Commitment Costs and Default Energy Bid Enhancements

Issue Paper

November 18, 2016

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1 Executive Summary

The purpose of this document is to introduce issues stakeholders have raised regarding the California ISO's market design features impacting suppliers' bidding flexibility to submit supply offers that reflect their willingness to provide energy at a given price based on their own expectation of costs and risks.

The purpose of this initiative is to evaluate the California ISO's bidding flexibility design and whether modifications to its design should be pursued. The bidding flexibility evaluated will include flexibility to:

- Balance allowing suppliers to submit economic prices reflecting their willingness to provide energy based on their expectation of costs and risks measured against the need to protect against structural or behavioral issues

- Ensure mitigated prices are reasonable reflections of suppliers' cost expectations

The California ISO seeks comments on advantages and disadvantages to the various approaches described in this issue paper. Under this initiative, the California ISO will evaluate possibilities to increase suppliers' bidding flexibility for (1) their commitment costs under competitive market conditions and (2) their commitment costs and default energy bids under uncompetitive market conditions. It will evaluate these possibilities in light of finding an appropriate balance between increased flexibilities and sufficient market power mitigation.

Based on consideration of stakeholder input on this issue, the California ISO will structure the scope of a straw proposal in four possible ways:

		Improve balance of allowing suppliers to submit economic prices for commitment cost offers reflecting their willingness to provide energy measured against need to protect against structural or behavioral issues	
		Yes	No
Increase assurance that mitigated prices are reasonable reflections of suppliers' cost expectations	Yes	Propose Enhancements for Both	Propose Enhancements to Improve Mitigated Prices Reflection of Suppliers' Cost Expectations
	No	Propose Enhancements to Adjust Market Power Mitigation Method for Commitment Cost Offers	Determine No Enhancements Needed

To begin evaluating if any bidding flexibility enhancements are needed, this issue paper discusses:

Background
Discussion covers electric and natural gas markets, bidding rules, market power mitigation methods, reference level calculations, and supply offers settlements. This section describes the different components of supply offers, bidding flexibility, and market power mitigation methods used by the various regional transmission organizations or independent system operators (organized markets) with an emphasis on the California ISO's supply offer structures and bidding flexibility. The FERC jurisdictional organized markets surveyed includes the California ISO, Midwest ISO (MISO), Southwest Power Pool (SPP), PJM, New York ISO (NYISO), and New England ISO (ISO-NE).

Issue - Stakeholders Concerned Assets May Not Be Reasonably Valued
This section describes the issues raised by some stakeholders or identified previously by the California ISO that affect supply offers and their mitigation to reference levels such as commitment cost bid caps and default energy bids. Stakeholders largely feel comfortable with the California ISO mitigating suppliers' offer curves to a mitigated price when the California ISO detects structural or behavior issues. However, some stakeholders have expressed that (1) the method used to mitigate commitment costs (i.e. the bid cap) may result in over-mitigation of units that limits ability to submit prices based on willingness to sell at a given price or expectation of costs and risks and (2) the method of determining the mitigated price has several limitations imposing a risk on that the mitigated price is lower than suppliers' cost expectations. With any consideration of increased flexibility, the California ISO will need to review its market power mitigation methods for market dispatches and exceptional dispatches.

Discussion
This section introduces the discussion points the California ISO is putting forward on this issue paper. As a part of this discussion, the section will cover possible design paths that could be considered to address concerns. Additionally, another discussion on possible paths to enhance commitment cost mitigation is included as these issues were previously identified under the *Bidding Rules Enhancements* initiative and we are seeking feedback based on lessons learned through the organized markets survey.

Appendices A-C
Appendix A reviews California ISO's plan for the stakeholder initiative targeting a July 2017 board of governors meeting. This initiative is anticipated to be categorized as advisory for the Energy Imbalance Governing Body as it involves changes that will affect the real-time market in general. Appendix B, Organized Market Survey contains survey results on bidding rules and market power mitigation. Appendix C, Reference Level Calculations, has formulas for start-up, minimum load, default energy bid variable option, and estimate of delivered price at generating unit using fuel region-specific gas price.

2 Introduction

Stakeholders have raised concerns that the current market design introduces risks that their units could be inaccurately valued in the market processes, reducing the efficiency of market solution and potentially compromising cost recovery.

This risk is of concern to the California ISO for many reasons including that the California ISO will need to rely on fast start gas units to provide the ramping speed needed to provide the generation to meet load when renewable generation drops off. The large magnitude of generation needed during the evening peak hours to meet load cannot currently be provided by the amount of storage capacity online so the California ISO expects to continue to need to rely on gas generation to contribute to power balance.

Conceptually and in a world absent of market power or gaming concerns, the California ISO would develop market mechanisms that provides a marketplace where buyers and sellers bid or offer the price at which they are willing to purchase or sell the good. This market place would result in a market clearing price[1] with an efficient market solution constrained by the physical boundaries of the electric system.

However, that world does not exist and there is a risk that suppliers would try to exercise market power or extract rents through gaming. So the electricity market design must support a market place where suppliers can bid prices that reflect their willingness to provide power at given output levels and the market can protect consumers against exercise of market power or gaming strategies. California ISO must reasonably protect consumers against artificial market solutions.

For all types of generating units, suppliers have the ability to bid their units into the day-ahead or real-time markets and receive a market award for cleared offers. Under competitive market conditions, the California ISO expects that profit maximizing suppliers will submit offers with prices that reflect their expectation of incremental costs of operating its unit at specific dispatch operating points. If the supplier offers its unit at the price at which it values its asset and the California ISO accepts that offer price, the California ISO gives the supplier a market award. The market award is for the supplier to operate at a given operating level and at its offered price.

The California ISO pays the supplier its total cost of producing power at the dispatch point through market revenues and uplift payments. However, settlement mechanisms can only compensate suppliers to the extent the market rules allow the supplier to submit offers at prices that reflect their expected production costs. Ideally under competitive market conditions, suppliers can submit offer prices that show how the supplier assesses the units' value when it is committed and generating power at various levels. This way the California ISO market can optimize and find the least-cost, security constrained solution consistent with both it and the suppliers' expectations.

Under uncompetitive market conditions, accepting a supplier's offer price based on how it assesses the units' value could open the markets up to market power. For energy offers, it has a direct impact on setting the energy price if the marginal unit. For commitment cost offers, it could introduce market power effects into the energy price through impacting the commitment decisions that situate the fleet in a certain manner to result in a higher energy price.

In these instances, there is insufficient supply to ensure market forces can manage bidding incentives so that there is a disincentive to submit prices that are intended to artificially increase energy prices for the supplier's benefit, or exercise market power. Market power mitigation mechanisms are necessary to provide the controls against such supply offers even if it is a good faith price based on how supplier values the power production since the "value" under uncompetitive conditions could harm ratepayers if allowed to drive up prices.

The California ISO believes that when uncompetitive conditions exist it is reasonable to mitigate the supply offers to price levels that are a reasonable reflection of the suppliers' cost expectations, which restricts additional valuation of the asset outside of its expected production costs. We will refer to this valuation of other costs, risks, externalities, or influences of supply and demand as "other factors". The California ISO's position is that suppliers should not be allowed to recover these other factors, even if it contributes to their willingness to sell, when mitigated due to market power concerns.

Since actual costs can be unknown until after operating, there is an issue around how to value these costs so that the mitigated price is cost-based but not overly restrictive to suppliers' ability to reflect their expectations of those costs. The California ISO understands from its Stakeholders that it could take days or months to determine their actual costs.

If actual costs are unknown, the supplier is "taking a short position" in a physical power contract. The expectation is that actual costs will go down or at least equal the fixed sale price of the award. After receiving its market award but before it realizes its operating costs, suppliers are exposed to price changes on their accrual of profits or losses (price risk). This is because they do not know their costs until after operating the unit. After the fact, the supplier is able to see their actual operating expenses and compare it to their California ISO settlements. This is how they determine whether they incurred profits or losses for that trade day. The supplier assumes this price risk regardless of whether they are awarded in the day-ahead or real-time market.

To illustrate, if the supplier's actual cost for producing the awarded amount is less than the California ISO market settlement payment, it will make a profit on that trade day. In contrast, if the supplier's actual cost is higher than the California ISO market settlement payment, it will incur losses for that trade day.

When mitigated, the California ISO may be limiting suppliers' to energy offers or bid caps that do not reasonably represent the units' cost expectations. In this instance, the market imposes a greater price risk on the supplier rather than the supplier willing entering into that position at the cleared offer prices.

We understand from stakeholders that they willingly assume price risks on market awards based on their submitted prices and incur profits or losses as a normal course of business. As a result, we posit that the main policy issue for discussion is whether market enhancements should be pursued that would provide be greater flexibility to submit and clear commitment cost offers at suppliers' valuation of the asset and that would ensure mitigated prices are reasonable reflections of suppliers' cost expectations.

Under this initiative, the California ISO will work with the Stakeholder community to examine what changes can be made to reduce imposing greater price risks on suppliers when they participate in the markets than they would willing assume.

We are seeking feedback on whether this discussion of the bidding flexibility, market power mitigation methods, and mitigated price determination concerns raised are inclusive of the issues raised by Stakeholders or if there are any refinements or expansions to the discussion that should be made.

IS THE PROBLEM STATEMENT COMPLETE AND ACCURATE?

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3 Background

3.1 Gas-Electric Markets

The purpose of this section is to discuss the interplay between the gas and electric markets and system operations that affect gas-fired generating units. The challenges these units face provide background knowledge for understanding why stakeholders that manage these units have raised concerns with the current market design for commitment cost bidding and the determination of mitigated prices for supply offers.

To do so the following will be discussed:

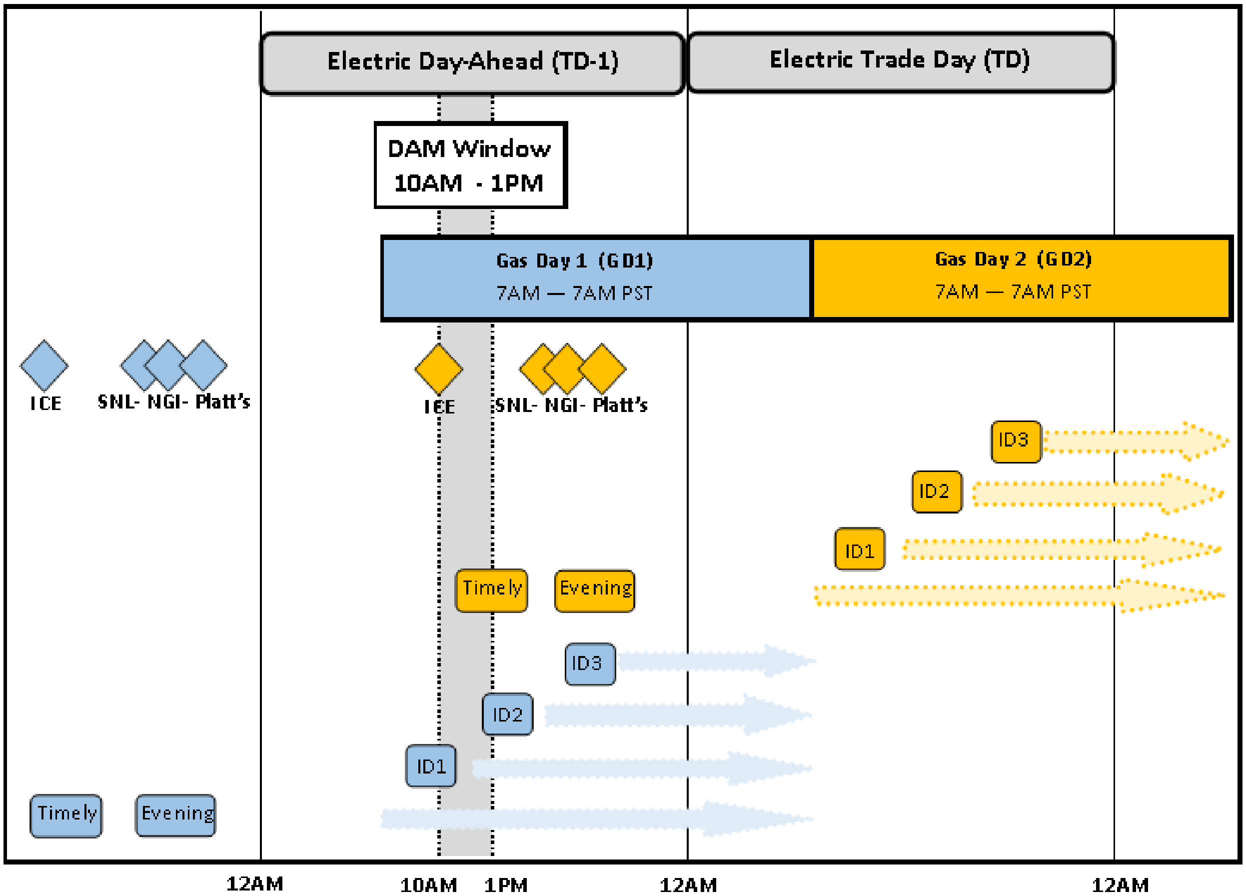
- Next Day Gas and Day-Ahead Electric Markets
- Challenges Facing Suppliers
- Challenges Facing Gas System

3.1.1 Next Day Gas and Day-Ahead Electric Markets

To illustrate how the gas market nomination cycles and gas commodity price publication times affect the California ISO's market operations, Figure 1 visualizes the interplay between the gas trade day and electric trade day. Gray bars, titled "Electric Day-Ahead (TD-1)" and "Electric Trade Day (TD)", show the electric days. Further in the diagram, one vertical strip of gray shows the day-ahead market window from 10AM-1PM Pacific.

The colored items in this diagram show the gas trade day and publication timing for the first gas day that began flows TD-1 at 7AM Pacific (Gas Day 1 ,GD1) in blue and second gas day that begins flowing on TD at 7AM Pacific (Gas Day 2, GD2) in orange.

Figure 1: Gas and Electric Day Timelines effective April 1, 2016 (Order 809)



The colored blocks represent each nomination cycle during the gas day from its deadline to final notification with arrows associated with each cycle showing the effective flow hours. The publication times associated with GD1's GPI are shown in Figure 1 as blue diamonds and the flows hours under that contract is shown by the blue box entitled "Gas Day 1". The publication times associated with GD2's GPI are shown in Figure 1 as orange diamonds and the flows hours for that product type is shown by the orange arrows under the orange box entitled "Gas Day 2".

Table 1 lists the details for the five gas nomination cycles.

Table 1: Gas nomination deadlines effective April 1, 2016 (PT)

Nomination Cycle	Nomination Deadline (PT)	Notification of Nominate (PT)	Nomination Effective (PT)	Bumping of interruptible transportation
Timely	11:00 a.m.	3:00 p.m.	7:00 a.m. Next Day	N/A
Evening	4:00 p.m.	7:00 p.m.	7:00 a.m. Next Day	Yes

Intra-day 1	8:00 a.m.	11:00 a.m.	12:00 p.m. effective	Yes
Intra-day 2	12:30 p.m.	3:30 p.m.	4:00 p.m. effective	Yes
Intra-day 3	5:00 p.m.	8:00 p.m.	8:00 p.m. effective	No

3.1.2 Challenges Facing Suppliers

Suppliers face unique challenges for their gas procurements and nominations needed to meet California ISO commitments or dispatches due to the different timelines across the gas and electric markets. The California ISO publishes its day-ahead market at 1PM Pacific coming after the timely gas nomination cycle deadline at 11AM Pacific when the majority of gas trading has already occurred that morning. Suppliers may choose to delay procuring fuel until they receive their financially binding day-ahead schedules so they have certainty of the quantity to procure. Some stakeholders have expressed to the California ISO that if they cannot reasonably anticipate their electric day-ahead schedules in the morning before the California ISO publishes them, they might forego purchasing gas during this more liquid trading period and choose to wait to procure in less liquid periods.

The ISO understands that suppliers may do a risk assessment as to whether procuring gas with uncertainty as to the needed quantity versus procuring during illiquid periods is less risky. When the day-ahead market results are available, suppliers who determined waiting has less risk will procure and schedule gas to meet their schedules. In this scenario, the supplier will procure gas during the most illiquid trading periods since the timely cycle is already complete.

On the other hand, suppliers who receive more consistent dispatches or perform sophisticated economic modeling to predict dispatch will attempt to procure as much gas as possible to produce the amount of energy that they can anticipate. If they overestimate their needs and need to sell off gas in real-time, they could be at risk of losing money on that fuel if costs are lower during real-time than when they procured the fuel. As can be seen, suppliers engage in a complex risk assessment to evaluate what is the optimal procurement strategy and these strategies will vary by supplier.

If suppliers determine they can enter into longer term contracts either for delivery or hedging purposes, these contracts could either be transacted with market products that settle off of these monthly gas market prices (price taking for standard monthly published indices) or could even by procuring products where the trading in that product sets the monthly gas market prices (price setting of the standard monthly published indices). The gas market prices for forward products suppliers use for hedging or price forecasting include: NYMEX futures price for Henry Hub prompt-month contract available on the third day of bid week[2], first of month (FOM) prompt-month contracts[3], end of month contracts (gas daily average)[4], and next day gas contracts (i.e. gas daily).

While much of the liquidity in the natural gas markets is traded during "bidweek" trading setting the gas commodity price for the first of month gas index, which is a published index representing monthly value at the beginning of the month, the liquidity intra-month is more modest. "Bidweek" is the last five business days prior to the beginning of the delivery month, called the "prompt-month," where physical basis or fixed price physical transactions contribute to setting the volume weighted average price across the five business days. Market participants that buy or sell prompt-month physical contracts during bidweek will contribute to the price formation of the natural gas first of month index for flows during the prompt-month. This is significant because it explains why electric suppliers confront difficulties finding liquidity in the gas spot market and non-standard products.

The California ISO understands that since suppliers would likely not have much certainty in the amount of gas needed to meet their dispatches over the next month as well as because the amount needed will vary day by day, electric suppliers would likely not begin to procure until the next day markets or later. After the next day market closes, liquidity has largely dried up. Since most liquidity traded during bidweek, liquidity begins to thin in the next day markets and after that market closes, supplies are expected to carry premiums relative to the standard published next day gas commodity price.

In next day trading, the procurement is largely for nominations made during the timely cycle. The next day gas commodity price will be set by the volume weighted average price of physical basis or fixed price physical transactions cleared during the qualifying trades window; trades cleared prior to timely nomination deadline of 11AM Pacific set gas market price. Table 2 below emphasizes the relationship between the next day gas commodity prices used for the various published next day gas commodity prices and the nomination cycles

For each publication used to determine the estimate of delivered price in the reference levels, Table 2 shows the time period that completed transactions qualify to be included in the price index calculation in the "Qualifying Trades Window" column, the earliest time made available, the latest time made available and the methodology details[5].

Table 2: Natural gas day-ahead indices publication times[6]

Source	Qualifying Trades Window (PT)	Earliest Time Available (PT)	Latest Time Available (PT)	Details
ICE	4:00AM – 11:00 AM	11:30 AM	1:30 PM	Volume weighted average price of fixed price completed deals on ICE's trading platform.
SNL Energy/BTU Daily	That day before 3:00 PM	That day before 4:00 PM	That day before 7:00 PM	Volume weighted average price of next day contracts (typically) [7]

NGI[8]	Next day trades must have been completed prior to industry [timely] nomination deadline at 11AM PT for next-day pipeline flows.	7:00 PM	2:00 AM (flow date)	Volume weighted average of reported fixed-price physical deals delivery .[9] Note, ICE reports cleared transactions to NGI so ICE trades automatically included and supplemented by other reported trades.
Platt's[10]	Next day trades must have been completed prior to industry [timely] nomination deadline at 11AM PT for next-day pipeline flows.	5:00 PM	7:00 PM	Volume weighted average of reported fixed-price physical deals delivery.[11] Note, ICE reports cleared transactions to Platt's so ICE trades automatically included and supplemented by other reported trades.

All the publishers produce a gas daily index that largely contains trades completed in the morning for flows onto a pipeline the next day. The discussion that follows will refer to this gas daily index as the "next day gas commodity price." Publishers calculate from the qualifying transactions a volume weighted average price that is then published as the next day gas commodity price. Almost all publishers cut off the eligibility for a qualifying trade at 11AM Pacific.

Compare the nomination deadline for the timely cycle in Table 1 to the cut off time used by each publisher for qualification to contribute to the index price in Table 2.[12] Both are 11AM Pacific.

It is clear that gas market trading patterns are closely tied to the nomination deadlines created by the North American Energy Standards Board for natural gas nominations. The ISO understands suppliers will try to the best of their ability to procure gas in the next day markets that close prior to the timely cycle's nomination deadline at 11AM Pacific. Due to its higher liquidity and higher likelihood of available pipeline capacity, suppliers are more likely to be able to reserve (i.e. nominate) sufficient pipeline capacity to deliver gas to their units than during later cycles.

For both the monthly and daily gas market prices, fixed price physical contracts representing price for gas delivered at the location defined under that price index is the most active product traded on the West Coast. This is because while deliveries to the East are largely sourced from the Gulf so a basis to NYMEX Henry Hub prices is attractive, the fixed price of delivered gas into the western trading points is not generally closely correlated to Henry Hub prices making fixed price gas more active. For example, western locations indexed at next day commodity prices (i.e. gas market prices) could be much closer to the price of sourcing gas from Canada or the Rockies.

The above describes largely normal operations. Suppliers are faced with additional challenges when either the electric or gas systems are under strained conditions. When there is a gas system reliability concern the electric suppliers as customers on that system will be faced with requirements imposed on them by the gas system. These will be discussed in the context of the challenges facing the gas system.

3.1.3 Challenges Facing Gas System

Gas system operators need to ensure that the gas system is operating in their gas operating day in a manner that does not compromise its reliability. The gas system operator will assess after the nomination cycles how much capacity is available for additional nominations and whether scheduled deliveries and storage inventory can support its customer demand.

If an issue supporting customer demand or pipeline usage, too low or too high, that could compromise ability of pipeline and gas burners to continue to function, the gas system operation will issue notifications to their customers. These notifications could include operational flow orders (OFO), emergency flow orders (EFO), or curtailments.

The operational flow orders are designed to bring the nominated gas flows and gas demand closer to balance pipeline pressure. These notifications can be issued on both the high and low side. Gas customers can use their pipeline pack or storage facilities inventory to increase or decrease their gas burn to their scheduled flows depending on system needs. If time permits, the gas customers could also procure and nominate flows on or off system. These nominations depend on the type of action needed to help ensure system integrity.

Below are descriptions of low operational flow orders, high operational flow orders, and curtailments.

3.1.3.1 Low Operational Flow Order

If expected storage withdrawal capacity is higher than the withdrawal capacity allocated for balancing needs, a low operational flow order is issued in advance of the gas day. In this scenario, scheduled deliveries are expected to be lower than the gas burn in real-time. The gas operator would anticipate its customers would need to rely on storage to balance the difference between their scheduled deliveries and their gas burn. However, if the amount needed to balance this difference is greater than the system's withdrawal capacity, the system could be compromised. The gas operator needs its customers to schedule additional deliveries so balancing functions can be reliably done with the available withdrawal capacity.

Suppliers need to either nominate flows onto the gas system or decrease their gas burn to increase gas quantity on the pipeline. If the supplier does not decrease its burn levels to within a percent allowed of its scheduled deliveries (i.e. tolerance band), they will incur a noncompliance penalty.

An emergency flow order is invoked when the low operational flow order was insufficient to ensure system integrity and threatened deliveries to end-use customers. In response, suppliers need to reduce their usage to less than or equal to their scheduled deliveries by sending flows off-system or by reducing its own gas burn. If the supplier does not decrease its burn levels to below its scheduled deliveries, it will incur a noncompliance penalty.

3.1.3.2 High Operational Flow Order

A high operational flow order is issued when expected system capacity is greater than the scheduled deliveries. The expected system capacity includes expected gas demand and storage injection capacity. It is offset by the scheduled deliveries off-system. In this scenario, the gas operator is concerned with scheduled deliveries being brought onto the gas pipeline and if not used would need to be injected into its storage facilities.

Suppliers need to either nominate flows off the gas system or increase their gas burn to reduce gas quantity on pipeline. If the supplier does not burn within the tolerance band provided by the gas company, it will incur a noncompliance penalty.

When gas companies require suppliers to keep their gas consumption within a tolerance band around their nominated gas flows, the gas companies' noncompliance charges are intended to make gas users view the cost of gas differently. They would view the gas cost differently because the gas effectively costs them more if they operate outside the tolerance band.

3.1.3.3 Curtailments

Curtailments are interruptions of natural gas service to customers, also called schedule cuts. The gas operator will issue cuts to the scheduled gas based on an order of priority. Electric suppliers (suppliers) are a part of the first tier of customers curtailed because they generally use interruptible services. If the suppliers purchased firm noncore transmission service, the supplier would not be curtailed until all the interruptible services were cut. The final customer to be cut would be the core end-use customers.

Some types of curtailments include:

- System occurrences where the system cannot maintain pressure,
- Localized occurrences affected by capacity restrictions or emergencies,
- Emergency occurrences of a threatened or actual shortage undermining ability to serve end-use customers (this curtailment can deviate from the order of priority),
- Planned maintenance occurrences where cuts are needed to complete safety or maintenance work on the pipeline.

3.2 Supply Offers & Settlement Designs

The purpose of this section is to describe the different components of supply offers used by the various organized markets compared to the California ISO's supply offer structures and bidding flexibility. For a detailed description of the results of the organized market survey see Table 3 in Appendix B: Organized Markets Survey.

To do so the following will be discussed:

- Bid Structures
- Bidding Flexibility
- Settlement Mechanisms

3.2.1 Bid Structures

In all organized markets, suppliers submit (i.e. bid) supply offers into the market that represent their willingness to provide energy at a given price and are broken into up to four cost components.

There are two different approaches across the organized markets for establishing a benchmark against which the supply offers are evaluated for mitigation purposes. On one hand, California ISO, ISO-NE, NYISO, and MISO have bidding rules where their bid-in supply offers are evaluated in reference to an administratively calculated reference level for mitigation purposes. On the other hand, PJM and SPP's bidding rules allow suppliers to submit separate price-based supply offers and cost-based offers and there supply offers are evaluated in reference to their cost-based offers for mitigation purpose. The California ISO will refer to the price-based supply offers as "supply offers", the cost-based supply offers as "cost-based offers", and the administratively calculated reference level as "reference levels".

There are two primary designs for supply offer structures, i.e. bid structures, used by organized markets. The first design has supply offers with a minimum load cost component and without a no load cost component, a minimum load structure. The second design has supply offer curves without a minimum load cost component and with a no load cost component, a no load structure.

The California ISO's supply offers have a minimum load structure. The supply offer includes up to four components that represent the total production cost of the unit:

- startup costs associated with bringing a unit online from being shut down[13],
- transition costs associated with moving from one configuration to another for multi-stage suppliers (MSG),
- minimum load costs associated with operating the unit at the minimum operating level (Pmin) where a unit cannot drop below without compromising the unit's operation, and
- incremental energy costs associated with producing energy above Pmin.

Other markets with the minimum load cost structure have three bid components as they do not model transition costs for MSGs.

While the second design functions similarly for the startup cost and incremental energy cost components, the markets with a no load cost structure were designed to bid no load costs and an economic minimum operating level for use in the market process instead of the minimum load cost component. No load costs are largely fuel costs associated with synchronizing a unit to the grid and sustaining a net zero output from the unit. The incremental energy costs are the cost to produce energy above the economic minimum level.

For example, PJM requires suppliers to establish their minimum operating levels through submitting economic minimum operating levels and emergency minimum operating levels. The market systems are optimized using economic minimum levels and the emergency minimum is reserved for emergencies on the system.

Throughout the rest of this document, the California ISO will refer to "commitment cost offers" when discussing the up to three bid components valuing the cost of committing a unit to operate as commitment cost offers (start-up, transition, and minimum load cost or no load cost components), "energy offers" when discussing the incremental energy cost component, and "supply offers" when discussing total offer including up to all four components representing unit's production cost.

3.2.2 Bidding Flexibility

The California ISO requires suppliers to submit supply offers to its day-ahead market no later than 10AM Pacific the day prior to its trade day. The energy offer can vary between hours in both the day-ahead while the commitment cost offer cannot vary by hour. The commitment cost offer does not vary by hour today as it was originally designed to represent an event based cost incurred when awarding a commitment.

The California ISO's survey of organized markets bidding rules showed that its energy bidding rules are very flexible. Energy offers submitted in the real-time market can be different than day-ahead market bids. Whether the unit received a day-ahead schedule or not, the supplier can adjust the units energy offer up until 75 minutes prior to the operating interval[14] limited by the $1,000/MWh offer cap and subject to local market power mitigation. These rules are very similar to ISO-NE, NYISO, and MISO's energy bidding rules.

In addition to the limitation to vary by hour noted above, the California ISO currently does not provide as much rebidding flexibility for commitment cost offers. It limits suppliers' commitment cost offers by applying a bid cap method for mitigation purposes. The bid cap limits commitment cost offers to no more than 125 percent of their unit-specific reference level calculation. Further, suppliers cannot adjust these commitment cost offers in in real-time.

In response to stakeholders concerns that the rules were too restrictive and that they were at risk of incurring commitment costs above CAISO's commitment cost bid cap, the California ISO analyzed the flexibility provided across the organized markets during the *Bidding Rules Enhancements* initiative. The California ISO found that NYISO, PJM, and SPP allow resources without a day-ahead schedule to rebid commitment costs in the real-time market and MISO and ISO-NE allow even greater flexibility to adjust up until 30 minutes before the operating hour.

In the case of the NYISO, NYISO chose not to allow full bidding flexibility such as MISO or ISO-NE because of reliability concerns. The concern was that there is an operational need to lock commitment costs for units that received a day-ahead schedule to support reliability. However it would not adversely impact reliability to allow rebidding flexibility for units without day-ahead schedules. NYISO notes that "for system reliability, the NYISO needs to be able to rely on the Day-Ahead commitment of Suppliers sufficient to serve expected real-time Load. Maintaining the Minimum Generation and Start-up Bids for Day-Ahead scheduled Suppliers allows the NYISO to rely on them for incremental Energy, should the need arise."[15]

On the other hand, ISO-NE found it required the greater level of flexibility because it has experienced significant reliability degradation from gas supply constraints causing suppliers to not respond to dispatch. For example, the ISO-NE found in "an examination, conducted in early 2012, of dispatch response performance following the 36 largest system contingency events over the last three years indicates that, on average, the response rate for New England's non-hydro generating resources was less than 60 percent of the amount requested during the events."[16]

After finding sufficient benefit to increasing its commitment cost bidding flexibility, the California ISO filed tariff amendments to increase flexibility in its real-time market. Pending FERC approval of the *Bidding Rules Enhancements* tariff filing[17], the California ISO will no longer lock in the commitment cost offers used in the day-ahead but will now allow suppliers to revise these offers in real-time. A generating unit will be able to adjust these offers for (1) hours without day-ahead schedules and (2) once committed in real-time for hours after it reaches its minimum run time. If the unit is not bid into the day-ahead market, the supplier can rebid commitment costs in the real-time market at any point up until the real-time market closes for a particular hour.

These updated bidding rules are consistent with the bidding flexibility found in the other organized markets.

3.2.3 Settlement Mechanisms

Energy prices generally only reflect the marginal cost of the next unit needed to meet demand, which is an incremental cost not a total cost. The market runs a security constrained unit commitment run which minimizes the total costs of power production given a set of physical constraints using supply offers representing the short-run total production costs at a given output level. The short-run total production costs are modelled using the commitment cost and incremental energy cost components of the supply offer[18].

After the set of units committed are determined, the market will produce prices that reflect the marginal cost of serving an additional unit of demand, which generally is set by the energy offers and does not include commitment cost offers. Energy prices are not intended to reflect the impact of start-up costs, transition costs, no load or minimum load costs. As noted above, these costs will influence which units are committed so there is an indirect impact to the energy price. Instead, the energy price is intended to reflect the marginal cost of energy given commitment decisions.

The California ISO settles a unit's market award so that they are compensated at the price submitted in their supply offer through their market revenues and uplift payments. For the incremental energy produced, the supplier will receive payment for this energy at the energy price (market revenues). To the extent a unit has a market revenue shortfall where its market revenues do not exceed its supply offer, the unit is compensated for the difference between its supply offer and its market revenues through uplift mechanisms.

Uplift mechanisms provide make-whole payments to suppliers who had a market revenue shortfall. The California ISO will generally pay this make-whole payment either through its bid cost recovery mechanism for market awards or excess cost payments for out-of-merit exceptional dispatches[19] (uplift payments). The need for uplift payments tends to occur more when energy demand is lower or when the ISO dispatches a unit to operate at or near its minimum load.

Initially, electricity markets when designed envisioned that energy prices would be sufficiently high so that the need for uplift payments would be limited. As energy markets and operations shifts to reflect the impact of renewable output, the market is concerned that need for uplift payments to serve as primary source of compensation for lumpier commitment costs may be resulting from its observation of more instances of low prices and an increased need to dispatch units near minimum load. Both of these factors could result in suppliers needing uplift to make whole their supply offers.

3.3 Market Power Mitigation Methodologies

Each market has a methodology used to detect market power and trigger bid mitigation. This section will describe the primary market power mitigation methodologies, mitigated prices and validation features used on adjustable fuel prices that are used by organized markets and how the California ISO applies these methodologies within its market processes. For a detailed description of the results of the organized market survey see Table 4 in Appendix B: Organized Markets Survey.

To understand the various market features, the following will be discussed:

- Methodology for Triggering Mitigation
- Methodology for Mitigated Price
- Methodology for Validating Offers

3.3.1 Methodology for Triggering Mitigation

This section discusses the various methods used to trigger mitigation of commitment costs and incremental energy costs generically as well as by market.

In this section the California ISO describes below:

- Conduct and Impact Test
- Three Pivotal Supplier Test
- Overview of Organized Markets

3.3.1.1 Conduct and Impact Test

A conduct and impact test is a two-step mitigation methodology. A unit fails the conduct test when the offer reaches a pre-determined threshold, e.g., 200 percent above the reference level or supplier submitted cost-based offer. It is then subject to the impact test. How the impact test is conducted in each market varies, but essentially it replaces the supply offer with the reference level or cost-based offer and compares the resulting energy prices or change in uplift payments to see if the supply offer has the ability to impact the market. An impact test on energy prices alone would not be effective at capturing market power related to inflated commitment cost offers.

While some markets only review impact to energy prices and others such as NYISO include impact to uplift payments, the California ISO believes that an impact test applied to commitment cost offers needs to include changes to the overall amount of uplift payments to reliably capture market impacts from inflated commitment cost offers.

When an organized market applies an impact test on energy prices or uplift payments, it reruns the market using the reference levels or cost-based offers to see if there is a decrease in uplift payments or energy prices in the market power test run. If the market power test shows lower energy prices or uplift payments than the run using the supply offer, the supply offer fails the impact test and the reference level or cost-based offer will be used in the final market run.

For example of an impact test on energy price changes, a unit located in a load pocket that is the marginal unit necessary to serve local load. The market operator’s minimum load reference level for the unit is $5,000 and the unit has a default energy bid of $50/MWh. Assume the unit bids $50,000 for minimum load and $50/MWh for energy. The market solution would commit the unit and have an energy price of $50/MWh at that location. Under a conduct and impact test structure, it would fail the conduct test and be subject to an impact test. The market operator replaces the supply offers with the minimum load reference level of $5,000 and the default energy bid $50/MWh.

Then, the market operator reruns the market and compares the energy prices or uplift payments. The energy price remains the same at $50/MWh. If the test just looks at energy prices, since the two resulting energy prices are the same, the unit would not have its minimum load bid of $50,000 mitigated. However in some markets, if the supplier’s offer would have resulted in higher uplift costs then it could be mitigated (e.g. NYISO).

A concern with the use certain forms of a conduct and impact test is that units withholding capacity from the market to impact prices for an external benefit could be successful unless a screen for withholding is included in the design. To address this, NYISO evaluates units that were not cleared in its market process. This is done by replacing supply offers not cleared in the market process with either the reference levels or cost-based offers and then rerunning the market solution to apply the conduct and impact test. If when evaluating the new commitment decisions and energy prices, the energy prices or uplift payments with are lower than prices determined with the supply offer the supplier will fail the impact test even if not committed in market run. In NYISO, MISO and ISONE, there is one impact test that is applied to all mitigated resources, not to each portfolio.

3.3.1.2 Three Pivotal Supplier Test

A three pivotal supplier test evaluates if a given constraint is competitive or un-competitive. If there is sufficient supply to meet demand, after removing the largest suppliers, the constraint is competitive. Otherwise, it is uncompetitive and provides opportunity for the exercise of market power. Suppliers whose can provide supply to uncompetitive constraints are subject to mitigation procedures.

These tests are triggered by a binding constraint or another defined need for supply in a defined area. Offers would be mitigated if, without the largest suppliers, the demand could not be met. The determination that demand could not be met without the supply is made by comparing the demand at that location to the supply offered with the three largest suppliers removed. If dispatched, the supply offered would be injected on the system and depending on its distribution factor[20] would flow a portion of that power across the applicable constraint in the counterflow direction relieving congestion in the prevailing flow direction.

3.3.1.3 Overview of Organized Markets

The organized markets generally apply one of two mitigation methods either a conduct and impact test or a three pivotal supplier test. Once failing a mitigation test, markets mitigate the supply offers to reference levels or suppliers submitted cost-based offers. In all markets that mitigate to reference levels except for California ISO, the markets provide an opportunity to request a fuel price adjustment in the reference level calculation or to provide opportunity for after-the-fact uplift payments. This more accurately reflects suppliers' cost expectations the reference levels or cost-based offers as well as ensures after-the-fact compensation for actually incurred costs that exceed these values.

ISO-NE, MISO, SPP, and NYISO apply a conduct and impact test to its supply offers, all components of its supply offers. Whereas, PJM applies a three pivotal supplier test to its supply offers, all components of its supply offers. The California ISO is unique in that it applies a form of both tests to different components of its supply offer.

For commitment cost offers, the California ISO applies a form of a conduct and impact test where there is no impact test and the trigger is solely based on violating what is effectively a conduct test. The California ISO mitigates commitment cost offers using a commitment cost bid cap that limits commitment cost offers to a conduct threshold level of 125 percent of the reference levels. If commitment cost offers are submitted in excess of 125 percent of the reference levels the California ISO will replace the commitment cost offer with the unit-specific commitment cost bid cap.

For energy offers, the California ISO applies a form of the three pivotal supplier test called the local market power mitigation (LMPM). If energy offers are submitted and fail the market power mitigation test, the energy offer is mitigated to the reference level for incremental energy cost component of the supply offer.

3.3.2 Methodology for Mitigated Price

This section describes the California ISO's reference level calculations as background for an evaluation of whether these reference levels sufficiently allow suppliers' to bid offers reflective of their expectations of short-run variable costs.

To explain the California ISO's process, the California ISO describes below:

- Overview of Organized Market Mechanisms
- Overview of California ISO Mechanisms

The two main methods for determining the mitigated price to settle the mitigated supply offers are to either mitigate to the reference level or the submitted cost-based offer. In the first instance, the market operator replaces and settles the supply offers with the administratively calculated reference levels. In the second instance, the market operator replaces the supply offers with the cost-based offers when the unit tests positive for market power.

3.3.2.1 Overview of Organized Market Mechanisms

The NYISO, ISO-NE, and MISO adopted the method based on a reference level.[21] Whereas, PJM and SPP adopted the second method to mitigate to the cost-based offer bid in by the supplier.

3.3.2.2 Overview of California ISO Mechanisms

The California ISO determines reference level estimates of a generating unit's incremental production cost for use in its market power mitigation mechanisms.

3.3.2.2.1 Mitigating Energy and Commitment Cost Offers

For mitigating its energy offers, the California ISO mitigates non-gas fired units to their energy cost registered in Master File and gas-fired units to their default energy bid or competitive LMP. The default energy bid will either be based off the locational marginal price, variable cost, or negotiated option. For these gas-fired units, the supplier will rank its preference for default energy bid calculation between these three options. The variable cost option as it is (1) the administratively calculated option, (2) it largely provides the basis for the negotiated default energy bid calculation as well for units who the variable cost option does not reasonably value the unit, and (3) it serves to highlight scenarios driving suppliers need for alternatives to the variable cost estimate.

For mitigating its commitment cost offers, the California ISO mitigates potential market power through an established bid cap that limits commitment cost offers to its unit-specific cap. If a supplier submits a commitment cost offer that exceeds its bid cap, the California ISO mitigates the commitment cost offers to the bid cap levels not to the reference levels. To set the unit-specific commitment cost bid caps, the California ISO multiplies the reference levels by 125 percent of gas-fired units' reference levels or non-gas fired units' registered commitment cost values in Master File[22]. The bid cap is designed to provide headroom for suppliers to submit bids reflecting their expectation of the units' short-run incremental costs due to commitment decisions balanced against the need to protect against market power.

3.3.2.2.2 Determining Reference Levels

The California ISO determines reference levels somewhat differently for gas-fired and non-gas fired units. It developed proxy cost methodology to estimate reference levels for the largest block of price setting units, the gas-fired resources, and then decided to allow suppliers with non-gas fired units to register their expectation of those units' production costs in master file[23].

For gas-fired units, the California ISO calculates an estimate of the unit-specific production costs for each component of the supply offer curve using the unit's heat rate and an estimated delivered price of fuel to estimate short-run incremental costs for fixed or variable costs. Reference levels by component are:

- Proxy startup cost: reference level for startup costs associated with bringing a unit online from not operating shown in Appendix C, Equation 3
- Proxy transition cost: reference level for transition costs associated with moving from one configuration to another for multi-stage generator (MSG)
- Proxy minimum load costs: reference level for minimum load costs associated with operating the unit at the Pmin output level that a unit cannot operate below without compromising the operation of the unit shown in Appendix C, Equation 4
- Default Energy Bids (DEBs): reference level for incremental energy costs associated with producing energy above Pmin shown in Appendix C, Equation 2

Whether the California ISO calculates an estimate of a units' cost or the supplier registers its unit-specific cost information, the cost information should be reflective of a unit-specific expectation of cost for producing power at a given output level. The reference levels generally include estimates for fuel costs, variable operations and maintenance charges, grid management charges, greenhouse gas compliance costs, start-up energy costs, and where applicable negotiated major maintenance charges and/or default energy bid adders. The reference level for incremental energy costs associated with producing energy above Pmin includes a 110 percent scalar in its incremental energy costs reference levels to cover incidental costs outside of the prior listed cost estimates.

The foundational assumptions made to enable these mechanisms are:

- There is only one fuel type support for each generating unit.
- There is one procurement location for a fuel region.
- There is one pipeline shipping company (shipper) for a fuel region.
- Next day gas commodity prices are a reasonable proxy for expected procurement costs.

3.3.2.2.3 Estimating Delivered Price by Market

The California ISO estimates the fuel cost portion of its reference levels as the product of the unit's heat rate and the fuel region's estimated delivered price. To enable the California ISO to estimate this delivered price, the California ISO requires suppliers to register its units in a fuel region. The fuel region designation is selected based on the most likely procurement location and pipeline shipping company used to deliver fuel to the unit. For each fuel region, the California ISO calculates a daily estimate of delivered fuel costs (gas price index); the region's delivered price is set as a combination of procurement costs, shipping costs, and other variable fuel costs.

Depending on the market, the California ISO uses an average of next day gas commodity prices for gas flowing on either the first or second gas days[24] to estimate the procurement cost piece of the delivered price. The average is performed using the available published next day gas commodity prices from ICE, SNL Energy/BTU daily, NGI, or Platt's Gas Daily. The formula for the estimated delivered price of gas at a unit is shown in Appendix C: Reference Level Calculations in Equation 1. It shows the different formulations by market for the gas price index used to determine the delivered price estimate.

First in the day-ahead market, the California ISO calculates reference levels using the gas commodity price that is an average of natural gas transactions done the morning two days prior and largely for flows one day prior to electric trade day (GPI_{DA}, day-ahead delivered price). The trading day two days prior is used because the next day commodity price for trading one day prior is not available at 10AM Pacific, when the day-ahead market closes. The day-ahead delivered price will reflect the gas commodity price for the morning hours of its electric day[25].

Second in the real-time market, the California ISO calculates a unit's reference level using the gas commodity price that is an average of natural gas transactions. These are done the morning one day prior and largely for flows on the electric trade day (GPI_{RT}, real-time delivered price). The California ISO's real-time delivered price will reflect the next day gas commodity price for the majority of hours across the electric day.[26]

The gas commodity prices used in the real-time market are more representative of expected costs for the trade day than those used in the day-ahead market. There is an exception to this – the manual price spike procedure.

In this procedure, the California ISO tracks day-over-day price trends in the gas market looking at the published next day gas commodity prices between the second and first gas days. The California ISO will trigger its manual gas price spike process when it observes that second gas day's next day gas commodity price is 125 percent of the first gas day's gas commodity price calculated the prior evening. When this happens, the manual gas price spike procedure updates the day-ahead reference levels with the second gas day's next day gas commodity price. The suppliers can take advantage of a re-offer period initiated around 11:30 AM Pacific and the market will re-run the day-ahead with the new offer stack.

Without this procedure, the market could face limitations when it uses the day-ahead delivered price instead of the real-time delivered price in the day-ahead market's reference level calculations. If market conditions are different between the two days, the gas daily indices published for each day will not be strongly correlated with each other, in other words sufficiently different as to not be appropriate proxies. When this happens, the California ISO's day-ahead reference levels would represent expectations of production costs if the power was produced on the day the California ISO runs its day-ahead market. It would not reflect suppliers' expectations of production costs for producing power during the California ISO trade day.

For a review of the formulas for the day-ahead delivered price (GPI_{DA}) and the real-time delivered price (GPI_{RT}) see Appendix C, Equation 1. This is one of the major inputs into the reference level calculations on which the California ISO's mitigated prices are based. In summary, the purpose of the estimated delivered price is to provide a market-based estimate of the fuel cost for power production.

3.3.3 Methodology for Validating Offers

In association with suppliers having the ability to submit their cost-based offers to the market as opposed to relying on reference levels, PJM and SPP adopted validation methods to protect against the exercise of market power from submission of inflated or inaccurate cost-based offers. Both PJM and SPP validate the bid-in mitigated offers by requiring a supplier to register a fuel cost policy with them and develop the mitigated offers consistent with cost development guidelines. Suppliers are responsible for providing information needed to assess total fuel costs[27].

The market monitoring units screen the mitigated offers for deviations from the guidelines and fuel policy. Then also refer any deviations to FERC. For example, SPP requires cost data to be submitted consistent with the information detailed in the supplier's cost policy. SPP's market monitoring unit replicates the bid-in mitigated offers using the fuel cost policy and the supplier's cost data and evaluates the bid-in mitigated offers against their replicated bids (or reference levels). The advantage to this method is it provides more flexibility for suppliers to establish its short-run variable cost methodology. SPP's Mitigated Offer Developments Guidelines, SPP states that:

> *"Each Market Participant will be responsible for establishing its own method of calculating delivered fossil fuel cost, limited to inventoried cost, replacement cost or a combination thereof, that reflects the way fuel is purchased or scheduled for purchase."*[28]

While SPP permits suppliers' to submit their cost-based offers to the market, SPP adopted an interesting blended design where it uses these bid-in offers but screens for potential market power using calculated reference levels. The advantage of this blended design is it balances the increased flexibility for suppliers to submit cost with a robust market monitoring regime to protect against the exercise of market power.

Regardless of the design adopted, the organized markets have become increasingly concerned that either the reference levels calculated by the ISOs or even the bid-in cost-based offers could not fully reflect the production costs of a unit. This has led to the introduction of two market design enhancements across the organized markets. The two market design enhancements are:

- Opportunities for fuel price adjustments in advance of the market run when reference level calculation is expected to insufficiently reflect expectation of unit's fuel cost estimates; and

- Opportunity to seek after-the-fact recovery when actual costs exceed offered or mitigated price.

NYISO, ISO-NE, MISO allow suppliers to request fuel price adjustments in real-time for the fuel price used in the reference levels. They approve requests to revise gas commodity prices in reference levels if the default gas commodity price used does not fully reflect prevailing gas market prices or actual costs to the supplier. The CAISO does not currently have this functionality in its market.

ISO-NE allows suppliers to update the fuel price used in its reference level when the supplier has an expectation its procurement costs will exceed the fuel price used in the ISO-NE's reference level. This fuel price adjustment must be made in sufficient time prior to the market close. If this update is requested, the ISO-NE requires suppliers to perform the following:

> *"Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction…The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price." (III.A.3.4(b))*

Even if a supplier is allowed to bid its cost-based offer, there can still be instances when a suppliers incurred costs exceeds its cost-based offer. This is why in PJM and SPP, the markets provide after-the-fact uplift payments for actual incurred costs exceeding cost-based offer. ISO-NE also provides for after-the-fact cost recovery for supply offers mitigated or above the offer cap through a Federal Power Act Section 205 filing at FERC. Pending FERC approval of its *Bidding Rules Enhancements* filing, the California ISO will also provide this after-the-fact cost recovery opportunity for actual incurred commitment costs above its commitment cost bid cap not recovered through market revenues. On a temporary basis, the measures approved under the *Aliso Canyon* emergency filings included extended this filing right to incurred costs above the incremental energy offer's mitigated price.

4 Issue – Stakeholders Concerned Assets May Not Be Reasonably Valued

This section evaluates whether the current California ISO market rules have sufficiently struck a balance between suppliers' need to submit supply offers based on their asset valuation and the California ISO's need to protect consumers against market power. The California ISO will do so through discussing:

- Overview
- Commitment Cost Mitigation May Be Overly Restrictive
- Exceptional Dispatch Mitigation May Not Be Restrictive Enough
- Reference Levels Exclude Price Impact of Externalities
7
- Reference Levels May Not Reasonably Reflect Cost Expectations

4.1 Overview

Stakeholders have raised concerns that the current market design introduces risks that energy from their units could be inaccurately valued in the market processes, reducing the efficiency of market solution and potentially compromising cost recovery.

This risk is of concern to the California ISO for many reasons including that the California ISO will need to rely on fast start gas units to provide the ramping speed needed to provide the generation to meet load when renewable generation drops off. The large magnitude of generation needed during the evening peak hours to meet load cannot currently be provided by the amount of storage capacity online so the California ISO expects to continue to need to rely on gas generation to contribute to power balance.

Conceptually and in a world absent of market power or gaming concerns, the California ISO would develop market mechanisms that provides a marketplace where buyers and sellers bid or offer the price at which they are willing to purchase or sell the good. This market place would result in market clearing prices[29] with an efficient market solution constrained by the physical boundaries of the electric system.

However, that world does not exist and there is a risk that suppliers would try to exercise market power or extract rents through gaming. So the electricity market design must support a market place where suppliers can bid prices that reflect their willingness to provide power and the market can protect consumers against exercise of market power or gaming strategies. California ISO must reasonably protect consumers against artificial market solutions.

Stakeholders largely feel comfortable with the California ISO mitigating suppliers' offer curves to a mitigated price when the California ISO detects structural or behavior issues. However, stakeholders have expressed that (1) the method used to mitigate commitment costs may result in over-mitigation of units that limits ability to submit prices based on willingness to sell and (2) the method of determining the mitigated price for commitment costs and default energy bids has several limitations imposing a larger price risk on them to potentially incur losses.

The California ISO is seeking stakeholder feedback on whether these concerns are still in need of market design enhancements to address these concerns.

DO STAKEHOLDERS STILL FEEL THERE IS FREQUENT COMMITMENT COSTS OVER-MITIGATION LIMITING THEIR ABILITY TO REASONABLY REFLECT THE ASSET'S VALUE IN THE MARKETS?

DO STAKEHOLDERS STILL FEEL THAT WHEN MITIGATED THEY ARE AT RISK OF BEING REFLECTED IN THE MARKETS TO A LOWER PRICE LEVEL THAN THEIR OWN COST EXPECTATIONS?

4.2 Commitment Cost Mitigation May Be Overly Restrictive

Stakeholders expressed concerns that the California ISO's commitment cost market power mitigation methodology may result in over-mitigation of commitment costs since it assumes uncompetitive market conditions always exist. To address the concern that market conditions could be competitive but suppliers' offers are still limited the California ISO would need to design an impact test or a structural test for commitment costs that could look like a form of an impact threshold on energy prices or uplift, a static pivotal supplier test, or some other more dynamic market power mitigation methodology. The impact test or structural test would test for uncompetitive market conditions.

The current design limits suppliers' ability to submit prices based on their willingness to sell regardless of whether the supplier could adversely impact the market based on an assumption that reasonable range of costs should be constrained within 25 percent of reference levels. This assumption is empirically supported by analysis performed by the Department of Market Monitoring. Under most scenarios, the 25 percent appears to provide a sufficient margin of error to allow the suppliers' cost expectations to be reflected in their commitment cost offers.

However, this disregards that under competitive conditions it is within the market design to allow supply offers that reflect a suppliers' willingness to sell power based in part on their own expectations of costs and risks. As discussed in the Background section, this is appropriate because the competitive market forces exist to provide incentives that limit adverse market impacts from market power.

The California ISO seeks stakeholder feedback on whether it has understood this issue expressed by Stakeholders and whether these concerns are still in need of market design enhancements to address these concerns.

IS THIS AN ACCURATE AND COMPLETE DESCRIPTION OF THE MARKET DESIGN LIMITATION FELT BY STAKEHOLDERS UNDER THE CURRENT MARKET DESIGN?

4.3 Exceptional Dispatch Mitigation May Not Be Restrictive Enough

Under the current market design there are potentially two gaps in the current rules for mitigating exceptional dispatches. The policy for mitigating exceptional dispatches is that if an exceptional dispatch could affect a non-competitive constraint its settlement price will be mitigated. This only applies to incremental exceptional dispatches as there is no mitigation design for decremental exceptional dispatches. The first potential gap is whether the exceptional dispatch mitigation policy should be expanded to include mitigation for units dispatched to resolve natural gas system issues. The second potential gap identified is that there is no mitigation method for decremental exceptional dispatches.

Currently, California ISO mitigates exceptional dispatches in real-time that are related to a non-competitive transmission constraint. The transmission constraints are determined to be non-competitive if in recent months the constraint was congested in 10 or more hours or deemed competitive in 75 percent or more of the instances where the constraint was binding when tested by the dynamic competitive assessment. If constraint fails these thresholds it will be added to a default list and exceptional dispatches that could relieve the constraint will be mitigated.

First potential gap was that it may be appropriate to mitigate settlement prices for exceptional dispatches made for natural gas system reliability purposes. DMM highlighted this issue in light of the limited operability of the Aliso Canyon natural gas storage facility in Southern California and believes these dispatches may be under uncompetitive conditions. The method may need to be different than that used for the determination of non-competitive default list based on the congestion and competitive triggers described above. In fact, it may need to be unrelated to any binding constraint analysis as these dispatches are to resolve concern that can only be resolved by that unit.

Second, there is no design for determining when it would be appropriate to mitigate decremental exceptional dispatches or shut-down energy (energy from minimum load to shutdown). This initiative would evaluate other potential settlements for decremental exceptional dispatches if uncompetitive market conditions are identified than settling unit at the lower of the energy price, energy reference level, or energy offer. Also the current market design does not specify a price for settling decremental exceptional dispatch energy when a resource is exceptionally dispatched to shut down from minimum load. This initiative would explore settlement alternatives to the current practice of not charging any price for this buy back of energy.

4.4 Reference Levels Exclude Price Impact of Externalities

The energy market can only consider gas reliability needs if its market design reflects the cost of supplier potentially undermining reliability.

California ISO understands the supplier may also be at risk that the gas pipeline system will not have sufficient capacity available for additional nominations or storage withdrawals. When suppliers are not able to procure and schedule supply in advance of operating their unit, they can withdraw gas from the pipeline and burn this "borrowed" gas to meet its electric dispatch. This advance use of the pipeline is an acceptable practice, as long as the "borrowed" gas is replaced or balanced by the end of the month. This practice is not acceptable when the gas operator identifies a gas reliability issue. If there is an expectation of this occurring, next day trading will price the risk of incurring noncompliance charge into the bids and offers transacted. When a gas operator identifies an issue and release flow orders, we understand from Stakeholders that intra-day or same-day trading will transact at prices that include the noncompliance charge.

Under *Aliso Canyon Gas-Electric Coordination* initiative, the California ISO explored with its stakeholders how strained gas market conditions such as these could impact the ability of the electric supplier to balance their obligations to both the gas and electric operators. As a result, the California ISO better understands suppliers need an avenue to balance their obligations to both systems.

When a gas system operator is concerned with its system reliability, the operator can issue instructions to its customers such as operational flow orders (OFO), emergency flow orders (EFO), or curtailments. As described in the Background section, these notifications are intended to incentivize gas customers to adjust their behavior so it supports gas system reliability.

It seems to the California ISO that noncompliance charges for violating tolerance bands are set for reliability purposes. By introducing the potential risk of incurring a noncompliance charge into the gas market, gas system operators are introducing an externality into that market place. This should affect suppliers' view of their gas costs to generate power. This view is consistent with California ISO's observations that natural gas commodity prices are trading with risk premiums consistent with noncompliance charges to incentivize specific behaviors.

Based on the understanding not including the economic signals would impose an externality on the market, the California ISO believes changes in suppliers' economics that are introduced by risk of noncompliance with a gas flow order place a monetary value on the social cost imposed if the gas is burned contrary to how the notification implies customers should behave. The noncompliance charge monetizes this cost. The order is intended to incentivize behaviors that maintain the integrity of the gas system.

Ideally, the supplier could use its bids to reflect the cost of deviating from a gas instruction that would undermine gas system reliability. If done, the California ISO markets could co-optimize the cost of dispatch consistent with both the electric and the gas system constraints.

As an example. For low operational flow orders, a supplier could reduce its burn by bidding high costs including the social cost, appears less economic, and is dispatched down. For high operational flow orders, a supplier could increase its burn by bidding low costs including the social cost or self-scheduling at the burn level needed. The market can then co-optimize the gas and electric physical system conditions and produce a least cost solution that does not undermine gas or electric reliability.

Additionally, the California ISO has temporarily introduced rules allowing it to enforce a gas constraint when electric operators anticipate reliability needs necessitate a market constraint when we identify trade-offs between the costs of both systems are not appropriate under extreme market conditions. However today, the California ISO markets rules may limit the ability of suppliers to manage their dispatch consistent with gas system needs through including this social cost.

Under the current market design for commitment cost bidding, suppliers can increase or decrease bids to include these costs as long as energy offers are not mitigated and the social cost does not increase costs above bid cap. For commitment cost offers, these are limited to 125 percent of the reference levels where suppliers are prevented from reflecting the economic incentives imposed by the gas company in its production costs when their costs exceed the bid caps. The supplier may be unable to manage gas usage by submitting higher priced bids due to these commitment cost bid caps. Further for energy offers that are mitigated, these may be limited from reflecting the incentives since reference levels only contain a 110 percent scalar for incidental costs other than the fuel proxy costs likely insufficient to reflect operating costs and this social cost.

The California ISO posits that there is a social cost and should be reflected in reference levels when applicable so the market can solve consistent with electric and gas reliability needs. Including these costs in reference levels would allow mitigated prices to reflect the higher cost of dispatching the unit given the negative externality imposed if gas reliability is not maintained. Further it seems appropriate for the market to reflect gas reliability needs to find a solution that co-optimizes electric and gas reliability.

4.5 Reference Levels May Not Reasonably Reflect Cost Expectations

This section will focus on the implications of calculating reference levels for gas-fired units under the proxy cost option. Stakeholders expressed concerns that the California ISO's reference levels have several limitations that may result in them not reflecting suppliers' cost expectations for that unit; this imposes a larger price risk on the supplier to potentially incur losses than the supplier would have been willing to assume. Further, we understand that some stakeholders have seen reference levels that do not always adequately reflect their incremental costs resulting in overly restrictive commitment cost bid caps and undervalued default energy bids.

If the California ISO restricts the ability for suppliers to submit their expectation of production costs it could undermine the efficiency of the market solutions. Generally speaking the California ISO's reference levels do not overly restrict suppliers' ability to reflect cost expectations. If supply offers are limited by a mitigation method then the market could produce less efficient market solutions and insufficient uplift payments to make-whole suppliers for their costs incurred.

Stakeholders have expressed concern that the current method while it is most often effective can be ineffective sometimes. To address this concerns underlying issue that reference levels under the current design may not reasonably reflect suppliers' cost expectations, the California ISO will evaluate the foundational assumptions necessary to rely on reference levels that do not provide adjustments to the inputs.

The four notable assumptions are:

- Assumption 1: One Fuel Type per Unit
- Assumption 2 and 3: One Procurement Location and One Shipper
- Assumption 4: One Price as Proxy
- Assumption 5: Next Day Price as Proxy

While California ISO stresses it is confident with its reference level design on the whole, it acknowledges and will discuss in the remainder of this section potential limitations with assuming these five assumptions.

4.5.1 Assumption 1: One Fuel Type per Unit

While other organized markets provided the ability for suppliers to register fuel switching capabilities at a specific unit and under the fuel policies, the markets provide guidelines for reflecting different value of power production based on fuel type.

The California ISO identified a concern with not providing this fuel switching capability when during strained conditions in Southern California in 2016 it began exploring viability of liquefied natural gas (LNG) to serve as fuel substitute when gas is extremely limited in Southern California.

We discovered that even if the capabilities were added to units in the area, the current market design does not support gas-fired resources burning conventional gas to adjust its reference levels to be calculated based on different commodity prices. If a supplier were to pursue this functionality they would likely incur losses on at least their commitment costs unless energy prices were sufficiently high to compensate them for their actual costs. If energy prices were insufficient to result in a revenue surplus, the supplier would need to pursue cost recovery at the Federal Energy Regulatory Commission.

In summary, having market design features that facilitate reflecting market costs for functionality such as fuel-switching is desirable so that it allows suppliers to make investment decisions and have the energy from a unit valued appropriately in the market.

4.5.2 Assumption 2 and 3: One Procurement Location and One Shipper

Through the *Bidding Rules Enhancements* initiative, the California ISO discovered that the assumption that one unit sources its fuel from one viable procurement location and pipeline shipping company was identified as not always accurate. This assumption especially breaks down in the context of the Energy Imbalance Market and regional expansion. Given the placement of other balancing areas against possible indexed procurement locations and multiple networks of pipelines, it could be possible that some entities may ship its fuel across more than one pipeline shipping company or as normal course of business procure fuel from different locations valued at different gas market prices.

In *Bidding Rules Enhancements* draft final proposal the California ISO proposed to define a fuel region representing a combined commodity price or combined base gas transportation rate based on weighted price. Where the combined price or rate is weighted by the percent of volumetric usage shipped by each company in the prior month, if available, and averaged to represent a reasonable estimate of resource-specific costs. Anticipating the appropriate weighted average costs is fairly static, California ISO proposed to limit revisions to weights annually.

The California ISO has determined that this scenario falls under the issues raised in this initiative. Under this initiative we will evaluate the need to accommodate these more complex scenarios in combination with the evaluations of the other assumptions limitations.

4.5.3 Assumption 4: One Price as Proxy

The California ISO will evaluate under this initiative whether using only one value for prevailing gas market prices results in reference levels that effectively value the suppliers' cost expectations. Using one gas market price to value power production which encompasses hours in two gas flow days increases likelihood that estimate will not perfectly align with a suppliers' estimates of its costs given the fuel costs across one electric day will be influenced by both days. One day, the later day, will have more of an impact on actual costs as it represents gas commodity prices for ~75 percent of the hours.

The two different gas days will often have similar fundamental drivers so on a routine basis prices day-over-day in a month will be generally correlated. However, if fundamentals such as outages on the gas system differ between days the fundamental drivers might be significantly different so as to drive a weaker correlation between prices. The reference level approach with a fuel cost estimate driven by next day gas commodity prices has generally worked well because there has been limited volatility. Stakeholders have expressed to the California ISO that "working well" means they did incur large losses on a particular day as result of market features.

4.5.4 Assumption 5: Next Day Price as Proxy

The California ISO will evaluate under this initiative whether using an average, next day gas commodity price to determine reference levels may not allow suppliers to fully reflect their expected costs, production costs and externalities, in their supply offers.

Current market design has generally "worked well." However, when there is volatility the next day gas commodity prices can be significantly lower or higher than prevailing market prices during the electric operating day. Not to mention if a prudent market participant transacts in advance but to do so need to complete non-standard deals, products that could be trading quite differently than the standard next day product. This exposes market participants to price risk. While stakeholders expressed to the California ISO that they can procure forward hedging instruments to mitigate some of these risks, they will likely procure fuel for the operating day either in the next day gas market or later.

In both the day-ahead and real-time markets, the California ISO reference levels may not reflect natural gas delivered prices for gas purchases in intra-day, same-day, custom daily or Monday products[30]. The market will buy and sell the next day gas contract based on each counterparty's assessment of the value of gas flows for tomorrow based on quantitative or fundamental valuations. If the fundamentals or risks are uncertain during the next day trading window, it is likely the next day contract will trade at a premium – a risk premium.

If fundamentals or risks change after the next day markets, buyers and sellers of gas will likely trade at different prices after the next day trading concludes than the prices traded during that window reflecting prevailing market conditions. Suppliers could choose to procure intra-day, same-day, custom daily, or even a special Monday-only package to purchase gas outside of the timely trading period. Since many gas customers do not have gas needs that vary across a gas day, the liquidity in these custom deals is lower. Sellers of gas will generally increase the price they are willing to sell the commodity after the next day trading given the illiquidity.

The California ISO has previously discussed with stakeholders the limitations using the first gas day's next day gas commodity price to determine reference levels in in the day-ahead market. In response, the California ISO introduced its manual gas price spike procedure to allow the California ISO to use the better price when the published indices between the two days differ by more than 125 percent. For the purpose of this initiative, the California ISO assumes this manual gas price spike procedure does not exist. Instead the California ISO is evaluating whether there is a need for a long-term enhancement allowing the Gas Day 2 price information to set values of mitigated prices in its day-ahead process.

5 Discussion

As mentioned in the Executive Summary, the purpose of this initiative is to evaluate the California ISO's bidding flexibility design and whether modifications to its design should be pursued. To engage in a discussion of the issues raised on the existing market design, this discussion will cover the following points:

- Possible Design Paths to Address Some Stakeholder Concerns
- Possible Paths to Enhance Commitment Cost Mitigation

5.1 Possible Design Paths to Address Some Stakeholder Concerns

The California ISO will discuss possible design paths to address concerns in two parts, both leveraging lessons learned from the survey of bidding and market power mitigation rules across the organized markets. The first part will pose whether methodology for determining mitigated prices should be aligned across technology types. The second part will pose four specific questions seeking input on whether specific features in other markets should be considered. The third will pose four general design paths identified through analyzing the various market rules and discuss merits of each

5.1.1 Potential Refinement to Be Technology Agnostic

First, it seems as if the method either to calculate reference levels or allow supplier submitted cost-based offers should likely be the method across all technology types. California ISO is seeking feedback on whether it should consider re-examining its assumption that gas-fired units reference levels can by calculated.

Should California ISO re-examine its policy that gas-fired units' costs can be estimated while other technology types cannot?

5.1.2 Potential Refinements to Bid Structure and Mitigated Prices

Second, the California ISO seeks stakeholder input on whether four features identified in the survey could address stakeholder concerns regarding the existing market design. After reviewing other organized markets' rules as presented in Section 3.3, it appears there is a significant difference in how the California ISO mitigates its supply offers to reference levels largely based on administratively calculated prices (i.e. ISO calculated) while the other markets that adopted a reference level approach now include flexibility to request adjustments to the fuel prices used to determine the mitigated price.

A reference level approach without the ability to request an adjustment to the fuel price may result in mitigated prices that do not reflect a reasonable expectation of units' costs. The California ISO posits that fuel costs reflecting reasonable expectation of unit's cost should represent the incremental cost of fuel procurement based on range of prevailing market prices. The incremental cost of fuel procurement is the replacement cost to replace the next 1MMbtu of gas needed to fuel the unit. Put differently, the incremental fuel procurement costs should be approximated using a gas commodity price in $/MMBtu that should be used to estimate units' value that is within range of prevailing market prices. The fuel price adjustment allows an adjust to the fuel input to the reference level so that if the variable cost is based on replacing next 1MMBtu in an intra-day, the price could change to reflect prevailing prices in that less liquid market.

For question two and three, the California ISO has been told by some stakeholders that the core structure of its bids restricts their ability to reflect costs. Under a no load structure, no load costs for being synchronized to the grid are event based costs so treatment of it similarly to start-up and transition costs is valid. Today the California ISO treats minimum load costs like event-based costs even though we understand from business cases provided to us that these costs are more similar to operating costs as they functionally increase as the online time extends. On the other hand, start-up and transition costs do not increase as online time increases. We also understand that these costs can vary hourly as can the minimum load itself. This hourly variation concern seems to be held mainly by MSGs or other thermal units that are sensitive to ambient temperature. For these reasons, the California ISO would like to open the discussion up to whether it should consider these enhancements.

We seek stakeholder input on five specific questions that arose through the evaluation of its survey on other organized markets' bidding and market power mitigation rules.

What is a reasonable approach to valuing expected production costs that results in an efficient market solution and cost recovery?

SHOULD THE CALIFORNIA ISO CONSIDER MOVING TO A "NO LOAD" VERSUS A "MINIMUM LOAD" STRUCTURE?

SHOULD THE CALIFORNIA ISO CONSIDER ENHANCING ITS MINIMUM LOAD, OR NO LOAD COSTS, TO ALLOW HOURLY VARIATION?

SHOULD THE CALIFORNIA ISO CONSIDER MOVING FROM A REFERENCE LEVEL TO A BID-IN MITIGATED OFFER SUPPORTING DAILY SUBMISSION OF MITIGATED OFFERS?

SHOULD THE CALIFORNIA ISO CONSIDER INTRODUCING FUEL PRICE ADJUSTMENTS TO ITS REFERENCE LEVEL CALCULATIONS TO REDUCE THE RISKS THAT SUPPLIERS' WILL NOT HAVE MITIGATED PRICES THAT REASONABLY REFLECT THEIR COST EXPECTATIONS?

5.1.3 Refinements to Reduce Cap/Scalar Limitation

The California ISO will evaluate how applying bid caps and scalars to adjust an average price upward to account for the range of next day market prices may not be the best method to ensure the market has effectively protected against opportunities for market power. The use of an index that is an average price introduces need for features that can create market limitations.

The California ISO is concerned that through the application of the current bid cap mitigation method, the California ISO likely allows select units the opportunity to over-state their actual cost expectations while potentially understating the costs for other units. Also of concern, is that mitigated energy bids with a 110 percent scalar would ensure over compensation for select units whose cost expectations are less than the reference level with the 10 percent margin. Caps and Scalars introduce a market design limitation that introduces risk that supplier could either bid up to cap or be mitigated to reference level at higher value than it sees its unit and over-recover payments above cost expectations. This limitation exists because the markets approach to caps and scalars is to provide adequate compensation for the select few with cost expectations well outside of the average. This could be introducing inefficiencies into the market solution and increasing cost recovery through uplift payments.

5.1.4 Refinements to Improve Bidding Flexibility and Market Protection Balance

Third, the California ISO is seeking Stakeholder feedback on its illustration of the four high-level design paths Stakeholders would support pursuing to address the issues they raised. To do so, we present Figure 2 and Figure 3, which show the trade-offs between the four identified market design paths to attempt to find the optimal path balancing allowing suppliers to submit economic prices reflecting their willingness to provide energy measured against need to protect against structural or behavioral issues and ensuring mitigated prices are reasonable reflections of suppliers' cost expectations. There are four major paths that identified that could lead to a balance.

Figure 2: Size Risk that Market is Vulnerable to Market Power or Gaming

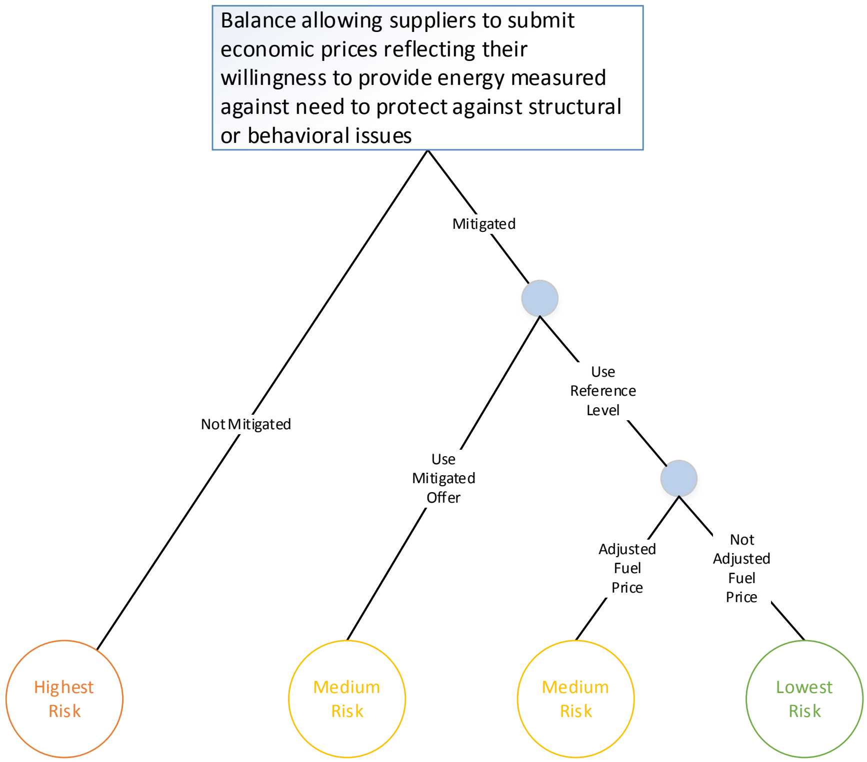


Figure 3: Size Risk that Suppliers' Value Not Reflected in Market

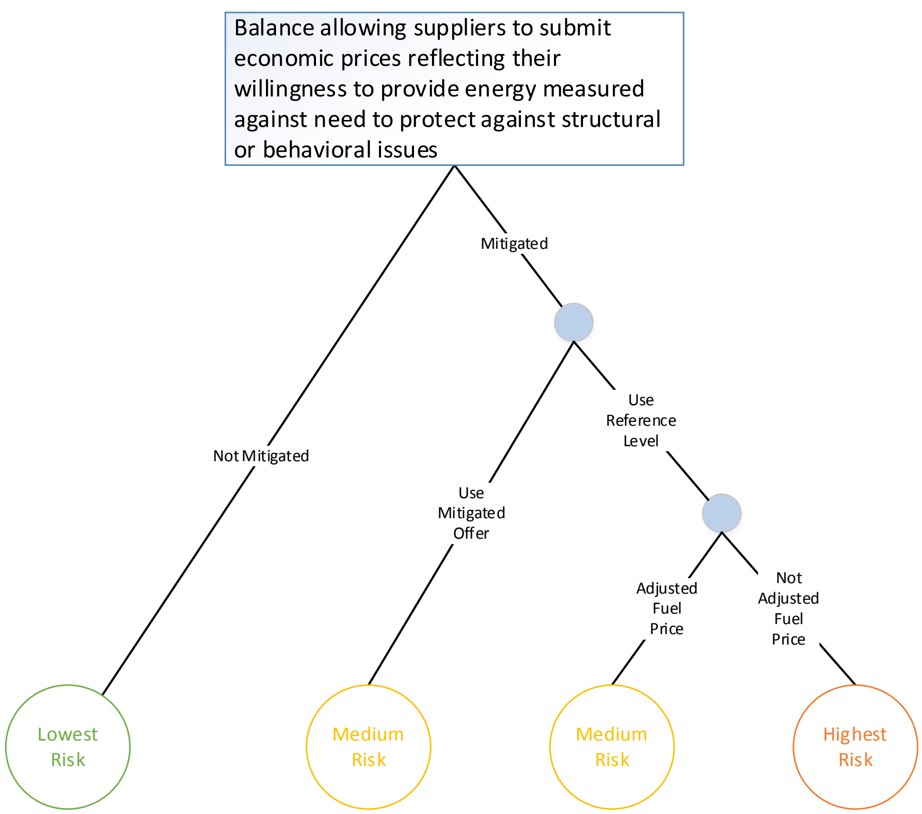


Figure 2 sizes the risk that the market will be made vulnerable to potential exercise of market power or gaming strategies for each of these four paths. Directly following, Figure 3 sizes the risk that suppliers' assets values are not able to be fully reflected in the market for each of these four paths. The probability that it will not be fully reflected is shown as ranging from low to high.

The California ISO's current design is the path that imposes a potentially unacceptable risk that the suppliers' cost expectations will not be reasonably reflected in the market in order to ensure against undo exercise of market power. This is shown by the farthest right path on the second decision tree showing the likely size of the risk suppliers' valuations will not be reflected in the market. While the farthest right path is the highest risk path for the risk on suppliers it is the lowest risk path for the risk to the market since it maintains the lowest risk that the market could be exposed to opportunities to exercise market power or gaming strategies. The design choice sacrifices bidding flexibility to ensure the lowest risk to consumers of artificial pricing. This is consistent with the California ISO's current policies.

The California ISO posits that the optimal balance would promote a market efficient solution that results in energy prices reflecting suppliers' willingness to sell under competitive market conditions and suppliers' cost expectations under uncompetitive market conditions. Such a path would likely fall within one of the two middle paths that have a medium-level risk to both the suppliers and the markets.

The California ISO seeks stakeholder input as to whether the California ISO has found this balance. If not, the California ISO would like to receive feedback as to what is the preferred path to strike the optimal balance sought by both stakeholders and the California ISO.

WHAT ARE STAKEHOLDER VIEWS OF THE PREFERRED PATH ON THESE DECISION TREES?

ARE THERE MORE THAN FOUR DESIGN PATHS THAT SHOULD BE CONSIDERED TO EVALUATE FOR A PREFERRED PATH?

5.2 Possible Paths to Enhance Commitment Cost Mitigation

As introduced in the Issue section, stakeholders expressed concerns that the California ISO's commitment cost market power mitigation methodology may result in over-mitigation of units since it assumes uncompetitive market conditions. To address the concern that market conditions could be competitive but suppliers' offers are still limited the California ISO would need to design an impact test or a structural test for commitment costs that could look like a form of an impact threshold on energy prices or uplift, a static pivotal supplier test, or some other more dynamic market power mitigation methodology. The impact test or structural test would test for uncompetitive market conditions.

As noted by the Department of Market Monitoring (DMM) during the *Bidding Rules Enhancements* initiative, the California ISO market faces several challenges when developing commitment costs mitigation methodology including an impact test. DMM recommends that any future methodology would:

- Need to consider transmission and contingency constraints, exceptional dispatches, operator action to override market software, and outage re-rates among others to be effective

- Need to effectively identify opportunities for market power and appropriately applying mitigation.

Additionally, the California ISO would need to determine whether an impact test in the California ISO markets should test for adverse market impacts by:

- Examining changes in energy prices, uplift payments, or both

- Examining changes as result of committed units, non-committed units, or both

- Examining changes as result of one units impact or impact of a portfolio of resources

Mitigating market power for unit commitment is more important in the California ISO market than other ISOs because of the greater amount of load pockets with limited generation alternatives. Because of the importance of these issues, the California ISO believes that an impact test on commitments should include an examination of non-committed units' impacts. Additionally, there might be a need to examine how effectively portfolio of resources' impacts are evaluated.

The California ISO seeks Stakeholder feedback and input on whether introducing some form of an impact test would reduce likelihood of over-mitigation, which of the possible impact or structural test options, and analysis needed to support changes.

SHOULD THE CALIFORNIA ISO RE-EXAMINE ITS POLICY ON COMMITMENT COST BIDDING TO INTRODUCE AN IMPACT TEST TO ITS MARKET POWER MITIGATION MECHANISMS?

DO STAKEHOLDERS HAVE FEEDBACK ON THE DMM'S RECOMMENDATION FOR NECESSARY CONSIDERATIONS FOR A FUTURE METHODOLOGY LISTED ABOVE?

WHAT ANALYSIS SHOULD BE DONE TO SUPPORT WHICH APPROACH FOR DESIGNING IMPACT THRESHOLDS COULD BE EFFECTIVE FOR THE CALIFORNIA ISO MARKETS?

WHAT ANALYSIS SHOULD BE DONE TO SUPPORT WHETHER A TEST SHOULD BE PERFORMED ON NON-COMMITTED AS WELL AS COMMITTED RESOURCES?

HOW COULD THE CALIFORNIA ISO TREAT PORTFOLIO OF RESOURCES IN TESTING A SUPPLIER'S MARKET IMPACT?

The remainder of this section will introduce two prevailing methodologies for testing for adverse market impacts – conduct and impact test or pivotal suppliers test. We introduce scenarios and concerns identified by the California ISO under both designs in the following sections:

- Evaluating a Conduct and Impact Test Design for Unit Commitment
- Evaluating Pivotal Supplier Test Design for Unit Commitment

5.2.1 Evaluating a Conduct and Impact Test Design for Unit Commitment

If the California ISO were to consider enhancements to its conduct and impact test design, the California ISO would need to (1) design an impact test to develop a non-zero impact threshold and (2) determine whether conduct threshold should be adjusted in light of non-zero impact threshold.

A conduct and impact test is a two-step mitigation methodology. A unit fails the conduct test when the offer reaches a pre-determined threshold, e.g., 200 percent above the reference level or supplier submitted cost-based offer. It is then subject to the impact test. How the impact test is conducted in each market varies, but essentially it replaces the supply offer with the reference level or cost-based offer and compares the resulting energy prices or change in uplift payments to see if the supply offer has the ability to impact the market. An impact test on energy prices alone would not be effective at capturing market power related to inflated commitment cost offers.

As discussed in the background (Section 3.3.1), the California ISO's mitigation method for commitment costs effectively applies a 125 percent conduct test trigger and a 0 percent impact test trigger on its commitment cost offers. Stakeholders have advocated for relaxing the conduct threshold and applying an impact threshold. The California ISO understands this is more of a norm in the other markets to have conduct thresholds that are higher than 25 percent for commitment cost offers and if adopted would provide greater bidding flexibility while limiting adverse market impacts. Table 5 in Appendix B: Organized Markets Survey shows that for organized markets that mitigate based on reference levels, a conduct threshold of offers that exceed either 200-300 percent or $100/MWh relative to the reference level with an outlier at 50 percent (ISO-NE, NYISO, and MISO). For SPP's market that mitigates to a submitted cost-based offer instead of an administratively calculated level, their conduct thresholds are more modest in a range of 10-25 percent increase relative to submitted cost-based offer.

If the California ISO were to implement the impact test portion of a conduct and impact test for commitment cost mitigation, the California ISO has identified two questions that need to be considered.

WHAT WOULD BE AN APPROPRIATE THRESHOLD THAT SHOULD FAIL THE CONDUCT TEST TO BE SUBJECT TO THE IMPACT TEST?

HOW COULD THE CALIFORNIA ISO EFFECTIVELY CAPTURE IMPACTS OF COMMITMENTS?

5.2.1.1 Appropriate Conduct Threshold

The California ISO's view on the first question regarding an appropriate conduct test threshold is that a conduct threshold should sufficiently protect the market against gaming or market power. The California ISO's current market power mitigation design, the 125 percent conduct threshold, already is limited in ability to protect against adverse market impact since it the 25 percent margin could allow suppliers to submit inflated offers higher than their cost expectations and under uncompetitive market conditions adversely impact the market.

One limitation of relaxing the conduct threshold for triggering the impact test is that the methodology would allow a greater degree of mark-up before failing the conduct test – exacerbating the existing limitation. In the long run, such a limitation could inappropriately increase overall market costs through inflated commitment cost offers that avoid being subject to mitigation.

From a design perspective and assuming an appropriate level is determined, it seems there are three options for setting pre-determined thresholds. The options include triggers that are:

- Percentage of the reference level bid (e.g., 200 percent above reference levels or cost-based offers),

- flat mark-up in terms of dollars (e.g. $100 above reference levels or cost-based offers), or

- a combination.

California ISO seeks Stakeholder feedback on these design options and analysis needed to support changes.

WHAT ANALYSIS SHOULD BE DONE TO SUPPORT A DESIGN CHANGE TO ONE OF THE OTHER OPTIONS SUCH AS FLAT MARK UP OR A COMBINATION OF PERCENTAGE AND MARK UP?

WHAT ANALYSIS SHOULD BE DONE TO SUPPORT WHAT CONDUCT THRESHOLD IS APPROPRIATE?

Do Stakeholders prefer a specific design change on the California ISO's conduct threshold?

5.2.1.2 Appropriate Impact Threshold

Regarding the second area of concern, it seems an impact test in the California ISO markets would need to determine whether to test for adverse market impact by:

- Examining changes in energy prices, uplift payments, or both
- Examining changes as result of committed units, non-committed units, or both
- Examining changes as result of one units impact or impact of a portfolio of resources

First, while some markets only review impact to energy prices and others such as NYISO include impact to uplift payments, the California ISO believes that an impact test applied to commitment cost offers needs to include changes to the overall amount of uplift payments to reliably capture market impacts from inflated commitment cost offers. The California ISO believes that an impact test applied to commitment cost offers needs to include changes to the overall amount of uplift payments to reliably capture market impacts from inflated commitment cost offers.

Second, the California ISO identified in its background on organized markets' mitigation methods a concern that the use of certain forms of a conduct and impact could allow units to withhold capacity from the market and impact prices for an external benefit. To address this, NYISO evaluates units that were not cleared in its market process. This is done by replacing supply offers not cleared in the market process with either the reference levels or cost-based offers and then rerunning the market solution to apply the conduct and impact test. If when evaluating the new commitment decisions and energy prices, the energy prices or uplift payments with are lower than prices determined with the supply offer the supplier will fail the impact test even if not committed in market run. The California ISO believes that an impact test applied to commitment cost offers would need to review market impacts from non-committed impacts.

Third, the California ISO intends to review the organized markets' rules for whether any include an impact by a portfolio of resources. At this stage, we would like to seek input on whether Stakeholders support a consideration of an impact test performed on a Scheduling Coordinators' impact from all of its units.

California ISO seeks Stakeholder feedback on which of these design options and analysis needed to support changes.

What analysis should be done to support which approach for designing impact thresholds could be effective for the California ISO markets?

SHOULD THE IMPACT TEST EXAMINE IMPACT TO ENERGY PRICES, UPLIFT PAYMENTS OR BOTH?

WHAT ANALYSIS SHOULD BE DONE TO SUPPORT WHETHER A TEST SHOULD BE PERFORMED ON NON-COMMITTED AS WELL AS COMMITTED RESOURCES?

HOW COULD THE CALIFORNIA ISO TREAT PORTFOLIO OF RESOURCES IN TESTING A SUPPLIER'S MARKET IMPACT?

5.2.2 Evaluating Pivotal Supplier Test Design for Unit Commitment

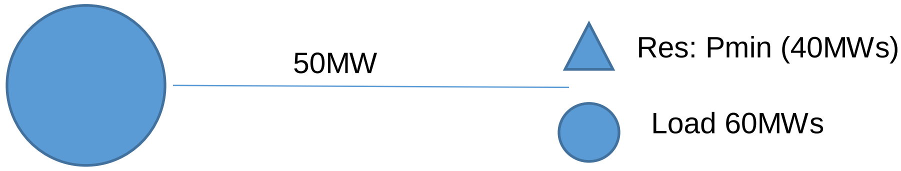
The California ISO is concerned that there might be some instances where market power would not be detected as result of unit commitment under a pivotal supplier test. For example, if market power is exercised through commitments with inflated offers that result in fully relieving a binding constraint, then a pivotal supplier test based on binding constraints would not capture the adverse market impact. Commitment can result in fully relieving a binding constraint because commitment is "lumpy," and the minimum load of a unit is more than enough to fully relieve a binding constraint such that it cannot be observed in the final market solution.

A three pivotal supplier test evaluates if a given constraint is competitive or un-competitive. If there is sufficient supply to meet demand, after removing the largest suppliers, the constraint is competitive. Otherwise, it is uncompetitive and provides opportunity for the exercise of market power. Suppliers who can provide supply to uncompetitive constraints are subject to mitigation procedures.

These tests are triggered by a binding constraint or another defined need for supply in a defined area. Offers would be mitigated if, without the largest suppliers, the demand could not be met. The determination that demand could not be met without the supply is made by comparing the demand at that location to the supply offered with the three largest suppliers removed. If dispatched, the supply offered would be injected on the system and depending on its distribution factor[31] would flow a portion of that power across the applicable constraint in the counterflow direction relieving congestion in the prevailing flow direction.

To illustrate the concern with a pivotal supplier test, the California ISO shows a simple radial system in Figure 4 below. A transmission line rated at 50MW serves a load pocket of 60MW at peak. There is a unit in the load pocket with a minimum load of 40MW. The only way to serve the load when it exceeds 50MWs is with the local unit at minimum load. If the transmission line is binding, it would trigger mitigation of the local unit if the unit did not have to be committed to 40 MW minimum load. However, once the unit is committed to minimum load, the transmission line will no longer bind.

Figure 4: Example of difficulties applying dynamic mitigation to commitment costs



Therefore the unit could exercise market power through high commitment cost bids. Also, the unit would not be mitigated because the commitment decision would relieve any congestion on the transmission line.

A potential solution would be to conduct a pivotal supplier test on all constraints in the critical constraint list for any iteration of the optimization during a market run. This would likely result in over-mitigation since it would view constraints as binding that were not binding in the final solution. Units that are effective in relieving congestion on an uncompetitive constraint in any iteration would be subject to mitigation. Even with the possibility that the constraint would never bind, the unit would not have the ability to exercise market power.

Another drawback to this approach is that it could be seen as a step backward from adopting mitigation methodologies balancing mitigation to levels that do not over or under mitigate at unacceptable levels. From a market design perspective, applying a pivotal supplier test to all critical constraints for commitment cost mitigation would likely over-mitigate since constraints would be evaluated that are not binding in the final solution.

One of the main drivers of the California ISO moving away from the static competitive path assessment to the dynamic path assessment for energy offer mitigation was to reduce the instances of over-mitigation. The California ISO holds the same design goal for any commitment cost methodology that it employed in moving to a dynamic assessment for its energy offer methodology.

Another drawback is that there is questionable feasibility of performing a dynamic assessment evaluating all the factors the California ISO believes are needed for an effective test. For example, the California ISO believes testing the effect of units not committed or testing portfolio of units may introduce a significant computational burden if performed in its real-time market which will be run every 5 minutes. Any dynamic pivotal supplier test run in the market would need to have a low computation time to be effective in market without compromising the real-time solution.

California ISO seeks Stakeholder feedback on how a pivotal supplier test might be introduced for commitment costs.

WOULD A DYNAMIC ASSESSMENT PERFORMED IN TANDEM WITH THE ENERGY MITIGATION BE PREFERABLE TO STAKEHOLDERS?

WOULD STAKEHOLDERS SUPPORT CONSIDERING A STATIC COMPETITIVE PATH ASSESSMENT FOR COMMITMENT COST MITIGATION IF A DYNAMIC ONE IS NOT FEASIBLE?

Appendix A: Stakeholder Engagement Plan

Stakeholders will be engaged in the development of potential market design enhancements in two phases. The target completion for both phases and presentation of the draft final proposal to the EIM Governing Body and ISO Board of Governors is July 2017.

The current schedule for this initiative is shown below.

Milestone	Date
Issue paper posted	November 18, 2016
Stakeholder call	November 22, 2016
Stakeholder written comments due	December 9, 2016
Working group meeting	December 21, 2016
Stakeholder written comments due	January 11, 2017
Working group meeting	January 26, 2017
Stakeholder written comments due	February 2, 2017
Straw Proposal Posted	February 7, 2017
Stakeholder meeting	February 14, 2017
Stakeholder written comments due	February 28, 2017
Working group meeting	March 14, 2017
Stakeholder written comments due	March 28, 2017
Working group meeting	February 14, 2017
Stakeholder written comments due	February 28, 2017
Revised straw proposal posted	May 4, 2017
Stakeholder call	May 11, 2017
Stakeholder written comments due	May 18, 2017
Draft final proposal posted	May 31, 2017
Stakeholder call	June 7, 2017
Stakeholder written comments due	June 21, 2017

Milestone	Date
Board of Governors meeting	July 2017

The California ISO will discuss this issue paper with stakeholders during a call on Tuesday, November 22, 2016 After the stakeholder call, the California ISO will issue a stakeholder comments template with the questions posed throughout this document. Stakeholders are asked to submit their written comments to initiativecomments@caiso.com by close of business on December 9, 2016.

Appendix B: Organized Markets Survey

Under the *Bidding Rules Enhancements* initiative, the California ISO committed to perform a survey of other organized markets' bidding flexibility rules and market power mitigation methods as a tool for evaluating whether comparatively the California ISO's rules are more or less restrictive to other market operators. The California ISO expands this review to include the mitigated prices to which supply offers are mitigated and flexibility provided to support appropriate cost recovery.

The intent of CAISO's survey was to understand how the bidding rules and mitigation methodologies of other ISOs are similar or differ from each other. The California ISO is evaluating whether other design features could effectively be applied in its markets to address the concerns raised by Stakeholders in this initiative.

First, Table 3 shows the results of the survey on bidding rules, directly following Table 4 shows the results on market power mitigation methodologies, and the last table, Table 5, provides additional detail on markets' conduct and impact tests. The mitigation results in Table 4 include description of the price levels that the bids are mitigated to if either test fails, opportunities for fuel price adjustments in advance of the market run, opportunity to seek after-the-fact cost recovery, and validation methods to ensure market is protected from submission of artificial prices.

Table 3: Survey of Organized Markets' Bidding Rules

Organized Markets	Bid structure	DA Market Close	RTM rebidding (Last time to modify)	
			Commitment Costs	Incremental Energy
CAISO[32]	Submit energy, start-up, minimum load, and transition cost offers	10:00 PT TD-1	(Pending) For hours with no day-ahead award and once committed when not under a minimum run time limitation: T-75[33]	T-75
ISO-NE[34]	Submit energy, start-up and no load offers All cost offers may vary by hour	10:00 ET TD-1	T-30	T-30
MISO[35]	Submit energy, no load and start-up offers	11:00 CT TD-1	T-30	T-30

			Eligibility for uplift payments are subject to more nuanced uplift rules so changed bid may not be guaranteed uplift.	Eligibility for uplift payments are subject to more nuanced uplift rules so changed bid may not be guaranteed uplift.
NYISO[36]	Submit energy, minimum load, and start-up offers	5:00 ET TD-1	T-75 If no day-ahead schedule then no limit on price level bid but price level locked for offers with day-ahead schedules.	T-75 Eligibility for uplift payments are subject to more nuanced uplift rules so changed bid may not be guaranteed uplift.
PJM[37]	Submit price-based and cost-based schedules for start-up, no load, and energy offers Choice of cost-based option for start-up and no load fees or price-based option start-up and no load fees.	10:30 ET TD-1 Daily bidding under cost-based option for start-up and no load. Twice per year for price based start-up and no load. .	<u>Price-based</u> 14:15 ET TD-1: May update offers for hours not committed in day-ahead May not change from self-schedule to economic bidder <u>Cost-based</u> If no day-ahead, may opt to instruct market to use its cost-based schedules for an hour by three hours prior to the operating hour If day-ahead awards, must opt to use cost-based schedules prior to 2100 ET TD-1	<u>Price-based</u> 14:15 ET TD-1: May update offers for hours not committed in day-ahead May not change from self-schedule to economic bidder <u>Cost-based</u> If no day-ahead, may opt to instruct market to use its cost-based schedules for an hour by three hours prior to the operating hour If day-ahead awards, must opt to use cost-based schedules prior to 2100 ET TD-1
SPP[38]	Submits unit offers and mitigated unit offers for start-up, no load, and energy offers	11:00 CT TD-1	<u>Unit offers:</u> T-30 <u>Mitigated offers:</u>	<u>Unit offers:</u> T-30 <u>Mitigated offers:</u>

	Mitigated offers must be consistent with Mitigated Offer Development Guidelines		If day-ahead award then no rebidding If no day-ahead award and not eligible for intra-day adjustments then up to 17:00 CST TD-1 If units online past DA or RUC commitment period, fuel-switching units, or a quick start unit:[39] T-30	If day-ahead award then no rebidding If no day-ahead award and not eligible for intra-day adjustments then up to 17:00 CST TD-1

Table 4: Various Mitigation Methods for Commitment and Energy Costs

Organized Markets	Mitigation method	Provisions for ad hoc reference level adjustments	Uplift compensation when supplier is limited in reflecting costs in supply offer	Validation Method
CAISO	<u>Both Methods</u> For commitment costs: conduct test applied and mitigates to bid cap For dispatchable energy: Dynamic structural test (three pivotal suppliers)	None	Proposed an after-the-fact cost recovery for commitment costs exceeding bid cap due to marginal fuel procurement costs through extending 205 filing right at FERC. Pending at FERC	None, ISO calculates reference level and does not adjust its reference levels prior to or after the market run.

ISO-NE[40]	<u>Conduct and impact test applied and mitigated to reference level</u> Pivotal supplier test and a constrained area test to determine which conduct thresholds to apply for general mitigation Apply conduct test only to minimum load cost, start-up and no load based on criteria If energy or commitment fails, mitigates all parameters	May request revisions to reference level calculation no later than 17:00 ET TD-2 with exceptions up until 21:30 ET TD-1; May seek a fuel price adjustment intra-day by submitting expected fuel price to replace bid-in price in reference level calculation when its expected price will be greater than that used in calculation.	Federal Power Act Section 205 filing right at FERC to seek recovery of supply offers mitigated or above the offer cap exceed settlement payments for costs above the offer cap or for mitigated energy offers.[41]	Fuel price adjustment in reference level must reflect price at which supplier expects to procure fuel and must submit supporting documentation within 5 business days.
MISO[42]	<u>Conduct and impact test applied and mitigated to reference level</u> Conduct thresholds applied to reference level to trigger impact Impact test on prices or uplift payments Mitigation only applied in the presence of binding transmission constraints or reserve zone constraints.	May contact the IMM to make other arrangements including intra-day changes if the Reference Levels do not accurately reflect their costs	NONE	None the CAISO could find

NYISO[43]	Conduct and impact test applied and mitigated to reference level Conduct thresholds to trigger impact test	May update fuel prices in reference levels if submitted in sufficient time prior to market close	If not able to submit timely and extraordinary circumstance, may request to revise fuel cost and recalculate reference levels, restore accepted bids that would not have failed mitigation with new reference level and settle after-the-fact. Also - extend 205 filing right at FERC	MMU screens for fuel type and fuel price information submitted for potentially inaccurate information, for updates to reference level before market close expected to retain invoices and supporting documentation under data retention requirements
PJM[44]	Pivotal Supplier Test applied and mitigated to cost-based offer Structural test (three pivotal suppliers) for active constraints Bid-in cost-based offers required to be consistent with unit-specific fuel policy	N/A	Cost-based adjustments May request compensation for differences between bid-in cost-based offer and actually incurred costs after-the-fact through uplift Energy costs above offer cap May seek uplift payments after-the-fact for cost based energy offers greater than $2,000/MWh by submitting relevant supporting documentation.	Cost-adjustments MMU reviews requested adjustments after-the-fact. If unsatisfied, may request PJM review and include MMU finding in request. Energy costs above offer cap, must submit by 1030 ET TD+1 documentation of the Market Seller's calculation of the cost-based offer in accordance with cost development guidelines and applicable fuel cost policy.
SPP	Conduct and impact test[45] applied and mitigated to mitigated offers Conduct thresholds to trigger impact test	N/A	NONE	MMU verifies mitigated offers using fuel cost policy and cost day submitted consistent with mitigated offer development guidelines

	Mitigation only applied in presence of a binding constraint or reserve zone, or unit committed to address Local Reliability Issue. Pivotal supplier test used to determine constrained areas. Mitigated offers consistent with Mitigated Offer Development Guidelines			

Table 5: Conduct and Impact Thresholds

Economic Withholding			Conduct Threshold	Impact Threshold	Tariff Section
ISO-NE	Energy	General	lower of 300% or $100/MWh increase relative to reference level (except if offer less than $25/MWh)	lower of either 200% or $100MW/h of energy prices	III.A.5.5.
ISO-NE	Energy	Constrained	lower of 50% or $25/MWh increase relative to reference level	lower of either 50% or $25/MWh of energy prices	III.A.5.5.
MISO	Energy	Broad Constrained Area (sufficient compensatio n expected)	lower of 300% or $100/MWh increase relative to reference level (except if offer less than $25/MWh)	lower of 200% or $100/MWh increase of energy prices or any increase in uplift payments	64.1.2
MISO	Energy	Narrow Constrained Area (insufficient	lower of 300% or $100/MWh increase relative to reference level	calculated threshold relative to energy prices or any increase in uplift payments	64.1.2

		compensation expected)	(except if offer less than $25/MWh)		
NYISO	Energy	General	lower of 300% or $100/MWh increase relative to reference level (except if offer less than $25/MWh)	lower of 200% or $100/MWh increase of energy prices	23.3.1.2.1
NYISO	Energy	Constrained	Distribution factor greater than 0 and increase of more than calculated threshold	lower of 200% or $100/MWh increase of energy prices or uplift payments	23.3.1.2.2
SPP	Energy	Frequently Constrained Area	17.5% increase relative to submitted mitigated offer (except if offer less than $25/MWh)	$25/MWh increase of energy prices, uplift payments,	AF 3.2, 3.7
SPP	Energy	Local Reliability Issue Commitment	10% increase relative to submitted mitigated offer (except if offer less than $25/MWh)	$25/MWh increase of energy prices, uplift payments,	AF 3.2, 3.7
SPP	Energy	General	25% relative to submitted mitigated offer (except if offer less than $25/MWh)	$25/MWh increase of energy prices, uplift payments,	AF 3.2, 3.7
NYISO	Minimum Load	General	lower of 300% or $100/MWh increase relative to reference level (except if offer less than $25/MWh)	lower of 200% or $100/MWh increase of energy prices	23.3.1.2.1
NYISO	Minimum Load	Constrained	Distribution factor greater than 0 and increase of more	lower of 200% or $100/MWh increase	23.3.1.2.2

			than calculated threshold	of energy prices or uplift payments	
MISO	Minimum Load (No-Load plus Energy up to Hourly Economic Minimum) Level	Broad Constrained Area (sufficient compensation expected)	lower of 300% or $100/MWh increase relative to reference level (except if offer less than $25/MWh)	lower of 200% or $100/MWh increase of energy prices or any increase in uplift payments	64.1.2
MISO	Minimum Load (No-Load plus Energy up to Hourly Economic Minimum) Level	Narrow Constrained Area (insufficient compensation expected)	Distribution factor greater than 0 and increase of more than calculated threshold	calculated threshold relative to energy prices or any increase in uplift payments	64.1.2
SPP	No-load	Local Reliability Issue Commitment	10% increase relative to submitted mitigated offer	$25/MWh increase of energy prices, uplift payments,	AF 3.2, 3.7
SPP	No-load	General	25% relative to submitted mitigated offer (except if offer less than $25/MWh)	$25/MWh increase of energy prices, uplift payments,	AF 3.2, 3.7
MISO	Start-up	Broad Constrained Area (sufficient compensation expected)	200% of reference level	lower of 200% or $100/MWh increase of energy prices or any increase in uplift payments	64.1.2
NYISO	Start-up	General	200% of reference level	lower of 200% or $100/MWh increase of energy prices	23.3.1.2.1

NYISO	Start-up	Constrained	200% increase relative to reference level	lower of 200% or $100/MWh increase of energy prices or uplift payments	23.3.1.2.2
SPP	Start-up	Local Reliability Issue Commitment	10% increase relative to submitted mitigated offer	$25/MWh increase of energy prices, uplift payments,	AF 3.2, 3.7
SPP	Start-up	General	25% relative to submitted mitigated offer (except if offer less than $25/MWh)	$25/MWh increase of energy prices, uplift payments,	AF 3.2, 3.7
MISO	Start-up Offers	Narrow Constrained Area (insufficient compensation expected)	50% of reference level	calculated threshold relative to energy prices or any increase in uplift payments	64.1.2

Appendix C: Reference Level Calculations

This appendix provides the formulations for the day-ahead delivered price estimate (GPI_{DA}), real-time delivered price estimate (GPI_{RT}), and reference levels used in the California ISO markets. Note that while mitigated energy offers are settled at the price level at the default energy bid the commitment costs are settled at the maximum allowable price level at 125 percent of the calculations shown.

Equation 1: Gas Price Index for Delivered Price Estimate [46]

Gas Price Index

$$GPI_{DA} = Commodity\ Price_{GD1} + Transportation\ Rate + \text{Shrinkage Allowance}_{GD1} + Cap\ \&\ Trade\ Credit + Miscellaneous$$

$$GPI_{RT} = Commodity\ Price_{GD2} + Transportation\ Rate + \text{Shrinkage Allowance}_{GD2} + Cap\ \&\ Trade\ Credit + Miscellaneous$$

Where

$$Commodity\ Price_{GD1} = average(SNL_{GD1}, Platts_{GD1}, ICE_{GD1}, NGI_{GD1})$$

$$\text{Shrinkage Allowance}_{GD1} = Commodity\ Price_{GD1} * \frac{Fuel\ Reimbursement\ Rate}{1 - Fuel\ Reimbursement\ Rate}$$

$$\text{Shrinkage Allowance}_{GD2} = Commodity\ Price_{GD2} * \frac{Fuel\ Reimbursement\ Rate}{1 - Fuel\ Reimbursement\ Rate}$$

Transportation Rate, Cap & Trade Credit are the approved gas pipeline shipping company rates on the company's electric supplier rate for that region.

Miscellaneous costs will be defined specific to the fuel region.

Equation 2: Default Energy Bid Cost Calculation

Default Energy Bid Cost

$$= \begin{cases} (\text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder}) * Scalar, GHG_{COMPLIANCE} =' N' and\ DE \\ (\text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost}) * Scalar, GHG_{COMPLIANCE} =' Y' a \\ (\text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + DEBA) * Scalar, GHG_{COMPLIANCE} =' \end{cases}$$

Where:

$$\text{Segment's Fuel Cost} = Unit\ Conversion * \text{Heat\_Rate} * GPI$$

$$\text{GHG Cost} = Unit\ Conversion * \text{Heat\_Rate} * \text{Emissions Rate} * \text{GHG Allowance Rate}$$

$$\text{Scalar} = 1.1$$

$$\text{Unit conversion} = 0.001$$

Equation 3: Proxy Start-Up Costs

Start-up Cost

$$= \begin{cases} \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder}\,, GHG_{COMPLIANCE} =' N' and \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost}\,, GHG_{COMPLIANCE} =' Y \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA\,, GHG_{COMPLIANCE} \end{cases}$$

Where:

$\text{Start-up Fuel Cost} = STRT_{STARTUP_{FUEL}} * GPI_{DA,RT}$

$\text{Start-up Energy Cost} = STRT\_STARTUP\_AUX * EPI$

$\text{GMC Adder} = Pmin * (STARTUP\_RAMP\_TIME/60min) * \frac{GMC}{2}$

$\text{GHG Cost} = STRT\_STARTUP\_FUEL * \text{Emissions Rate} * \text{GHG Allowance Rate}$

Equation 4: Proxy Minimum Load Costs

Minimum Load Cost

$$= \begin{cases} \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder}\,, GHG_{COMPLIANCE} =' N' and\ MMA = (\\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost}\,, GHG_{COMPLIANCE} =' Y' and\ MM \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + MMA\,, GHG_{COMPLIANCE} =' Y' and \end{cases}$$

Where:

$\text{Minimum Load Fuel Cost} = Unit\ Conversion * \text{Heat\_Rate} * Pmin * GPI_{DA,RT}$

$\text{VOM} = \text{VOM} * \text{Pmin}$

$\text{GMC Adder} = Pmin * GMC$

$\text{GHG Cost} = Unit\ Conversion * \text{Heat\_Rate} * Pmin * \text{Emissions Rate} * \text{GHG Allowance Rate}$

$\text{Unit conversion} = 0.001$

Notes

[1] A market clearing price is the price at which the profit maximizing buyers and sellers are the same for a given quantity demanded.
[2] Henry Hub NYMEX contract (HH) index prices is formed by the volume weighted average price of HH contracts transacted during a 30 minute period on the third day of bidweek (2:00 – 2:30 EST).
[3] IFERC, NGI, and NGX are some examples of publishers that publish the first of month contracts that are formed by the volume weighted average price of fixed price or physical basis contracts transacted around the clock during bidweek.
[4] End of month or gas daily average contracts are formed by the simple average of each next day gas index published during the contract month.
[5] The ISO averages next day gas indices published by ICE, SNL Energy/BTU daily, NGI, or Platt's Gas Daily indices to determine its day-ahead or real-time gas price indices (GPI).
[6] Market Instruments BPM at 191.
[7] Transactions done on Friday are for flow on Saturday, Sunday and Monday and generally the prior day's index will apply to holidays.
[8] NGI's Price Index Methodology Point-By-Point Index Descriptions and Code of Conduct Statement, http://www.naturalgasintel.com/ext/units/Daily-GPI/NGIMethodology.pdf.
[9] Transactions done on Friday are for flow on Saturday, Sunday and Monday and generally the prior day's index will apply to holidays.
[10] Platt's North American Natural Gas Methodology: June 2016, http://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/na_gas_methodology.pdf
[11] Transactions done on Friday are for flow on Saturday, Sunday and Monday and generally the prior day's index will apply to holidays.
[12] FERC released a final order on April 16, 2015 (Order 809, RM14-2) establishing new times for nomination practices used by the interstate pipelines to nominate natural gas transportation.[12]
[13] These costs will vary be the amount of time the unit has been shut down generally referred to as "hot", "intermediate", or "cold" starts. "Cold" starts will be the most expensive of the three as it is likely to require the most fuel or auxiliary power to bring the unit from off to on.
[14] The ISO dispatches its real-time market in five minute intervals where those dispatches are cleared against real-time load. Advisory dispatches are sent up to four and a half hours prior to the operating interval from through the five minute market (5MM).
[15] NYISO, FERC docket no. ER10-1977, July 26, 2010, p. 4.
[16] ISO-NE, FERC docket no. ER13-1877, transmittal letter, July 1, 2013, p. 3.
[17] August 19, 2016 Tariff Amendment on Bidding Rules Enhancements, Minimum Load Costs, RE16-2445, http://www.caiso.com/Documents/Aug19_2016_TariffAmendment_BiddingRules_CommitmentCostsEnhancements_ER16-2445.pdf .
[18] Any solution within the boundaries defined by these constraints will be a valid solution but the optimal solution within the boundary will be the one that produces the lowest cost to consumers.
[19] The California ISO settles the excess cost for exceptional dispatches used to mitigate or resolve congestion as a result of transmission related modeling limitations through exceptional dispatch uplift settlements (Charge Code Configuration Guide 6488). The California ISO settles the excess costs for system emergency exceptional dispatch energy types through the real-time excess cost uplift settlements (Charge Code Configuration Guide 6482). Both of these excess cost uplift settlements are made at the supplier's offer price or better.
[20] Distribution factor or shift factor is the percentage of an injection or withdrawal at a given node flows across the constraint in the direction of the reference bus to determine whether the injection or withdrawal exacerbates or relieves congestion. There is a shift factor for each constraint, node combination so that the power transfer across the constraint can be modelled. Injections at location with positive shift factors will exacerbate the congestion where withdrawals at that location will relieve congestion. Conversely, injections at location with negative shift factor will relieve congestion where withdrawals will exacerbate congestion.
[21] In all of the other ISO/RTOs sampled, the market monitoring unit either calculates or works with the ISO/RTO to calculate reference level commitment costs in conjunction with performing a market power mitigation test.
[22] This is for units under the proxy cost option. There is an exception for gas-fired units that are use-limited, the California ISO allows suppliers to elect the registered cost option for these units where there is no bidding flexibility as costs are not bid-in but fixed for 30 days but it does provide a higher bid cap set to 150 percent of the calculated cost.
[23] The master file contains all the units' technical parameters including those impacting their variable costs.
[24] California ISO Tariff, Section 30.4 and 39.7.1.1.1.3.
[25] This paragraph does not include any discussion of the temporary measure approved under the *Aliso Canyon* filings to allow the gas commodity price used to determine the delivered price (GPI_{DA}) is the second gas day's volume weighted average price morning of the day-ahead market made available between 8 and 9 AM Pacific via webICE.
[26] Temporarily suspended in combination with Endnote 25 on a temporary basis due to *Aliso Canyon* filing.

[27] See generally PJM Manual 15, Cost Development Guidelines at § 2.3
[28] SPP Market Protocols Integrated Marketplace Appendices.
[29] A market clearing price is the price at which the profit maximizing buyers and sellers are the same for a given quantity demanded.
[30] One caveat to this is that next day trading will be transacted at prices that are the expectation of costs for delivery based on expected market fundamentals. If the expected fundamentals are aligned with the real fundamentals, the next day and intra-day prices will be correlated.
[31] Id to Endnote 20.
[32] CAISO, Tariff section 30.5.1 General Bidding Rules.
[33] Pending tariff filing as result of Bidding Rules Enhancements policy.
[34] ISO-NE Market Rule 1, Sections III.1.7.6, III.1.10.9
[35] MISO, Tariff Module C: Energy and Operating Reserve Markets, Section 39.2.5 and 40.2.5, Required Generation Offer and Demand Response Unit - Type II Offer Components.
[36] NYISO, Market Services Tariff (MST), Section 4.2 and 4.4 MST.
[37] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[38] SPP Market Protocols Integrated Marketplace, Section 4.2.2.1.
[39] SPP Market Protocols Integrated Marketplace, Section 8.2.2.
[40] ISO-NE, Market Rule 1, Section III.A.3 and Section III.A.5.
[41] Reference to ISO-NE after-the-fact cost recovery language
[42] MISO, Tariff Module D: Market Monitoring and Mitigation Measures, Section 63, 64 and 65.
[43] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1 and 23.3. Specifically section 23.3.1.4.6.9 for reference to start-up and minimum load costs, specifically section 23.3.1.4.7 for changes to the reference level for fuel, and section 23.3.1.4.6.7 for timing before real-time market close.
[44] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost based offers: Market Power Mitigation.
[45] SPP Market Protocols Integrated Marketplace, Attachment AF, Section 3.
[46] Formula will be effective when *Bidding Rules Enhancements* is implemented to add the shrinkage allowance, cap-and-trade credits, and miscellaneous costs.