Attachment F – DMM Comments

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

California Independent System Operator Corporation

May 9, 2016

Comments on Final Aliso Canyon Gas-Electric Coordination Proposal

Department of Market Monitoring

May 6, 2016

The Department of Market Monitoring (DMM) has worked closely with the ISO in developing the ISO's Final Proposal for Aliso Canyon Gas-Electric Coordination. DMM supports the key elements of the ISO's final proposal, which was modified and expanded over the course of the stakeholder process based on input from DMM. DMM provided input through written comments, as well as by directly working with ISO staff.[1] Section 1 of these comments summarizes DMM's recommendations and analysis of key elements of the ISO proposal. Section 2 provides a more detailed analysis performed by DMM to assess and recommend the 75 percent adder being proposed for gas price indices used to calculate bid caps for commitment costs for resources in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E) service areas (collectively referred to as the SoCal gas system in these comments).

1. Key provisions of proposal

1.1 Increase in gas prices used for commitment costs

Background

Currently, start up and minimum load bids in the real-time market for most gas-fired capacity in the ISO system are capped at 125 percent of estimated costs. These cost-based caps are based on an index of gas prices for gas purchases in the market for next day delivery. Thus, these prices may not reflect actual prices for any gas that is purchases in the same day market as a result of resources being committed in the real-time energy market. In addition, generators cannot submit bids in excess of these cost-based caps as a means of managing how units are committed or dispatched in the real-time market in order to avoid gas imbalances and potential imbalance penalties or charges.

Because of the special gas balancing provisions and restrictions being implemented in the SoCal gas system, the ISO is proposing to increase the gas index used in calculating these commitment cost bid caps in the real-time market for resources in these areas. Under the ISO's proposal, the level by which the current gas price indices for the SoCal gas system would be increased is based on the following objectives:

- Enable the ISO market to dispatch generators served by the SoCal gas system only for local electricity needs and not for system electricity needs that can be met by other resources;
- Account for any systematic premium for gas procured in the same day market relative to the next day delivery gas prices used to calculate bid caps; and

[1] *Comments on Aliso Canyon Gas-Electric Coordination Straw Proposal*, Department of Market Monitoring, April 22, 2016, http://www.caiso.com/Documents/DMMComments_AlisoCanyonGasElectricCoordinationStrawProposal.pdf.

Comments on Aliso Canyon Gas-Electric Coordination Draft Final Proposal, Department of Market Monitoring, April 29, 2016, http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationDraftFinalProposal.pdf

- Improve generators' ability to manage gas company requirements on the constrained systems to limit differences between individual generator's gas schedules and usage (i.e., gas balancing requirements).

Analysis by DMM indicates that prices for gas in the same day market in the SoCal gas area have not, on average, historically exceeded prices in the market for next day delivery and that same day prices have significantly exceeded next day prices on a very small portion of days.[2] The extent to which the additional gas restrictions created by Aliso Canyon may increase same day prices relative to next day prices is uncertain and cannot be estimated at this time. Therefore, DMM has recommended that the initial increase in gas price indices used for commitment cost bids be based on a level designed to enable the ISO market to dispatch generators on the SoCal gas system only for local electricity needs and not system electricity needs that can be met by other resources.

Units are committed (or kept on-line for additional hours) in the real-time market by the market optimization based on a combination of three-part bids: start-up, minimum load and energy.[3] Generators can affect unit commitment decisions by submitting energy bids up to the $1,000/MW energy bid cap. To avoid additional commitment and dispatch of resources in the real-time market within a gas constrained area for system needs that could be met by other resources, it is only necessary that total costs for resources in the gas constrained area (based on three part bids) be marginally higher than total costs for resources in the non-gas constrained areas.

To help determine how to set the initial value by which gas prices may be increased under this framework to limit real-time unit commitments in the SoCal gas system for local area needs, DMM assessed the degree that commitment cost bid caps for these resources might need to be increased so that most of this gas-fired capacity is slightly higher in the economic merit order than other units that could be committed to meet system needs. Based on this analysis, DMM recommended that an increase in the gas indices for units in the SoCal gas system of 75 percent appears sufficient to achieve this objective.

Figure 1-1 shows the economic merit of gas-fired capacity within the SoCal gas system relative to resources within the rest of the ISO system based on minimum load cost caps with current gas price indices. Figure 1-2 shows how this merit order changes with the initial 75 percent increase in the gas cost indices being proposed for units in the SoCal gas system. As illustrated by these results, the proposed 75 percent adder ensures that most capacity in the SoCal gas area will have a higher minimum load bid cost cap than gas-fired capacity located elsewhere in the ISO system. Detailed results of this analysis are provided in Section 2 of these comments.

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[2] *Report on natural gas price volatility at western trading hubs,* Department of Market Monitoring, May 14, 2015: http://www.caiso.com/Documents/DMMReport-GasPriceAnalysis.pdf

Report on natural gas price volatility, Department of Market Monitoring, September 21, 2015: http://www.caiso.com/Documents/DMMReport-gas_price_analysis_september2015.pdf

[3] Once a unit is on-line start-up bids are treated as a "sunk" cost.

Figure 1-1. Minimum load proxy cost caps (No SoCal gas adder)
All gas-fired resources

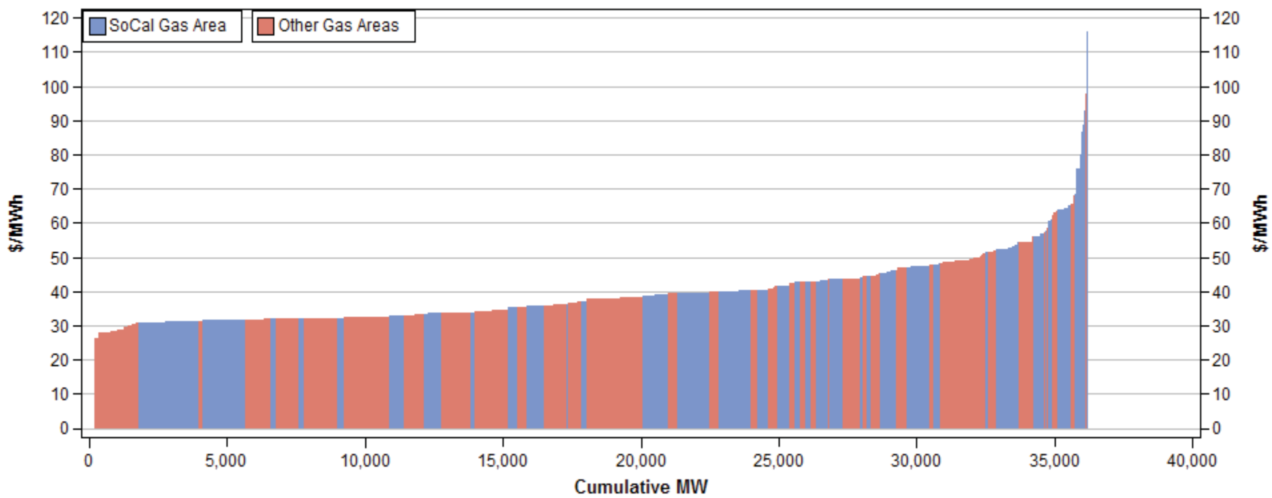
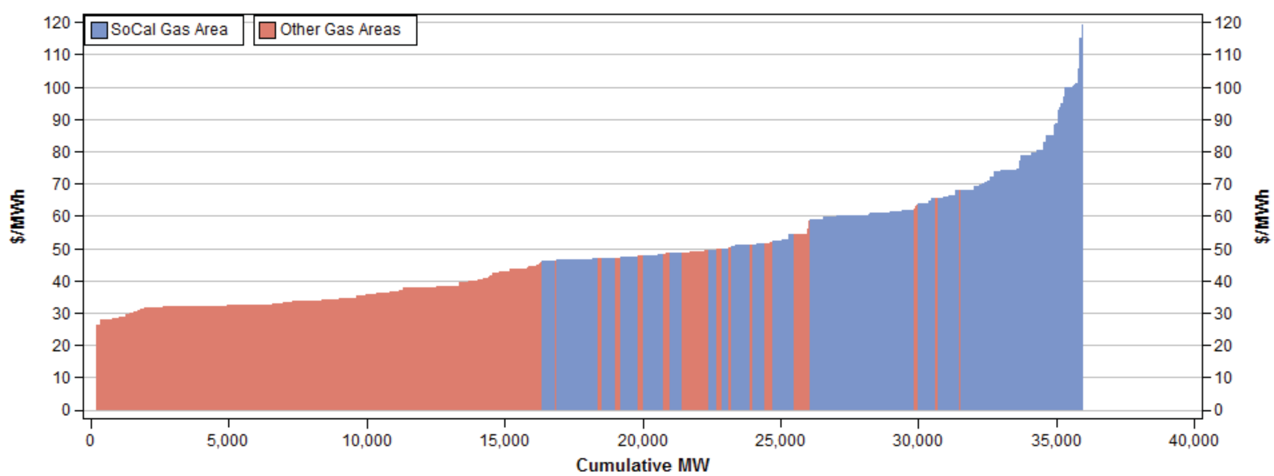


Figure 1-2. Minimum load proxy cost caps (75 percent SoCal gas adder)
All gas-fired resources



DMM strongly recommends that the ISO should have the flexibility necessary to adjust the gas price level used in calculating commitment cost bids caps based on observed market conditions and outcomes. However, DMM does not believe that the ISO should set the maximum value of the commitment cost cap up to the cost of an operational flow order penalty. Based on current gas prices, when combined with the 25 percent headroom already applied to commitment costs, this would represent an increase of over 300 percent in the gas prices used in calculating commitment cost bid caps to 4 times the gas price index value.[4] This is discussed in Section 1.2 below.

[4] The ISO's cap is proposed to be $2.50 plus two times the next day gas index. Prevailing natural gas prices at the SoCal Citygate are currently around $2.10/MMBtu. This results in an adder of $2.50 + $2.10 *2 = $6.70/MMBtu. Combined with

1.2 Basing commitment cost caps on gas penalties

In its filing, the ISO seeks to have the authority to set the gas indices used in calculating commitment costs up to a level that could effectively be more than enough to cover potential operational flow order penalties.[5]

As previously noted, DMM is not supportive of increasing gas prices used in calculating commitment cost bid caps to a level that could cover potential operational flow order penalties. This would simply remove the incentive for generators to avoid penalties and be likely to result in much higher bid cost recovery payments – without decreasing the amount of generation (and gas) actually needed to meet local needs within non-competitive areas.

Setting commitment cost caps to cover potential gas imbalance penalty prices essentially represents a worst case scenario and could reduce the incentive to avoid such penalties. DMM also notes that under the ISO's proposal, any commitment costs that are not recovered through the market or through bid cost recovery should be recoverable as part of the ISO's proposal on after-the-fact bid cost recovery. While DMM agrees that cost-based bid caps should be set high enough to result in efficient unit commitment and dispatch – and recover full cost under most cases – these caps also need to be set at levels that protect against excessive costs for consumers.

DMM has recommended that the ISO explicitly address whether any penalties should be eligible for inclusion in cost recovery. DMM supports explicit provisions on allowing recovery of gas penalties which are incurred as a direct result of (1) an ISO real-time commitment, (2) exceptional dispatch or (3) real-time energy dispatch when a unit was subject to bid mitigation. This approach provides more protection against local market power, potential gaming of commitment costs, and excessive costs to consumers in excess of actual incurred gas procurement costs.

1.3 Increase in gas prices used for Default Energy Bids

While commitment cost bids submitted by generators are currently capped at 125 percent of estimated costs based on the price of gas in the next day market, generators can submit energy bids up to the $1,000/MW energy bid cap. These energy bids are only subject to mitigation in the event that congestion occurs and the supply that can relieve this congestion is deemed uncompetitive under the

the current adder of 125 percent this would result in a total fuel cost of ($6.70/MMBtu * 1.25) = $8.375/MMBtu. This is an increase of about 300 percent of a $2.10/MMBtu gas price.

[5] The ISO has proposed a cap that is similar to a stage 5 operational flow order penalty on the SoCal gas systems. For example, assume gas prices of $2.50/MMBtu. The ISO's proposed cap increase would be $2.50 plus $2.50/MMBtu times two which would be $7.50/MMBtu. After factoring in the current 125 adder on proxy costs, the total fuel cost adder would be $7.50 * 1.25 = $9.375/MMBtu. We understand that the stage 5 operational flow order penalty in the SoCalGas system is $2.50 plus the daily balancing standby rate, which is equivalent to the InterContinental Exchange (ICE) Day-Ahead Index (including FF&U and brokerage fee) for the SoCal-Citygate, rounded up to the next whole dollar (see Sheet 12 https://www.socalgas.com/regulatory/tariffs/tm2/pdf/4822.pdf). Thus, if the gas price was $2.50/MMBtu, the stage 5 operational flow order penalty would be $2.50 plus $2.50 rounded up to the nearest dollar, which would be about $8/MMBtu ($5 + $3). Thus, in this example, the ISO's total fuel cost cap would be $9.375/MMBtu, which would be higher than the emergency flow order penalty of about $8/MMBtu plus the including FF&U and brokerage fee.

ISO local market power mitigation procedures.[6] When subject to mitigation, market bids submitted by generators are capped at the higher of competitive market prices or Default Energy Bids (DEBs) based on estimated marginal costs.

Like commitment cost bids caps, Default Energy Bids for the real-time market must be calculated in advance based on the price of gas in the next day market. However, unlike commitment costs, energy bids submitted by participants are only subject to mitigation and can only be dispatched based on a mitigated bid if they are needed to meet a local need within an uncompetitive area. Since units can only be dispatched based on Default Energy Bids for local needs, DMM believes it is unnecessary to inflate Default Energy Bids in the SoCal gas system to avoid having units in this area dispatched for system rather than local needs. Increasing Default Energy Bids above actual cost in this situation is likely to simply raise prices, without decreasing the amount of additional generation (and gas) needed from suppliers within the uncompetitive area to relieve congestion and ensure local reliability.

In addition, it is important to note that – unlike commitment costs—energy bids set the market price for the entire market. Generators would earn this higher price for all sales, but may incur an actual penalty only on the incremental amount of gas burned in excess of the tolerance band incorporated in the SoCal gas operational flow order or daily imbalance provisions. In addition, higher prices in the real-time market can raise prices in the day-ahead market, especially if virtual bidding is allowed.

For these reasons, DMM recommended that a different price index and criteria be used to determine any increase in Default Energy Bids than are used for commitment costs. Specifically, DMM suggests that it is only appropriate to increase the gas price index for Default Energy Bids to (1) reflect any systematic premium observed in same day gas prices relative to next day prices used to calculated Default Energy Bids, or (2) allow generators with units in the SoCal gas region to manage the merit order of resources that can meet local needs in the SoCal gas area to avoid potential penalties.

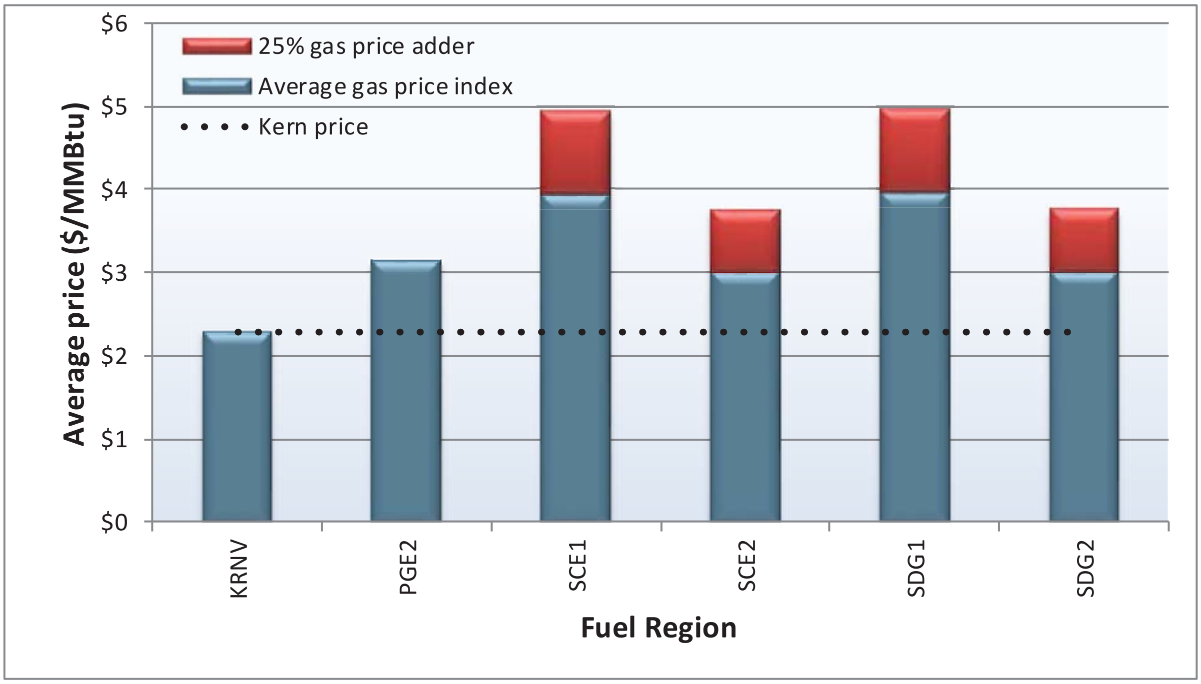
As noted in Section 1.1, the extent to which the additional gas restrictions created by Aliso Canyon may increase same day prices relative to next day prices is uncertain and cannot be estimated at this time. Therefore, DMM has recommended that the initial increase in gas price indices used for Default Energy Bids be based on a level that will allow generators with units in the SoCal gas region to manage the merit order of resources that can meet local needs in the SoCal gas area to avoid potential penalties. In addition, DMM also noted that the gas index used in calculating Default Energy Bids in the SoCal gas area would need to be inflated by a much lower amount than the gas index used in calculating commitment costs to achieve this objective.

Based on this recommendation, the ISO's final proposal was modified so that gas prices used in calculating Default Energy Bids for units in the SoCal gas area would be increased by a lower level than ISO has proposed for commitment cost bids. The ISO is proposing to initially increase gas prices used to calculate Default Energy Bids for these units by 25 percent, with a maximum increase of 100 percent.

[6] When bids are subject to mitigation, bids are frequently not mitigated down to cost-based Default Energy Bids, but are instead lowered only to a competitive market price that is usually greater than the cost-based Default Energy Bids of many units.

DMM believes the 25 percent increase proposed by the ISO is sufficient to achieve the goals of this increase. Figure 1-3 shows average gas prices from January 2015 to May 2016 for the various regions in the ISO used in calculating commitment cost caps and Default Energy Bids. These prices include gas commodity prices plus application of distribution charges for the applicable gas region.

Figure 1-3. Comparison of average gas price indices (January 2015 – May 2016)



As shown in Figure 1-3, gas prices for the Kern River pipeline (KRNV), which serves some generators in Southern California, are significantly lower than gas price indices for the areas served by the SoCal gas system (SCE1, SCE2, SDGE1, SDGE2). Over 1,600 MW of highly efficiency combined cycle gas-fired capacity is served by the Kern River pipeline south of Path 26 in SP15. The lower gas prices in this area – combined with the additional 25 percent adder proposed for units in the SoCal gas areas – should ensure that when congestion occurs in the north-to-south direction on Path 26, gas-fired capacity in the Kern area that is available in the real-time market should be available for dispatch to meet any real-time demand in the Southern California area outside of the gas-constrained areas in the SoCal gas system. At the same time, this provides further assurance that that the 25 percent adder proposed for units in the SoCal gas system will cause units in this gas-constrained area to be dispatched for additional energy in the real-time only when needed to meet demand within these areas.

1.4 Cost adders based on same day gas prices

Analysis by DMM indicates that historically the same day market in the SoCal gas area is very thin and that prices do not tend to exceed next day prices on average – and have significantly exceeded next day prices on a very small portion of days.[7] DMM believes it is uncertain whether the additional gas restrictions created by Aliso Canyon will change this historical trend and the degree to which available data on same day trades will provide a basis for determining if same day prices are systematically higher than next day prices. However, to the extent that there is an actual market for same day gas (for which reliable price data are available), DMM agrees Default Energy Bids should reflect this price.

Following implementation of new gas balancing rules in the SoCal gas area, DMM is prepared to work with the ISO to assess available data on same day gas trades to determine if same day prices are systematically higher than next day prices. Based on this analysis, DMM is also prepared to work with the ISO to determine how this might warrant increasing gas price adders used in determining commitment cost and Default Energy Bids.

1.5 Improved day-ahead gas price index

The ISO proposes to improve the day-ahead gas price index used in the day-ahead market. Currently, the ISO uses an index developed from a set of price indices from the market for next day delivery. However, due to the timing of the release of these indices, the ISO uses prices from delivery on the prior day. The ISO is proposing tariff revisions so that prices used in the day-ahead market would be based on an index calculated by the ISO based on data from the Intercontinental Exchange (ICE) that are available in the morning prior to the start of the day-ahead market. This will eliminate the one-day lag in the next day market gas prices currently used for the ISO's day-ahead market.

The ISO's proposal indicates the index calculated by the ISO will be a volume weighted average price consistent with the methodology that ICE uses to calculate its own gas index. During the stakeholder process, the ISO indicated this enhancement would only be implemented once it was "completely automated." DMM expressed concern that complete automation of this process may not be completed in the time frame in which the ISO's proposal is intended to be implemented.

Consequently, DMM has recommended that the ISO maintain flexibility to use an estimate of next day price based on available ICE data even if full automation or the calculation of a weighted average price is not in place. For instance, if prices appear to be about 20 percent higher and the ISO can reasonably estimate this 20 percent increase based on ICE data, the ISO should have authority to increase the gas prices used in the day-ahead market using its best estimate based on available gas market price data.[8]

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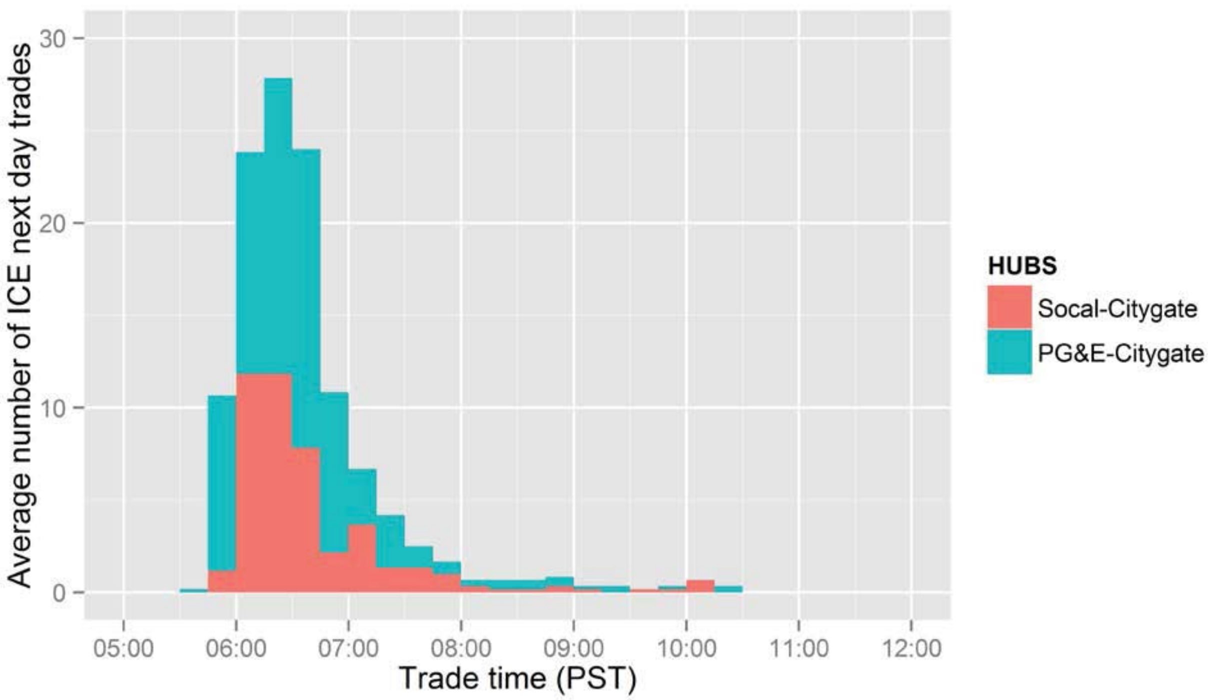
[7] *Report on natural gas price volatility at western trading hubs,* Department of Market Monitoring, May 14, 2015: http://www.caiso.com/Documents/DMMReport-GasPriceAnalysis.pdf

Report on natural gas price volatility, Department of Market Monitoring, September 21, 2015: http://www.caiso.com/Documents/DMMReport-gas_price_analysis_september2015.pdf

[8] DMM notes that this approach would appear to be at least as accurate and involve even less discretionary judgement as approaches used by some other ISOs, under which generators submit their own cost-based bids, subject to review by the ISO. When reviewing such bids, ISOs would need to routinely rely on rough comparisons

Figure 1-4 provides an example of the timing and volume of trades on ICE for the gas market for next day delivery during a typical period (flow dates April 1-8, 2016). As shown in Figure 1-4, the bulk of trades on ICE for the gas market for next day delivery are concluded by 8 a.m. PST. Thus, it appears that when there is a significant change in prices from the prior day in next day gas prices, even a reasonable approximation of the final ICE index could be developed that is much more accurate than the gas price indices for the prior day that would otherwise be used.

Figure 1-4. Timing and volume of next day ICE gas trades (April 1 - 8, 2016)



of bid prices to gas market prices during the gas trading period, and these accepted bid prices would be used in the market.

1.6 Rebidding of commitment costs in the real-time market

The ISO proposes to allow generators to re-bid commitment costs in the real-time market. This change would allow generators to utilize the higher caps on commitment costs being allowed in the real-time market. Allowing generators to change commitment cost bids throughout the operating day in real time will create significant new opportunities for generators with intertemporal constraints (such as minimum up and minimum down times) to exploit bid cost recovery. This could result in generators receiving payments in excess of the generators' actual commitment costs. This potential for exploiting bid cost recovery will be further exacerbated by the ISO's proposal to increase the commitment cost caps above 125 percent of proxy costs.

Therefore, DMM has encouraged the ISO to develop real-time commitment cost bidding guidelines that strike a balance between allowing flexibility for generators to bid costs they would expect to incur if dispatched and safeguarding against unreasonable bid cost recovery uplift payments.

The ISO has proposed versions of the following real-time commitment cost bidding guidelines:

1) No changing of day-ahead commitment costs in real-time for trading hours in which the generator has a day-ahead award; and
2) No changing of real-time commitment costs for the duration of the minimum up time of a unit (or configuration) after the unit (or configuration) has been committed in real time.

DMM supports these rules. However, market participants and FERC should be aware that the second rule above is unlikely to be able to be automatically enforced by the ISO's software. Therefore, market participants will be *physically* able to adjust a generator (or configuration) commitment cost in real-time during the generator's (or configuration's) minimum up time. The adjusted commitment cost will be used by the optimization and in settlements. However, DMM understands that it will be considered to be a tariff violation for the scheduling coordinator to execute this change to the generator's real-time commitment cost.

DMM will be closely scrutinizing changes to commitment costs in real time that coincide with bid cost recovery payments. However, DMM notes there are inherent difficulties and shortcomings in relying on behavioral monitoring to differentiate between (1) legitimate uses of real-time commitment cost bidding flexibility; and (2) potential exploitative uses of real-time commitment cost flexibility to inflate bid cost recovery payments. In this case, DMM supports relying on monitoring of real-time market bidding behavior during the interim period – as opposed to more restrictive rules -– in order to allow the potential benefits of re-bidding of higher real-time commitment costs that include gas cost adders.

DMM also notes the potential for behavior designed to trigger excessive bid cost recovery due to the provision allowing re-bidding of commitment costs in real time would be exacerbated if the ISO inflated the gas index used to calculate commitment cost caps to higher levels (e.g. significantly more than the 75 percent level incorporated in the ISO proposal). This would be of particular concern to DMM if the

ISO inflated this gas index to a much higher level based on potential penalties for excessive gas imbalances.

1.7 Authority to deem constraints uncompetitive based on gas limitations

The ISO's current local market power mitigation procedures are triggered based on an automated assessment of the structural competitiveness of each constraint on which congestion is projected to occur. However, this procedure will not incorporate the impact of special gas usage constraints being proposed on restricting the actual amount of gas-fired generation available in Southern California to relieve congestion and meet local needs. As a result, constraints such as Path 26 could be deemed competitive when in fact the amount of supply in Southern California that can be dispatched to relieve congestion on these constraints is more restricted and uncompetitive. Thus, DMM has recommended that the ISO seek special tariff authority to deem selected constraints uncompetitive based on a determination that actual supply conditions may be uncompetitive due to special gas usage constraints being imposed on gas-fired units in the SoCal gas system.

Background

The ISO's local market power mitigation provisions involve several steps. First, when congestion is projected to occur on a constraint, the constraint is designated as either *competitive* or *non-competitive* using the *dynamic competitive path assessment* (DCPA). If a constraint that is projected to be congested is found to be structurally non-competitive based on this automated test, then resources that can relieve congestion on this constraint are subjected to potential bid mitigation.

The DCPA measures the competitiveness of each constraint using a residual supply index (RSI) based on supply and demand of counter-flow from internal resources that can relieve congestion on each binding constraint. The RSI is the ratio of competitive supply of counter-flow compared to total demand for counter-flow for the constraint. When this ratio is greater than 1.0, the constraint is considered to be competitive. If the RSI is less than 1.0, the constraint is considered non-competitive and can trigger bid mitigation.

The automated DCPA procedure incorporated in the ISO's market software does not incorporate the impact of special gas usage constraints being proposed on restricting the actual amount of gas-fired generation available in Southern California. This gas usage constraint will cause the amount of generation capacity available to relieve congestion and meet local needs in Southern California to be lower than the amount included in the DCPA. As a result, constraints such as Path 26 could be deemed competitive when in fact the amount of supply in Southern California that can be dispatched to relieve congestion on these constraints is more restricted and uncompetitive.

Analysis

To illustrate the ISO's potential need to deem some paths non-competitive due to the gas usage constraint, DMM has analyzed the results of the DCPA for Path 26 in the 15-minute market. Figure 1-5 shows a histogram of how frequently the RSI fell within different ranges when congestion has been projected to occur in the north-to-south direction on Path 26 over the two year period from May 2014 to May 2016. For example, the RSI was between 1.0 and 1.03 during over 19 percent of the 15-minute intervals during which congestion was projected to occur during this period.

As illustrated in Figure 1-5, when Path 26 has been congested in the north-to-south direction, this constraint has usually been deemed structurally competitive based on an RSI greater than 1.0. However, during many of these intervals, the RSI has been relatively close to the 1.0 threshold below which the constraint would be deemed noncompetitive. In other words, the RSI is often above 1 but usually not very far above 1.0. This indicates that when the gas usage constraint being proposed is binding and reducing the actual real available supply of competitive counter-flow, results of the automated DCPA may indicate the constraint is competitive when it may in fact be structurally non-competitive.

These findings are further illustrated in Figure 1-6. This figure shows the amount by which residual supply of competitive counter flow exceeded the demand for counter-flow for the intervals when congestion was projected to occur in the north-to-south direction on Path 26 and this constraint was deemed structurally competitive during this two year period. This highlights the sensitivity of the DCPA results from any overestimation of the actual supply of available counter-flow due to the gas usage constraint.

For example, during about 43 percent of the intervals in which Path 26 was projected to be binding, the competitive supply of counter-flow exceeded demand by less than 200 MW. If the gas usage constraint were in place in those intervals and decreased the competitive supply of 15 minute counter-flow by 200 MW or more, the constraint would be structurally non-competitive. However, since the DCPA cannot account for the impact of the gas usage constraint, the automated DCPA results would indicate the constraint is structurally competitive and bid mitigation would not be triggered. This could lead to unmitigated high bids setting prices.

Both of these analyses show that Path 26, like other constraints in the ISO system, is often close to the threshold between competitive and non-competitive. The impact of the gas usage constraint may be enough to change the competitive status of constraints at times, but cannot be incorporated into the DCPA. While this analysis centers on Path 26, the gas usage constraint may cause the DCPA to overestimate the competitiveness of a variety of constraints within Southern California.

At this time, the impact of the gas usage constraint on the DCPA cannot be determined or estimated. This can only be assessed based on actual system conditions once the constraint is in place. Because of this, DMM is recommending that the ISO have the authority to deem constraints within Southern California for which the RSI is affected by the gas usage constraint to be non-competitive during some days or hours. The type of analysis provided in this section provides an example of how the ISO may assess whether to deem a constraint non-competitive.

Figure 1-5. Residual supply index for Path 26 (north-to-south) during congested 15-mintue intervals (May 2014 to May 2016)

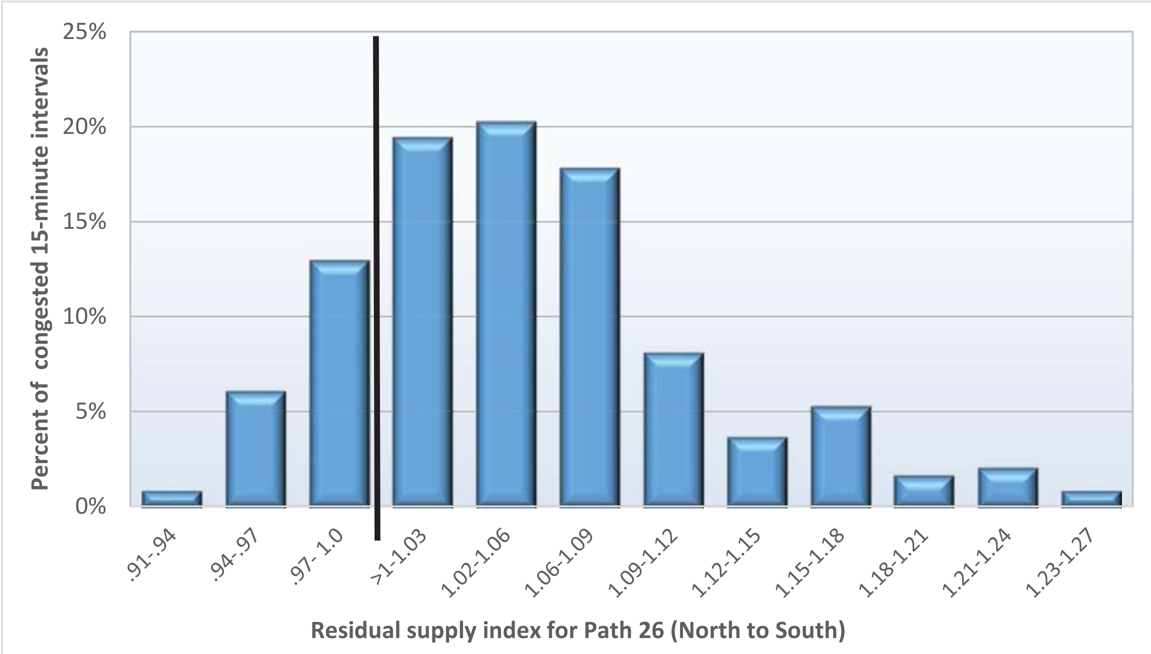
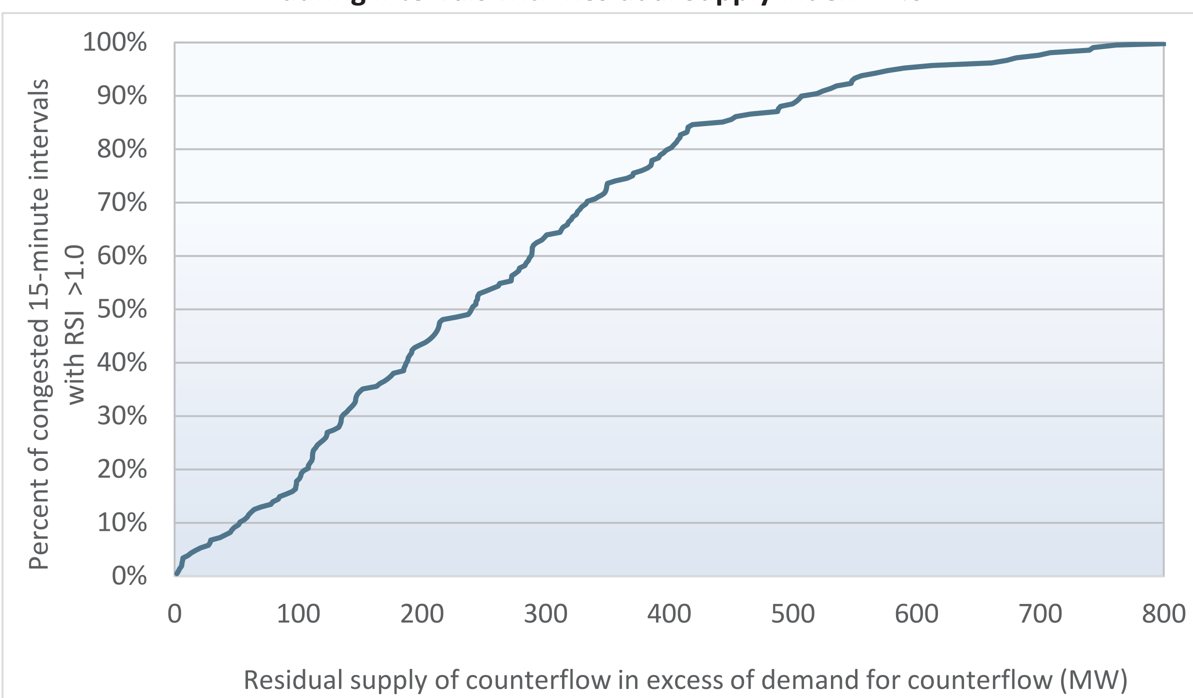


Figure 1-6. Sensitivity of residual supply index results to supply of counter flow on Path 26 during intervals with Residual Supply Index > 1.0



1.8 Expand authority to limit virtual bidding based on market impacts

The ISO tariff currently outlines the reasons for suspension of convergence bidding related to System Reliability or grid operations "if such activities contribute to threatened or imminent reliability conditions."[9]

As a general principle, DMM believes that when modeling, structural or market rule differences exist between the day-ahead and real-time markets, virtual bidding can often be profitable but provide little or no benefits – and can actually decrease market efficiency, make it more difficult to manage system reliability and result in inequitable market outcomes. Consequently, DMM strongly recommends the ISO modify its tariff to clarify its authority to suspend or limit virtual bidding – including at specific locations or regions – to prevent or protect against potential detrimental or inequitable market impacts.

One example of a virtual bidding strategy that could reduce market efficiency is related to the ISO's proposal to reserve transfer capability into a gas-constrained region in the day-ahead market. When the ISO releases the reserved transfer capability in real time, the day-ahead congestion price of the transfer path is likely to be higher than the real-time congestion price. Virtual supply placed downstream of the path and virtual demand placed upstream of the path could expect to profit from this difference in the path's congestion price.

However, downstream virtual supply and upstream virtual demand would reduce the day-ahead schedules of downstream gas-fired generation and increase the day-ahead schedules of upstream generation. The impact of such virtual schedules on day-ahead generation schedules is the opposite of the intended effects of reserving transfer capability. Such virtual schedules would therefore undermine the effectiveness of this reliability tool.

Although this virtual supply may cause more physical capacity within the SoCal system to be scheduled in the residual unit commitment (RUC) process, this is a much less efficient process for scheduling of electric supply. Additional capacity can be committed by the RUC process based on start-up and minimum load bids. However, most RUC requirements are met by capacity above minimum load for units that are committed in the day-ahead market or by the RUC process. This capacity is not awarded based on energy bid prices. Instead, RUC capacity bids are used, with most RUC awards being met by resource adequacy capacity, which is required to bid into the RUC process at a price of $0/MW.

The RUC process is also less efficient and effective from the perspective of maximizing the scheduling of gas prior to the real-time market. Since minimum load schedules for any long start units committed through the RUC process are financially and physically binding, generators may be expected and able to schedule gas for these commitments. However, since RUC schedules for capacity above minimum load and for all short-start units are not financially binding, generators may not be expected to schedule gas for this capacity. Thus, in the event virtual bidding increased reliance on the RUC process, this would

[9] See ISO tariff Section 7.9.2.

also undermine the goal of maximizing the scheduling of both electric supply and the needed gas on a day-ahead basis within the SoCal gas system.

Meanwhile, not routinely releasing the reserved transfer capability in real time would reduce the likelihood of such virtual schedules. However, not releasing the transfer capability in real time would be an inefficient use of available transmission capacity if most of the reliability benefits of reserving transfer capability in the day-ahead market can be achieved while still releasing the transfer capability in the real-time market.

DMM also recommends that the ISO closely monitor the impacts of virtual bidding and be prepared to quickly exercise this authority to suspend virtual bidding – including at specific locations or regions.

1.9 Limit sale of congestion revenue rights

DMM supports the proposal to reserve transmission capacity into the SoCal gas area in the day-ahead market to help limit gas imbalances in the real-time market. However, DMM has noted that this could cause the amount of congestion revenue rights (CRRs) allocated or sold by the ISO to exceed the amount of transmission capacity actually available in the day-ahead market. This causes CRR revenue inadequacy that is allocated to load-serving entities.

Given the uncertainty about the capacity into the SoCal gas area that will actually be available, DMM has recommended that the ISO carefully assess the amount of capacity that may be unavailable due to outages and any transmission reserved in the day-ahead market due to gas limitations in Southern California.

Path 26 is the most widely discussed example of a transmission path on which the ISO may reserve transmission capacity in the day-ahead market. Based on discussions with ISO staff, DMM understands that about 65 to 70 percent of the 4,000 MW of capacity in the north-to-south direction on Path 26 during the summer months (July to September) has already been allocated to load-serving entities or sold through prior auctions. Before additional capacity on Path 26 is made available in the monthly auctions for these months, DMM recommends the ISO assess the amount of additional transmission capacity that will be available with a high level of confidence, taking into account the following factors:

- **Transmission reservations.** The upper range of the amount of transmission capacity the ISO may reserve in the day-ahead market to help manage additional gas usage from real-time commitments and dispatches of electric generation capacity in the SoCal area.
- **Base flows.** The amount of capacity that may be needed to accommodate base flows in the day-ahead market created by the ISO's full network model, which represent unscheduled flows (or loop flows) created by energy and loads in other balancing areas.
- **Outages.** Potential unplanned transmission outages and de-rates.

Since the bulk of CRRs are purchased by purely financial entities, auctioning off more CRRs would appear to provide few benefits to participants interested in purchasing CRRs as a hedge for physical load or generation. In addition, entities interested in purchasing CRRs as a hedge for physical load or generation are free to contract directly with other parties for such hedges.

1.10 Limit time period of proposed actions

The ISO intends to sunset the provisions in its proposal by December 1 and reevaluate the effectiveness and the need for continuing the provisions moving forward. We agree with the ISO's proposal and recognize that some elements of the ISO's proposal could translate into more permanent changes.

2. Analysis of gas price adder for minimum load costs

This section summarizes analysis of how an extra fuel cost adder for commitment costs for resources in the SoCalGas areas would affect the likely system-wide dispatch order. The analysis shows that, if the objective is to make most these resources have a higher commitment cost than most resources outside the SoCalGas areas, then a 75 percent adder appears to be a reasonable starting point.

The ISO market software is designed to minimize total system bid-costs subject to both system-wide and resource-specific constraints. Therefore, the probability that a unit is committed (or kept on-line) in the real-time market depends on all three bid components (start-up, minimum load and incremental energy), as well as any resource-specific characteristics or constraints (e.g. start-time, minimum up time, minimum down time). Because of this complexity, it is not possible to precisely estimate how a gas-adder for commitment costs would influence the order in which resources would be committed for system needs.

This analysis focuses on one of the commitment cost bid components: the minimum load cost. This represents a major component affecting whether a unit is committed (or kept on-line) in the real-time market which can be directly compared across resources.

2.1 Comparison of minimum load costs

For this analysis, minimum load proxy cost caps are compared across resources by dividing the minimum load proxy cost cap by the resource's minimum operating level (or Pmin).[10] For multi-stage generators, this is done at the configuration level with the configuration-specific minimum load proxy cost cap and Pmin.[11] Only gas fired resources under the proxy cost option are included. These resources are grouped into two categories based on the resource's elected Master File fuel region:

- **SoCal gas area:** This includes gas resources in the SCE1, SCE2, SDG1 or SDG2 fuel regions, excluding resources identified by the ISO to be served by the Kern River Gas Transmission Company.
- **Other gas areas:** This includes gas resources in the CISO and PGE2 fuel regions as well as resources identified by the ISO to be served by the Kern River Gas Transmission Company.

Figure 2-1 shows the current ordering of minimum load cost bid caps for the set of resources described above without any extra gas adder.[12] Each bar represents one resource (or configuration), with the height of the bar reflecting the minimum load proxy cost bid cap per Pmin MWh, and the width representing the Pmin MW capacity. The resources are sorted by minimum load proxy cost cap per Pmin MWh from low to high. Blue bars represent resources in the SoCal gas area and red bars represent other gas area resources. As seen in this figure, the SoCal gas area resources are fairly evenly distributed across the stack of resources.

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[10] This analysis excludes the use-limited resources that are under the registered cost option. These resources have the option of switching to the proxy cost option. Moreover, these use-limited resources do not have the same must offer obligation as other resources.

[11] Including all configurations of all resources will result in some double-counting of capacity for multi-stage generating resources.

[12] This is as of May 1, 2016.

Figure 2-2 shows the same data as in Figure 2-1, except that a 75 percent adder has been added to the fuel cost component of the minimum load proxy bid cap for the SoCal gas area resources. With a 75 percent adder, the ordering changes such that SoCal gas area resources have a higher proxy cost cap than the majority of other resources.

Figure 2-1 Minimum load proxy cost caps (No SoCal gas adder)
All gas-fired resources

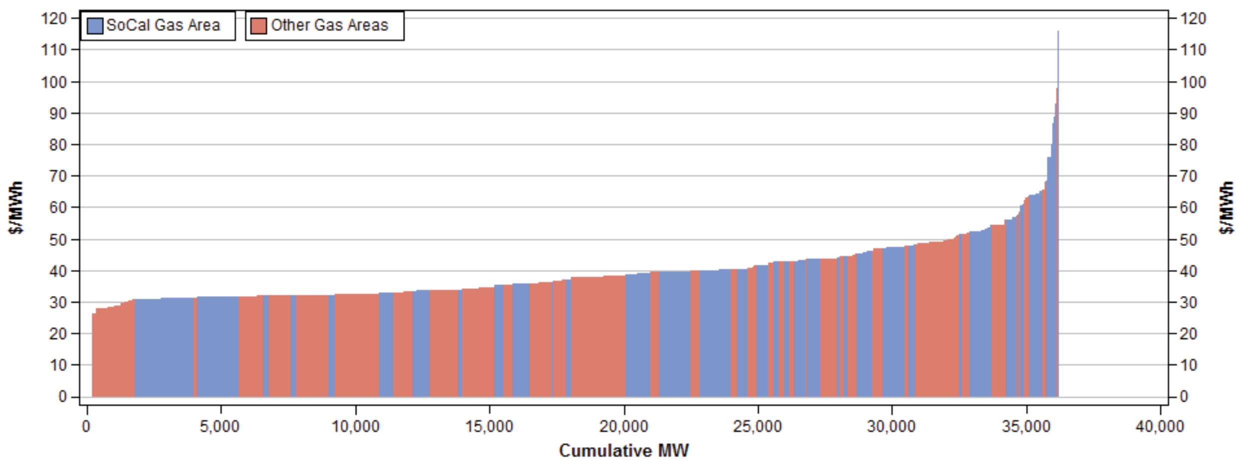
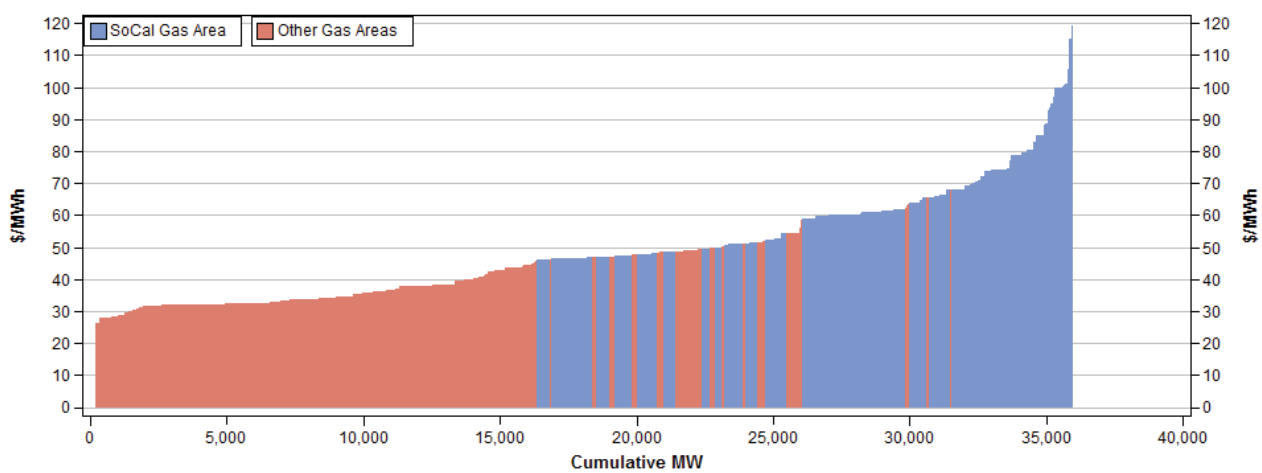


Figure 2-2 Minimum load proxy cost caps (75 percent SoCal gas adder)
All gas-fired resources

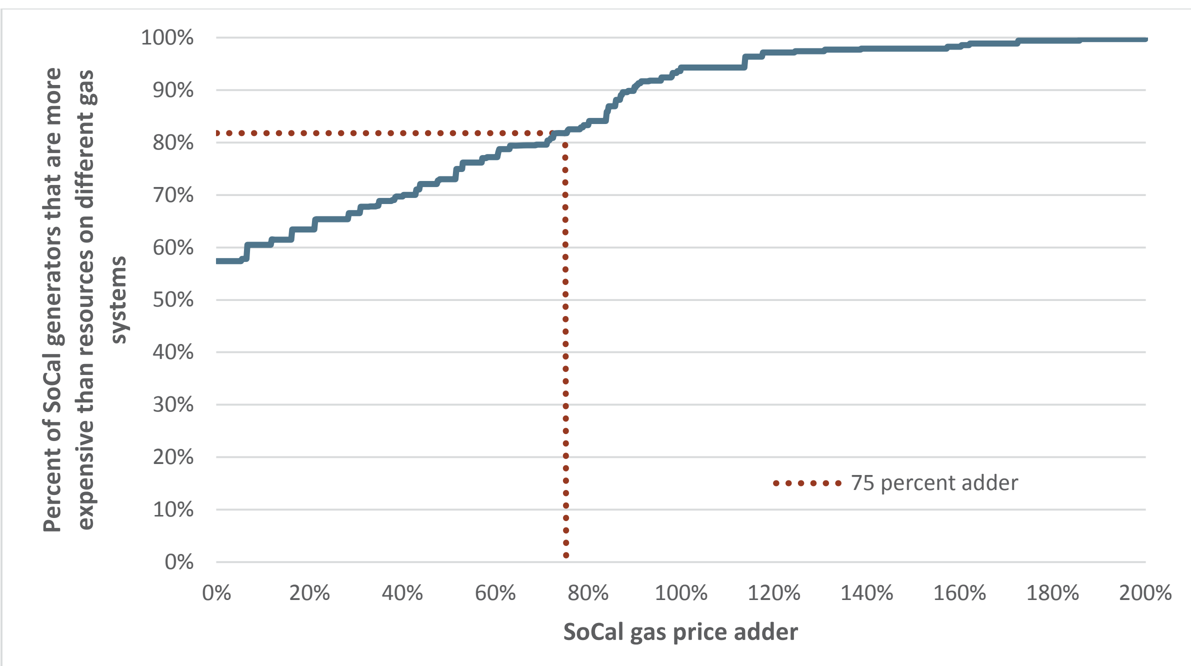


To compare the percentage of SoCal gas area resources that are higher than other gas area resources that is achieved using different adders, we have constructed the following methodology:

1. We first calculate the cumulative MW point at which all resources in the SoCal gas area have a higher cap than all other resources. This ordering defines a cut-off point between the two categories. This cut-off point is necessary because the quantity of resources in the affected SoCal gas areas are not the same total quantity as resources in other gas areas.
2. We then calculate the ordering of resources using different SoCal gas adders.
3. Using the ordering from step 2, we consider only the quantity of resources that are above the cut-off point defined in step 1. We then calculate the percent of this capacity that are SoCal gas area resources.

The resulting measure can be interpreted as the percent of SoCal gas generators that have higher minimum load bid caps than resources on other gas systems. Figure 2-3 shows this percent (y-axis) as a function of the SoCal gas adder (x-axis). As indicated by the red dashed line, a 75 percent adder results in about 82 percent of SoCal gas generation having higher minimum load bid caps than gas-fired capacity in the rest of the ISO system.

Figure 2-3 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (All gas-fired units)



This analysis is inclusive of all natural gas-fired generator types including combustion turbines, combined cycles and steam generators. While there may be times that the different resource types may compete with each other, it is likely that not all resources compete with each other at any given time because of differing operational parameters such as start-up times and ramp rates, and also because of different day-ahead commitment decisions. Thus, in the subsequent sections of this report, we provide the results of the same analysis performed in this section by gas-fired resource type.

Steam turbine resources

Figures 2-4, 2-5 and 2-6 are equivalent to Figures 2-1, 2-2 and 2-3 but only includes steam turbine units. As seen in these figures, using a 75 percent adder will result in about 97 percent of Southern California steam turbines having higher minimum load bid caps compared to steam turbines in other areas of the ISO.

Figure 2-4 Minimum load proxy cost caps (No SoCal gas adder) Steam Turbines

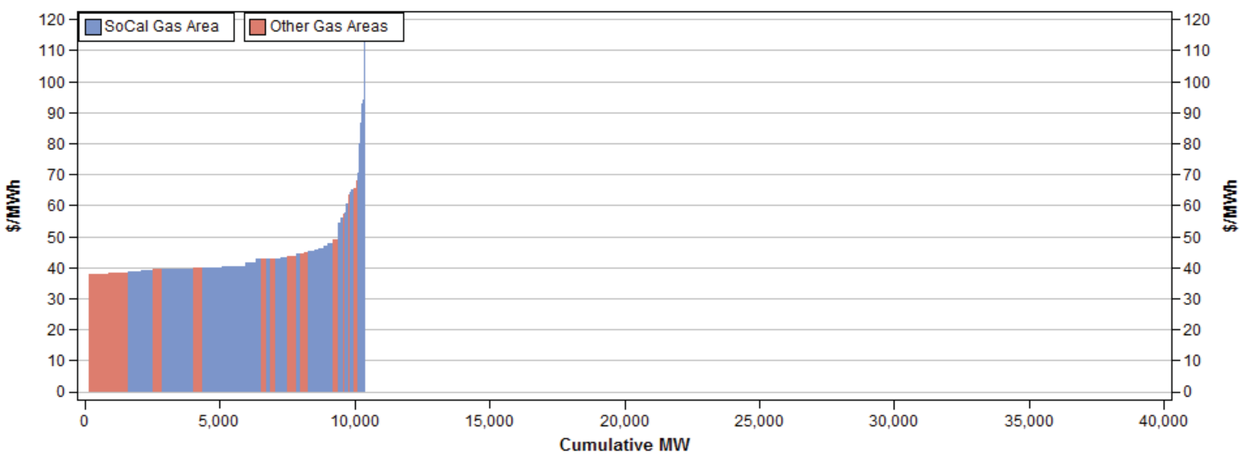


Figure 2-1 Minimum load proxy cost caps (75 percent SoCal gas adder) Steam Turbines

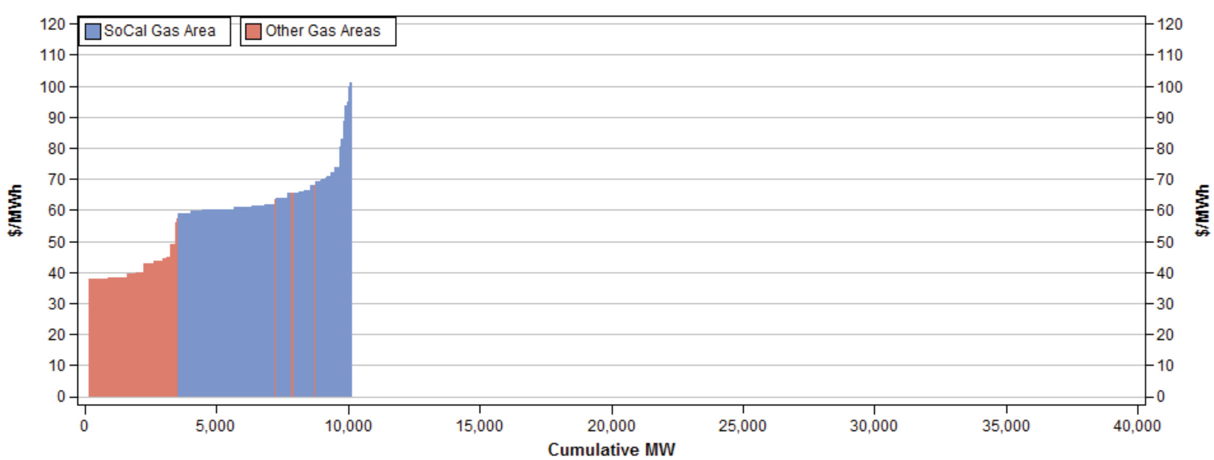
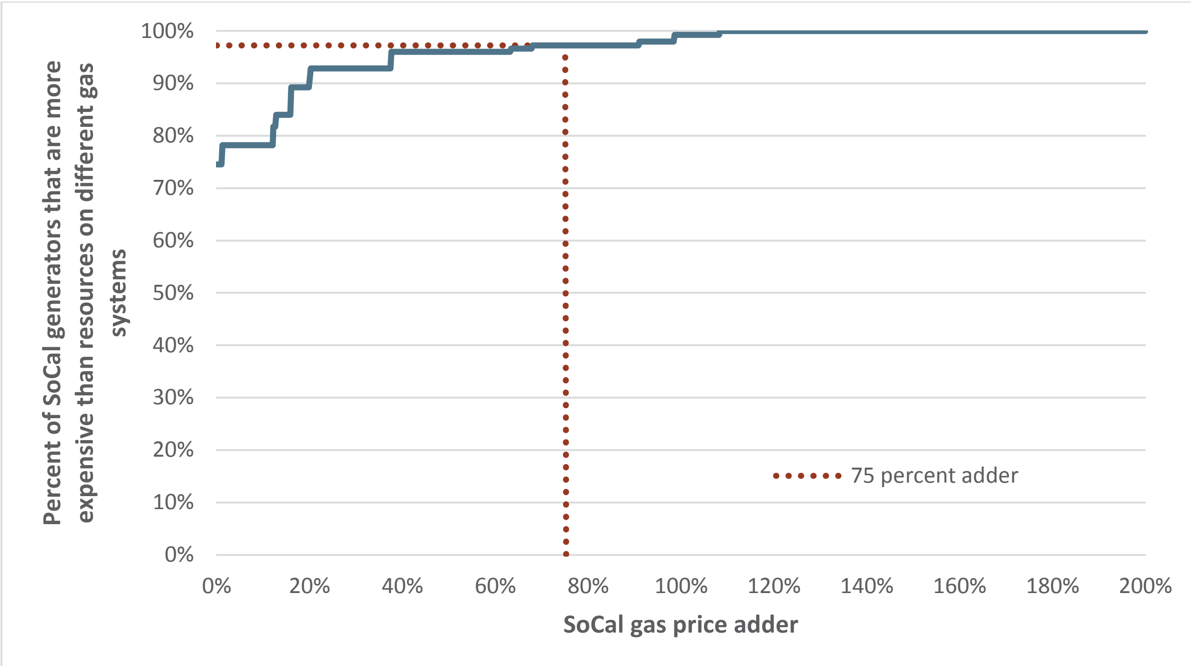


Figure 2-2 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (Steam Turbines)



Combined cycle resources

Figures 2-7, 2-8 and 2-9 include only combined cycle resources. As seen in these figures, using a 75 percent adder will result in about 95 percent of Southern California combined cycle configurations having higher minimum load cost than combined cycle capacity in other systems. With a 35 percent adder, about 92 percent of combined cycle capacity in Southern California capacity would have higher minimum load bid caps compared to combined cycle capacity in other areas.

Figure 2- 3 Minimum load proxy cost caps (No SoCal gas adder)
Combined Cycle units

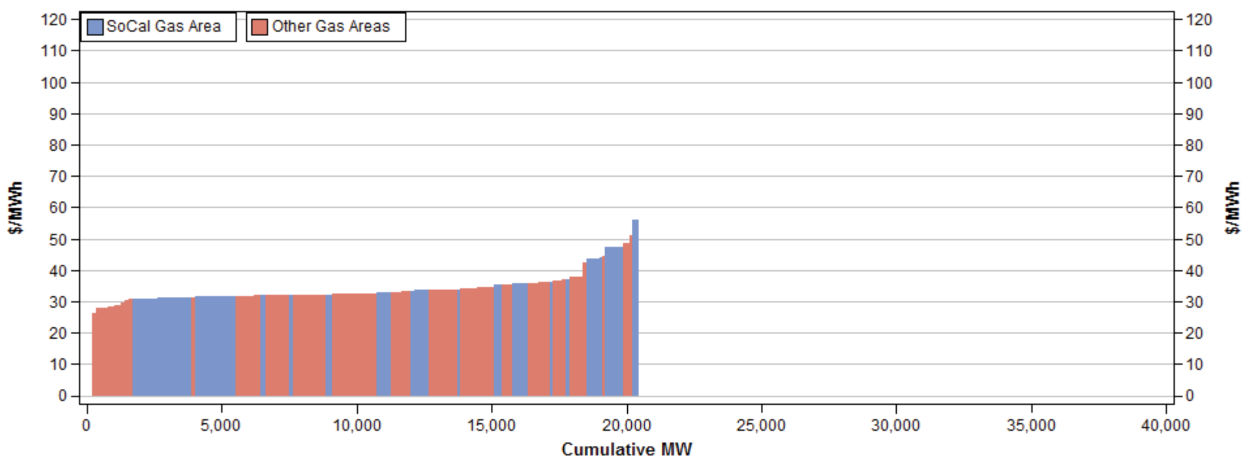


Figure 2- 4 Minimum load proxy cost caps (75 percent SoCal gas adder)
Combined Cycle units

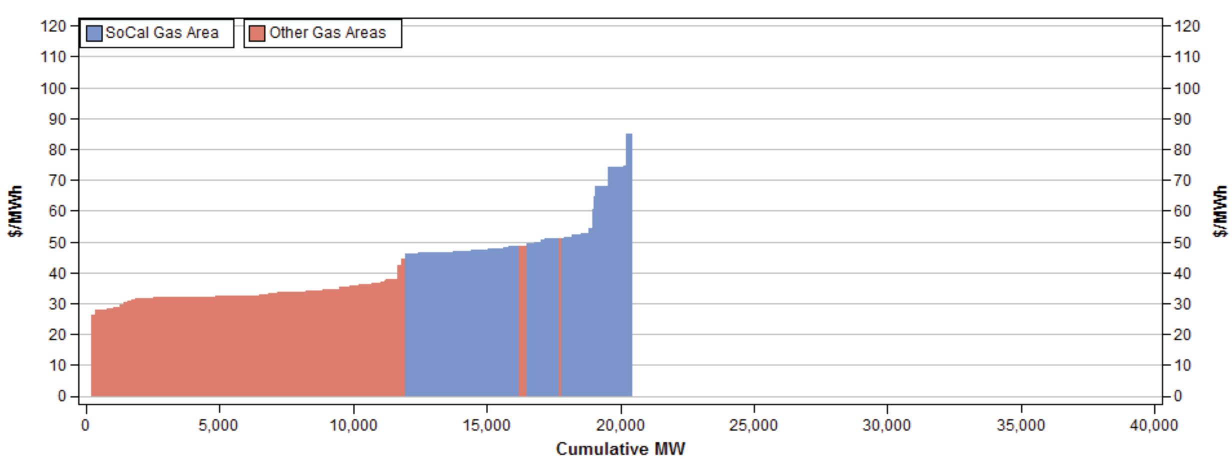
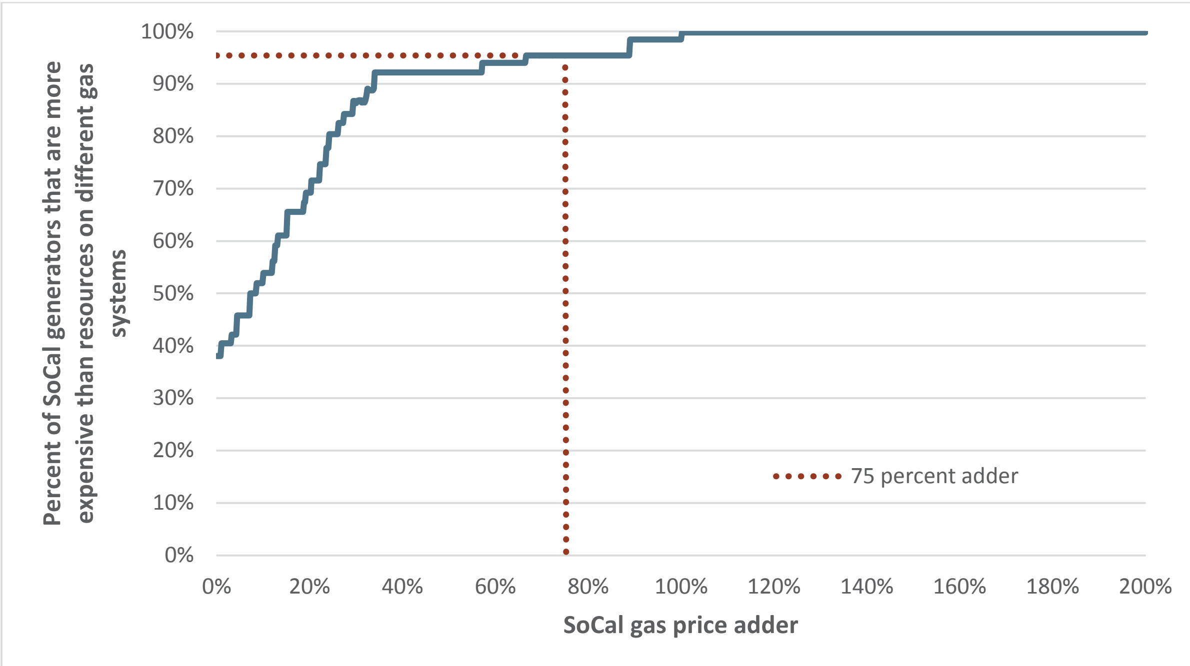


Figure 2- 5 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (Combined Cycle units)



Gas turbines

Figures 2-10, 2-11 and 2-12 include only gas turbines. As seen in these figures, using a 75 percent adder will result in about 98 percent of Sothern California gas turbine capacity having a higher minimum load bid cap than gas turbines in other systems. Since the Southern California gas turbines tend to have relatively high minimum load costs, an 8 percent adder is sufficient to cause almost 90 percent of this peaking capacity to have higher minimum load bid caps compared to peaking capacity in the rest of the system.

Figure 2-6 Minimum load proxy cost caps
Gas Turbines (No SoCal gas adder)

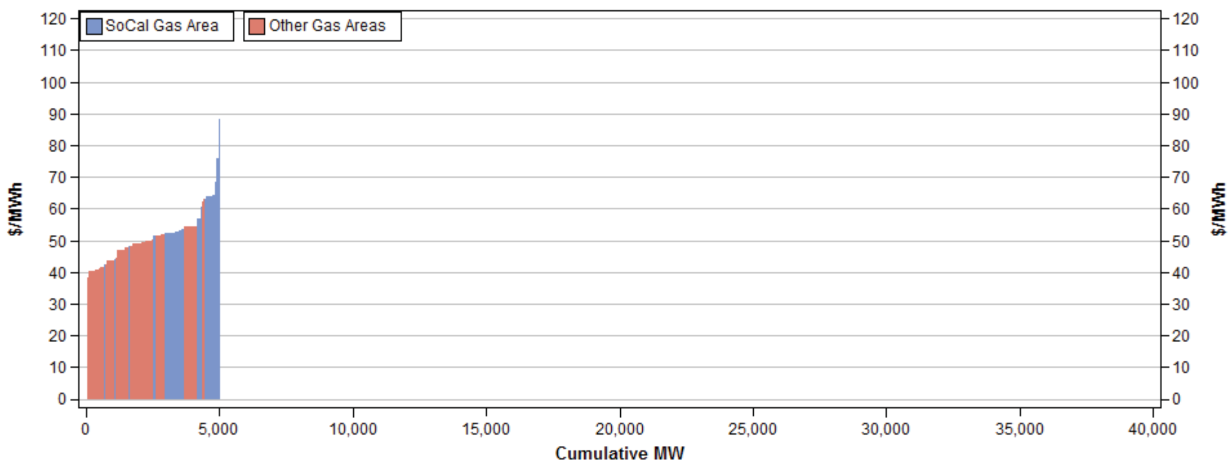


Figure 2-7 Minimum load proxy cost caps
Gas Turbines (75 percent SoCal gas adder)

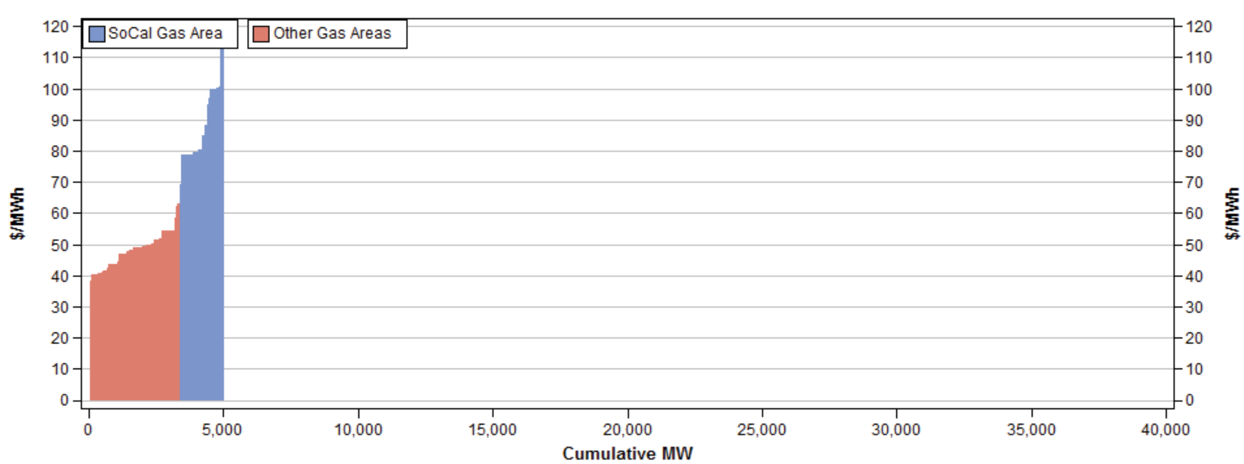


Figure 2-8 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (Gas Turbines)