the next, on average. Exceptional Dispatches are not likely to fit this pattern. Given that CAISO's Business Process Manual (BPM Market Instruments, Version 6) for DEB gas cost recovery is aimed at local market power mitigation and not Exceptional Dispatch, the Business Process Manuals do not allow for adequate recovery of actual intra-day gas and gas transport costs, Firm Access Rights (soon to be required to be able to schedule intrastate gas into the SoCalGas system) or Local Distribution Company imbalance charges and penalties. The cost recovery provided in the DEB or Business Process Manual may appear adequate for local market power compensation, but it is certainly not compensatory for a generating resource operating under a short-notice forced startup under Exceptional Dispatch.

For example, a verifiable cost that is not addressed either in the Business Process Manuals and CAISO's Exceptional Dispatch proposals are costs associated with an intra-day Exceptional Dispatch that occurs during either day 5, or indeed on any winter day, of the SoCalGas Winter Balancing period which runs from November through March.[10] SoCalGas requires electric generators and other loads to be within 50% balance by the end of each 5-day period during the winter balancing season under normal circumstances. A resource can be out of balance during days 1-4 of the 5-day period, but if on Day 5 it is out of compliance with the balancing limit, the generating resource will be assessed a 150% penalty of the highest index price during the 5-day period.[11] However, if SoCalGas system is short gas supplies SoCalGas imbalance rules become

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[7] CAISO Straw Proposal, page 14, footnote 14.

[8] 116 FERC ¶ 61,274 (2006), accessible at: http://caiso.com/1878/1878f9725ef80.pdf

[9] *Id.* at P 1033.

[10] During non-winter periods the SoCalGas tariff provides for a noncore customer, such as a generator, to operate with a certain amount of daily gas imbalance flexibility. Generally, a generating unit can be out-of-balance during the month but must be within a certain imbalance tolerance by the end of the month. This flexibility may appear generous but it is not cost-free. The cost of imbalance flexibility is quantified and embedded within the rates all noncore customers pay. This operational flexibility has been part of the SoCalGas service structure for decades and is vital for the efficient and low-cost operations of generators in Southern California since no viable alternative to SoCalGas service exists. For information on the distinction between core and noncore natural gas customer classifications, see "Natural Gas and California", http://www.cpuc.ca.gov/PUC/energy/Gas/natgasandCA.htm

[11] See www.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf, Rule No. 30, Tariff Sheet 6:
The Utility requires that customers deliver (using a combination of flowing supply and firm storage withdrawal) at least 50% of burn over a five day period from November through March. **As the Utility's total storage inventory**

tighter. For example, the SoCalGas tariff requires customers to be balanced (flowing supply plus firm storage withdrawal) at a minimum of 70% to 90% of burn on a daily basis, or be exposed to imbalance penalties at 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day.[12]

However, if the CAISO Exceptionally Dispatches a generator on the 5th day of the 5-day period[13], the resource is forced to be out of balance on the SoCalGas system with automatic penalties applicable. The non-compensated costs for, in this example, a 500 MW generator that is Exceptionally Dispatched on day 5 of a SoCalGas winter balancing period is represented in Figure 3:

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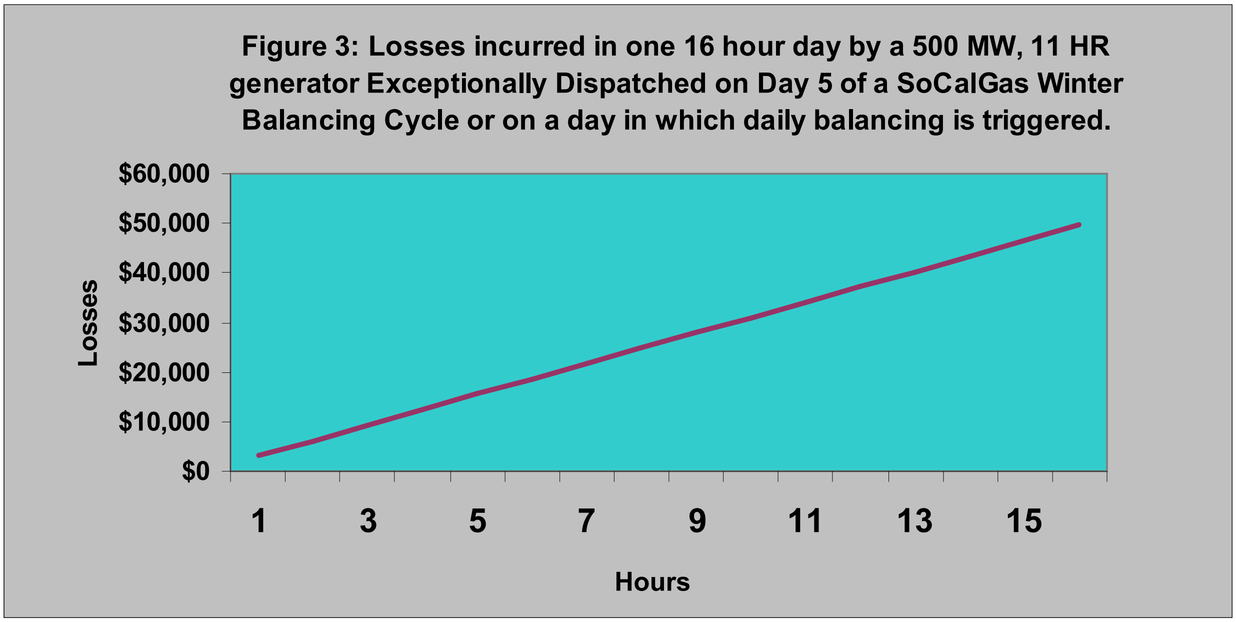
declines through the winter, the delivery requirement becomes daily and increases to 70% or 90% depending on the level of inventory relative to peak day minimums.

> 1. From November 1 through March 31 customers are required to deliver (flowing supply and firm storage withdrawal) at a minimum of 50% of burn over a 5-day period. In other words, for each 5- day period, the Utility will calculate the total burn and the total delivery. If the total delivery is less than 50% of the total burn, a daily balancing standby charge is applied. The daily balancing standby rate is 150% of the highest Southern California Border price during the five day period as published by Natural Gas Intelligence in "NGI's *Daily* Gas Price Index," including authorized franchise fees and uncollectible expenses (F&U) and brokerage fees. Imbalance trading and as-available withdrawals may not be used to offset the delivery minimums. As an additional requirement, retail core and core aggregation will deliver a volume no less than 50% of their allocated firm interstate pipeline rights. (Emphasis supplied).

[12] SoCalGas Rule No. 30, Tariff Sheet 7 and 8, in pertinent part, states:

> 2. **When total inventory declines to the "peak day minimum + 20 Bcf trigger," the minimum daily delivery requirement increases to 70%. Customers are then required to be balanced (flowing supply plus firm storage withdrawal) at a minimum of 70% of burn on a daily basis. The 5-day period no longer applies since the system can no longer provide added flexibility**. The daily balancing standby rate is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees) and is applied to each day's deliveries which are less than the 70% requirement. In this regime as-available storage withdrawal is cut in half. All Hub activity contributing to the underdelivery situation (i.e., Hub deliveries greater than Hub receipts) is suspended.
>
> 3. When total inventories decline to the "peak day minimum + 5 Bcf trigger," the minimum daily delivery requirement increases to 90%. **Customers are required to be balanced (flowing supply plus firm storage withdrawal) at a minimum of 90% of burn on a daily basis. Similar to the 70% regime the 5 day period no longer applies**. **The daily balancing standby rate is charged daily and is 150% of the highest Southern (continued) California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees). In this regime there are no as-available storage withdrawals.** (Emphasis supplied). *Id.*, at sheets 7-8.

[13] Example five-day periods are: Nov. 1 through Nov. 5, Nov. 6 through Nov. 10, Nov. 11 through Nov. 15 and so on. November with 30 days has six 5-day periods. December, January and March with 31 days have a 6-day period at the end of the month. February has a shortened 3 or 4-day period at the end of the month. *Id.*, at sheet 6.



Given that the CAISO's Straw Proposal does not adequately address this situation, Reliant offers "Option 3". In Option 3, both a) and b), as seen below, would apply to Exceptionally Dispatched generation resources:

a). A single Exceptional Dispatch would "trigger" the resource for ICPM designation of capacity service and entitlement to compensation based on the target ICPM annual capacity price for a term capacity payment as ultimately determined by FERC in the ICPM proceeding; and

b). Both RA/ICPM and non-RA/non-ICPM resources would be eligible for compensation for all actual, verifiable gas costs (gas commodity costs, any Local Distribution Company penalties, gas transportation costs) incurred to respond to the Exceptional Dispatch. These gas costs would include SoCalGas Winter balancing period charges and penalties, low OFO charges and intra-day gas costs that are above day-ahead gas costs that the DEB and the pertinent Business Process Manual is based upon.

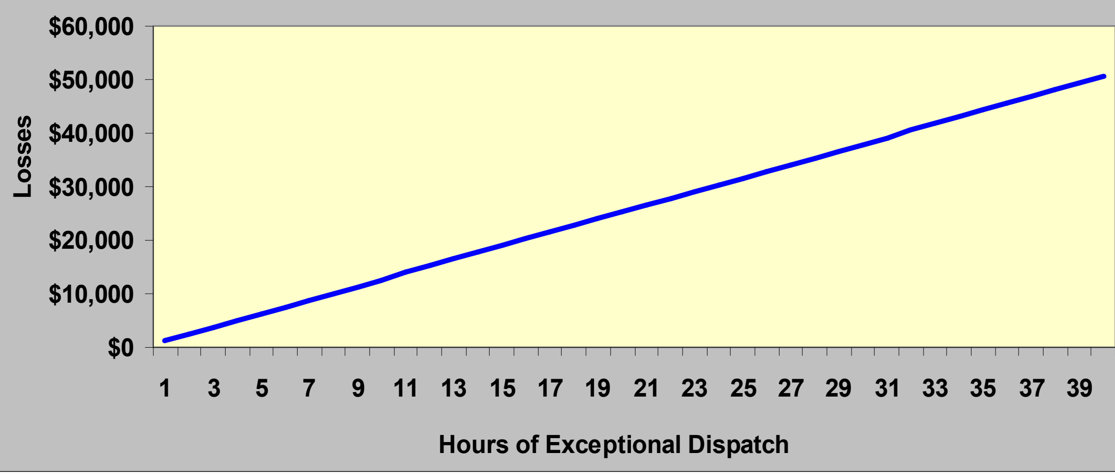
3. Effect of the Exceptional Dispatch options on incentive to accept or decline ICPM designation

An Exceptionally Dispatched generating resource without an RA contract or that has not been procured under ICPM would not logically turn down an ICPM designation in order to be eligible to receive one of the two supplemental payment options. For one, payments for ICPM procurement are payments that should be for a term reliability service for which the payment should be defined (i.e., as available capacity to provide reliability services), consistent and knowable. Conversely, revenues from one of the two supplemental payments mechanisms would be limited to instances of Exceptional Dispatch, which are far from certain, and are, in any event, capped at the ICPM payment for Option 2.

4. Types of Exceptional Dispatch that should or should not be eligible for supplemental payments or subject to relaxed mitigation

The CAISO's use of the phrase "relaxed mitigation" in describing its revised proposal is a misnomer. What is being "relaxed" is the rate at which a generating resource might incur losses when responding to an Exceptional Dispatch call. Indeed, what is being 'mitigated' by the CAISO when it imposes Exceptional Dispatch mitigation is not market power, but rather a generating resources' appropriately bid and duly formed operating costs. As shown in Figure 3, assuming $7.25/MMBTU day-ahead gas, a 25% premium of intra-day gas costs over day-ahead indices used in the DEB, and a 100 MW generating resource Exceptionally Dispatched for 40 hours will lose more than $50,000 responding to the CAISO instructions.[14]

Figure 4: Losses incurred by 100 MW, 11 HR generator with proposed ED mitigation and 10% DEB adder. Assumes normal gas market circumstances (i.e., no OFO or Winter Balancing)



What is being accomplished with "relaxation" of this mitigation is nothing more than reducing the losses that some generating resources might incur in responding to an Exceptional Dispatch. Thus, Reliant recommends that all instances of Exceptional Dispatch should trigger ICPM procurement for a term capacity payment as ultimately determined by FERC in the ICPM proceeding; and if the resource is not already an RA or ICPM resource, and be eligible, as discussed above in response to question 2, for compensation for actual, verifiable gas costs associated with an Exceptional Dispatch that are not captured in the DEB, or in CAISO's Business Process Manual for Market Instruments, Version 6, pages C-1 to C-3.[15] In particular, all types of Exceptional Dispatch should be eligible for compensation of Local Distribution Company penalties, when as discussed above and illustrated in Figure 3, an Exceptional Dispatch occurs on Day 5 of a SoCalGas Winter balancing period or when SoCalGas, as described in Footnote 11, *supra*, requires daily balancing, or as illustrated in Figure 4, it is simply the case that intra-day costs are materially above day-ahead gas costs.

[14] These results are scalable, i.e., a 500 MW resource would lose over $500,000 responding to 40 hours of Exceptional Dispatches.
[15] See: http://www.caiso.com/1c97/1c97e98846b40.pdf

5. Requirement to bid into the CAISO markets in order to be eligible to receive the Bid Adder option

Reliant has no comment on this question at this time.

6. General comments

Exceptional Dispatches for which the CAISO will impose mitigation, such as reliability requirements related to non-competitive transmission constraints, ramping units up from minimum operating levels to minimum dispatchable levels in order to protect against reliability contingencies that are not directly incorporated or sufficiently met by the MRTU software; other special unit-specific operating or environmental constraints not incorporated in the MRTU model[16] are not instances where market power may be categorically exercised (as implied by the CAISO in its proposal to categorically exercise market power) because the CAISO may well have a range of resources to choose from.

As indicated in the CAISO stakeholder meeting on April 15, 2008, the CAISO has stated that it will choose the cheaper RA resource that does not have bid adders when faced with the need to make an Exceptional Dispatch. This statement is an implicit admission that competition from suppliers to supply Exceptional Dispatch is, in some instances, envisioned by the CAISO. Given a pool of generators to choose from, CAISO could conduct a manual auction to secure needed resources. Alternatively, if the CAISO does not have a pool of resources to choose from, the CAISO could impose on generators that it Exceptionally Dispatches an *ex post* market power review if the bid price does not match market circumstances and exigencies. Either approach this would be clearly less distortive than categorical mitigation of bids.

[16] CAISO Straw Proposal, at page 11.