California ISO

Contingency Modeling Enhancements

Draft Final Proposal

August 11, 2017

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1. Stakeholder comments and changes to this proposal

1.1. Stakeholder comments

Background

Peak Reliability suggested that the ISO explore the initiative's relation to additional standards and methodologies, including its system operating limit methodology for the operations horizon. The ISO reviewed its proposal to look for additional opportunities to cite relevant reliability standards, practices, and methodologies.

Capability to bid in corrective capacity

Calpine and NRG support the initiative but still advocate for the capability to bid for corrective capacity. The proposed capacity pricing fully captures and compensates for the capacity needed to meet the reliability constraints. The preventive-corrective constraint will allow for compensation at the capacity price, which will be paid to all resources at each location. The capacity price reflects: (1) a resource's opportunity costs, (2) marginal congestion cost savings, and/or (3) the marginal capacity value to follow dispatch. As discussed in prior stakeholder meetings, providing bidding for corrective capacity surfaces significant questions, both about the additional amount of complexity allowing bidding would introduce into the design and compensation of the corrective capacity product as well as how to apply local market power mitigation to that product. Also, as noted previously by the Division of Market Monitoring, because there is no identifiable cost associated with providing the corrective capacity, under competitive conditions the market would expect to see price-taking offers if bidding were allowed.

Impact of virtual bidding

The Six Cities, SCE, and SDG&E are concerned about the impact of virtual bidding on the preventive-corrective constraint and the resulting corrective capacity awards. As proposed, virtual bids in the IFM will have the same impact on the preventive-corrective constraint as it does for other constraints and products in the IFM today. The ISO currently allows virtual bids to cause flows which impact pre-contingency flow-based reliability criteria in the day-ahead Market. The ISO cannot find a reason to differentiate the new post-contingency flow-based requirements from the current pre-contingency flow-based requirements with respect to virtual bidding. The corrective capacity awards will be free to be re-optimized in the real-time based on changing market conditions.

All stakeholders agree that virtual supply should not be able to receive corrective capacity awards. The ISO will not rely on virtual supply for the ISO's corrective capacity needs, and therefore will not award corrective capacity to virtual supply.

The Six Cities' concerns about virtual bidding and its relation to reliability indicated that the ISO should further clarify the use of the constraint in the residual unit commitment run for the appropriate reliability result.

Potential benefits

The Six Cities and SCE see little benefit in implementing this policy. The ISO currently achieves a transmission feasible dispatch using exceptional dispatches and minimum online commitments as a supplement to the day-ahead market. The ISO reviews results, and when required issues exceptional dispatches. Instead of relying on manual reviews, determinations, and interventions, all of which inherently have clear precision disadvantages, the ISO proposes to achieve a transmission feasible solution in the market at minimized cost. The proposal also clearly and transparently values energy through the LMP and capacity through the LMCP sending appropriate signals to the market related to locational scarcity of energy and capacity.

Complexity and transparency

SCE is concerned that the market design is untested, complex, and therefore, less transparent. The ISO has been testing its CME prototype on stressed system scenarios for over 3 years. The proposal to value capacity needed to meet reliability constraints in the market improves overall market transparency, pricing, and dispatch. The proposal will also decrease market operator reliance on exceptional dispatches and minimum online commitment constraints, further improving price formation. These benefits outweigh the perceived solution complexity.

Relation to resource adequacy

NRG continues to object to any construct in which a non-RA resource that submits an energy bid to the ISO's markets effectively renders itself ineligible for RA-like (i.e., CPM) compensation. This distinction fails to recognize when non-RA resources provide RA-equivalent capacity reliability service to the ISO. NRG requests that the ISO should further elaborate as to under what circumstances non-RA capacity that the ISO's market optimization assigns corrective capacity is eligible for a CPM designation for that capacity.

Consistent with the tariff, any unloaded capacity that does not have any kind of market award should be eligible for CPM compensation in the event the ISO issues an exceptional dispatch. Similar to an ancillary services award, corrective capacity will be a market award priced into the market to meet the reliability criteria discussed in the proposal and will be compensated for this service; it should not be eligible for additional CPM compensation.

Congestion revenue rights

On November 20, 2015, the ISO published its *third revised straw proposal* which proposed one method to enhance the congestion revenue rights market/settlement to correct the over-allocation of congestion revenue rights to market participants consistent with the proposed preventive-corrective day-ahead market design changes. The ISO received valuable feedback from market participants through its stakeholder meeting, the market surveillance committee meeting, and written comments in response to the third revised straw proposal.

On January 28, 2016, the ISO published a *congestion revenue rights alternatives discussion paper* to explore various alternatives to align the congestion revenue rights market with the proposed changes to the day-ahead market and protect the integrity of the congestion revenue rights product.

After robust discussion of congestion revenue rights through the third revised straw proposal, the congestion revenue rights alternatives discussion paper, associated stakeholder meetings, and market surveillance committee meetings, we propose enhancements to the settlement of congestion revenue rights.

In comments on the *congestion revenue rights alternatives discussion paper*, stakeholders generally support the ISO in its focus on potential revenue insufficiency in the congestion revenue rights market. Most stakeholders were amenable to pursuing a solution within the third paradigm where new products distribute congestion revenue associated with the available transmission capability. Most stakeholders also oppose options where the ISO would use a single bid for allocation and auction of products. SCE, SDG&E, Powerex, Vitol, and PG&E supported finding a workable interim approach, each with different interim measures the ISO should pursue. Overall, most stakeholders did not express an outright opposition to pursuing the option where the ISO allocates and auctions only congestion revenue rights associated with the preventive congestion and updates the settlement of the product to only settle the preventive congestion as an interim or final solution. Because this solution also has minimal impact, it may be aligned with stakeholders that support the proposed minimal impact approaches. However, Powerex expects that this option, on a stand-alone basis, would be of limited initial value as a hedge for physical delivers and implores the ISO to examine the capability to purchase packaged products.

Since publication of the discussion paper, the ISO used its contingency modeling enhancements prototype to run real market scenarios to determine how often we believe the constraints would bind in practice. Under many stressed system scenarios and during a two week parallel operations period, the ISO found that the constraint rarely binds in practice.

The ISO proposes to make minimal changes to the congestion revenue rights settlement and monitor the congestion revenues associated with the preventive-corrective constraint going forward. Aligned with the option to allocate and auction only congestion revenue rights associated with the preventive congestion and update the settlement of the product to only settle the preventive congestion, the ISO proposes to allocate and auction congestion revenue rights associated with preventive congestion components and settle those congestion revenue rights only on the difference in the preventive constraint congestion components.

Powerex expects that this option will be of limited value without a capability to purchase a packaged product that settles the preventive-corrective congestion revenue as well. While the packaged capability may not be practical or feasible to implement at first, the ISO chose a solution that lays the groundwork for easily understood future improvements.

A packaged product approach is less complex and easier to understand under the third paradigm presented in the discussion paper. Indeed, PG&E has included a derivation of this capability in its reply comments to the discussion paper.

1.2. Changes to this proposal

The ISO made the following changes to address stakeholder comments:

- In ***Section 4***, the ISO focused its interconnection reliability operating limit and system operating limit compliance discussion on the NERC standards and the Peak Reliability Coordinator (Peak Reliability) SOL methodology because the Western Electricity Coordinating Council retired its regional reliability standard TOP-007-WECC-1a. The ISO now proposes to use the preventive-corrective constraints when operations engineers and market operators identify situations that must be protected in accordance with the NERC standards and Peak Reliability SOL methodology. This will still include critical transmission paths discussed in the previous versions of this proposal.
- As described in ***Section 6.1.2***, the ISO will settle downward corrective capacity awarded to intertie resources.
- As described in ***Section 6***, this version clarifies that virtual supply is not eligible to receive corrective capacity awards.
- As described in ***Section 7***, the ISO will not award corrective capacity in RUC and, as today, only unscheduled capacity from the IFM in excess of RA Capacity will be eligible to receive RUC awards.
- As described in ***Section 11***, this version provides further clarifications related to corrective capacity's interplay with ancillary services. Any overlapping corrective capacity will be paid the shadow price for each corrective contingency that binds regardless of the overlap.
- As described in ***Section 13.3***, this version further simplifies the "no pay" proposal by modeling the rules to be more similar to energy settlement rather than ancillary services settlement. Corrective capacity awards will be rescinded for unavailable capacity due to deviations between the metered output and the dispatch.
- In ***Section 15.2***, the ISO removed its proposal to update the energy max value used in the real-time residual supply index calculation. The energy max value does not need to be reduced by the corrective capacity award when evaluating preventive constraints because this capacity is available to the optimization. This is unlike ancillary services where the capacity is locked in and not available to the optimization.
- As described in ***Section 15.4***, the ISO proposed to make no changes to the current day-ahead supply of counterflow calculation because there are currently no ramping or operating reserve constraints in the day-ahead supply of counterflow calculation. The alternative described in previous proposals could have also applied to the supply of counterflow for energy, was not a corrective constraint specific consideration, and therefore had broad implications beyond the scope of this initiative.
- As described in ***Section 18 and Section 19***, the ISO proposes modifications to address congestion revenue right (CRR) revenue inadequacy that may result when the contingency modeling enhancements market feature reduces flows to ensure sufficient corrective capacity. The ISO proposes to settle CRRs only on the difference in the preventive constraint congestion components.

2. Background

In the 2012 Stakeholder Initiatives Catalog the following discretionary initiative was highly ranked by stakeholders and the ISO: *Additional Constraints, Processes, or Products to Address Exceptional Dispatch*. The initiative was highly ranked because it will explore more efficient ways to maintain reliability and reduce reliance on exceptional dispatch. As the title of the initiative suggests, there may be different approaches to addressing the underlying causes of exceptional dispatch, each with its own resource and cost profile. Therefore, this umbrella initiative reflects both stakeholder concerns about the increase in exceptional dispatch and a broad range of tools the ISO may deploy to effectively address those concerns.

As noted in the 2012 Stakeholder Initiatives Catalog, the first issue the ISO will address under the umbrella initiative is the need to position resources to effectively reposition the system after a contingency within 30 minutes. According to North American Electric Reliability Corporation (NERC)[1] and the ISO's reliability coordinator, Peak Reliability[2], the ISO is required to return flows on transmission paths to acceptable levels within 30 minutes when a real-time contingency leads to the system being in an insecure state.

The ISO conducted a stakeholder process in 2008 to discuss the need for a mechanism to provide 30-minute operating reserves. During that process several stakeholders had suggested developing an additional 30-minute reserve product or increase procurement of 10-minute reserves. At the time, it was decided to continue using exceptional dispatch to position generation in case of a contingency while the ISO gained more experience in the MRTU market. Since then the ISO has also incorporated the use of minimum online commitment (MOC) constraints. MOC constraints also ensure real-time reliability by committing resources in the day-ahead market to ensure system security can be maintained following a contingency in real-time. The constraint identifies the minimum generation capacity requirement, the set of generators that are effective in meeting the interconnection reliability operating limits and system operating limits, and the effectiveness of each generator where appropriate.[3]

3. Scope of initiative and plan for stakeholder engagement

This stakeholder initiative is narrowly focused on alternatives to exceptional dispatch and the minimum online commitment constraints in addressing interconnection reliability operating limits and system operating limits with corrective time requirements. While exceptional dispatch is used for other tariff-approved purposes, we are addressing the 30-minute need as the most important issue because this aligns with the results of the 2012 Stakeholder Initiatives Catalog and addresses a significant portion of the total instances of exceptional dispatch.

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[1] NERC standards FAC-011-3 and FAC-014-2
[2] Peak Reliability "System Operating Limits Methodology for the Operations Horizon"
[3] http://www.caiso.com/Documents/TechnicalBulletin-MinimumOnlineCommitmentConstraint.pdf

The schedule for stakeholder engagement is provided below and targeted for the September 2017 Board of Governors meeting.

Date	Event
Mon 3/11/13	Issue paper posted
Tue 3/26/13	Stakeholder call
Tue 4/9/13	Stakeholder comments due
Wed 5/15/13	Straw proposal posted
Wed 5/22/13	Stakeholder meeting
Tue 5/28/13	Stakeholder comments due on straw proposal
Tue 6/18/2013	Revised straw proposal posted
Tue 6/25/2013	Stakeholder call
Mon 7/1/2013	Stakeholder comments due
Thu 3/13/14	Second revised straw proposal posted
Thu 3/20/14	Stakeholder call
Thu 3/27/14	Stakeholder comments due on second revised straw proposal
Mon 11/20/15	Third revised straw proposal posted
Mon 12/2/15	Stakeholder call
Tue 12/18/15	Stakeholder comments due on third revised straw proposal
Wed 1/27/16	CRR Alternatives Discussion Paper posted
Wed 2/17/16	Stakeholder comments due on CRR alternatives
Fri 2/03/17	Market Surveillance Committee, initial prototype technical analysis results
Mon 7/10/17	Market Surveillance Committee, follow-up prototype technical analysis results
Fri 8/11/17	Prototype technical analysis results and draft final proposal posted
Tue 8/22/17	Stakeholder meetingl
Mon 8/31/17	Stakeholder comments due on draft final proposal
Tue-Wed 9/19/17-9/20/17	September BOG

4. Reliable transmission operations

This section describes transmission system operations reliability concerns, the considerations in meeting transmission system operating limits, how the ISO is currently meeting these requirements, and where the ISO and market participants can benefit from enhancements.

The ISO must protect the transmission system for interconnection reliability operating limits and system operating limits with corrective time requirements. The ISO currently protects for these scenarios using inefficient exceptional dispatches and minimum online commitment constraints. It seeks to find a better and transparent solution from a reliability perspective and market efficiency perspective. This section discusses why other measures which would at first appear to provide this same benefit will not effectively do so. These measures include using 10-minute reserves, altering 10-minute reserve procurement to be more granular, and making a new type of 30-minute ancillary reserve product. The ISO's current strategies for reliable operations and all of these potential solutions suffer from deliverability issues, effectiveness issues, efficiency issues, and energy price transparency issues. Therefore, the ISO introduced the preventive-corrective constraint to address interconnection reliability operating limits and system operating limits with corrective time requirements.

Before discussing shortfalls of using existing or slightly altered ancillary services products to meet interconnection reliability operating limits and system operating limits with corrective time requirements, the ISO provides related background on the NERC standards, WECC standards, and the Peak Reliability SOL Methodology.

4.1. WECC standards, NERC standards, and the Peak Reliability SOL Methodology

4.1.1. Background

NERC is responsible for establishing and enforcing reliability standards for the bulk power system. NERC reliability standards are minimum requirements for all of North America. Regional variations are allowed and developed via eight NERC regional entities that are also responsible for compliance monitoring and enforcement. As a balancing authority and transmission operator, the ISO falls within the Western Electricity Coordinating Council (WECC) regional entity.[4]

In previous versions of this proposal, the ISO described the difference between the NERC standards (TOP-007) and the applicable WECC variations (TOP-007-WECC-1a). On December 3, 2015, the WECC Board of Directors approved the retirement of WECC Regional Reliability Standard TOP-007-WECC-1a and FERC approved the retirement in April 2016. The original purpose of the WECC standard was to limit instances where actual flows on critical transmission paths exceed system operating limits on those paths for more than 30 minutes. At the time, the ISO had authority under other NERC TOP standards to take whatever actions needed to ensure the reliability of its area, but the WECC standard did not explicitly reference load shed as a pre-contingency normal operating plan, nor would the ISO have used load shed as a pre-contingency

[4] The ISO is considered under NERC standards as a Balancing Authority (BA), Transmission Operator (TOP), Planning Coordinator (PC), and a Transmission Service Provider (TSP).

normal operating plan if there were adequate resources available on the system. As such, the ISO began developing the preventive-corrective constraint to resolve these issues. Since implementation of the WECC standard, NERC has revised several of its own national standards that address system operating limit exceedance for all bulk electric system facilities. This led to an overlap that made the regional TOP-007-WECC-1a unnecessary. The WECC Board therefore voted to retire the regional standard because it was duplicative of the NERC standards.

Over the past several years, NERC has been yielding responsibility for determining appropriate operating limits to the appropriate functional entities. NERC has recognized that it is not optimally positioned to enforce standards that create an obligation to build or buy transmission assets. The expectation is that these functional entities adopt appropriate measures to ensure electric reliability given their operating situations. The Reliability Coordinator (RC) for the WECC region, Peak Reliability, is the functional entity that determines the methodology the ISO is to follow when developing system operating limits.

The NERC standards require each reliability coordinator to have a documented SOL methodology for its area. The Peak Reliability "SOL Methodology for the Operations Horizon" establishes the methodology used in the Peak RC area for determining interconnection reliability operating limits and system operating limits for use in the operations horizon. The ISO must meet the minimum requirements stipulated in this methodology. Under this methodology, the ISO must return the flows on transmission facilities when a contingency happens below the normal rating in less than the emergency rating time duration. For many of the ISO's transmission facilities this time duration is 30 minutes, but can be up to four hours.

Interconnection reliability operating limits and system operating limits have corrective time requirements that the ISO must operate within. For instance, after a contingency that loads a transmission line up to its 30 minute emergency rating occurs, the ISO must return the line to below its normal rating within 30 minutes. If effective generation is not pre-dispatched such that it could ramp and return the line to below its normal rating within 30 minutes, the ISO is not meeting its system operating limits. Today, the ISO ensures it can meet interconnection reliability operating limits and system operating limits that have corrective time requirements using exceptional dispatch and minimum online commitment constraints.

The ISO must serve load reliably given its current generation, transmission capabilities, and constraints. Although load shedding, for example, can contribute to maintaining reliability, the ISO considers load shedding a last resort; especially where there are adequate resources available on the system to mitigate system issues. Consistent with NERC FAC standards and the Peak Reliability SOL methodology, the ISO does not plan to use load shedding following a single contingency to either re-position the system to be ready for the next contingency or return facilities to within their normal ratings within the emergency rating time duration.

While the ISO could conceivably continue its current practice of relying on exceptional dispatches to position generation to be able to be back within operating limits after a contingency, operators cannot optimally exceptionally dispatch generation like the market optimization can. In addition, they add to market inefficiency because the effect of the need to position generation is not reflected in energy prices.

In addition, the Federal Energy Regulatory Commission (FERC) has directed the ISO in several instances to reduce reliance on exceptional dispatches and increase market-based solutions.[5] This includes using market-based solutions to address system needs as well as developing appropriate compensation via locational marginal prices or through other market signals.

Moreover, as part of its recent settlement agreement with FERC and NERC related to the September 8, 2011 pacific southwest blackout, the ISO agreed to commit to mitigation and compliance measures to mitigate the allegations FERC described in the settlement agreement, namely, a commitment to implement the Contingency Modeling Enhancement Project to ensure that the CAISO market procures the appropriate resources to ensure the ability to recover from a contingency and be ready for the next N-1 contingency as soon as possible but no longer than 30 minutes.[6] In short, more efficient procurement of the most effective resources will improve reliability and compliance with relevant standards. To the extent the ISO can use the market to procure needed capacity and compensate those resources, the ISO will increase the overall effectiveness and efficiency of this procurement.

As such—and because acceptable post-contingency performance is the same now as it was under the retired WECC standard—this initiative will help to ensure that the ISO has the tools necessary to take the most appropriate actions to resolve critical reliability constraints.

4.1.2. Description of acceptable performance

The Peak Reliability "SOL Methodology for the Operations Horizon" establishes the methodology to be used in the Peak RC area for determining system operating limits and interconnection reliability operating limits for use in the operations horizon pursuant to NERC Reliability Standards FAC-011-3 and FAC-014-2. All transmission operators and the RC must meet the minimum requirements stipulated in the system operating limit methodology.

Under this methodology, system operating limits are the facility ratings, system voltage limits, transient stability limits, and voltage stability limits that are used in operations – any of which can be the most restrictive limit at any point in time pre- or post-contingency. For example, if an area of the bulk electric system is at no risk of encroaching upon stability or voltage limitations in the pre- or post-contingency state, and the most restrictive limitations in that area are pre- or post-contingency exceedance of facility ratings, then the thermal facility ratings in that area are the most limiting system operating limits. Conversely, if an area is not at risk of instability and no facilities are approaching their thermal facility ratings, but the area is prone to pre- or post-contingency low voltage conditions, then the system voltage limits in that area are the most limiting system operating limits.

[5] See for example 126 FERC ¶ 61,150 and 128 FERC ¶ 61,218.
[6] 149 FERC ¶ 61,189

System operating limits including interconnection reliability operating limits have corrective time requirements that the ISO must operate within. The ISO faces three practical operating limits it must comply with under this methodology:

(1) Post-contingency line flows must be returned below normal ratings within the emergency rating time duration (for many transmission elements, this time duration ranges from 30 minutes up to four hours), and
(2) Stability-based interconnection reliability operating limits must be corrected within 30 minutes,
(3) Cascading outage-based interconnection reliability operating limits must be corrected within 30 minutes

Operations engineers identify these limits ahead-of-time during seasonal assessments and outage studies for the day-ahead and real-time market.

4.1.3. Considerations

In order to operate within interconnection reliability operating limits and system operating limits with corrective time requirements, the ISO must consider several factors including temporal constraints, locational limitations, and the dynamic nature of contingencies. The ISO must transition from the post-contingency system to the next secure state within established timeframes. For many transmission facilities, this must be done within 30 minutes. This requires the ISO to quickly adjust the output of resources so that the post-contingency flows are within the new system operating limit. Contingencies that constrain transmission paths can occur in a number of areas on the system and each (or a combination of them) will result in a different post-contingency topology. In other words, each contingency (or a combination of them) will change the flows on the system in different ways. The ISO evaluates the post contingency flow considering the impacts from the potential contingencies and then manually re-dispatches to respect known time constraints. This complexity presents a challenge to the ISO in pre-dispatching and responding to temporal and flow-based contingency events.

4.2. U.S. ISO/RTO 30-minute reserves and mechanisms

It is important to distinguish operating practices and strategies from the system operating limit itself. As stated above, the system operating limit is the actual set of facility ratings, system voltage limits, and stability limits that are to be monitored for the pre- and post-contingency state. How an entity remains within these system operating limits can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one transmission operator may utilize offline static calculations based on line outage distribution factors or other similar calculations as a mechanism to ensure system operating limits are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

U.S. independent system operators and regional transmission operators may meet NERC, regional, or local standards using explicit 30-minute reserves or other supplemental mechanisms. Those with an explicit 30-minute reserve are shown in below.[7] This section summarizes each market and provide some context around how each relies on its 30-minute reserves.

Table 1
Comparison of ISO/RTO 30-minute reserves

ISO/RTO	30-min reserve requirement (source)	ISO/RTO specific requirements	Procurement mechanism	Settled?
ISO New England	Equal to at least one-half of second contingency loss (NPCC Directory # 5 – Reserve)	Locational consideration for three reserve zones with historical import constraints and for the Rest of the System[8]	Via Forward Reserve Market for summer and winter seasons by location[9]	Yes
NYISO	Equal to at least one-half of second contingency loss (NPCC Directory # 5 – Reserve)	NY control area: 1.5x 10 min reserves for largest contingency Eastern NY: single largest contingency (only 10 min reserves are used) Long Island: restore loss of transmission circuit in 30 min[10]	Co-optimized with energy in day-ahead market based on separate demand curves for NY control area, Eastern NY, and Long Island[11]	Yes
PJM	Condition of RPM settlement agreement to establish 30-min reserve market-based mechanism (117 FERC ¶ 61,331 (2006)	~7 percent of peak load (which is sum of peak load forecast error and forced outage rate)[12]	Day-Ahead Scheduling Reserve Market system-wide	Yes
ERCOT	30-minute non-spinning reserve requirement	The sum of: (a) 30-minute non-spinning reserve requirement; plus (b) 500 MW of 10-minute	Co-optimized with energy in day-ahead	Yes

[7] SPP will not be discussed as its market design will change with the implementation of a nodal market. It does currently have a 30 minute supplemental reserve service.
[8] http://www.iso-ne.com/mkts_billing/mkt_descriptions/line_items/reserve_market.html
[9] http://www.iso-ne.com/mkts_billing/mkt_descriptions/line_items/reserve_market.html
[10] http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf
[11] NYISO, Manual 2: Ancillary Services Manual, March 2013, p. 6-25.
[12] Monitoring Analytics, LLC, *2012 State of the Market Report for PJM*, “Section 9: Ancillary Services”, p. 289. Requirement was 7.03 percent in 2012 and 7.11 percent in 2011.

	calculated based on load and wind forecast risk and single largest contingency (ERCOT)[13]	spinning reserve; plus (c) average amount of Regulation Up procured Should cover: at least 95 percent of load and wind forecast risk Also consider loss of single largest contingency.	market system-wide with offer curves Cap: 1,500 MW Floor: Single largest unit minus 500 MW	

Most independent system operators and regional transmission operators consider 30-minute reserves supplemental to 10-minute reserves. The 30-minute reserves exist mainly to replenish depleted 10-minute reserves or serve as additional backup. In other words, the 30-minute reserve is not expressly procured to address 30-minute limits associated with interconnection reliability operating limits and system operating limits. Based on our research and discussion with eastern independent system operators and regional transmission operators, they use a combination of their primary reserves supported by supplemental reserves (if any), out of market manual operations, and reserve sharing agreements to address 30-minute system operating limits. In the eastern interconnection, interconnection reliability operating limits can be the interfaces between balancing authority areas. Therefore, in those instances, system wide reserves can help meet the interconnection reliability operating limit needs with good accuracy. This is not typically the case for the ISO. Most of the ISO's facilities requiring corrective timeframes for interconnection reliability operating limits and system operating limits are wholly internal to our balancing area, and are not in the same granularity as ancillary service regions.

ISO New England and NYISO are both balancing authorities under the Northeast Power Coordinating Council (NPCC). NPCC imposes a regional reliability requirement to have 30-minute reserves to account for real-time contingencies.

ISO New England holds seasonal capacity procurement markets for these reserves based on local reserve zones created by historical import constraints. However, as a result of aggressive transmission upgrades from 2007 through 2009, the dramatic increase in transfer capability means that "local reserve constraints have rarely been binding."[14]

NYISO has more stringent and differentiated obligations for each sub-region to address the major load pockets in its control area. Since there is limited transmission capability between the sub-regions, NYISO uses demand curves to reflect scarcity pricing. NYISO procures hourly reserves in the day-ahead market and co-optimizes it with energy. NYISO's 30-minute reserves are considered supplemental to its 10-minute ancillary services and can be directly converted to energy when those 10-minute reserves start to deplete. The decision to convert 30-minute reserves to energy is a partially manual operation based on operator judgment and the outcome

[13] ERCOT, "ERCOT Methodologies for Determining Ancillary Service Requirements," as presented to and approved by ERCOT Board of Directors at public meeting March 19, 2013.
[14] Potomac Economics, *2011 Assessment of the ISO New England Electricity Market*, June 2012, p. 45.

of its forward looking real-time commitment. In addition, the NYISO can use manual out-of-merit dispatch to in the event of a contingency or other violation.

In total, NYISO procures operating reserves to cover 150% of its single largest contingency (1,965 MW for a contingency of 1,310 MW).[15] The 1,965 MW is comprised of 1,310 MW of 10-minute reserves and 655 MW of 30-minute reserves. The location of these reserves varies by a regional requirement. For example, the Eastern NY region does not have both 10- and 30-minute reserves – it only relies on deliverable 10-minute reserves. Of the total 1,310 MW of 10-minute reserves procured for the entire NY control area, 1,200 MW of it is *deliverable* reserves to Eastern NY.[16] NYISO selects "Operating Reserves Resources that are properly located electrically so that all locational Operating Reserves requirements are satisfied, and so that transmission constraints resulting from either the commitment or dispatch of Resources do not limit the NYISO's ability to deliver Energy to Loads in the case of a Contingency."[17]

PJM does not have a regional reliability obligation but was required by FERC to create a market-based mechanism to procure 30-minute reserves, pursuant to PJM's capacity market settlement terms.[18] PJM procures these reserves to account for forecast error and generator outages rather than to account for real-time contingencies. PJM has set the procurement obligation to be equal to the sum of its peak load forecast error (*i.e.*, under-forecasted error) and generator forced outage rate calculated annually. Although PJM procures its other ancillary services based on deliverability to one of two major zones within its footprint, 30-minute reserves are procured system-wide.[19] PJM considers its 30-minute reserves to be a form of *supplemental* reserves and relies on its 10-minute reserves (referred to as primary reserves) for real-time contingencies. For example, supplemental reserves are procured in the day-ahead but are not maintained in real-time. PJM relies heavily on its primary reserves and procures up to 150 percent of its single largest contingency, comprised of two-thirds spinning and one-third non-spinning reserve.[20] By comparison, WECC requires and the CAISO procures spinning and non-spinning reserves to sum to the greater of either the single largest contingency or the sum of 3 percent of hourly integrated load plus 3 percent of hourly integrated generation.[21]

ERCOT relies on its 30-minute reserves largely to account for variations in load and wind forecasting due to the high penetration of wind generation in its balancing area. ERCOT procures a combination of 30-minute reserves, 10-minute spinning reserves, and regulation up service to cover at least 95 percent of load and wind forecast risk. All ancillary services are procured in the

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[15] NYISO, Locational Reserve Requirements. Available from:
http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf.
[16] NYISO, Locational Reserve Requirements. Available from:
http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf.
[17] NYISO, Manual 2: Ancillary Services Manual, Section 6.2.1 NYISO Responsibilities, Version 3.26 March 2013.
[18] 117 FERC ¶ 61,331 (2006).
[19] PJM System Operations Division, Manual 13: Emergency Operations, Revision 52, effective February 1, 2013, pp. 11-12.
[20] Monitoring Analytics, LLC, *2012 State of the Market Report for PJM*, "Section 9: Ancillary Services," p. 279.
[21] WECC standard BAL -002-WECC-2a

day-ahead, system-wide, and not re-optimized in real-time.[22] On-line non-spinning and offline non-spinning reserve have minimum energy offer curves of $120/MWh and $180/MWh, respectively, to reflect shortage pricing.[23] There is a capacity procurement floor of 30-minute reserves equal to the single largest unit minus 500 MW and a capacity cap of 1,500 MW.[24] A 30-minute reserve is also used to replenish or support the 10-minute spinning reserves used to maintain frequency.[25]

The **Midwest ISO** does not carry 30-minute reserves but it is currently undergoing deliverability testing for its 10-minute reserves. It is currently manually disqualifying reserves that are not deliverable to each of its reserve zones. In future, the Midwest ISO will move forward on a 30-minute product that can be considered at a nodal level.

Lastly, the **California ISO** also does not explicitly carry 30-minute reserves but relies on 10-minute spinning and non-spinning ancillary services, minimum online commitment (MOC) constraints, and exceptional dispatch to ensure system reliability. The system operating limits are met by a combination of pre-contingency flow management and post-contingency reserve deployment. Spinning and non-spinning reserves are procured 100 percent day-ahead and optimized with energy. They are settled at the ancillary service marginal price, which is based on the marginal resource's spinning or non-spinning reserve bid and any opportunity cost for providing reserves rather than energy. A minimum online commitment constraint is a market mechanism used to ensure sufficient unit commitment is available that is effective in addressing specified contingencies. Minimum online commitment constraints are enforced in the day-ahead market, and thus affect unit commitment and dispatch. But minimum online commitments do not have marginal contributions to the energy prices.

An exceptional dispatch in the California ISO is an out-of-market manual operation to start specific units or move them to specified output levels. It is an important device the CAISO uses to meet the interconnection reliability operating limits and system operating limits. Like minimum online commitment constraints, the bid costs from exceptionally dispatched energy are not reflected in energy prices. Both minimum online commitments and exceptional dispatches are used for broader reasons than meeting interconnection reliability operating limits and system operating limits.

[22] Moorty, Sai, ERCOT, "Look Ahead SCED," November 28, 2011, slide 6.
[23] ERCOT, "6.4.3.2 (a) Energy Offer Curve for Non-Spinning Reserve Capacity," ERCOT Nodal Protocols, Section 6: Adjustment Period and Real-Time Operations, April 1, 2013.
[24] ERCOT, "ERCOT Methodologies for Determining Ancillary Service Requirements," as presented to and approved by ERCOT Board of Directors at public meeting March 19, 2013.
[25] ERCOT, "3.17.3 (2) Non-Spinning Reserve Service," ERCOT Nodal Protocols, Section 3: Management Activities for the ERCOT System, April 2, 2013. s

4.3. Existing strategies for reliable operations

4.3.1. Available mechanisms

4.3.1.1. 10-minute ancillary services

10-minute ancillary reserves are procured primarily to meet NERC and WECC operating reserve requirements.[26] As mentioned above, reserves in WECC must cover the greater of the single largest contingency or the sum of three percent of hourly integrated load plus three percent of hourly integrated generation and be comprised of at least 50 percent spinning.[27]

10-minute ancillary services can be used to address an interconnection reliability operating limit violation to avoid cascading outages. We stress that this does not mean the reserves can be procured for system operating limit purposes. Use of these reserves is more complicated when addressing a system operating limit violation on transmission paths. The effectiveness of the ancillary services capacity may be limited or counter-productive if the capacity is located on the wrong side of the constraint. In fact, resources in the wrong location can cause flows to go higher if dispatched. We have anecdotal evidence in both the ISO market, other independent system operators, and regional transmission operators that stranded ancillary services, even if procured sub-regionally, are an operational challenge.

10-minute ancillary services are procured to comply with NERC and WECC BAL standards, and not for operating within interconnection reliability operating limits and system operating limits. The different standards also reflect different system needs. The operating reserve requirement is based on a static or pre-calculated system capacity need whereas the interconnection reliability operating limit and system operating limits are a more dynamic need based on current system topology and post-contingency flows. Creating smaller ancillary service sub-regions would be a very rough way to target the flow-based need under interconnection reliability operating limits and system operating limits.

4.3.1.2. Exceptional dispatch

Exceptional dispatch is primarily used to resolve constraints that are not modeled in the market. The ISO also uses it to position generation so that it can meet applicable operating limits with corrective time requirements after contingencies. Specifically, for the interconnection reliability operating limits and system operating limits, an exceptional dispatch is used to position a unit to an acceptable level of generation (e.g., above its minimum load range) so that it can mitigate post-contingency exceedances within 30 minutes. Exceptional dispatches are issued based on operator experience and judgment about the effectiveness of particular units. The units selected are not market-optimized and the resulting dispatch may not be the most efficient solution. In other words, exceptional dispatch will ensure that the operators have sufficient ramping capability but the effectiveness and deliverability of the units may not be the optimal solution that would have been procured in the market which uses the effectiveness and deliverability. Manual

[26] For example, WECC standard BAL- 002-WECC-2a
[27] WECC standard BAL-002-WECC-2a

operations are prone to both under- and over-procurement, but the average procurement is generally more conservative.

4.3.1.3. Minimum online commitment constraint

Minimum online commitment constraints are used to identify the minimum generation capacity needed to address a reliability requirement and to enable the ISO to operate paths at acceptable higher loading levels. They are used to address interconnection reliability operating limits and system operating limits but are also deployed to address non-flow-based constraints, procedural, and outage-related constraints. While minimum online commitment constraints are preferable to exceptional dispatch because they are accounted for in the day-ahead market runs, they do have several drawbacks. First, the definition of the constraint is determined via an engineering analysis but the unit is not optimally positioned to provide energy depending on the contingency. Second, like ancillary services sub-regions, the minimum online commitment constraints pre-define a set of resources that may be most effective but retain this static definition regardless of where the contingency occurs and regardless of the post-contingency topology. Third, the minimum online commitment constraint only commits units to their Pmin (output above Pmin is optimized in the market). Therefore, the minimum online commitment constraints do not have a marginal contribution to energy prices (which the energy bids above Pmin may have). Most importantly, because commitments are based on conservative offline studies, the ISO does not know whether the commitment was the most efficient use of market resources in maintaining reliability.

4.3.2. Reliability challenges with available mechanisms

The table below summarizes the ISO's current mechanisms to address interconnection reliability operating limits and system operating limits. Column [A] lists the three current mechanisms and column [B] describes the primary reason each exits. Column [C] summarizes for each mechanism the amount of capacity procured and how that amount is determined and column [D] provides the locational definition. Column [E] summarizes the effectiveness of each mechanism of ensuring reliability.

Table 2
Reliability comparison of ISO mechanisms to meet system operating limits

Mechanism	Addresses:	Amount of capacity procured determined by:	Locational definition	Ensures accurate amount of capacity procured at right location?
[A]	[B]	[C]	[D]	[E]
10 minute contingency reserves	NERC/WECC reserve requirements[28]	WECC reserve requirements[29]	Predefined static zone	Partially – deliverability issues because not flow-based and granularity
Exceptional dispatch	As specified in ISO tariff[30]	Operator judgment	Location specific based on operator judgment	Partially – potential deliverability issues and imprecise procurement
Minimum online commitment constraints	SOLs/IROLs and non-flow based constraints	Predefined static region and requirement	Predefined static region	Partially – predefined static regions and only commits units to Pmin

For 10-minute contingency reserves, the basis for procurement is neither interconnection reliability operating limits nor system operating limits, but rather NERC/WECC BAL standards. The NERC/WECC operating reserve requirements specify the capacity that needs to be procured on a system-wide basis to protect against a contingency (columns [C] and [D]). The ISO has attempted to use the 10-minute contingency reserve to address interconnection reliability operating limits and system operating limit exceedances when possible and appropriate. However, the capacity procured is not tested for post-contingency deliverability and therefore the ISO has no guarantee that the capacity can fully meet flow-based interconnection reliability operating limits and system operating limit requirements (column [E]).

Exceptional dispatch can be used for several reasons specified in the ISO tariff and has been used to address interconnection reliability operating limits and system operating limit exceedances (column [B]). The technical paper attached to this initiative's issue paper showed that for 2012, 21 percent to 77 percent of all exceptional dispatch volume measured in MWhs issued by month (40 percent annual) were due to meeting applicable system operating limits with 30-minute requirements.[31] Therefore, a significant portion of exceptional dispatches were used to address this specific reliability concern. Exceptional dispatches are manual interventions in the market based on operator judgment (column [C]) and since the units are individually selected, the location is known and specific (column [D]). However, exceptional dispatch is used to ensure

[28] WECC standard BAL002-WECC-2a.
[29] WECC standard BAL -002-WECC-2a.
[30] See ISO tariff such as Section 34.9.
[31] Measured in MWhs of exceptional dispatch volume. See Contingency Modeling Enhancements Issue Paper, March 11, 2013, Technical Paper attachment, p. 3.

the units can provide the correct ramping capability within the 30-minute time limit but the units procured are not tested for post-contingency deliverability. Because the amount of capacity procured is not optimized, the ISO cannot definitively say that it procured the "right" amount of capacity to address interconnection reliability operating limits and system operating limits with 30-minute requirements.

For minimum online commitment constraints, the main purpose is to address interconnection reliability operating limits and system operating limits with corrective time requirements but some are used for non-flow based constraints (such as those related to voltage support) as shown in column [B]. Each minimum online commitment constraint has a predefined static location and list of units (columns [C] and [D]). However, minimum online commitment constraints are only partially effective in addressing interconnection reliability operating limits and system operating limits with 30-minute requirements because the units within the constraint are only committed to their Pmin. Most importantly, the minimum online commitment constraint definition is based on static offline studies with assumed generation patterns that may differ from the actual market dispatch.

4.3.3. Efficiency challenges with available mechanisms

In addition to reliability challenges, exceptional dispatch and minimum online commitment constraints do not position units at a level that is the product of an optimization and therefore could benefit from more efficient procurement and dispatch, including pricing signals that reflect need, valuation of operationally desirable characteristics, and maintaining reliability at lowest cost. The table below compares the efficiency of the ISO's current mechanisms to meet interconnection reliability operating limits and system operating limits with 30-minute requirements.

Table 3
Efficiency comparison of ISO mechanisms to meet IROL/SOLs with 30-minute requirements

Mechanism	Optimized procurement	Efficiently dispatched post-contingency?	Bid cost	Fast response valued in market?
[A]	[B]	[C]	[D]	[E]
10-minute contingency reserves	Yes, for system-wide need co-optimized with energy	May have deliverability issues	Reflected in LMP	Yes
Exceptional dispatch	No, manual process	Very likely	Not reflected in LMP	No
Minimum online commitment constraints	No, constraint is pre-defined and not dynamic	Likely	Not reflected in LMP	No, ramping speed not considered

Column [B] shows that only 10-minute ancillary reserves are procured through an optimization (co-optimized with energy). However, the optimization is for system-wide needs (and the need is broader than the potential interconnection reliability operating limits and system operating limits with 30-minute requirements) so there may be deliverability limitations in real-time as shown in Column [C]. Exceptional dispatches and minimum online commitment constraints are not optimized as one is a manual process and the other is a pre-defined, non-dynamic constraint added to the market (though the energy is optimized). Exceptional dispatches are likely efficiently ramped after the contingency because the operator selects (to the best of his or her knowledge) a highly effective unit with no deliverability constraints that can resolve the overloads within 30 minutes. Minimum online commitment constraints are also likely to provide efficient dispatch but the actual mechanism of the constraint only *commits* units that could be effective but does not consider the energy that may be provided once a contingency occurs. Both mechanisms are "likely" effective but this is not verified unless the contingency occurs.

Column [D] shows that only the bid costs of 10-minute reserves are reflected in energy prices, which signals the need for generation in the market at a nodal level.

Column [E] asks whether the mechanism values the fast response nature of the resources being procured in the market. Since contingency reserves must respond within 10 minutes, their fast response is directly valued. Exceptional dispatch, on the other hand, allows operators to select a fast response unit but this value is not reflected in any price signal to the market. Lastly, the minimum online commitment constraint does not value fast response directly because it does not differentiate the ramping capabilities of the units within the constraint.

4.4. Solutions considered

At first glance the ISO's current procurement of 10-minute reserves could provide a model to address interconnection reliability operating limits and system operating limits with 30-minute requirements. The ISO could procure a 30-minute reserve product in the same manner as it procures 10-minute reserves. This seems logical because it would appear to provide the benefits of the 10-minute product, but avoid using more expensive resources than needed. However, as explained above, the ISO's current ancillary services are procured to meet a system capacity requirement rather than the interconnection reliability operating limits and system operating limits with 30-minute requirements. In an attempt to address these requirements, some stakeholders have suggested procurement of 30-minute reserves at a sub-regional level assuming that smaller regions will provide greater granularity. However, the only way to accurately evaluate whether the interconnection reliability operating limits and system operating limits with 30-minute requirements are being met is via a nodal model for capacity. Without it, we will not know if we have adequately procured enough 30-minute reserves and will likely rely on over-procurement in order to ensure reliability. The lack of a 30 minute product in the ISO market should not reflect a refusal to consider such a proposal but rather a careful consideration of a broader range of solutions that could provide superior performance from a reliability and market efficiency standpoint.

Interconnection reliability operating limits and certain system operating limits have 30-minute requirements. We have found that 30-minute reserves in other markets are not expressly procured to meet this criteria and that primary 10-minute reserves and manual operations are the first line of defense. While the ISO also has these options, they suffer from deliverability issues, effectiveness issues, efficiency issues, and energy price transparency issues. The ISO generally does not consider firm load shedding an option unless adequate resources are not available and there is an imminent threat to the transmission system that could lead to widespread cascading outages or equipment damage.

The issue paper for this initiative introduced a preventive-corrective constraint to address interconnection reliability operating limits and system operating limits with 30-minute requirements. Given the technical nature of this issue, we provided the description of the constraint ahead of time to help facilitate discussion with stakeholders. The technical paper, *Preventive-Corrective Market Optimization Model*, proposed a framework that will maintain reliability by modeling the ISO's post-contingency need with subsequent compensation to affected generators or demand response providers. The enhancements include the modeling of post-contingency preventive-corrective constraints in the market optimization so that the need to position units to meet applicable reliability criteria would be incorporated into the market model. The constraints will reduce exceptional dispatches, replace some minimum online commitment constraints, provide greater compensation through energy prices and may result in a separate capacity payment for resources that help meet the reliability standards.[32] The major concepts discussed in the technical attachment were introduced to stakeholders at the Market Surveillance Committee meeting on January 17, 2013 by Dr. Lin Xu of the ISO. The next section discusses the preventive-corrective constraint in greater detail.

5. Preventive-Corrective Market Optimization Model

5.1. Background

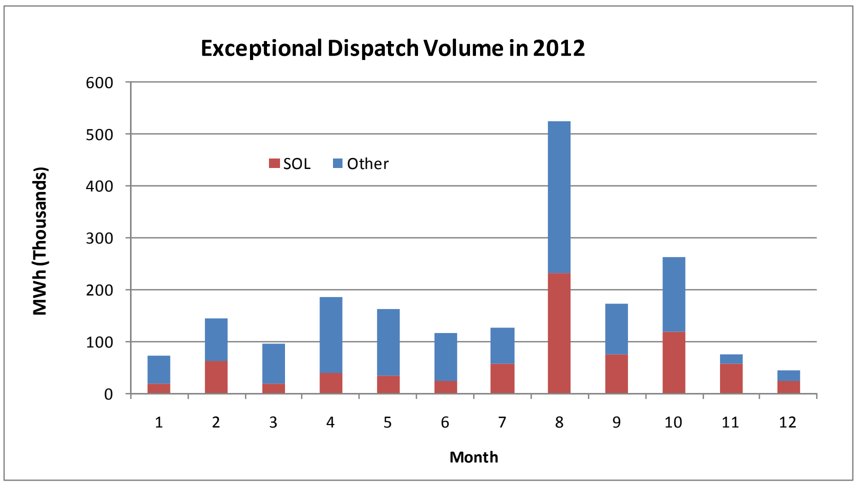
In order to operate the power system reliably, the ISO must comply with the reliability standards set forth by North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). Among the standards are security standards that are related to contingencies. The most fundamental one is the N-1 secure standard that the system must not violate any operating limit after a transmission element outage. Currently, the ISO's market optimization is able to model the N-1 standard as preventive security constraints[33]. The term "preventive" means that the optimization will produce a pre-contingency dispatch that keeps the post contingency system conditions within operating limits. There are other mandatory standards that would require re-dispatch to resolve post contingency operating limits. These standards include but are not limited to System Operating Limits (SOLs) and generation contingencies. The post contingency re-dispatches are "corrective" actions taken after the contingency occurs. By incorporating the corrective actions into the preventive model, the market will have a more advanced optimization model which co-optimizes the preventive pre-contingency dispatch and the corrective post contingency re-dispatch. This new model is called the preventive-corrective

[32] While some level of exceptional dispatch is needed in every market, minimizing such manual operations and preferably replacing them with optimized solutions improves reliability.
[33] Sometimes the impact of contingency is included in the pre contingency system operating limit (SOL), so as long as the pre contingency condition is within the SOL, the system is N-1 secure. In this case, a preventive optimization only models base case constraints for these SOLs.

model, which can help the ISO systematically meet the N-1 standard and SOL standard. The preventive model and the preventive-corrective model are both classic models in academic research. For example, these models are taught in a graduate level power engineering course in Iowa State University[34].

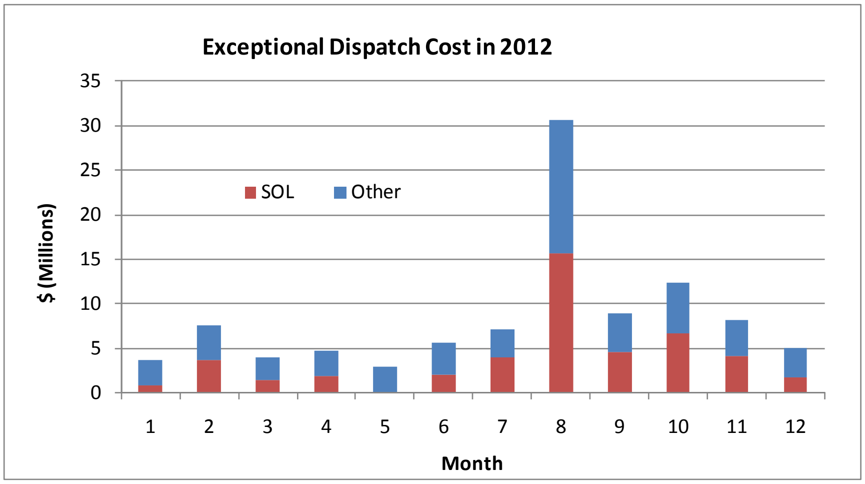
Without this preventive-corrective model in production, currently the ISO has to meet the interconnection reliability operating limits and system operating limits by enforcing minimum online capacity constraints (MOCs) or through manual exceptional dispatches. The ISO estimated the SOL related exceptional dispatches through operator logs[35], and showed the volume (MWhs) by month in 2012 in Figure 1. The percentage of SOL related exceptional dispatches varied from 21 percent to 77 percent month by month in 2012. The ISO also estimated the cost of exceptional dispatches by the sum of exceptional dispatch energy cost, the minimum load cost and the startup cost.[36] The cost estimate is shown in Figure 2. The total exceptional dispatch cost estimate was about $101 million in 2012, and about $47 million of that cost is attributable to SOL related exceptional dispatches.

Figure 1
SOL Related Exceptional Dispatch Volume in 2012 (Thousands of MWhs)



[34] James McCalley, EE553, Steady-state analysis, Class 18: security constrained OPF, Iowa State University, http://home.eng.iastate.edu/~jdm/ee553/SCOPF.pdf
[35] The numbers shown in Figure 1 may over or under estimate the actual volume of SOL related exceptional dispatches due to the complexity of analyzing operator logs.
[36] Minimum load cost and start up cost are not directly settled. Instead, they need to go through the bid cost recovery settlement process. Directly using the minimum load cost and start up cost may over estimate the cost. The bid cost recovery calculation is netted against profit over a trade day, so it is impossible to unravel the exact exceptional dispatch cost. To reduce the bias, the ISO excluded the optimal energy cost associated with exceptional dispatches from the total cost estimate.

Figure 2
SOL Related Exceptional Dispatch Cost in 2012 (Million dollars)



The ISO proposes to enhance the contingency model in the market optimization to handle the post contingency corrective actions. With the contingency model enhancement (CME), the market optimization advances from a pure preventive mode to a preventive-corrective mode, where both pre contingency dispatches and post contingency re-dispatches are co-optimized to meet the reliability standards. With the mandatory standards incorporated into the market optimization, the need for operators to exceptionally dispatch resources to their dispatchable Pmin or utilize MOCs to comply with the SOL standards is expected to significantly decrease.

5.2. Preventive-corrective market optimization

In this section, the discussion first reviews the power system security framework, and then the modeling enhancement to the market optimization. For simplicity and ease of understanding, the discussion focuses on a linear lossless model throughout the straw proposal. The ISO employs marginal loss model in the market optimization and full AC power flow in the network applications. How the preventive-corrective model works on top of the marginal loss model is excluded from the straw proposal. We can provide these details in the future when the need arises.

5.2.1. Power system security framework

The modeling enhancement is related to contingency. Contingency is the key concept in the power system security framework. It will be helpful to review the power system framework for a better understanding the modeling enhancement.

Power system security is the ability of the system to withstand disturbances without unduly impacting the service to the loads or its quality. In powers system operations, security assessment analyzes the vulnerability of the system to a set of contingencies, known as the contingency list. Contingencies are predefined disturbances/outages that have not occurred yet. The ISO maintains a contingency list that contains the most severe and/or most likely disturbances yet to occur. The classic power system security study framework is illustrated in Figure 3.

In the classic security study framework, power system can be operating under one of the three states[37]:

- Normal state: when all loads are serviced without any operating limits being violated. Normal state can be further classified into two states:
    - Secure state: when the system is still under normal state post contingency,
    - Insecure state: when the system is under emergency state post contingency.
- Emergency state: when all loads are serviced with one or more operating limits being violated.
- Restorative state: when there is loss of load without any operating limits being violated.

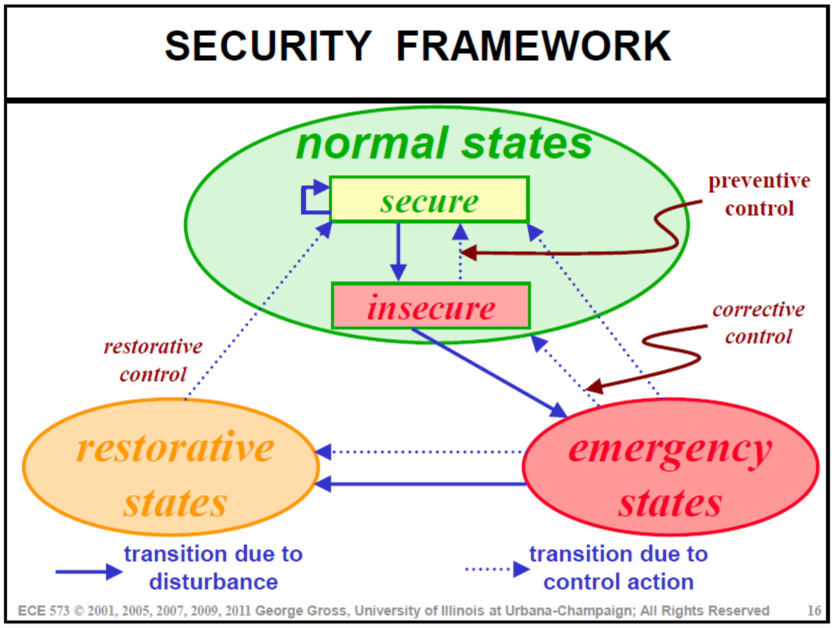
A significant disturbance, e.g., loss a generator or a transmission element, may change the power system operating state. Power system state may change from secure to insecure, from insecure to emergency, and from emergency to restorative. These transitions are automatically triggered without human intervention.

System operators may take control actions that also change the power system states. The control actions either try to resolve a current violation of operating limits or prevent a violation after one of the contingencies occurs. They can be classified as follows:

- Restorative control transitions the system from restorative state to secure state.
- Corrective control transitions the system from emergency state to normal state.
- Preventive control transitions the system from insecure state to secure state.
- Controlled load shedding transitions the system from emergency state to restorative state.

[37] Dy Liacco: T. E. Dy Liacco, “Systems Security: the Computer’s Role,” IEEE Spectrum, June 1978, pp. 43-50

Figure 3
Power System Security Study Framework



Implementing the security framework into the Energy Management System (EMS) can provide the operators online security analysis functionality to closely monitor, assess, and control system security.

5.2.2. Preventive market optimization

Section 5.2.1 discussed the security framework that is applicable to system operations. In this section, we will focus on the market aspect of power system security. As discussed in the last section, the preferred power system operating state is the secure state. In electricity markets, the market solution typically tries to operate the system under secure state. In order to achieve N-1 security, the market optimization, typically an optimal power flow (OPF) program or a unit commitment (UC) program, will:

- enforce SOL on applicable paths, and
- consider each contingency in the contingency list, and include constraints of the immediate post contingency system conditions.

The decision variables are the pre contingency unit commitments and dispatches. The post contingency system conditions are solely determined by the pre contingency dispatches and the post contingency network topology. If there is a violation after the contingency occurs, then the optimization will try to change the pre contingency dispatches to prevent it from occurring. That is why this model is called a preventive model.

The terms preventive model and preventive control can be confusing. Both have the term preventive, but they are different things. Preventive control is the actions operators take to transition the current system state from insecure state to secure state. Preventive model is the market optimizations model that produces a secure market solution for the future.

The structure of a typical preventive market optimization is as follows:

$$\min \sum_{i=1}^{n} C_i\left(P_i^0\right)$$

s.t.

$$g^0(P^0) = 0$$

$$h^0(P^0) \leq h^{0,max}$$

$$h^k(P^0) \leq h^{k,max}, \forall k = 1,2,\cdots,K$$

where

- the numeric superscript represents the case number with 0 being the based case, and 1, 2, up to *K* are the contingency cases,
- $g^0(\cdot)$ are the equality constraints.
- $h^k(\cdot), \forall k = 0,1,\cdots,K$ are the inequality constraints.

See Section 21 for a list of nomenclature used in this paper.

Market optimization has become more and more sophisticated with more and more constraints. Among these constraints, there are two crucial ones, namely the power balance constraint and the transmission constraint, because their associated Lagrangian multipliers (i.e., shadow prices) are needed to calculate the locational marginal prices (LMPs).

The energy balance constraint is an equality constraint

$$\sum_{i=1}^{n} P_i^0 = \sum_{i=1}^{n} L_i$$

which says the total generation equals total load in a lossless model. Note that power balance constraint is only enforced in the base case, but not in any contingency case in the preventive model. This is because power injections do not change in any transmission contingency case immediately after the transmission contingency occurs, so the power balance in a transmission contingency case will be automatically satisfied if it is satisfied in the base case.

The transmission constraint is an inequality constraint, which says that for every case *k*, the power flow on a transmission line *l* has to be within its flow limit $\overline{FL}_l^k$. In a linear lossless model, the transmission constraint is

$$\sum_{i=1}^{n} SF_{l,i}^k (P_i^k - L_i) \le \overline{FL}_l^k$$

where $SF_{l,i}^k$ is the shift factor from location *i* to constraint *l* in case *k*. Note that the transmission constraint is enforced for every case, including both the base case and contingency cases[38]. In addition, the shift factors are case specific, because the post contingency system topology changes from case to case.

Denote the Lagrangian multiplier for the power balance constraint by λ^0 and the Lagrangian multiplier for the transmission constraint by μ_l^k. The LMP[39] at location *i* is

$$\lambda^0 + \sum_{k=0}^{K} \sum_{l=1}^{m} SF_{l,i}^k \cdot \mu_l^k$$

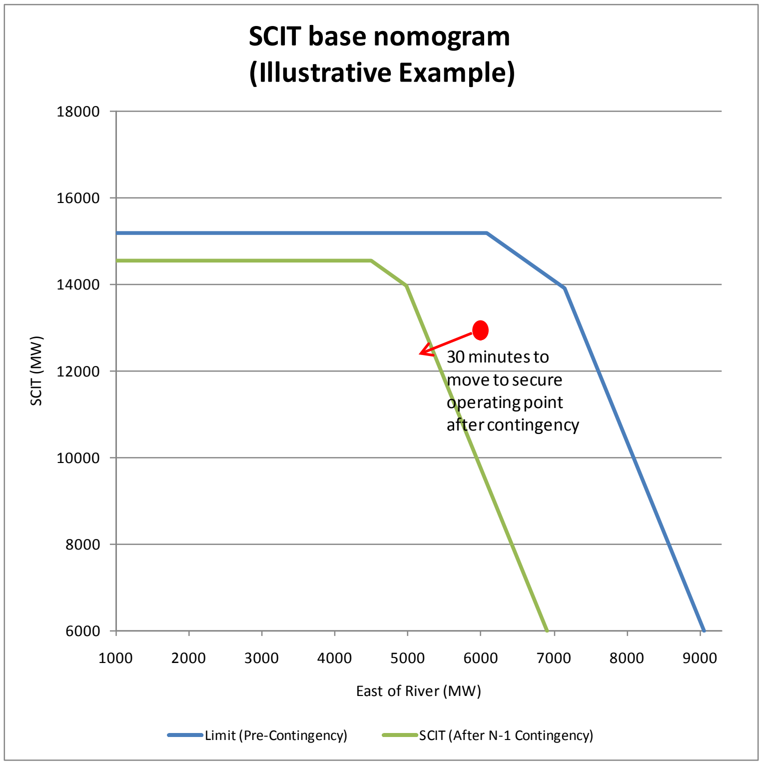
where the first term is the energy component, and the second term is the congestion component. Note that congestion in a contingency case will impact LMP in a similar way as congestion in the base case.

5.2.3. Preventive-corrective market optimization

Assume the system operates at the N-1 secure state from the solution of the preventive market optimization. Suddenly, a system disturbance occurs. Because the pre-contingency case is N-1 secure, the post-contingency system is under a normal state without any violations. However, it may be insecure, and vulnerable to the next contingency yet to occur. The ISO must transition the system back to a secure state within 30 minutes after the system disturbance. The system must not only be N-1 secure (below the original SOL rating), but also be able to reach another N-1 secure state (below the new SOL rating) 30 minutes after a contingency. An example of SCIT is illustrated in Figure 4.

[38] Transmission constraints for contingency cases are often referred as security constraints.
[39] In the lossless model, the LMP only has two components: the energy component and the congestion component.

Figure 4
SCIT Pre-contingency rating and post-contingency rating



If all elements are in service, the normal SCIT nomogram limit (SOL) is the blue curve. If the system operates inside the blue curve, it is N-1 secure. Assume that pre contingency, the system is operating at the red dot with 13,000 MW flow on SCIT and 6,000 MW flow on East of River. Suddenly, one of the SCIT lines trips. With one element out of service, the new SCIT nomogram limit is the green curve. To reliably operate the system, the ISO needs to bring the operating point from the red dot to inside the green curve in 30 minutes such that the system operates under new N-1 secure state 30 minutes after the disturbance. In addition, it is expected that the re-dispatch function execution set up, run time, publishing results, and resources start ramping may take some time (e.g. few minutes) to complete after the disturbance occurs. Therefore, the policy must reduce the 30-minute timeframe to the practical available response time in the preventive-corrective model. Discussion in this paper assumes this time to be *T*. The corrective re-dispatch may or may not involve operating reserve deployment depending on the relevant reliability standards.

5.2.4. Preventive-corrective optimization model

A preventive-corrective market optimization can explicitly model the timeframe to re-dispatch resources to comply with the new limit. The structure of a preventive-corrective model is as follows.

$$\min \sum_{i=1}^{n} C_i\left(P_i^0\right)$$

s.t.

$$g^0(P^0) = 0$$

$$h^0(P^0) \leq h^{0,max}$$

$$h^k(P^0) \leq h^{k,max}, \forall k = 1,2,\cdots,K$$

$$g^{kc}\left(P^0 + \Delta P^{kc}\right) = 0, \forall kc = K+1, K+2, \cdots, K+KC$$

$$h^{kc}\left(P^0 + \Delta P^{kc}\right) \leq h^{kc,max}, \forall kc = K+1, K+2, \cdots, K+KC$$

$$RCD(P^0) \leq \Delta P^{kc} \leq RCU(P^0), \forall kc = K+1, K+2, \cdots, K+KC$$

where

- $kc = K+1, K+2, \cdots, K+KC$ are contingencies that involve corrective re-dispatch,
- $RCU(P^0)$ is the upward ramping capability from the base case P^0 in the given timeframe *T*,
- $RCD(P^0)$ is the downward ramping capability from the base case P^0 in the given timeframe *T*.

Compared with the preventive model, the preventive-corrective model adds corrective contingency cases indexed by *kc*. The corrective contingency cases allow re-dispatching resources after the contingency occur s. The re-dispatch capability from the base case dispatch is ΔP^{kc}, which is limited by the resource's ramp rate and the given timeframe. The preventive-corrective model is only concerned about the feasibility of capacity to comply with the post contingency new limit, but not the energy cost of post contingency re-dispatch. This is because the probability that a contingency would occur is close to zero, and thus the expected re-dispatch cost is also close to zero.

As long as a resource that can deliver energy in the given time frame, it can provide the corrective capacity. Operating reserves will be included in the corrective capacity supply as applicable. The supply of corrective capacity includes but not limited to generators, demand response, and pump storage. Offline generators can provide corrective capacity as long as it can start within the given time frame.

When a contingency occurs, ΔP^{kc} is a feasible solution to comply with the new limit. However,

ΔP^{kc} may not be the most economic re-dispatch to comply with the new limit. The dispatch cost from resources without the corrective capacity awards may be lower than from the resources with the capacity awards. In this case, the actual dispatch after the contingency occurs may not be ΔP^{kc}, but the more economic solution from re-dispatching resources without the corrective capacity awards. This design secures the availability of the required capacity, but provides better market efficiency and robustness than restricting the re-dispatch to resources with capacity awards. The same design also applies to the ancillary service procurement and deployment.

The power balance constraint and transmission constraint in the corrective contingency cases are indexed by *kc*. These constraints are referred to as the preventive-corrective constraints in the earlier sections of the paper. Recall that in the preventive model, there is no power balance constraint for a contingency case, because the power balance condition remains the same immediately after the transmission contingency occurs. In the preventive-corrective model, we allow a timeframe to re-dispatch resources, and we evaluate the system at time *T* after the actual time at which the contingency occurs. In order to make sure the re-dispatches do not violate power balance, the modelenforces a power balance constraint for each corrective transmission line contingency case *kc* as follows:

$$\sum_{i=1}^{n} \Delta P_i^{kc} = 0$$

Denote the Lagrangian multiplier for the power balance constraint for corrective contingency case *kc* by λ^{kc}.

The power balance constraint for the base case is energy constraints. In contrast, the new power balance constraints for corrective contingencies are capacity constraints. If there is transmission constraint violation in any contingency case, the optimization may resolve the violation with corrective capacities. The capacity balance constraints are needed to make sure the established energy balance in the base case is not adversely affected in the transmission congestion management process, such as resulting in involuntary load shedding. The capacity balance constraints do not directly affect the feasibility of the energy balance constraint in the base case, because the energy dispatches do not participate in the capacity balance constraints; however, the total capacity dispatched in the base case and reserved as corrective capacity ($P^0 + \Delta P^{kc}$) must be within the applicable resource capacity limits (e.g., lower and upper operating limits), considering also ancillary services awarded in the base case.

The transmission constraint in the corrective contingency case *kc* says the power flow on a transmission line *l* has to be within its flow limit $\overline{FL}_l^{kc}$ after the corrective re-dispatches. In a linear lossless model, for each corrective contingency case *kc*, the transmission constraint is

$$\sum_{i=1}^{n} SF_{l,i}^{kc}\left(P_i^0 + \Delta P_i^{kc} - L_i\right) \leq \overline{FL}_l^{kc}$$

Note that in the preventive-corrective model, the transmission constraint is enforced for every case, including the base case, normal contingency cases indexed by *k*, and corrective contingency cases indexed by *kc*. Denote the Lagrangian multiplier for the transmission constraint for corrective contingency case *kc* by μ_l^{kc}.

If the pure preventive model market solution already has enough corrective capacity to resolve any possible post contingency violation within the given timeframe, the system wide λ^{kc} and shadow price of the post contingency transmission constraint μ_l^{kc} are zeroes. This is because there is no cost associated with corrective capacities in the preventive-corrective model objective function, and thus the preventive-corrective model will produce the same pre-contingency dispatch as the pure preventive model. If the pure preventive model market solution does not have enough corrective capacity to resolve the post contingency violation within the specified timeframe, then the preventive-corrective model will adjust the pre-contingency (base case) dispatch to create more corrective capacity and/or reduce the pre-contingency flow such that the violation can be resolved within the timeframe after contingency occurs. In this case, because the pre-contingency base case dispatch cost is included in the objective function, the marginal dispatch adjustment cost due to resolving the post contingency violation will manifest itself in λ^{kc} and μ_l^{kc}.

Similar to an offline resource providing non-spin reserve, an offline resource can also provide the corrective capacity as long as the resource can start up within the allowed time frame. The corrective capacity award is limited by the capacity that the resource can reach within the allowed time frame.

5.2.5. Preventive-corrective model compensation

For the base case, the LMP for energy dispatch at location *i* is

$$\lambda^0 + \sum_{k=0}^{K} \sum_{l=1}^{m} SF_{l,i}^{k} \cdot \mu_l^k + \sum_{kc=K+1}^{K+KC} \sum_{l=1}^{m} SF_{l,i}^{kc} \cdot \mu_l^{kc}$$

The structure of the LMP in the preventive-corrective model is the same as the LMP in the preventive model except that the preventive-corrective model has included more contingencies, i.e. the corrective contingencies indexed by *kc*. The LMP breaks down to the energy component λ^0, and the congestion component $\sum_{k=0}^{K}\sum_{l=1}^{m} SF_{l,i}^{k} \cdot \mu_l^k + \sum_{kc=K+1}^{K+KC}\sum_{l=1}^{m} SF_{l,i}^{kc} \cdot \mu_l^{kc}$. Note that the LMP congestion component includes congestion impact from every case. A resource will receive energy compensation at the LMP.

Because LMP includes congestion impact from every case, the local market power mitigation triggered by LMP non-competitive congestion component works effectively in the preventive-corrective model. Regardless of whether a binding constraint is uncompetitive in the base case, in a normal contingency case, or in a corrective contingency case, the potential impact will manifest itself in the LMP non-competitive congestion component so that the market power mitigation is able to mitigate the resources that are potentially benefiting from the locally uncompetitive constraint. Department of Market Monitoring (DMM) expressed concern of market power that a resource may bid below its marginal energy cost in order to increase the LMCP, and provided two examples to illustrate the issues. DMM's example 1 demonstrates that if the corrective capacity market is uncompetitive, a generator (G3 in the example) can bid lower than the true energy marginal cost, and effectively increase the opportunity cost for the corrective capacity. As a result, the resource could benefit from the higher LMCP. A generator can take advantage in the capacity market even if the energy market is competitive. DMM's example 2 demonstrates that when a scheduling coordinator clears more corrective capacity than energy, it could game the market by sacrificing energy payment for higher capacity payment. Both DMM's concerns are valid, and are generally applicable to all capacity products, including ancillary services. Since these issues are not originated from this contingency modeling enhancement initiative, and are more general than the contingency modeling enhancement initiative could handle, this stakeholder process may not be the right place to deal with them. The ISO will work with DMM to closely monitor market power issue in capacity markets. Once the market power is observed in the capacity markets, and the impact is significant enough, the ISO will pursue developing a market power mitigation mechanism for all capacity products.

As discussed in the previous section, the marginal values of corrective capacity depend on λ^{kc} and μ_l^{kc}, and thus depend on location. Therefore, the corrective capacity will have a locational marginal capacity price (LMCP). The LMCP at location *i* for case *kc* is

$$LMCP_i^{kc} = \lambda^{kc} + \sum_{l=1}^{m} SF_{l,i}^{kc} \cdot \mu_l^{kc}$$

The LMCP may reflect

- a resource's opportunity cost of being dispatched out of merit,
- the marginal congestion cost saving, and/or
- the marginal capacity value to null the incentive of uninstructed deviations in order to support the dispatch.

The following examples will demonstrate the meaning and appropriateness of the locational marginal capacity price.

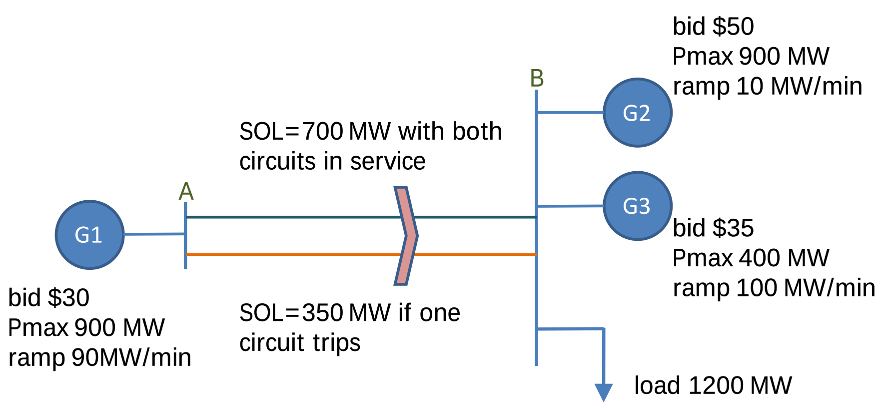
5.3. Examples

This section describes several examples. Each example will serve one more purposes. The first example is a very basic example, and the other examples will be variations of the first example. To keep the examples simple, generation is used in each one; however, the corrective capacity can be supplied by demand response as well.

5.3.1. Example 1: Out-of-merit dispatch with LMCP reflecting opportunity cost

This is a two-node example with three generators. Branch A-B has two circuits. Assume $K = 0$, and the $KC = 1$. Branch A-B has pre contingency SOL of 700 MW with both circuits in service, which is N-1 secure. If one of the two A-B circuits trip, and next N-1 secure SOL for branch A-B is 350 MW. The load is 1200 MW at node B.

Figure 5
A two-node system with three generators



The discussion below compare results of the following models:

- Weak preventive model: N-1 secure, but may not be able to meet the post contingency limit within 30 minutes after the contingency occurs (or assume 20 minutes after the re-dispatch instruction) without using MOCs or exceptional dispatch. This is the model that the ISO currently uses.
- Strong preventive model: N-2 secure, enforce the post contingency rating in the pre contingency dispatch.
- Preventive-corrective model: not only N-1 secure, but also meet the post contingency rating 30 minutes after contingency occurs (or assume 20 minutes after the re-dispatch instruction).

The weak preventive solution is listed in Table 4. The total generation cost is 40,000. If the contingency occurs, the 700 MW flow on branch 2-3 will exceed the next SOL 350 MW, which protects again the next contingency. The weak preventive model produces N-1 secure solution, but may not be able to meet the new limit 30 minutes after the contingency occurs.

As shown in Table 4, load energy payment is 1,200 MW*$50=$60,000. Note that the convention of the revenue column in Table 4 is that revenue is positive, and payment is negative. That is why the load revenue is –$60,000 in Table 4. If there is a CRR holder having 700 MW A to B CRR, it will be paid 700 MW*$20 = $14,000. The ISO is revenue neutral because the total generation and CRR revenue is exactly covered by load payment: $46,000+$14,000–$60,000=0. To simplify bid cost recovery calculation, let's assume the minimum load cost and startup cost are all zeros throughout all the examples in the proposal. In this example, there is zero bid cost recovery and zero uplift cost to load.

Table 4
Weak preventive solution and settlement

Resource	MW	LMP^{EN}	LMP^{CONG}	LMP	Bid cost	Revenue	Profit/uplift
G1	700	$50	–$20	$30	$21,000	$21,000	$0
G2	100	$50	$0	$50	$5,000	$5,000	$0
G3	400	$50	$0	$50	$14,000	$20,000	$6,000
Total gen	1,200	N/A	N/A	N/A	$40,000	$46,000	$6,000
Load	1,200	$50	$0	$50	N/A	–$60,000	$0
CRR_{AB}	700	N/A	N/A	$20	N/A	$14,000	N/A

To meet the next contingency SOL, one could enforce the new post contingency limit (350 MW) in the pre contingency dispatch even if the first contingency has not occurred yet. This is called the strong preventive model, which protects against N-2 contingency. The solution of strong preventive model is listed in Table 5. The total generation cost is $47,000. The strong preventive solution is much more costly than the weak preventive solution. The cost difference $47,000–$40,000=$7,000 is the cost to resolve the post contingency violation with the N-2 secure strong preventive model. Because it is often very costly to maintain N-2 secure, it is not a common reliability standard in power system operations. Instead, NERC and WECC allow certain timeframe (no more than 30 minutes) to reach another N-1 secure state after one contingency occurs. As will be shown in the preventive-corrective case, the solution will be more economic than the strong preventive case.

As shown in Table 5, load energy payment is still 1,200*$50=$60,000, and CRR revenue is 350 MW*$20 = $7,000. Note that with SOL being reduced to the N-2 secure rating 350 MW, the CRR sold quantity has been adjusted accordingly to 350 MW.[40] The ISO is revenue neutral because the load payment is just enough to cover the total generation and CRR revenue: $53,000+$7,000–$60,000=$0. There is zero bid cost recovery and zero uplift cost to load.

[40] If the CRR sold quantity stays at 700 MW, the ISO is short of $7,000 to cover the 700 MW CRR revenue, and has to uplift the $7,000 cost to load.

Table 5
Strong preventive solution and settlement

Resource	MW	LMP^{EN}	LMP^{CONG}	LMP	Bid cost	Revenue	Profit/uplift
G1	350	$50	–$20	$30	$10,500	$10,500	$0
G2	450	$50	$0	$50	$22,500	$22,500	$0
G3	400	$50	$0	$50	$14,000	$20,000	$6,000
Total gen	1,200	N/A	N/A	N/A	$47,000	$53,000	$6,000
Load	1,200	$50	$0	$50	N/A	–$60,000	$0

In the preventive-corrective model, in addition to the N-1 secure limit (700 MW), we allow 30 minutes after the contingency occurs (or assume 20 minutes after the re-dispatch instruction) to meet the next SOL 350 MW. The preventive-corrective solution is listed in Table 6. When the A-B SOL is reduced by 350 MW in the post contingency case, G2 and G3 need to ramp up the same amount in 20 minutes in order to meet load and provide counter flow. G2 has 10 MW/minute ramp rate, and can only ramp 200 MW in 20 minutes. The rest 150 MW ramp needs to come from G3. In order to provide this 150 MW ramp, G3 needs to be dec'ed 150 MW in the pre contingency case.

The LMPs and LMCPs are listed in Table 6. As described in section 5.2.3, for each corrective contingency case, the market calculates a set of case specific LMCPs. The LMP for the base case dispatch has an energy component λ^0, and a congestion component $SF^0_{AB,i} \cdot \mu^0_{AB} + SF^1_{AB,i} \cdot \mu^1_{AB}$, the sum of shift factors times shadow prices over all cases. Take G3 as an example. The base case λ^0 is $50, and G3's congestion component is $0 \cdot (-5) + 0 \cdot (-15)$ =$0, so G3's LMP is $50. In this example the LMCP to compensate the corrective capacity 150 MW is equal to $\lambda^1 + SF^1_{AB,B} \cdot \mu^1_{AB} = 15 + 0 \cdot (-15) = \$15$. In this case, the LMCP reflects G3's the opportunity cost, which equals to the LMP minus its energy bid ($50 –$35 = $15). Without this capacity payment, G3 is under compensated because it is decremented to help meet the post contingency constraint, and has lost profit from the reduced energy dispatch. It is a common misperception that bid cost recovery can make whole for the opportunity cost, so the capacity payment is unnecessary. Bid cost recovery only makes whole for dispatched energy, but not for opportunity cost of undispatched energy. In this example, bid cost recovery cannot make whole for G3's 150 MW corrective capacity. That is why we need the capacity payment to prevent G3 from being under compensated by holding its capacity for corrective contingency.

G2 will also receive the same LMCP as G3, because they are located at the same location, and their corrective capacities have the same marginal value. Providing the G2 the LMCP payment gives the correct incentive for infra marginal resources to improve the ramp rate. If the ramp rate is improved by, say 0.1 MW/minute, G2 could be awarded 0.1*20 = 2 MW of more corrective capacity, and be paid 2*15 = $30. Because the LMCP is a marginal price, the market incentive it provides only holds for a limited amount. If the corrective capacity supply is increased by a large account, the LMCP incentive may diminish. This is not something unique to the LMCP. The LMP may decrease if additional resources are committed at the same location. Shadow price for a transmission constraint may decrease or diminish if an additional transmission line is built. Some stakeholders argued that LMCP incentive is invalid because if G2's ramp rate is increased by 10 MW/min, the LMCP will become zero. Increasing G2's ramp rate by 10 MW/minute is equivalent to increase 200 MW of corrective capacity supply at $0 cost. With such a big change in supply, it is very likely the LMCP will diminish in this case, just like the LMP may diminish if a 200 MW resource bidding $0 is committed at the same location. The fact that marginal price may diminish if a large supply is introduced into the market does not imply the marginal price incentive is invalid. To the contrary, it implies the marginal price not only provides incentive for capacity investment, but also discourages over investment.

Table 6
Preventive-corrective solution and LMCP compensation

Energy in base case								
Generator	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP	Bid cost	Revenue	Profit
G1	700	$50	1	$–5	$30	$21,000	$21,000	$0
G2	250	$50	0	$–5	$50	$12,500	$12,500	$0
G3	250	$50	0	$–5	$50	$8,750	$12,500	$3,750
Corrective Capacity in contingency *kc*=1								
Generator	ΔP^1	λ^1	SF^1_{AB}	μ^1_{AB}	$LMCP^1$	Bid cost	Revenue	Profit
G1	–350	$15	1	$–15	$0	$0	$0	$0
G2	200	$15	0	$–15	$15	$0	$3,000	$3,000
G3	150	$15	0	$–15	$15	$0	$2,250	$2,250

Table 7
Preventive-corrective model settlement

Resource	MW	LMP	Bid cost	Revenue	Profit	Uplift
Total gen energy	1,200	N/A	$42,250	$46,000	$3,750	
Total gen capacity	350	N/A	N/A	$5,250	$5,250	
Load	1,200	$50	N/A	–$60,000		

The total generation cost of the preventive-corrective solution is $42,250. It resolves the post contingency constraint at the cost $42,250–$40,000 = $2,250. This is much more economic than the strong preventive solution, which incurs additional cost of $7,000 compared with the weak preventive case. The relationship between these three models is summarized in Table 8.

Table 8
Comparison of different optimization models

Model properties	Weak preventive	Preventive-corrective	Strong preventive
30-minute SOL compliance	Not modeled	Accurately modeled	Over modeled
Total bid cost	Lowest	Medium	Highest

5.3.2. Example 2: Reducing pre-contingency flow with LMCP reflecting congestion cost saving

Now we consider another scenario with G3 out of service. The preventive-corrective solution is listed in Table 9. Because G2 has maximum 200 MW corrective capacity limited by its ramp rate, G1 and G2 can resolve at most 200 MW of overload in 20 minutes. The optimization dispatches G1 at 550 MW in the base case, which is 200 MW above the post contingency 350 MW SOL. In this case, the optimization cannot create more corrective capacity, so it reduces the base case flow. As a result, the transmission constraint is not binding in the base case, but it is binding in the contingency case at 350 MW. Also, the total generation cost increases to $49,000. G2's corrective capacity has a marginal value, because if there is 1 more MW corrective capacity, the base case flow can be increased by 1 MW, and result in a cost saving of $20 by dispatching up G1 1 MW at $30 and dispatching G2 down 1 MW at $50. In this case, LMCP reflects the contingency case marginal congestion cost impact.

Under the LMCP compensation, G2 will receive its capacity payment 200 MW * $20=$4,000. This provides incentive for market participants to improve ramping capability at location B.

The settlement is summarized in Table 10. Load energy payment is still 1,200 MW*$50=$60,000.

Table 9
Preventive-corrective solution and LMCP compensation with G3 out of service

Energy in base case								
Generator	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP	Bid cost	Revenue	Profit
G1	550	$50	1	$0	$30	$16,500	$16,500	$0
G2	650	$50	0	$0	$50	$32,500	$32,500	$0
G3	0	$50	0	$0	$50	$0	$0	$0
Corrective Capacity in contingency *kc*=1								
Generator	ΔP^1	λ^1	SF^1_{AB}	μ^1_{AB}	$LMCP^1$	Bid cost	Revenue	Profit
G1	–200	$20	1	$–20	$0	$0	$0	$0
G2	200	$20	0	$–20	$20	$0	$4,000	$4,000
G3	0	$20	0	$–20	$20	$0	$0	$0

Table 10
Preventive-corrective model settlement with G3 out of service

Resource	**MW**	**LMP**	**Bid cost**	**Revenue**	**Profit**	**Uplift**
Total gen energy	1,200	N/A	$49,000	$49,000	$0	
Total gen capacity	200	N/A	N/A	$4,000	$4,000	
Load	1,200	$50	N/A	–$60,000		

5.3.3. Example 3: Dynamic ramp rate with LMCP zeroing out uninstructed deviation incentive

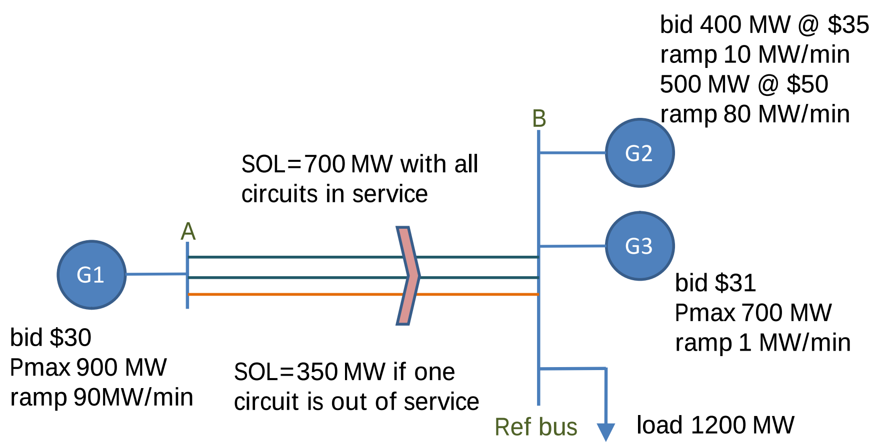


Table 11
Preventive-corrective solution and LMCP compensation with G2 having dynamic ramp rate

Energy in base case								
Generator	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP	Bid cost	Revenue	Profit
G1	700	$31	1	$-0.43	$30	$21,000	$21,000	$0
G2	218.57	$31	0	$-0.43	$31	$7,649.95	$6,775.67	-$874.28
G3	281.43	$31	0	$-0.43	$31	$8,724.33	$8,724.33	$0
Corrective Capacity in contingency *kc*=1								
Generator	ΔP^1	λ^1	SF^1_{AB}	μ^1_{AB}	$LMCP^1$	Bid cost	Revenue	Profit
G1	–350	$20	1	$-0.57	$0	$0	$0	$0
G2	330	$20	0	$-0.57	$0.57	$0	$188.10	$188.10
G3	20	$20	0	$-0.57	$0.57	$0	$11.40	$11.40

Table 12
Preventive-corrective model settlement with G2 having dynamic ramp rate

Resource	MW	LMP	Bid cost	Revenue	Profit	Uplift
Total gen energy	1,200	N/A	$37,374	$36,500	–$874	
Total gen capacity	350	N/A	N/A	$200	$200	
Load	1,200	$31	N/A	–$37,200		-686

In this example, G2 has a dynamic ramp rate:

- from 0 MW to 400 MW, the ramp rate is 10 MW/min,
- from 400 MW to 900 MW, the ramp rate is 80 MW/min.

If G1 generates 700 MW in the base case, the system needs to have 350 MW upward ramping capability at node B to cover the 350 MW of SOL reduction. G3 can provide 20 MW in 20 minutes limited by its 1 MW/minute ramp rate. The rest 330 MW needs to come from G2. G2 has 10 MW/minute ramp rate from 0 MW to 400 MW, so it can provide 200 MW in 20 minutes. In order to provide more, it has to be dispatch up to use the higher ramp rate starting from 400 MW. However, because the energy bid is also higher in the higher ramp rate range, the optimization will not try to position the resource in the higher ramp rate range. Instead, the dispatch will position the resource in the lower ramp rate range at a position such that it can exactly provide 330 MW in 20 minutes. By doing so, it meets the post contingency needs without incurring the higher cost in the higher ramp rate region. The optimal dispatch position is 218.57 MW:

- from 218.57 MW to 400 MW, ramp 181.43 MW in 181.43/10 = 18.14 minutes,
- from 400 to 548.57, ramp 148.57 MW in 148.57/80=1.86 minutes,

so the total corrective capacity is 181.43+148.57 = 330 MW in 18.14+1.86=20 minutes.

The LMP at node B is $31, as the incremental load will be met by G3. In order to get 1 MW of incremental corrective capacity at node B, we will need to dispatch up G2 by 0.143 MW and dispatch G3 down by 0.143 MW. The 0.143 MW upward dispatch for G2 will enable G2 to provide 331 MW in 20 minutes as follows:

- from 218.71 MW to 400 MW, ramp 181.29 MW in 181.29/10 = 18.13 minutes,
- from 400 to 549.71, ramp 149.71 MW in 149.71/80=1.87 minutes.

The LMCP at node B is $0.57, so the incremental dispatch cost is 0.143*$35–0.143*$ 31 = $0.57, which sets the LMCP at node B.

The LMP at node B is $31 set by G3. The LMP $31 at node B is lower than G2's bid $35. Even with the corrective capacity payment, G2 is still short of revenue, so G2 needs to go through bid cost recovery to make up the payment shortage.

In this example, the LMCP is neither reflecting G2's opportunity cost (G2 does not have any opportunity cost), nor reflecting the congestion value (the corrective capacity is not affecting the base case congestion cost). Then, what is the interpretation of the LMCP $0.57? We have observed that G2 has revenue shortage to cover its bid cost. Even we can cover the revenue shortage with bid cost recovery, because bid cost recovery is netted over the day, a resource may still have incentive to avoid the revenue shortage on an interval basis by deviating from the ISO's dispatch. In this case, the value of LMCP is to support the dispatch by eliminating the incentive of uninstructed deviations. Let's assume G2 wants to generate 1 MW less than the ISO's dispatch 218.57 MW, so it could avoid losing $4. However, by doing so, the corrective capacity it can provide reduces to 323 MW:

- from 217.57 MW to 400 MW, ramp 182.43 MW in 182.43/10 = 18.24 minutes,
- from 400 to 540.56, ramp 140.56 MW in 140.56/80=1.76 minutes,

a total of 323 MW corrective capacity in 20 minutes.

So G2 would lose corrective capacity payment for 7 MW, a total of 0.57*7=$4. The capacity payment loss offsets the gain from energy dispatch deviation, so G2 has no incentive to deviate from the ISO's dispatch. The fact that LMP and LMCP are able to support the dispatch verifies the correctness of LMP and LMCP in the preventive-corrective model. This example suggests that LMCP payment is necessary to support the dispatch even for resources that do not have lost opportunity cost. Without LMCP payment, a resource may have incentive to deviate from the ISO's dispatch instruction, and compromise system's ability to meet the reliability standards.

The settlement is summarized in Table 12. Load energy payment is 1200*31=$37,200.The ISO needs $686 uplift to load to remain revenue neutral. The $686 uplift is to cover G2's bid cost recovery. Note G2's bid cost is 218.57*35=$7,650, while its revenue is 218.57*31+330*0.57=$6,964, so its bid cost recovery is $686. Further note, for generator G3, the prices paid for scheduled energy and corrective capacity do cover the generator's bid costs. The revenue it receives is 281.43 MW * $31/MW + 20 * $0.57/MW = $8,735.73. Its bid cost is 218.57 MW * $35/MW + 20 * $0/MW = $8,724.33. This yields a profit of $11.40.

5.3.4. Example 4: Multiple contingencies with LMCPs reflecting location opportunity costs

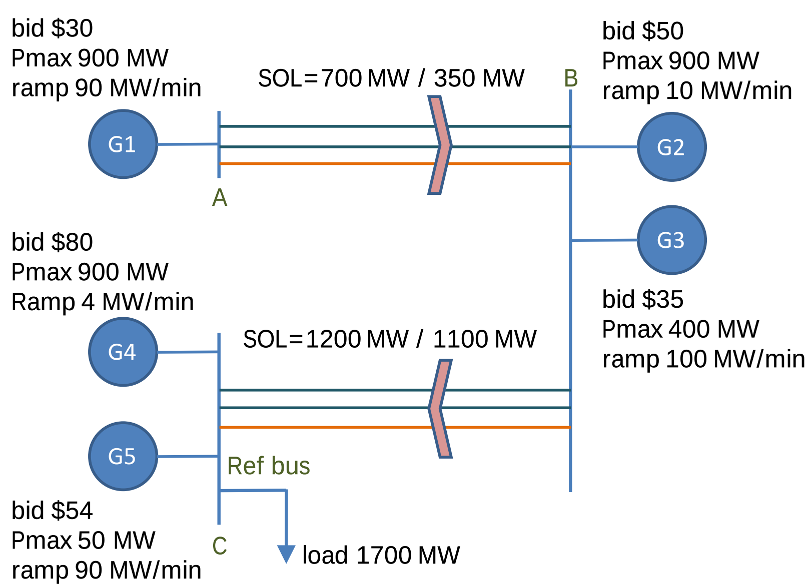


Table 13
Preventive-corrective solution and LMCP compensation with two SOLs

Energy in base case										
Generator	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	SF^0_{BC}	μ^0_{BC}	LMP	Bid cost	Revenue	Profit
G1	700	\$80	1	-\$5	1	-\$19	\$30	\$21,000	\$21,000	\$0
G2	150	\$80	0	-\$5	1	-\$19	\$50	\$7,500	\$7,500	\$0
G3	350	\$80	0	-\$5	1	-\$19	\$50	\$12,250	\$17,500	\$5,250
G4	470	\$80	0	-\$5	0	-\$19	\$80	\$37,600	\$37,600	\$0
G5	30	\$80	0	-\$5	0	-\$19	\$80	\$1,620	\$2,400	\$780
Corrective Capacity in contingency *kc*=1										
Generator	ΔP^1	λ^1	SF^1_{AB}	μ^1_{AB}	SF^1_{BC}	μ^1_{BC}	$LMCP^1$	Bid cost	Revenue	Profit
G1	–350	\$15	1	-\$15	1	\$0	\$0	\$0	\$0	\$0
G2	200	\$15	0	-\$15	1	\$0	\$15	\$0	\$3,000	\$3,000
G3	50	\$15	0	-\$15	1	\$0	\$15	\$0	\$750	\$750
G4	80	\$15	0	-\$15	0	\$0	\$15	\$0	\$1,200	\$1,200
G5	20	\$15	0	-\$15	0	\$0	\$15	\$0	\$300	\$300
Corrective Capacity in contingency *kc*=2										
Generator	ΔP^2	λ^2	SF^2_{AB}	μ^2_{AB}	SF^2_{BC}	μ^2_{BC}	$LMCP^2$	Bid cost	Revenue	Profit
G1	0	\$11	1	\$0	1	-\$11	\$0	\$0	\$0	\$0
G2	-150	\$11	0	\$0	1	-\$11	\$0	\$0	\$0	\$0
G3	50	\$11	0	\$0	1	-\$11	\$0	\$0	\$0	\$0
G4	80	\$11	0	\$0	0	-\$11	\$11	\$0	\$880	\$880
G5	20	\$11	0	\$0	0	-\$11	\$11	\$0	\$220	\$220

In this example, we have added node C, which is connected to node B by branch B-C, and two generators G4 and G5. Branch B-C has SOL reduction from 1200 MW to 1100 MW if one its circuits trips. G4 and G5 will need to have 100 MW upward corrective capacity in order to handle the 100 MW B-C SOL reduction. G4 can only provide 80 MW in 20 minutes, and the rest 20 MW needs to come from G5. G5 is more economic than G4 to meet load. In order to get 20 MW corrective capacity, G2 needs to be decremented by 20 MW, and that creates energy opportunity cost. The opportunity cost is \$80 – \$54 = \$26 with G4 setting the LMP at node C.

Next, consider branch A-B's SOL reduction 350 MW. The pool of resources to provide 350 MW upward corrective capacity include G2, G3, G4, and G5. Because G4 and G5 have provided 100 MW upward corrective capacity for branch B-C, this 100 MW also counts towards the 350 MW for SOL of A-B. It is more economic to get the rest of 250 MW corrective capacity from G2 and G3, because the marginal cost to provide corrective capacity at node B is \$15 (as shown in example 1), which is lower than \$26, the marginal cost of corrective capacity at node C. G2 can provide at most 200 MW in 20 minutes, so the rest 50 MW needs to come from G3. G3 is a more economic resource to meet load than G2. In order to get the 50 MW upward corrective capacity, G3 needs to be dec'ed 50 MW in the base case, and that creates energy opportunity cost. Again, the opportunity cost is \$50– \$35 = \$15.

Now we see how the prices are calculated.

$LMP^A = \lambda^0+\mu_{AB}^0+\mu_{BC}^0+\mu_{AB}^1+\mu_{BC}^1+\mu_{AB}^2+\mu_{BC}^2=80–5–19–15+0+0–11 = \$30.$

$LMP^B = \lambda^0+\mu_{BC}^0+\mu_{BC}^1+\mu_{BC}^2=80–19+0–11 = \$50.$

$LMP^C = \lambda^0= \$80.$

The LMPs can be easily verified, as the marginal resources are quite obvious. At node A, G1 sets the LMP \$30; at node B, G2 sets the LMP \$50; and at node C, G4 sets the LMP \$80.

The opportunity cost for G5 is \$80 – \$54 = \$26, and the opportunity cost for G3 is \$50– \$35 = \$15. As will be shown below, the LMCPs correctly reflect the opportunity costs.

$LMCP^1{}_B = \lambda^1 + \mu_{BC}^1 = 15+0 = \$15.$

$LMCP^1{}_C = \lambda^1= \$15.$

$LMCP^2{}_B = \lambda^2 + \mu_{BC}^2 = 11–11= \$0$

$LMCP^2{}_C = \lambda^2 = \$11$

Note that G5's 20 MW corrective capacity in contingency case *kc*=1 will be paid $LMCP^1{}_C$ = \$15, and the same 20 MW corrective capacity in contingency case *kc*=2 will be paid $LMCP^2{}_C$ = \$11. So overall, G5 gets paid $LMCP^1{}_C$+ $LMCP^2{}_C$ = 15+11 = \$26 for each corrective MW, which matches its opportunity cost. This again verifies that the case specific LMCPs are not mutually inclusive, and compensating at the LMCPs will correctly reflect opportunity costs.

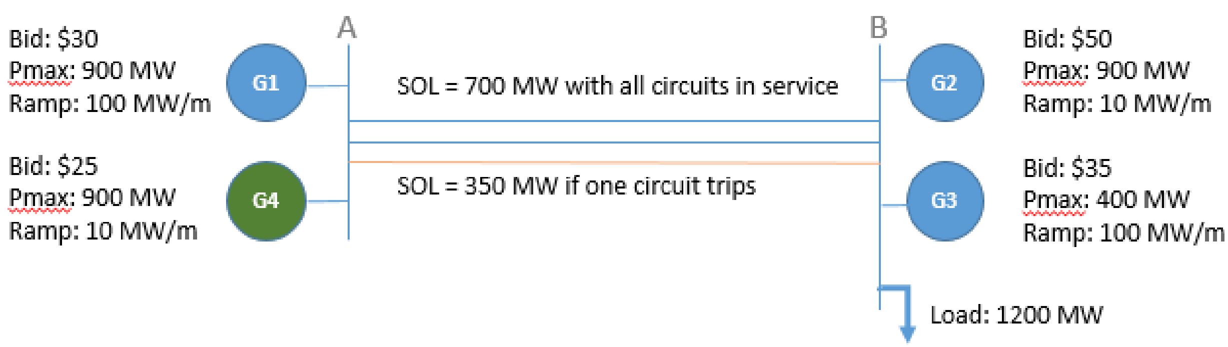
The settlement is summarized in **Table 14**. Load energy payment is 1,700 MW*\$80=\$136,000.

Table 14
Preventive-corrective model settlement with two SOLs

Resource	MW	LMP	Bid cost	Revenue	Profit	Uplift
Total gen energy	1700	N/A	$79,970	$86,000	$6,030	
Total gen capacity	350	N/A	N/A	$6,350	$6,350	
Load	1,700	$31	N/A	–$136,000		

5.3.5. Example 5: Downward corrective capacity award with negative LMCP

In this example, we introduce a slow ramping marginal resource at bus A (See Resource G4).



Let us compare the weak-preventive dispatch to the preventive-corrective dispatch. The weak-preventive dispatch would maximize the use of G4 as the cheapest available resource, then maximize the use of G3 followed by G2.

Weak-preventive model energy in base case								
Generator	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP	Bid Cost	Revenue	Profit
G1	0	$50	1	$-25	$25	$0	$0	$0
G4	700	$50	1	$-25	$25	$17,500	$17,500	$0
G2	100	$50	0	$0	$50	$5,000	$5,000	$0
G3	400	$50	0	$0	$50	$14,000	$20,000	$6,000

Below, the preventive-corrective dispatch must yield 350 MW of downward capacity at bus A. It first reserves as much capacity on the marginal resource as it can (200 MW on G4), but requires another 150 MW of downward capacity from G1. We adjust G1 to a 150 MW dispatch and G4 down to a 550 MW dispatch. The LMCP at bus A is $15 + 1(-$20) = -$5. G1 will receive -150(-$5) = $750 in compensation for downward capacity and G2 will receive -200(-$5) = $1,000 in compensation for downward capacity.

The LMCP at bus B is the same formulation as in Example 1. Recall, however, in Example 1 the LMCP at bus A was $0; this is because Example 1 has a fast ramping marginal resource at bus A with enough downward capacity to fulfill the entire 350 MW downward corrective capacity need. In this example, the marginal resource is not fast enough to fill that downward corrective capacity need.

Preventive-corrective model energy in base case								
Generator	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP	Bid Cost	Revenue	Profit
G1	150	$50	1	$-5	$25	$4,500	$3,750	-$750
G4	550	$50	1	$-5	$25	$13,750	$13,750	$0
G2	250	$50	0	$-5	$50	$12,500	$12,500	$0
G3	250	$50	0	$-5	$50	$8,750	$12,500	$3,750
Corrective capacity in contingency kc=1								
Generator	ΔP^1	λ^1	SF^1_{AB}	μ^1_{AB}	$LMCP^1$	Bid Cost	Revenue	Profit
G1	-150	$15	1	$-20	-$5	$0	$750	$750
G4	-200	$15	1	$-20	-$5	$0	$1,000	$1,000
G2	200	$15	0	$-20	$15	$0	$3,000	$3,000
G3	150	$15	0	$-20	$15	$0	$2,250	$2,250

The settlement of the weak-preventive model is summarized below.

Weak-preventive settlement				
	MW	Price	Bid cost	Revenue
Total Gen Energy	1,200	N/A	$36,500	$42,500
Total Gen Capacity UP	N/A	N/A	N/A	N/A
Total Gen Capacity DOWN	N/A	N/A	N/A	N/A
Load	1,200	$50	N/A	-$60,000

The settlement of the preventive-corrective model is summarized below.

Preventive-corrective settlement				
	MW	Price	Bid cost	Revenue
Total Gen Energy	1,200	N/A	$39,500	$42,500
Total Gen Capacity UP	350	N/A	N/A	$5,250
Total Gen Capacity DOWN	350	N/A	N/A	$1,750
Load	1,200	$50	N/A	-$60,000

5.4. Summary of reliability and market efficiency benefits

The ISO is dedicated to ensuring the reliability of the grid and operating within interconnection reliability operating limits and system operating limits with corrective time requirements. The interconnection reliability operating limits and system operating limits present an operational challenge to secure the appropriate level of reliability when the post-contingency topology is dynamic. **Table 15** below (partially reproduced from) compares the attributes of the preventive-corrective constraint to the ISO's current mechanisms. The preventive-corrective constraint is a general framework that can be applied to the interconnection reliability operating limits and system operating limits with corrective time requirements by procuring the appropriate capacity at the right nodes via an optimization. The constraint will also utilize the existing 10 minute ancillary services capacity when possible.

Table 15
Comparison of mechanisms to meet WECC SOL standard

Mechanism	Addresses:	Amount of capacity procured determined by:	Locational definition:	Ensures accurate amount of capacity procured at right location?
[A]	[B]	[C]	[D]	[E]
10 minute contingency reserves	NERC/WECC operating reserve requirements[41]	WECC operating reserve requirements[42]	System-wide	Partially – deliverability issues because not flow-based and granularity
Exceptional dispatch	As specified in ISO tariff[43]	Operator judgment	Location specific based on operator judgment	Partially – potential deliverability issues and imprecise procurement
MOC constraints	WECC standard TOP-007-WECC-1 R1 and non-flow based constraints	Predefined static region and requirement	Predefined static region	Partially – predefined static regions and only commits units to Pmin
Preventive-corrective constraint	WECC standard TOP-007-WECC-1 R1	Optimized solution	Nodal	Fully

Table 16 (partially reproduced from) compares each mechanism based on market efficiency where pricing signals reflect need, whether operationally desirable characteristics are valued, and

[41] WECC standard BAL-STD-002-0 B.WR1.
[42] WECC standard BAL-STD-002-0 B.WR1.
[43] See ISO tariff such as Section 34.9.

reliability is maintained via lowest cost. As compared to the other mechanisms, the preventive-corrective constraint is more efficient on all counts.

Table 16
Efficiency comparison of mechanisms to meet WECC SOL standard

Mechanism	Optimized procurement	Efficiently dispatched post-contingency?	Bid cost	Fast response valued?
[A]	[B]	[C]	[D]	[E]
10 minute contingency reserves	Yes, for system-wide need co-optimized with energy	May have deliverability issues	Reflected in LMP	Yes
Exceptional dispatch	No, manual process	Very likely	Not reflected in LMP	Inadvertently
MOC constraints	No, constraint is pre-defined and not dynamic	Likely	Not reflected in LMP	No, units within constraint not differentiated
Preventive-corrective constraint	Yes, at nodal level	Yes	Reflected in LMP and potential LMCP payment	Yes

There are several benefits to the preventive-corrective constraint, many of which are not easily quantified. The constraint will provide **reliability benefits** by precisely meeting the post-contingency system operating limit because it considers the flow-based nature of the requirement. This reliability benefit also reflects not dropping firm load, which is implicit in the system operating limit requirement (because facilities must be operated within their ratings at all times). Exceptional dispatch and minimum online commitment constraints can only approximate the flow-based need.

There are several aspects to **market efficiency benefits**. The preventive-corrective constraint can be procured more efficiently because the procurement is determined by the market optimization. In addition, the procurement is run in the day-ahead and then re-optimized in the real-time, both based on flow, which is more efficient than a MW capacity-based procurement. For example, assume that a transmission limit is 3,000 MW and the post-contingency SOL is 1,000 MW. If actual flow is not considered, a manual process might procure 2,000 MW of unloaded capacity to address the decrease in transmission limit. However, if a real-time analysis of the flow shows that there is only 1,800 MW of flow on the transmission line, the actual need is only 800 MW, much less than 2,000 MW. The **procurement efficiency benefit** lies in the manner in which capacity is procured, the quantity procured, and its location. There will also be **more efficient use of resources** under the preventive-corrective constraint. In **Section 4.2** we reviewed ISO/RTO 30 minute reserves. We noted that NYISO procures 30 minutes reserves but has decided to use only 10 minute reserves (1,200 MW) for its Eastern NY region. Note that operating reserves are procured and held in reserve in case of a contingency. There are three drawbacks to this approach if applied to the CAISO. First, 10 minute responsive reserve is a valuable resource but is a higher quality product than what is required to operating within interconnection reliability operating limits and system operating limits. This is an important consideration because, in NYISO's case, 1,200 MW of valuable, fast ramping capacity is essentially "pulled out" of the market. Second, the procurement is based on a set MW capacity which may not be required to operate within limits depending on the system dispatch. If the flow is not considered, it is likely that procurement will need to be made on the maximum need. All of these actions lead to inefficient use of existing resources and over-procurement.

Instead, the preventive-corrective constraint can include the procurement of 10 minute operating reserves in the set of effective resources to address interconnection reliability operating limits and system operating limits. In other words, we will not have to procure separate "buckets" of operating reserves and preventive-corrective capacity. Dividing up available and effective resources into too many separate categories will have the effect of decreasing the supply pool for any one need and could lead to market power or artificial scarcity concerns. Therefore, the preventive-corrective constraint will use available resources more efficiently by including units with ancillary service awards and procuring any additional need based on the longer 30 minute timeframe. The constraint will also improve procurement of operating reserves by locating them where they would be effective to address the contingency. Lastly, there are also benefits for the transmission system in terms of more efficient use of existing transfer capability.

The preventive-corrective constraint will also provide **price discovery** through LMPs and LMCPs. First, energy in the market will be priced based on LMP providing more realistic market signals. As discussed in Section 5, the LMCP compensates for opportunity costs, reflects the marginal value of capacity to encourage investment in ramping capability, and provides the appropriate economic signals to follow ISO dispatch. The preventive-corrective constraint will decrease the use of exceptional dispatches and MOC constraints leading to a decrease in price suppression and market uplift costs. This improves the LMP market signals.

6. Eligibility to count towards corrective capacity

6.1. Resources eligible to count as corrective capacity

6.1.1. Generally eligible resources

The types of resources generally eligible to provide corrective capacity include:

- physical generating units (online and offline),
- supply demand response,
- system resources also certified to provide ancillary services and only for the capacity reserved for spin or non-spin; and
- participating load/pumped storage

A resources' capacity will be eligible to provide corrective capacity to the extent it:

- Has a corresponding economic bid for energy (*i.e.*, Energy corresponding to the capacity is not self-scheduled. The resource can be offline if capable of providing energy within the time requirements as determined by the preventive-corrective constraint);
- Has sufficient ramping capability as determined by the preventive-corrective constraint;
- Can meet the time requirements as determined by the preventive-corrective constraint;
- The resource is appropriately located to address an SOL violation as determined by the preventive-corrective constraint;

6.1.2. Intertie resource eligibility

In addition to the generally eligible resources, the ISO will settle downward corrective capacity awarded to import/export resources.

This phenomena is projected to occur rarely and if it does occur, the compensation of the LMP plus the LMCP for the intertie resource ensures that the marginal import resource is made whole.

The ISO will model downward capacity on imports as available to the solution at no cost. For some monitored paths, when the preventive-corrective model adjusts pre-contingency flows, it may increase an import resource out-of-merit to rely on its downward capacity. In this scenario, the intertie will have an LMP (which takes into account the preventive-corrective constraint) and an LMCP. Since the ISO relies on a reduction of imports post-contingency, and the pre-contingency dispatch may be higher than otherwise supported by the LMP, the ISO proposes to settle corrective capacity awards for imports if they receive a downward corrective capacity award and a non-zero LMCP.

Imports are only eligible to receive downward corrective capacity awards. If an event occurred in real-time, the ISO would need to return flows below the post-contingency rating within 30 minutes. To do so, it will need the capability to actually move the resources to resolve the issue. Import schedules are established 22.5 minutes prior to the prompt interval. The ISO has the capability to cut schedules should a real-time reliability event occur, but it does not have the capability to increase import schedules. An increase in import schedules may require a scheduling coordinator to procure more or different transmission service in order to provide upward capacity, a task that would be impossible to implement within the corrective timeframe. However, a decrease in imports can be accomplished because the requisite transmission has already been procured, and the ISO has the capability to cut schedules to resolve the transmission reliability issue.

If the ISO did not settle the corrective capacity awards for import resources, they may be dispatched out of merit at a level not consistent with the LMP. The ISO would then need to either rely on bid cost recovery for the import resources or pay its corrective capacity award to make it whole. It will be more transparent to expose the LMP and LMCP to the market and settle the awards accordingly.

Exports have similar limitations to imports. The ISO will model reduction of exports as available to the solution at no cost. Exports are only eligible to receive corrective capacity awards for export reductions. The optimization will not rely on increases in exports. Exports will not receive corrective capacity awards for increases, and they will not be relied upon, because the corrective time frame does not allow for procurement of the requisite transmission capacity.

6.1.3. Capacity use coordination

The preventive-corrective constraints will be enforced in the IFM, RUC, and real-time markets (FMM and RTD). Virtual bids in the IFM will have the same impact on the preventive-corrective constraints as on other constraints and products in the IFM today. The corrective capacity awards will be re-optimized and settled for differences in the real-time market based on real-time market conditions.

The ISO seeks to coordinate to the greatest extent possible this proposal with other market changes and impacts and align market designs. **Table 17** below summarizes the similarities and differences between the corrective constraint, flexible ramping constraint and product.

Table 17
Efficiency comparison of mechanisms to meet WECC SOL standard

Capacity type	**Objective**	**Pre-contingency**	**Post-transmission contingency**
Corrective capacity	Prepare for contingencies pursuant to WECC TOP-007	• Market procures based on nodal location and amount based on flow • Procure in IFM, RUC, FMM, and RTD • Capacity reserved for contingencies	Use corrective capacity
Flexible ramping capacity	Ensures ramping capability for both forecast net load	• Procure in FMM and RTD • Use capacity as needed	Use flexible ramping capacity if available

	changes and net load uncertainty	• Capacity not reserved for contingencies	
10 minute contingency reserves	NERC/WECC operating reserve requirements[44]	• Market procures based on regions and in set amounts • Capacity reserved for contingencies	• Use 10 minute contingency reserves if needed and in appropriate location • Future WECC BAL standards will only allow contingency reserves to be dispatched for supply loss. Once in effect, ISO will only be able to dispatch 10 minute contingency reserves for losses of intertie transmission.

The ISO market will be able to award 10 minute contingency reserves and corrective capacity to the same portion of a resource's capacity if the particular critical transmission constraint allows for use of ancillary services. Both products will be paid their respective market prices. These products can overlap because they are both reserved for contingencies.

In contrast, flexible ramping capacity is not reserved for contingencies. The flexible ramping product procures capacity to ensure ramping capability for both forecast net load changes and net load uncertainty.[45] Consequently, capacity the market procures as corrective capacity or contingency reserves does not overlap with flexible ramping capacity. This is because if corrective capacity or contingency reserve capacity was used to meet net load ramps flexible ramping capacity is intended for then it would not be available for contingencies.

[44] WECC standard BAL-STD-002-0 B.WR1.
[45] See the flexible ramping product stakeholder initiative at: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

6.2. Resources not eligible to count as corrective capacity

The following capacity is not eligible to provide corrective capacity:

- Upward capacity from intertie resources that cannot provide ancillary services
- Capacity corresponding to an energy self-schedule
- Capacity procured under the flexible ramping product
- Capacity reserved for Regulation Up and Down
- Capacity from virtual resources

7. Residual Unit Commitment

The Residual Unit Commitment (RUC) process is a reliability function for committing resources and procuring RUC capacity not already scheduled in the IFM (as Energy, AS capacity, or corrective capacity), in order to meet the difference between the CAISO Forecast of CAISO Demand (including locational differences) and the Demand cleared in the IFM for each Trading Hour of the Trading Day.

Capacity which is not already scheduled in the IFM may be selected as RUC Capacity through the RUC process of the DAM. The RUC Capacity of a resource is the incremental amount of capacity selected in RUC above the resource's Day-Ahead Schedule. Similar to how other ancillary services are not re-procured in RUC, the ISO will not re-procure corrective capacity in RUC.

- Only unscheduled capacity from the IFM in excess of RA Capacity will be eligible to receive RUC awards.
- The ISO will not award additional corrective capacity in RUC.

8. Dispatch of corrective capacity

In the event of contingency, ISO operations will utilize real-time contingency dispatch (RTCD) to dispatch corrective capacity that overlaps with contingency only A/S capacity. The corrective capacity dispatched via RTCD will be considered instructed imbalance energy for settlement purposes. The market will automatically dispatch the portion of corrective capacity that does not overlap contingency only A/S to resolve real-time constraints. ISO operations is not prohibited from utilizing non-corrective capacity resources to address a preventive-corrective contingency. ISO operations may utilize exceptional dispatch to address preventive-corrective contingencies or any other tariff-approved reason should the operators deem it necessary.

9. Price for corrective capacity

The price for corrective capacity awarded in the day-ahead and real-time markets is based on the locational marginal capacity price (LMCP). As discussed in previous sections, the marginal values of corrective capacities depend on λ^{kc} and μ_l^{kc}, and thus depend on location. Therefore, the corrective capacity will have a locational marginal capacity price (LMCP). The LMCP at location *i* for case *kc* is

$$LMCP_i^{kc} = \lambda^{kc} + \sum_{l=1}^{m} SF_{l,i}^{kc} \cdot \mu_l^{kc}$$

10. Commitment of resources for corrective capacity

An award of corrective capacity in the day-ahead market constitutes a binding ISO commitment. This also applies to extremely long start units. Fully self-committed resources cannot provide corrective-capacity. If a portion of a resource is self-scheduled, that portion of the resource cannot provide corrective capacity. If a resource is awarded corrective capacity in the day-ahead and then self-schedules in the real-time, current self-schedule rules apply.

11. Capacity product's allocation to resource capacity

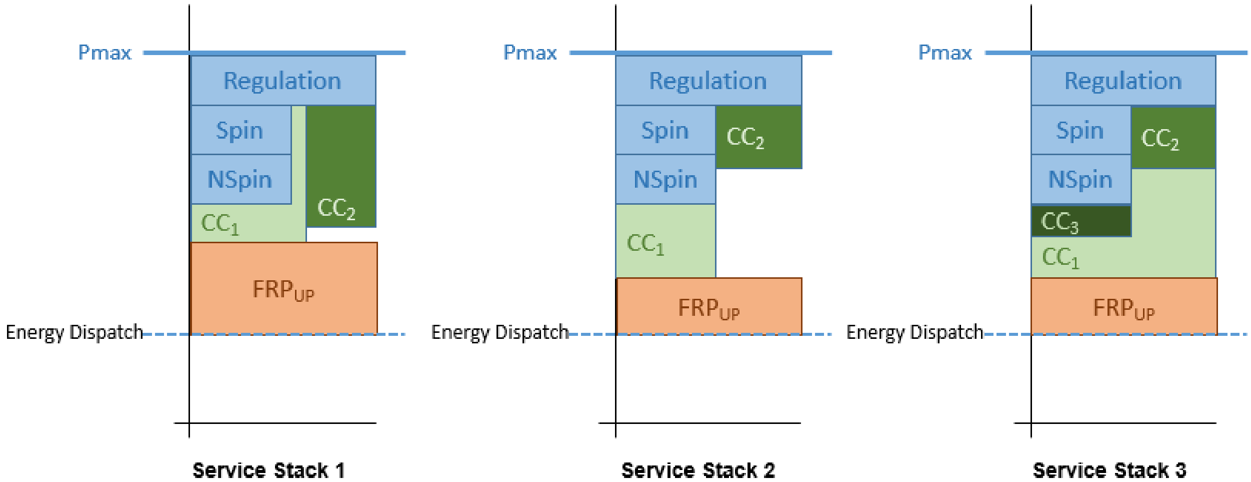
The ISO markets may award various types of capacity products to a resource at any given time (e.g., regulation, spin/non-spin, preventative-corrective, flexible ramping product) and because corrective capacity can be awarded for multiple constraints, the awards may yield multiple overlapping designations on the same resource. Corrective capacity:

- Will not overlap regulation and flexible ramping product
- Will overlap itself when awarded for multiple preventive-corrective contingency cases
- Can overlap ancillary services for some preventive-corrective contingencies and not for others

The ISO will procure corrective capacity to ensure that at any given time it can meet interconnection reliability operating limits and system operating limits with corrective time requirements. It allows overlapping corrective capacity because it does not need to ensure that at any given time it can withstand the occurrence of all contingency events occurring at the same time. A megawatt of capacity can be effective at resolving multiple corrective constraints and that megawatt will be paid the LMCP associated with each of the corrective constraints that bind. Where corrective capacity overlaps with A/S, the megawatt of capacity will be paid for A/S as well as the LMCP for each of the corrective constraints that it was procured to resolve.

In general, intertie path constraints will allow the corrective capacity to overlap ancillary service awards and internal path constraints will not allow the corrective capacity to overlap ancillary service awards.

The optimization may yield many different allocations of these products to a resource's physical capacity. The following figure shows several potential different awards for a given resource and how these products are allocated to the resource's physical capacity. In the figure, CC_{kc} stands for corrective capacity procured for case kc, and FRP_{UP} represents the upward flexible ramping product award.



In Service Stack 1, both CC_1 and CC_2 completely overlap the ancillary services. In Service Stack 2, CC_1 was awarded to protect for a contingency that reserves ancillary service and therefore does not overlap the ancillary services, while CC_2 partially overlaps the ancillary services. In Service Stack 3, CC_1 completely overlaps ancillary services, CC_2 partially overlaps ancillary services, while CC_3 does not overlap the ancillary services.

12. Bid cost recovery

Revenue a resource receives for corrective capacity (LMCP x MW corrective capacity award) in either the day-ahead or real-time market will count as revenue in the respective markets' bid cost recovery calculation. If a resource incurs commitment costs associated with a corrective capacity award, those commitment costs will be reflected in the bid cost recovery calculation the same as today; note that a self-committed resource is not eligible for bid cost recovery of commitment costs.

13. Settlement of corrective capacity

13.1. Re-optimization

Corrective capacity is awarded in the day-ahead market and the constraint is re-optimized in the fifteen-minute and five-minute markets. The ISO will financially settle corrective capacity in the day-ahead market, fifteen-minute market for deviations from day-ahead awards, and the five-minute market for deviations from fifteen-minute awards.

13.2. Buy backs

Since the preventive-corrective constraint will be re-optimized in the fifteen-minute and five-minute markets, economic buy-backs can occur on negative deviations. Fifteen-minute market buy-back will be the product of the fifteen-minute LMCP and the fifteen-minute corrective capacity deviation. Five-minute market buy-back will be the product of the five-minute LMCP and the five-minute corrective capacity deviation. This is similar to the settlement of imbalance energy. A buy-back of corrective capacity likely indicates that the unit is more valuable for energy (or another ancillary service) than it is for corrective capacity.

13.3. Real time pay back for unavailable capacity

The ISO additionally proposes a real time economic buy back to prevent resources from receiving corrective capacity payments if they cannot provide the capacity that was awarded. A resource would pay back corrective capacity at the RTD LMCP.

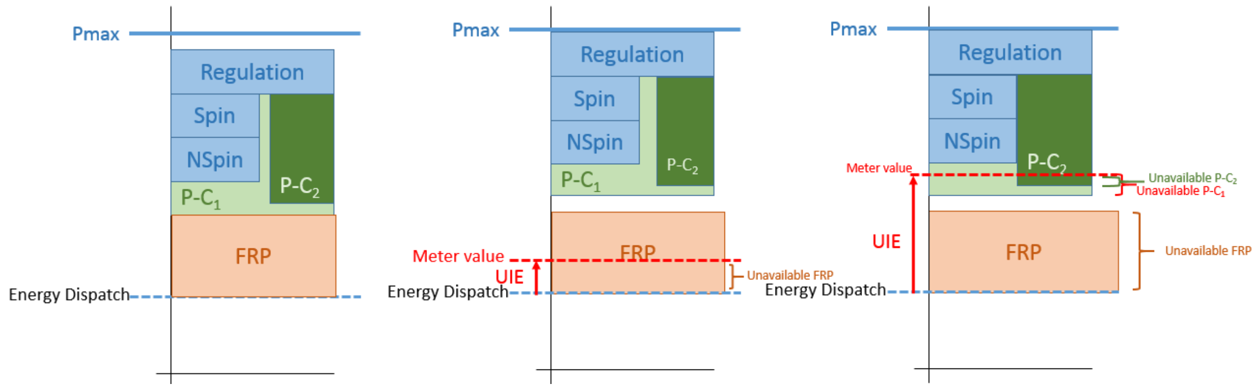
Any resource awarded corrective capacity payments must either convert that capacity into energy if dispatched in real-time after a contingency or keep that capacity unloaded and available for a potential dispatch for energy in real-time following a contingency. If the resource fails to fulfill these requirements, then it is subjected to the unavailable corrective capacity pay back.

Condition	Description
Unavailable	If corrective capacity is unavailable because it is converted to Energy without Dispatch Instructions from CAISO, the Scheduling Coordinator shall pay back the unavailable capacity at the RTD LMCP. Uninstructed Deviations in real-time may cause corrective capacity to be unavailable to CAISO.

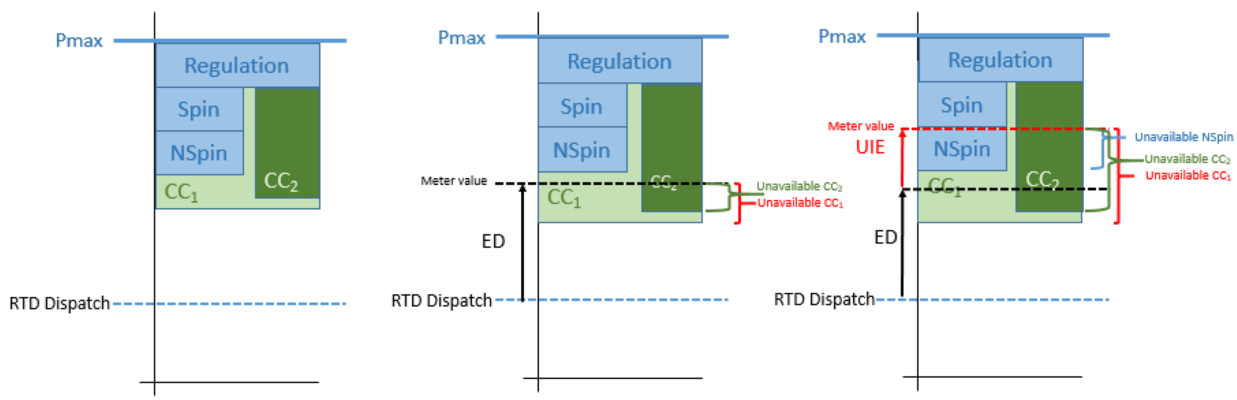
13.4. Unavailability Priority

There are various types of services on a resource at any given time (e.g. regulation, spin/non-spin, preventative-corrective, flexible ramping product). Corrective capacity will be treated at the same priority as operating reserves when evaluating its actual availability. Aligned with the flexible ramping product, any unavailability will first impact flexible ramping product capacity, followed by both operating reserves and corrective capacity, followed by regulation reserves.

The following figure shows a resource that does not follow its energy dispatch (energy dispatch does not equal meter value due to uninstructed imbalance energy). Note how the uninstructed imbalance energy impacts the flexible ramping product and the corrective capacity awards. Note that in this example it is assumed that corrective capacity may overlap spinning and non-spinning reserve.



As shown in the figure below, instructed energy could trigger a payback for unavailable corrective capacity in the current interval. However, the resource would still be paid for the additional energy given the meter value. For instance, if an operator exceptionally dispatches a resource up into its corrective capacity, in the current interval the scheduling coordinator will forfeit its corrective capacity payments in an amount equal to the MW unavailable as corrective capacity as well as collect energy payments on the additional energy provided. RTD will ensure future intervals will not be awarded corrective capacity in excess of the resource's available capacity. Note that this policy does not change current A/S no pay rules.



13.5. Day-ahead market settlement

Corrective capacity payments in the day-ahead markets are revenue adequate because they are paid for through energy schedules; when load pays the LMP at a node, the associated revenues include corrective capacity revenue and congestion rent. Each corrective capacity award will be paid its award MW multiplied by its LMCP and will be re-optimized and settled for differences in the real-time market. CRRs will be settled as proposed in Section 19 using the congestion rent.

13.6. Real-time market settlement

Corrective capacity payments in the real-time markets are revenue adequate because they are paid for through energy schedules; when load pays the LMP at a node, the associated revenues include a corrective capacity payment. Corrective capacity awards will be re-optimized in the real-time and settled for differences. The real-time changes will be settled in the real-time congestion account. Real-time congestion rents are already settled here today.

14. Bid in ramp rates

The ISO will address resource bid-in ramp rates in the *Bidding Rules* initiative. The ISO proposes to remove the capability to specify ramp rates in daily energy bids. Removing this functionality minimizes gaming or manipulation opportunities in the market as ramping capability increases in value. Alternatively, the ISO proposes to modify the master file to include: (1) market-based ramp rates reflecting the ramp rates the resource wants the ISO market to use to for its resource, and (2) a ramp rate reflecting a resource's maximum design capability to be used in emergency conditions.

15. Local market power mitigation

The Dynamic Competitive Path Assessment (DCPA) and Residual Supplier Index (RSI) calculation will need to be updated to incorporate the dual transmission and capacity aspects of the preventive-corrective constraint.

The corrective constraints are based on underlying preventive transmission constraints. Like the preventive constraints, corrective constraints require that enough counterflow is provided so the constraint limit is not violated. However, both energy and capacity can provide this counterflow.

Corrective constraints may be vulnerable to local market power when there is a limited supply of counterflow. By raising energy bids a supplier could increase the cost of relieving the corrective constraint. This would increase the shadow value on the corrective constraint, increasing locational marginal capacity prices (LMCPs) and energy LMPs.

As corrective capacity holds output in reserve, the available supply of counterflow to preventive constraints will be reduced by this award. The DCPA would need to account for this reduction similarly to how it currently accounts for ancillary service awards.

Furthermore, relieving the corrective constraints may cause the preventive constraints to no longer bind if the least cost solution is to decrease the pre-contingency flows. This would cause the local market power mitigation measures, as currently implemented, to not be applied to local generation even though the demand for that generation has increased.

Due to the potential for local market power on corrective constraints, the effect of corrective capacity on the supply of counterflow to preventive constraints, and the potential for market power when the preventive constraints are not binding, the DCPA needs to be updated to incorporate corrective constraints. The proposed changes to the Real-Time and Day-Ahead DCPA are summarized below.

Corrective capacity awards will need to be added to the demand for counterflow (DCF) for the corrective constraints and subtracted from the Real-Time supply of counterflow (SCF) for the current preventive constraints. The Real-Time SCF to corrective constraints will need to include how much energy and capacity can be used for, or withheld from, the corrective constraints given ramping limitations.

For the Day-Ahead market there are two approaches for calculating the RSI for corrective constraints. One is to calculate the RSI in the same manner as is done for preventive constraints. However, as currently proposed there are no separate offers for corrective capacity that can be used for economic withholding. An alternate approach recognizes that if a resource is committed via a self-schedule or through the Market Power Mitigation (MPM) run, it cannot withhold the capacity from the Day-Ahead market. Following this line of reasoning, the removal of potentially pivotal supplier resource minimum load energy from the RSI calculation for preventive constraints may need to be reconsidered.

A more detailed explanation of the proposed changes is given below.

15.1. Existing real-time dynamic competitive path assessment

The DCPA tests transmission constraints for competitiveness by comparing the DCF to a constraint to the available SCF. The DCPA employs a RSI test which finds the ratio of the SCF to the DCF, assuming some portion of the SCF from potentially pivotal suppliers (PPS) is withheld. Suppliers who are not potentially pivotal are considered to be fringe competitive suppliers (FCS). A transmission constraint is deemed competitive if the RSI is greater than or equal to one and uncompetitive if less than one. Currently, the test uses an RSI(3) test which treats the three highest ranked net suppliers, in terms of capacity that can be withheld, as potentially pivotal.

Equation 1 shows the RSI calculation for a preventive constraint, which equals the total SCF divided by the DCF. The SCF and DCF are calculated for each resource individually and then summed across all resources effective on the constraint.

Equation 1:

$$RSI_k = \left(SCF_k^{fcs} + SCF_k^{pps}\right)/DCF_k$$

The SCF from an individual fringe competitive supplier resource, which is assumed to withhold no energy supply, is the available effective energy supply[46] given ramping limitations. Due to ramping limitations, it may not be feasible for a potentially pivotal supply resource to withhold all their capacity for producing energy. Therefore the SCF that cannot be withheld from potentially pivotal suppliers is added to the SCF from fringe competitive suppliers to get the total SCF to the constraint. The DCF is the sum of all energy awards effective on the constraint, as shown in Equation 2.

Equation 2:

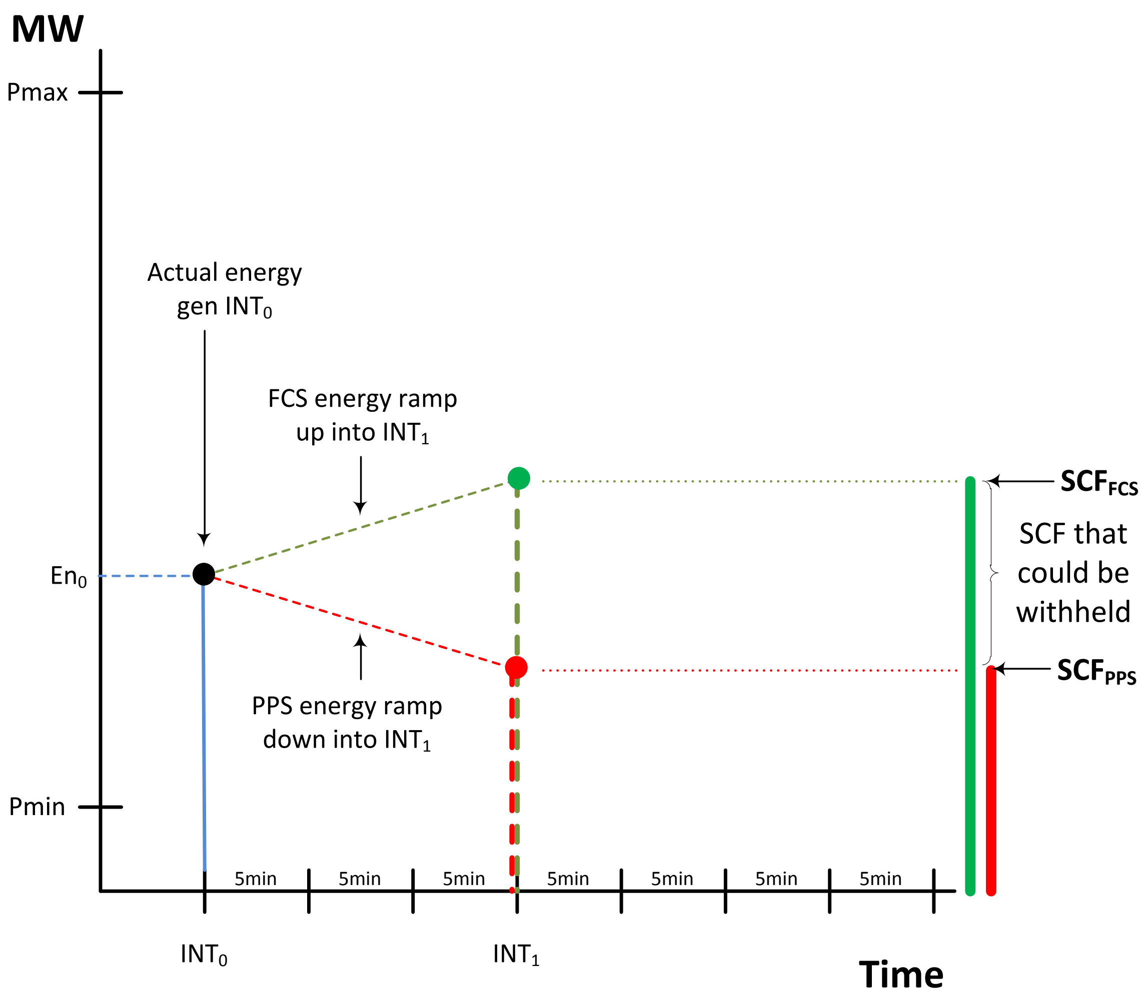
$$DCF_k = \sum_i -SF_{k,i} * DOP_i$$

$$\forall\, SF_{k,i} < threshold$$

Figure 6 shows the Real-Time SCF from a fringe competitive or potentially pivotal supplier resource. The SCF under consideration is for interval one, INT_1. The dispatch point, En_0, is already known for the prior interval, INT_0. The SCF from a fringe competitive supplier resource is the amount of energy the resource could provide in INT_1, 15 minutes after INT_0. Although the maximum capacity equals Pmax, it can only ramp up to the green dot within 15 minutes. The solid green line is therefore the total SCF that the resource could provide, and will be the SCF used in the RSI calculation if the resource is scheduled by a fringe competitive supplier.

[46] Effective energy supply is the available energy from the resource multiplied by its shift factor to the constraint, for resources with shift factors less than -0.02.

Figure 6
Real-Time Supply of Counterflow to *Preventive-Constraint* from Fringe Competitive Suppliers and Potentially Pivotal Suppliers



For a potentially pivotal supplier the calculation considers how much SCF the resource could withhold. In the 15 minutes from INT_0 to INT_1 the resource could ramp down to the red dot. The *solid red* line is the minimum SCF the resource must provide and is the SCF used in the RSI calculation if the resource is scheduled by a potentially pivotal supplier. The difference between the *solid green* and *solid red* lines is the SCF that could be withheld.

The Real-Time SCF from fringe competitive and potentially pivotal supplier resources is shown in Equations 3 and 4 for constraint k from resources indexed by i.

Equation 3:

$$SCF_k^{fcs} = \sum_i -SF_{k,i} * [min(En_o + RR_i^u * 15,\ EnerMax_i)]$$

$$\forall\ SF_{k,i} < threshold\ \ \forall\ i \in FCS$$

Equation 4:

$$SCF_k^{pps} = \sum_i -SF_{k,i} * \left[max\left(En_o - RR_i^d * 15,\ EnerMin_i\right)\right]$$

$$\forall\ SF_{k,i} < threshold\ \ \forall\ i \in PPS$$

The effective ramp rate may differ when ramping upwards (RR_i^u) versus ramping downwards (RR_i^d).[47] The total available SCF is capped by the maximum output of the resource (either the Pmax or maximum output bid) less de-rates, operation reserve awards (spin or non-spin), and regulation up awards, Equation 5.

Equation 5:

$$EnerMax_i = MaxCap_i - Derate_i - OR_i - RU_i$$

The minimum SCF that a potentially pivotal supplier resource could provide has a floor at the higher of minimum output (Pmin) plus regulation down awards or self-scheduled energy, Equation 6.

Equation 6:

$$EnerMin_i = \max[(MinCap_i + RD_i), SelfSched\ Energy]$$

[47] The effective ramps are a function of the time available to ramp, the initial resource output level, and physical ramp rates at different output levels. The effective ramp rate is also a function of the current output level of the resource.

15.2. Changes to the real-time dynamic competitive path assessment

With the addition of corrective constraints, the DCPA will need to be updated to account for the dual transmission and capacity nature of the constraint. Both energy and capacity can be used to provide “counterflow” to the corrective constraints. The calculation of the DCF will need to sum both the energy and corrective capacity awards effective on the corrective constraint kc as shown in Equation 7. The SCF will need to account for both the energy and corrective capacity that a resource can provide.

Equation 7:

$$DCF_{\mathbf{kc}} = \sum_i -SF_{\mathbf{kc},i} * (DOP_i + \mathbf{CC}_i)$$

$$\forall\, SF_{\mathbf{kc},i} < threshold$$

Figure 7 shows a proposal for how the SCF for a corrective constraint might be calculated for both fringe competitive and potentially pivotal supplier resources. The resource can ramp up energy production within 15 minutes, the *green* line. However, it can also provide 20-Minute corrective capacity to the constraint. The amount of corrective capacity the resource can provide is the amount of energy the resource could ramp to in 20 minutes[48] from INT_1, the *blue* line. The SCF from a fringe competitive resource is the sum of the available energy and capacity in INT_1, the sum of the *blue* and *green* lines.

Equation 8 shows the SCF calculation from a fringe competitive supplier resource for a corrective constraint. The ramp time has changed from 15 to 35 minutes to account for the ability to provide capacity.

Equation 8:

$$SCF_k^{fcs} = \sum_i -SF_{\mathbf{kc},i} * [min(En_o + RR_i^u * \mathbf{35},\ EnerMax_i)]$$

$$\forall\, SF_{\mathbf{kc},i} < threshold\ \ \forall\, i \in FCS$$

A potentially pivotal supply resource can withhold SCF by ramping down energy in the 15 minutes between INT_0 and INT_1. The total energy the resource would provide if withholding is the *red* line.

[48] Assuming that for the 30 minute requirement 10 minutes are used to run the real-time contingency dispatch, only 20 minutes would remain for the resource to ramp to the expected output.

Currently the CAISO proposes to not implement separate corrective capacity offers. Therefore a resource cannot directly withhold capacity. The amount of 20-Minute corrective capacity the resource could provide after ramping down would be added to the SCF, the *yellow* line. The total SCF from a potentially pivotal supplier resource would be the sum of the energy and capacity it could provide while withholding, the sum of the *red* and *yellow* lines.

Equation 9 shows the SCF calculation from a potentially pivotal supplier resource for a corrective constraint. Note that the effective ramp $RR_i^{u2}$is calculated from the point the resource ramps down to and not En_oas $RR_i^u$is in Equation 8.

Equation 9:

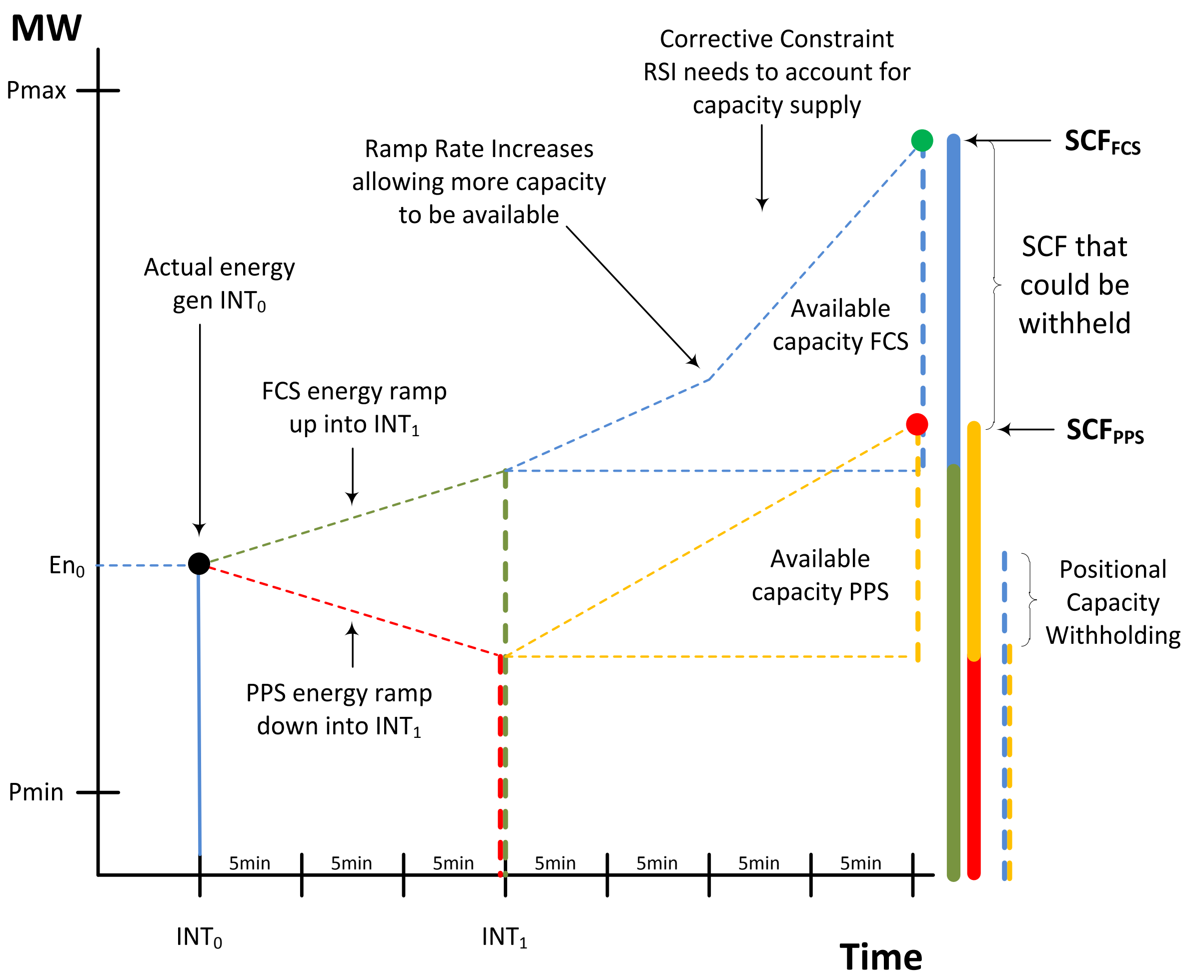
$$SCF_k^{pps} = \sum\nolimits_i -SF_{\mathbf{kc},i} * \mathbf{min}\begin{bmatrix} max\left(En_o - RR_i^d * 15,\ EnerMin_i\right) \\ \mathbf{+RR_i^{u2} * 20} \end{bmatrix}\mathbf{,\ EnerMax_i}\Bigg]$$

$$\forall\ SF_{\mathbf{kc},i} < threshold\ \ \forall\ i \in PPS$$

Although the resource cannot directly withhold capacity, it could indirectly withhold capacity by positioning its energy output so that it can provide less capacity (if the resource has different ramp rates at different output levels). The resource in Figure 7 is able to reach a higher ramp rate at the point where the dashed blue line is kinked. The resource is able to provide more capacity than if the ramp rate had not increased. When the potentially pivotal supplier ramps down, the amount of 20-Minute capacity it can provide is reduced because it never reaches the faster ramp rate. This "positional" withholding is shown by the difference between the *blue* and *yellow dashed* lines. The RSI proposal shown above will account for "positional" withholding of corrective capacity from a resource's ability to ramp down, which manifests in a lower SCF from the yellow capacity portion in Figure 7.

A resource may also increase output to engage in "positional" withholding of corrective capacity by increasing output. This might move the resource out of a faster ramp rate region or close the maximum capacity. However this will cause the resource to supply counterflow in the form of energy. Because the SCF to the corrective constraint can be from energy or capacity a resource could not withhold SCF to a corrective constraint by ramping to a higher output level (as the constraint is transmission based and not simply a capacity requirement).

Figure 7
Real-Time Supply of Counterflow to *Corrective-Constraint* from Fringe Competitive Suppliers and Potentially Pivotal Suppliers



Capacity awarded as spin and non-spin reserves is able to provide SCF to corrective constraints. The maximum available capacity able to provide SCF to corrective constraints should not be reduced by spin and non-spin awards as is done for preventive constraints. The maximum available capacity for corrective constraints is shown in Equation 11.

Equation 11:

$$EnerMax_i = MaxCap_i - Derate_i - RU_i$$

15.3. Triggering mitigation

Under the existing method, the bid mitigation process is triggered when the net impact of non-competitive preventative constraints on a resources' LMP is positive. The congestion component of the LMP at each resource is decomposed into the influence from competitive constraints ($LMP_{CC,i}$ below) and the influence from non-competitive constraints ($LMP_{NCC,i}$ below). Mitigation is triggered when $LMP_{NCC,i}$ is positive.

Equation 12:

$$LMP_i = LMP_{EN,i} + LMP_{CC,i} + LMP_{NCC,i} + LMP_{LOSS,i}$$

A corrective constraint, when binding, can also have an impact on the energy LMP through the congestion component. The impact of the binding corrective constraint on the energy LMP will be included in the competitive or non-competitive congestion components in the equation above depending on the RSI for the corrective constraint. In this fashion, corrective constraints can trigger mitigation through the energy LMP if tested and deemed non-competitive. Including the impact of corrective constraints in the LMP decomposition used to trigger mitigation covers instances where the market may have reduced flow on the preventative constraint such that it is not binding (and thus would not trigger mitigation itself) but the combined supply of counter-flow and corrective capacity is non-competitive and results in a binding non-competitive corrective constraint.

Bid mitigation would be the same process as is currently used except that the competitive LMP would exclude congestion from uncompetitive corrective constraints in addition to uncompetitive preventive constraints.

15.4. Day-ahead dynamic competitive path assessment

Currently for preventive constraints, the RSI calculations in the Day-Ahead DCPA are very similar to the Real-Time calculations. The IFM is optimized across an entire trade day. It can choose to reposition resources in adjacent hours and can choose between using capacity to provide energy or operating reserves. The restrictions from ramping constraints and the removal of operating reserves that are placed on the Real-Time market RSI calculations are not required in the Day-Ahead calculations. The available capacity from a generation resource is therefore its maximum output less any outages. The three largest net supplier holders of effective capacity on a constraint are considered potentially pivotal and all their capacity is treated as withheld, as shown in Equation 13. All other capacity is treated as fringe competitive and all their capacity is treated as available to supply counterflow, Equation 14.

Equation 13:

$$SCF_k^{pps} = \sum_i -SF_{k,i} * [0]$$

$$\forall\, SF_{k,i} < threshold \;\; \forall\, i \in PPS$$

Equation 14:

$$SCF_k^{fcs} = \sum_i -SF_{k,i} * [\, EnerMax_i]$$

$$\forall\, SF_{k,i} < threshold \;\; \forall\, i \in FCS$$

The demand for counterflow and RSI value are calculated as is done in the Real-Time market, as shown in Equations 1 and 2. Mitigation is triggered based on congestion components in the same manner as well.

The ISO proposes to calculate the SCF in the same manner as is currently done for preventive constraints because there are no ramping or operating reserve constraints in the day-ahead SCF calculation.

16. Bidding for corrective capacity

We appreciate stakeholders' comments on this issue. However, as explained in the ISO's responses to stakeholders, bids must reflect a cost. It does not reflect the "value" of the resource – the preventive-corrective constraint will determine the value of the resource to the market automatically via the market optimization.

Stakeholders have also drawn parallels with the ISO's current procurement of operating reserves and note that bidding is allowed for those products. We make a distinction between operating reserves and the preventive-corrective constraint. Resources providing ancillary services are certified to do so and meet a higher standard than energy-only resources. As such, resources with an ancillary service award are procured in the day-ahead market and *held* throughout the real-time market. In contrast, the corrective capacity procured by the preventive-corrective constraint will not be held. The constraint will be re-optimized in the real-time and the same capacity need not be "set aside" in order for the ISO to meet its reliability criteria. Should there be expectations that a unit awarded corrective capacity could instead receive higher real-time LMPs by providing energy, convergence bidding can be used to provide a hedge. This would also be effective for delivery of exports and other real-time expectations.[49]

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[49] See also the presentation by the Department of Market Monitoring on direct and opportunity costs that may be represented by bidding available at: http://www.caiso.com/Documents/Bidding-CapacityProducts-SpotMarkets-ISOPresentationJul2_2013.pdf

Lastly, the benefits of providing this functionality needs to be weighed carefully against market power manipulation concerns and implementation complexity. This type of monitoring is not yet established in the ISO market (or any other market that we are aware of). The ISO takes these matters very seriously and in fact view LMPM for capacity as a broader market-wide effort which would include operating reserves and the flexible ramping product. While the ISO has not come to the conclusion that there is market power, it does not want to deploy a constraint that would be vulnerable to potential abuse.

As discussed above, the dynamic competitive path assessment can be modified to consider corrective capacity based on the energy LMP because a corrective capacity constraint that is binding and non-competitive will have an impact on an effective resource's energy LMP. The current proposal does not provide for a bid (an offer price) for corrective capacity to be submitted by the supplier. If an offer price is allowed, the approach to applying local market power mitigation in both products will need to be reassessed.

Since bidding will not be available for corrective capacity, there will not be a separate grid management charge.

17. Data release

Information on the constraints enforced and contingencies will be provided via the Customer Market Results Interface (CMRI) and Open Access Same-Time Information System (OASIS).

18. The day-ahead market, congestion costs, and corrective capacity revenue

The ISO reviewed previous proposals to identify the cause of the apparent need for uplift in the examples provided; the need for uplift was counter-intuitive to the notion of pricing the constraints into the market.

While achieving transmission feasibility through the market, the preventive-corrective model produces LMPs that when paid by load serving entities include congestion revenues associated with the available transmission capability in the base case and the post-contingency cases. Payments also include revenues required to pay for the corrective capacity that enables the higher flows in the post-contingency case. The day-ahead market alone does not require additional uplift because it collects all revenues required to pay for the corrective capacity from load. Corrective capacity payments are completely revenue adequate because they are paid for through energy schedules; when load pays the LMP at a node, the associated revenues include a corrective capacity payment.

Currently, the CRR market does not model the proposed post-contingency constraints. The examples provided in previous proposals did not attempt to change the CRR market and instead showed what the resulting CRR revenues would have been if left unchanged; this is what leads to the uplift requirements. The ISO found that the CRR market may require complimentary enhancements to align with the proposed changes to the day-ahead market. A CRR market that does not recognize the limited post-contingency transmission capability could over-allocate CRRs to market participants leading to revenue inadequacy and uplift requirements.

There are several ways to ensure that the Contingency Modeling Enhancements initiative does not exacerbate revenue inadequacy in the CRR market due to a CRR market that does not additionally model the new post-contingency constraints introduced in this initiative. This particular revenue inadequacy is introduced solely due to this initiative, and as such should be resolved as part of this initiative.

18.1. Achieving transmission feasibility

In today's market design, congestion costs on transmission paths are shown through the differences in LMPs when energy schedules and power flow cause transmission constraints to bind. Typically the LMP accurately represents the cost of this congestion. However, in certain circumstances, the ISO relies on exceptional dispatch (ED) and minimum online commitments (MOC) to support the operation of the transmission path at greater flows than would be feasible without the exceptional dispatch or minimum online commitment. When the ISO relies on ED or MOC, the LMPs do not fully reflect all of the congestion costs because the exceptional dispatches or minimum online commitments are compensating for constraints not modeled in the market and are paid through uplift. These un-modeled additional constraints are essentially the corrective constraints the ISO proposes to enforce.

When the market fully models the preventive-corrective constraints, it exposes this "hidden" cost of preventive-corrective action through the kc shadow price. When the constraint binds and corrective capacity is procured, it is to maintain transmission feasibility instead of using exceptional dispatches and minimum online commitments to maintain transmission feasibility. The energy transactions that contribute to flows on the kc contingency constraints above the kc limit, and so drive the procurement of corrective capacity, are using transmission service provided by the corrective capacity. A schedule that does not contribute to flow on a given kc contingency constraint (including load schedules) does not use transmission service provided by corrective capacity and does not generate rents from the kc constraint.

Use the example from above to illustrate infeasible transmission dispatch and associated shadow prices versus a feasible transmission dispatch and associated shadow prices. Today's market would produce the weak-preventive dispatch:

Energy in base case					
Resource	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP
G1	700	$50	1	-$20	$30
G2	100	$50	0	-$20	$50
G3	400	$50	0	-$20	$50

Table 18: Energy in base case from example

The weak-preventive dispatch yields $20/MWh in congestion from A to B as calculated under the existing market model. This dispatch is <u>not</u> actually transmission feasible because the operator will have to intervene using exceptional dispatch to position resources G2 and G3 to ensure that the transmission system is capable of returning to a secure state to meet post contingency limits. The cost of transmission feasibility is not incorporated into the market through LMPs and is instead only in the cost of exceptional dispatch.

At this dispatch, one can see that the ISO is unable to meet the reliability constraint within 30 minutes.

- This is a transmission infeasible solution.
- Operators intervene via exceptional dispatch to make it feasible; this results in uplift.
- Operators reserve capacity but the value of the capacity is not exposed.

When the market actually models the constraints that allow transmission feasibility, the cost of transmission feasibility is now exposed in the corrective constraint shadow price. Use the example from above to illustrate. Recall the preventive-corrective dispatch:

Energy in base case					
Resource	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP
G1	700	$50	1	-$5	$30
G2	250	$50	0	-$5	$50
G3	250	$50	0	-$5	$50
Corrective capacity in contingency case = kc					
Resource	ΔP^1	λ^1	SF^1_{AB}	μ^1_{AB}	LMCP
G1	-350	$15	1	-$15	$0
G2	200	$15	0	-$15	$15
G3	150	$15	0	-$15	$15

Table 19: Preventive-corrective market results

The preventive-corrective dispatch yields \$5/MWh in congestion from A to B in the base case and \$15/MWh in congestion from A to B due to the corrective constraint. This dispatch is transmission feasible because it respects the post-contingency 350 MW path limit; the operator will not have to intervene using exceptional dispatch. The cost of transmission feasibility for flows above the kc limit is exposed in the corrective constraint shadow price.

At this dispatch, one can see that the ISO is able to meet the reliability criteria within 30 minutes.

- This is a transmission feasible solution.
- Operators do not have to intervene via exceptional dispatch to make it feasible; no uplift required.
- Capacity is reserved and the value of the capacity is exposed.

Under either model discussed above, in reality, 700 MW of flow is feasible in the base case, but only 350 MW of flow is feasible in the post-contingency case; the preventive-corrective model respects both constraints while the weak preventive model only respects the former.

18.2. Congestion rent and corrective capacity revenue

The goal of the initiative is to achieve a transmission feasible dispatch without relying on exceptional dispatch or minimum online commitments. In earlier proposals the ISO compared achieving transmission feasibility through a strong preventive model versus a preventive-corrective model. Both models would yield a transmission feasible solution without using ED or MOC, but the strong preventive model would rely on a very restricted transmission system. The preventive-corrective model maximizes the use of the transmission system, which is why the ISO proposes this approach.

The preventive-corrective model changes the LMP formulation. It can be shown that the congestion component, when viewed in terms of the flow-related revenue of energy scheduled to the node (that is the LMP multiplied by the generation at the node minus the load at the node), includes the revenue required to pay the corrective capacity.[50]

[50] See “Appendix A: Flow related revenue and its allocation” for a derivation of the flow related revenue.

LMP$_i$ flow related revenue =

$$\underbrace{\underbrace{\sum_{k=0}^{K}\sum_{l=1}^{m}\left[\mu_l^{k*}\cdot F_l^{k,\max}\right]}+\underbrace{\sum_{kc=K+1}^{KC}\sum_{l=1}^{m}\left[\mu_l^{kc*}\cdot F_l^{kc,\max}\right]}}_{\text{congestion rent collected}}-\underbrace{\sum_{kc=K+1}^{K+KC}\sum_{i}\left[\left(\lambda^{kc*}+\sum_{l=1}^{m}SF_{l,i}^{kc}\cdot\mu_l^{kc*}\right)\cdot\Delta P_i^{kc*}\right]}_{\text{corrective capacity revenue collected}}$$

Equation 1: LMP flow related revenue

It is clear from this breakdown that there are congestion revenues associated with the k case transmission limits, congestion revenues associated with the kc case transmission limits, and corrective capacity revenue bundled into the total revenues received from load through LMP. One can see that the corrective capacity revenue collected is the summation of LMCPs multiplied by the respective quantities of corrective capacities procured at that location. Intuitive to the notion of pricing products into the day-ahead market, the payment for the product itself is covered by day-ahead market revenues. The day-ahead market is revenue sufficient. When a market participant serving load pays the LMP at a node, those payments include the portion of revenue required to compensate the corrective capacity.

Bar graph diagrams help to visualize these revenues and understand the portion of revenue attributable to the available transmission capability in each case verses the portion of revenue attributable to the corrective capacity in each case. Recall the example from above where the k limit is 700 MW, the kc limit is 350 MW, the k congestion is $5, and the kc congestion is $15.

Below, the green bar on the left shows a total of $3,500 in revenues associated with the k constraint up to the 700 MW normal limit ($5×700 MW), the green portion of the bar on the right shows $5,250 in revenues associated with the kc constraint up to the 350 MW post-contingency case limit ($15×350 MW), and the blue portion of the bar on the right shows $5,250 in revenues associated with the corrective capacity above the 350 MW post-contingency case limit ($15×350 MW).

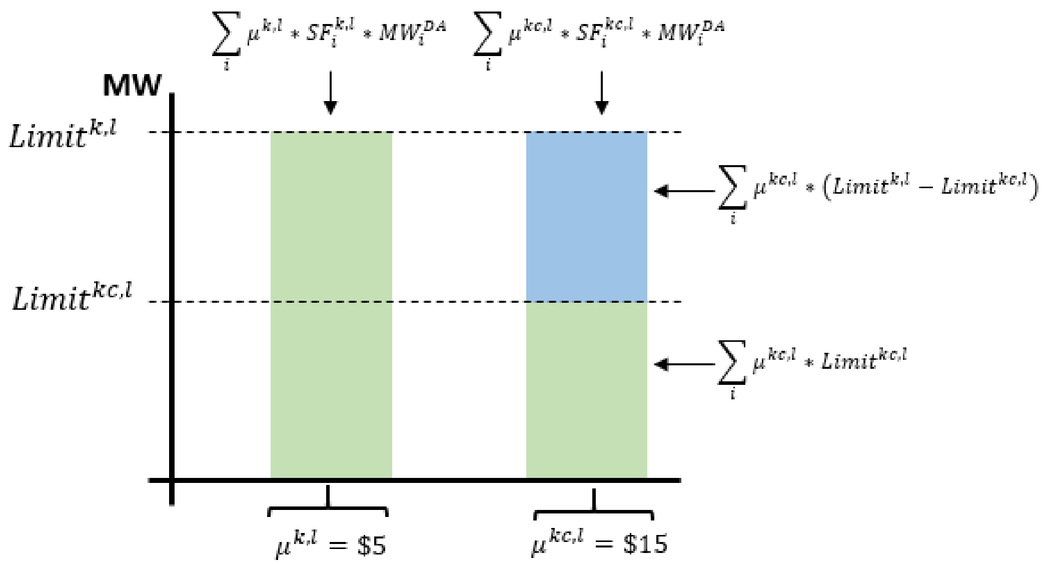

Figure 8: Graphic representation of market revenues

Through the LMP, the day-ahead market will collect $5,250 as corrective capacity revenue (shown as the blue portion in the bar graphs above) and will collect a total of $8,750 in congestion rent (shown as the total of the green portions in the bar graphs above). The revenue represented by the green portion is the revenue attributable to the total available transmission capability ($5×700+$15×350=$8,750). Note that there is a full 700 MW of available transmission in the base case but only 350 MW of available transmission in the post-contingency case.

It is easier to appreciate the difference between the post-contingency case congestion rent and the post-contingency case corrective capacity revenue using an example where the total congestion is isolated to the post-contingency case. This can be done by creating a case where the k constraint does not bind but the kc constraint does bind.

Consider an example with a fast ramping resource at Node A, two very slow ramping resources at Node B, and comparably lower load at Node B.

	Bid ($/MW)	Pmax (MW)	Ramp (MW/m)	Load (MW)
G1	$30	600	100	
G2	$50	900	1	
G3	$35	900	1	
Load				600

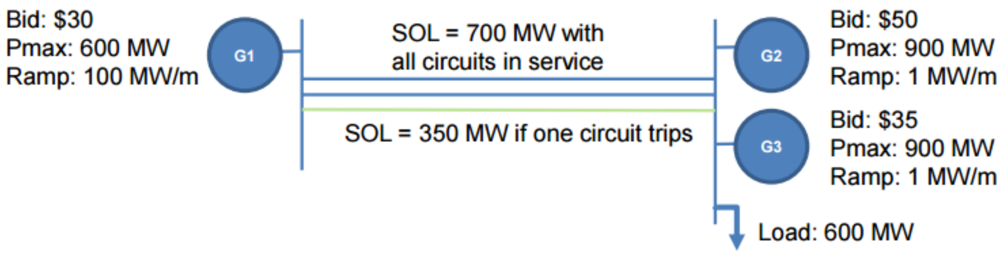

Figure 9: Example system where k constraint does not bind

The preventive-corrective market yields the following results. Notice that only 390 MW flow over the constrained path. This is enough to only make the 350 MW post-contingency limit bind.

Preventive-corrective model energy in base case					
Generator	P^0	λ^0	SF^0_{AB}	μ^0_{AB}	LMP
G1	390	$35	1	$0	$30
G2	0	$35	0	$0	$35
G3	210	$35	0	$0	$35
Corrective capacity in contingency kc=1					
Generator	ΔP^1	λ^1	SF^1_{AB}	μ^1_{AB}	$LMCP^1$
G1	-40	$5	1	-$5	$0
G2	20	$5	0	-$5	$5
G3	20	$5	0	-$5	$5

Table 20: Preventive-corrective market results

Because of the very limited upward ramping capability available on G2 and G3, the overall flow on the path is limited to 390 MW. The market reserves as much corrective capacity as is available on G2 and G3 (20 MW per resource) and limits the path flow to the post-contingency limit plus the available ramping capability (390 MW). The base case does not bind, but the post-contingency case does bind at a congestion shadow price of -$5. LMP at Node B is set at $35 and LMCP at Node B is set at $5.

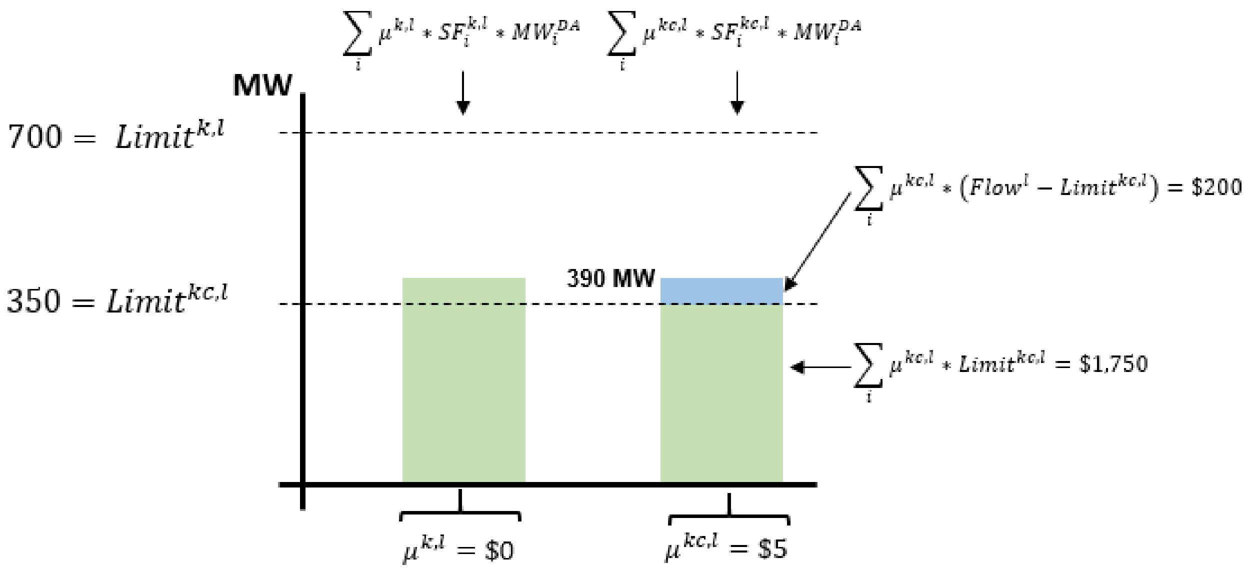

Figure 10: Graphic representation of market revenue

Through LMPs, the day-ahead market will collect $200 in corrective capacity revenue (shown as the blue portion in the bar graph above) and will collect $1,750 in congestion rent (shown as the green portions in the bar graph above). The revenue represented by the green portion is the revenue attributable to the total available transmission capability ($0×390+$5×350=$1,750). Note that there is a full 700 MW of available transmission in the base case, of which 390 MW is used, but only 350 MW of available transmission in the post-contingency case.

An entity that serves 600 MW of load at Node B with 600 MW of generation from Node A would potentially acquire 600 MW of CRRs from A to B. Without the preventive-corrective constraint in the day-ahead market and with no change to the CRR market and/or settlement, nothing would bind and the CRR holder would receive payment of 600 MW × $0 = $0 (CRRs held multiplied by the total congestion from A to B). However, with the preventive-corrective constraint in the day-ahead market but no change to the CRR market and/or settlement, those CRRs would receive payment of 600 MW × $5 = $3,000 while the total congestion revenue and corrective capacity revenue collected by the market is $1,950 ($1,750 in congestion rent + $200 in corrective capacity revenue).

It is apparent that if the ISO does not update its CRR market and/or settlement to be consistent with the changes to the day-ahead market, CRR settlement will be revenue inadequate when the kc constraint binds because CRRs would be allocated/auctioned up to the 700 MW limit and paid the sum of both congestion components up to 700 MW when there is actually only 350 MW of transmission available in the post-contingency case.

19. Congestion revenue rights enhancements

19.1. The CRR market does not model the new post-contingency constraints

The ISO investigated methods to resolve revenue inadequacy in the CRR market caused by a simultaneous feasibility test (SFT) in the CRR auction and allocation process that does not model the new post-contingency constraints introduced in this initiative. This particular revenue inadequacy is introduced solely due to this initiative, and as such should be addressed as part of this initiative.

The security constrained economic dispatch (SCED), which is the core component of the ISO market, determines a dispatch that produces feasible flows considering transmission constraints in the base case as well as in the N-1 preventive contingency cases. That is, the SCED produces a single dispatch that will be feasible for the base case and for all N-1 contingencies without any re-dispatch. To ensure the congestion revenues resulting from the dispatch will be adequate to compensate CRRs (absent any changes to the transmission system as modeled in the base case and contingencies), the CRR allocation and auction process assesses the simultaneous feasibility of the CRRs that it allocates and auctions. The simultaneous feasibility test for CRRs evaluates whether scheduling injections and withdrawals that correspond to the CRRs would produce flows on the transmission constraints that are feasible in the base case and N-1 contingency cases that are reflected in the CRR FNM. That is, the CRR SFT attempts to model the same transmission constraints that are modeled in SCED. It also models a fixed set of CRRs for the base case and a subset of N-1 contingencies in the same way that SCED models a fixed dispatch in the base case and N-1 contingencies. By doing this, the SCED market will collect sufficient congestion revenue to pay the CRRs.

When the preventive-corrective framework with contingencies are added to the SCED, the market will model transmission constraints differently. Similar to the current SCED, a single dispatch will produce feasible flows considering transmission constraints in the base case as well as in the N-1 preventive contingency cases. However, for a given corrective contingency, the dispatch that is feasible for the base case and N-1 contingencies may no longer be feasible in the corrective contingency. SCED determines corrective capacity to procure whose deployment in the corrective contingency restores feasible transmission flows. The SFT for CRRs should take into account that transmission flows in the corrective contingencies and net congestion rents may change when the ISO purchases corrective capacity for use in the corrective contingencies.

19.2. Proposed enhancements to congestion revenue rights

In previous proposals the ISO offered to distribute post-contingency case congestion revenue up to post-contingency transmission limits, but did so in a manner that appeared as an overall rescission of payment because it did not attempt to change the current CRR settlement. While, it appeared to be an overall rescission of revenue, the ISO's previous proposal actually would have payed CRR holders additional congestion revenue associated with the available transmission in the post-contingency case without exacerbating revenue inadequacy.

In response to the Third Revised Straw Proposal, market participants provided different approaches to consider in resolving or mitigating the potential revenue shortfalls in the CRR market caused by a simultaneous feasibility test that does not additionally model the new post-contingency constraints introduced in this initiative. Stakeholders also asked the ISO to weigh the cost/benefit of implementing various solutions. The ISO engaged stakeholders on the topic through a separate discussion paper which outlined nine approaches to resolving the issue.[51] Stakeholders generally agreed that some changes may be needed to resolve potential revenue inadequacy issues, however stakeholders wanted more information on how necessary it would be to enhance the CRR market. Actual revenue shortfalls would only materialize to the extent the new post-contingency constraints were actually binding in the day-ahead market.

Since publication of the CRR alternatives discussion paper, the ISO used its contingency modeling enhancements prototype to run real market scenarios to determine how often it believes the constraints will bind in practice. First, the ISO evaluated 12 recent stressed scenarios; it found stressed days in both spring and summer for six specific constraints that it protected with minimum online commitment constraints. In all but one scenario, the contingency modeling enhancement constraints did not bind, indicating that even on stressed days, there may be low likelihood of the contingency modeling constraint binding. Second, the ISO ran the prototype in parallel to its day-ahead market for two weeks at the end of March 2017 through the beginning of April 2017 to see how often the constraint would bind if enforced day-in and day-out over a period of time. Over the course of the parallel operations period, the contingency modeling constraints did not bind, further indicating that there may be a low likelihood of the constraint binding in practice.

The ISO proposes to make minimal changes to CRR settlement to appropriately to recognize the mechanics of the new day-ahead market constraints and maintain revenue adequacy, understanding that the constraint may rarely bind in practice.

The ISO proposes no changes to the CRR clearing mechanisms. Market participants will provide nominations or bids for CRRs as they do today. However, the awarded CRRs will settle only on the difference in the preventive constraint congestion components (represented in this proposal as “k” congestion). This solution was first described in Section 5.2.3 (Option 3(d)) of the CRR Alternatives Discussion Paper published on March 3, 2016.

In the allocation process, once the ISO receives nominations for CRRs, it will clear CRRs respecting the preventive constraint limits utilizing the weighted least squares technique (WLS) currently employed in the CRR market. The ISO will not additionally clear CRRs to settle the preventive-corrective constraint revenues.

In the auction process, once the ISO receives bids for CRRs, it will clear CRRs respecting the preventive constraint limits while maximizing auction revenue. The ISO will not additionally clear CRRs to settle the preventive-corrective constraint revenues. At the end of the CRR process,

[51] CRR Alternatives Discussion Paper, http://www.caiso.com/Documents/CRRAlternativesDiscussionPaper-ContingencyModelingEnhancements.pdf

market participants will hold CRRs that will only settle on the differences in the preventive constraint congestion components.

The CRR distributes congestion revenue associated with the available transmission capability; when preventive constraints bind, it will be paid the associated congestion revenues. The awarded CRRs will settle on the congestion associated with the preventive constraints.

The CRR will settle as follows: $CRR\ Payment = CRR\ MW_{AB}\ \times \left(MCC_B^k - MCC_A^k\right)$

This settlement results in the CRR balancing account accumulating any congestion rents associated with the preventive-corrective constraints binding, if they do bind, in the day-ahead market. Based on the results of the technical analysis of stressed scenarios and parallel operations showing that the preventive-corrective constraints may rarely bind in the day-ahead market, the ISO proposes not to distribute preventive-corrective congestion revenues that may be collected by the day-ahead market to CRR holders. The ISO will monitor and publicly report on the amount of preventive-corrective congestion revenues collected by the day-ahead market.

This is justified because, in this design, the kc constraints are not actually being sold in the CRR auction.

20. Next Steps

The ISO will discuss this draft final proposal with stakeholders during the call on August 22, 2017. Stakeholders should submit written comments by August 31, 2017 to initiativecomments@caiso.com.

21. Nomenclature

i: index for a location

l: index for a transmission constraint

n: total number of nodes in the system

m: total number of transmission constraints in the system

k: index for normal (preventive) contingency

kc: index for corrective contingency

K: total number of normal (preventive) contingencies

KC: total number of corrective contingencies

P: generation dispatch MW

L: load

$\overline{FL}$: transmission constraint limit

$C(\cdot)$: generation bid cost function

SF: shift factor

ΔP^{kc}: corrective capacity from base case dispatch

$RCU(\cdot)$: upward ramping capability

$RCD(\cdot)$: downward ramping capability

$g(\cdot)$: equality constraint

$h(\cdot)$: inequality constraint

λ: system marginal energy cost

μ: constraint shadow price

Appendix A: Flow related revenue and its allocation

In the lossless model considered in the proposal, the **flow related revenue** collected from the settlements of energy transactions is given by:

$$\sum_i \left[LMP_i \cdot \left(P_i^{0*} - L_i \right) \right] = \sum_i \left[\left(\lambda^{0*} + \sum_{k=0}^{K} \sum_{l=1}^{m} SF_{l,i}^{k} \cdot \mu_l^{k*} + \sum_{kc=K+1}^{K+KC} \sum_{l=1}^{m} SF_{l,i}^{kc} \cdot \mu_l^{kc*} \right) \cdot \left(P_i^{0*} - L_i \right) \right]$$

The equation could include treatment of losses, but do not at this stage in order to focus on congestion rents and corrective capacity payments.

In this expression, a negative value indicates monies collected by the ISO from participants while positive values indicate payments by the ISO to participants.

The expression on the right hand side of this equation is equal to

$$\sum_{k=0}^{K} \sum_{l=1}^{m} \left[\mu_l^{k*} \cdot \sum_i \left[SF_{l,i}^{k*} \cdot \left(P_i^{0*} - L_i \right) \right] \right] + \sum_{kc=K+1}^{KC} \sum_{l=1}^{m} \left[\mu_l^{kc*} \cdot \sum_i \left[SF_{l,i}^{kc} \cdot \left(P_i^{0*} - L_i \right) \right] \right]$$

which takes into account that

$$\sum_i \left(P_i^{0*} - L_i \right) = 0$$

in a lossless model as treated in the proposal.

A preventive transmission constraint, k, will have a non-zero shadow price only if the preventive transmission constraint is tight, that is if $\sum_i \left[SF_{l,i}^{k*} \cdot \left(P_i^{0*} - L_i \right) \right] = F_l^{k,\max}$. A corrective transmission constraint, kc, will have a non-zero shadow price only if the corrective transmission constraint it tight, that is if $\sum_i \left[SF_{l,i}^{kc} \cdot \left(P_i^{0*} + \Delta P_i^{kc*} - L_i \right) \right] = F_l^{kc,\max}$.

Taking into account this complimentary slackness at the solution to the dispatch model, the last expression for the flow related revenue can be written as

$$\sum_{k=0}^{K} \sum_{l=1}^{m} \left[\mu_l^{k*} \cdot F_l^{k,\max} \right] + \sum_{kc=K+1}^{KC} \sum_{l=1}^{m} \left[\mu_l^{kc*} \cdot F_l^{kc,\max} \right] - \sum_{kc=K+1}^{K+KC} \sum_i \left[\left(\sum_{l=1}^{m} SF_{l,i}^{kc} \cdot \mu_l^{kc*} \right) \cdot \Delta P_i^{kc*} \right]$$

Taking into account that

$$\sum_i \Delta P_i^{kc*} = 0$$

The last expression can be re-written as:

$$\sum_{k=0}^{K}\sum_{l=1}^{m}\left[\mu_l^{k*}\cdot F_l^{k,\max}\right]+\sum_{kc=K+1}^{KC}\sum_{l=1}^{m}\left[\mu_l^{kc*}\cdot F_l^{kc,\max}\right]-\sum_{kc=K+1}^{K+KC}\sum_{i}\left[\left(\lambda^{kc*}+\sum_{l=1}^{m}SF_{l,i}^{kc}\cdot\mu_l^{kc*}\right)\cdot\Delta P_i^{kc*}\right]$$

The congestion rent arising in the market is defined as the marginal value of available capacity on the transmission constraints. This is just

$$\sum_{k=0}^{K}\sum_{l=1}^{m}\left[-\mu_l^{k*}\cdot F_l^{k,\max}\right]+\sum_{kc=K+1}^{KC}\sum_{l=1}^{m}\left[-\mu_l^{kc*}\cdot F_l^{kc,\max}\right]$$

The ISO collects this amount in the flow related revenues from the settlements of energy transactions according to the first two terms.

The amount that the ISO pays for corrective capacity in settlements of corrective capacity transactions is

$$\sum_{kc=K+1}^{K+KC}\sum_{i}\left[\left(\lambda^{kc*}+\sum_{l=1}^{m}SF_{l,i}^{kc}\cdot\mu_l^{kc*}\right)\cdot\Delta P_i^{kc*}\right]$$

The ISO collects this amount in the flow related revenues from the energy settlements according to the third term. Note that the parenthetical term is the definition of the LMCP at node i which is then multiplied by the corrective capacity procured at node i; the corrective capacity price multiplied by the corrective capacity MW is the revenue needed to pay the corrective capacity.

This shows that flow related revenues arising from settlements of energy transactions exactly equals the congestion rents plus the revenue needed to pay for corrective capacity.

The energy transactions pay once to cover congestion rents and once to cover corrective capacity. The cost of corrective capacity is covered in the market requiring no additional uplift.

Appendix B: CRR settlement

Suppose that the ISO defines a set of CRRs for the set of contingencies consisting of the base case and preventive contingencies. These CRRs will be settled using the terms in the Marginal Congestion Components (MCCs) of the LMPs that arise from congestion on the transmission system in the base case and the preventive contingencies (*i.e.* for k = 0,…,K). These CRRs will not be settled using the terms in the MCCs of the LMPs that arise from congestion on the transmission system in the corrective contingencies. That is, these CRRs will be settled using:

$$\sum_{k=0}^{K}\sum_{l=1}^{m} SF_{l,i}^{k} \cdot \mu_l^{k*} \, .$$

These CRRs will **not** be settled using the full MCCs of the LMPs; they are **not** settled using:

$$\sum_{k=0}^{K}\sum_{l=1}^{m} SF_{l,i}^{k} \cdot \mu_l^{k*} + \sum_{kc=K+1}^{K+KC}\sum_{l=1}^{m} SF_{l,i}^{kc} \cdot \mu_l^{kc*}$$

The CRRs would each settle as follows:

$$CRR \quad Payment = CRR \quad MW_{AB} \times \left(\sum_{k=0}^{K}\sum_{l=1}^{m} SF_{l,B}^{k} \cdot \mu_l^{k*} - \sum_{k=0}^{K}\sum_{l=1}^{m} SF_{l,A}^{k} \cdot \mu_l^{k*} \right)$$