California ISO

Shaping a Renewed Future

Contingency Modeling Enhancements

Second Revised Straw Proposal

March 13, 2014

Table of Contents

Stakeholder comment matrix as a separate attachment available at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ContingencyModelingEnhancements.aspx

1. Changes from the revised straw proposal

Major changes from the revised straw proposal are summarized below.

Section 9 – The ISO has refined and added several proposals including what resources are eligible to provide corrective capacity, dispatch, pricing, commitment, settlement, bid cost recovery, economic buy-back and no pay provisions for corrective capacity. In addition, this section discusses refinements to the current dynamic competitive path assessment and residual supplier index used in the local market power mitigation process to consider the preventive-corrective constraint.

The ISO committed to market participants to develop a prototype of the preventive-corrective constraint to provide a proof of concept by testing it on an actual production savecase. The ISO will provide the results of this analysis at a future date to be discussed on the stakeholder call on March 20, 2014.

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 Western Electricity Coordinating Council (WECC)[2] standards, the ISO is required to return flows on critical transmission paths to its system operating limit (SOL) 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 we 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-

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[1] NERC standard TOP-007-0 R2
[2] WECC standard TOP-007-WECC-1 R1

time.   The constraint identifies the minimum generation capacity requirement, the set of generators that are effective in meeting the requirement, 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 MOC constraints in addressing the post-contingency 30 minute SOL requirement from NERC and WECC.   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.

The schedule for stakeholder engagement is provided below and targeted for the July 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
TBD	*Additional publication as necessary*
Tue 4/22/14	Draft final proposal posted
Wed 4/30/14	Stakeholder call
Tue 5/6/14	Stakeholder comments due on draft final proposal
Thu-Fri 7/17-7/18/14	July BOG

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[3] http://www.caiso.com/Documents/TechnicalBulletin-MinimumOnlineCommitmentConstraint.pdf

4. Comparison of NERC and WECC standards for corrective action

This section provides a sample comparison of the NERC and regional standards with which the ISO must comply after a contingency. The 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, but more stringent regional variations are allowed and developed via the eight regional entities as shown in Figure 1. The ISO is considered a balancing authority and transmission operator within the Western Electricity Coordinating Council (WECC).[4]

Figure 1
NERC Regional Entities

Florida Reliability Coordinating Council (FRCC)
Midwest Reliability Organization (MRO)
Northeast Power Coordinating Council (NPCC)
ReliabilityFirst Corporation (RFC)
SERC Reliability Corporation (SERC)
Southwest Power Pool, RE (SPP)
Texas Reliability Entity (TRE)
Western Electricity Coordinating Council (WECC)
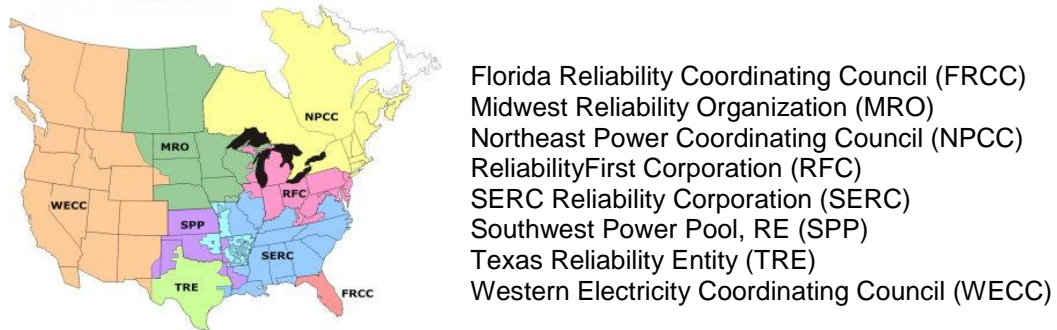
Source: North American Electric Reliability Corporation

The ISO must adhere to a more stringent regional standard under WECC standard TOP-007-WECC-1 versus the national standard under NERC standard TOP-007-0.

Table 1 below reprints the two standards and contains highlighted text where the WECC standard is more stringent than the NERC standard.

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

Table 1
Comparison of NERC and WECC TOP-007 Standards

Entity	NERC	WECC
Title	Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	System Operating Limits
Number	TOP-007-0	TOP-007-WECC-1
Purpose	This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.	When actual flows on Major WECC Transfer Paths exceed System Operating Limits (SOL), their associated schedules and actual flows are not exceeded for longer than a specified time.
Applicability	Transmission Operators and Reliability Coordinators	Transmission Operators for the major WECC paths[5]
Requirements	R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits. R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes. R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2. R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	R1. When the actual power flow exceeds an SOL for a Transmission path, the Transmission Operators shall take immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the Transmission path exceed the SOL for more than 30 minutes. R2. The Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL when the Transmission Operator implements its real-time schedules for the next hour. For paths internal to a Transmission Operator Area that are not scheduled, this requirement does not apply. R2.1 If the path SOL decreases within 20 minutes before the start of the hour, the Transmission Operator shall adjust the Net Scheduled Interchange within 30 minutes to the new SOL value. Net Scheduled Interchange exceeding the new SOL during this 30-minute period will not be a violation of R2.

On the "Applicability" row, the NERC standard is broad because it applies to all transmission operators and reliability coordinators. On the other hand, the WECC standard specifically applies to reliable operation of the major WECC transmission paths. The major WECC paths are critical because unlike the more densely populated eastern interconnection, the WECC is characterized by its reliance on a handful of high voltage transmission lines, which transfer large

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[5] See table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at:
http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf

amounts of energy across long distances from remotely located generation to load. As WECC notes with regard to its region-specific reliability standards, the "lack of redundant transmission in these corridors raises the level of scrutiny for these paths."[6] The ISO is responsible for eight major WECC paths, which are system operating limits (SOLs), as shown in Table 2.

**Table 2
CAISO's major WECC paths**

Path name	Path number
South of Los Banos or Midway- Los Banos	15
PG&E – SPP	24
Northern – Southern California	26
SDGE – CFE	45
West of Colorado River (WOR)	46
Lugo – Victorville 500 kV	61
COI	66
SCIT	

Source: See table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at:
http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf

WECC developed its own TOP-007 standard to comply with NERC's TOP-007 standard. The key distinction lies in the consideration of SOLs and interconnection reliability operating limits (IROLs). A system operating limit is the value (such as MW or frequency) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.[7] An interconnection reliability operating limit is a type of system operating limit which, if exceeded, could expose a widespread area of the bulk electric system to instability, uncontrolled separation(s) or cascading outages.[8] Under the NERC standard, violations of system operating limits only need to be reported (see "Title", "Purpose," and R1 under "Requirements"). Corrective action is not required until the violation of an interconnection reliability operating limit. WECC does not have IROLs under normal operating conditions. Instead, WECC relies on SOLs to comply with NERC's TOP-007 standard. WECC requires corrective action to transition to the next secure state when SOLs are violated. This makes the WECC standard potentially more stringent because violating a system operating limit would not necessarily lead to cascading outages, whereas violation of an interconnection reliability operating limit under the NERC standard would. Furthermore, the WECC standards (R2 and R2.1) require that the Net Scheduled Interchange stays within the path's system operating limit whereas NERC has no such requirement.

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[6] North American Electric Reliability Corporation, Docket RM09-14, March 25, 2009, p. 10.
[7] North American Electric Reliability Corporation, *Glossary of Terms Used in NERC Reliability Standards*, "System Operating Limit," April 5, 2013, p. 60.
[8] North American Electric Reliability Corporation, *Glossary of Terms Used in NERC Reliability Standards*, "Interconnection Reliability Operating Limit," April 5, 2013, p. 36.

Lastly, the NERC standard allows load shedding (R3) as an option to respect an interconnection reliability operating limit. Since the NERC standards also apply nationally, a WECC balancing authority experiencing an interconnection reliability operating limit violation may use load shedding. However, the WECC standard does not contemplate such an option for a system operating limit. The exception to this is if after the first contingency, the second contingency occurs within 30 minutes.[9] As we discuss later in Section 7, although load shedding can play a role in helping the system transition to a secure state, currently WECC does not consider it a viable option. However, if WECC converts some of the SOLs to IROLs in the future, load shedding would be considered in meeting the 30-minute standard.

5. U.S. ISO/RTO 30 minute reserves and mechanisms

U.S. ISOs and RTOs may meet NERC TOP-007-0 R2 and related regional or local standards via explicit 30 minute reserves or other supplemental mechanisms. Those with an explicit 30 minute reserve are shown in Table 3 below.[10] We discuss each market and provide some context around how each relies on its 30 minute reserves.

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[9] NERC standard TPL-003-0

[10] 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.

Table 3
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[11]	Via Forward Reserve Market for summer and winter seasons by location[12]	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[13]	Co-optimized with energy in day-ahead market based on separate demand curves for NY control area, Eastern NY, and Long Island[14]	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)[15]	Day-Ahead Scheduling Reserve Market system-wide	Yes
ERCOT	30-minute non-spinning reserve requirement calculated based on load and wind forecast risk and single largest contingency (ERCOT)[16]	The sum of: (a) 30-minute non-spinning reserve requirement; plus (b) 500 MW of 10-minute 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.	Co-optimized with energy in day-ahead market system-wide with offer curves Cap: 1,500 MW Floor: Single largest unit minus 500 MW	Yes

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

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[11] http://www.iso-ne.com/mkts_billing/mkt_descriptions/line_items/reserve_market.html

[12] http://www.iso-ne.com/mkts_billing/mkt_descriptions/line_items/reserve_market.html

[13] http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

[14] NYISO, Manual 2: Ancillary Services Manual, March 2013, p. 6-25.

[15] 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.

[16] ERCOT, "ERCOT Methodologies for Determining Ancillary Service Requirements," as presented to and approved by ERCOT Board of Directors at public meeting March 19, 2013.

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."[17]

On the other hand, **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 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).[18] 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 <u>deliverable</u> to Eastern NY.[19] 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."[20]

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.[21] 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. Though 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.[22] 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

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[17] Potomac Economics, *2011 Assessment of the ISO New England Electricity Market*, June 2012, p. 45.
[18] NYISO, Locational Reserve Requirements. Available from:
http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf.
[19] NYISO, Locational Reserve Requirements. Available from:
http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf.
[20] NYISO, Manual 2: Ancillary Services Manual, Section 6.2.1 NYISO Responsibilities, Version 3.26 March 2013.
[21] 117 FERC ¶ 61,331 (2006).
[22] PJM System Operations Division, Manual 13: Emergency Operations, Revision 52, effective February 1, 2013, pp. 11-12.

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.[23] By comparison, WECC requires and the CAISO procures spinning and non-spinning reserves in total equal to 100 percent of the single largest contingency or 5 percent of load served by hydro and 7percent of load served by thermal.[24]

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 day-ahead, system-wide, and not re-optimized in real-time.[25] 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.[26] 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.[27] 30 minute reserve is also used to replenish or support the 10-minute spinning reserves used to maintain frequency.[28]

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, **CAISO** 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 SOLs 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 MOC constraint is a market mechanism used to ensure sufficient unit commitment is available that is effective in addressing specified contingencies. MOC constraints are enforced in the day-ahead market, and thus affect unit commitment and dispatch. But MOCs do not have marginal contributions to the LMPs.   An exceptional dispatch is an out-of-market manual operation to start specific units or move them to specified output levels. It is an important device the ISO uses to meet the SOL standard. Like MOC constraints, the bid costs from exceptionally

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[23] Monitoring Analytics, LLC, *2012 State of the Market Report for PJM*, "Section 9: Ancillary Services," p. 279.
[24] WECC standard BAL-STD-002-0
[25] Moorty, Sai, ERCOT, "Look Ahead SCED," November 28, 2011, slide 6.
[26] 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.
[27] ERCOT, "ERCOT Methodologies for Determining Ancillary Service Requirements," as presented to and approved by ERCOT Board of Directors at public meeting March 19, 2013.
[28] ERCOT, "3.17.3 (2) Non-Spinning Reserve Service," ERCOT Nodal Protocols, Section 3: Management Activities for the ERCOT System, April 2, 2013.

dispatched energy are not reflected in LMPs. Both MOCs and exceptional dispatches are used for broader reasons than meeting the SOL standard.

For 30 minute reserves, most ISOs and RTOs consider them 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 the 30 minute limit described in NERC standard TOP-007 R2 for a violation of an IROL. Based on our research and discussion with eastern ISOs and RTOs, they use a combination of their primary reserves supported by supplemental reserves (if any), out of market manual operations, and reserve sharing agreements. In the eastern interconnection, IROLs can be the interfaces between interconnections. Therefore, in those instances, system wide reserves can help meet the IROL needs with good accuracy. In addition, they can arrange for reserve sharing agreements to meet the IROL needs. This is not typically the case for the CAISO. Most of CAISO's major paths (such as Path 26) are wholly internal to our market, and are not in the same granularity as ancillary service regions. We cannot rely on reserve sharing arrangements with our neighbors, either.

6. WECC standard compliance

This section describes the challenges to meeting WECC standard TOP-007-WECC-1 R1 (WECC SOL standard), how the ISO is currently meeting the standard, and where improvement is needed.

6.1.   WECC SOL standard challenges

Meeting the WECC SOL standard is challenging because of the combination of the 30 minute time limit and the flow-based nature of contingencies. The time limit requires the ISO to transition the post-contingency system to the next secure state by the end of 30 minutes. This requires the ISO to adjust the output of fast response resources so that the post-contingency flows are within the new system operating limit. Contingencies that constrain the major WECC 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 needs to be able to evaluate the post contingency flow with the impacts from the contingency and the re-dispatches. This presents a challenge to the ISO in defining where effective fast response resources should be located as the need is flow based, and cannot be accurately translated into regional requirements.

6.2.   10 minute ancillary services

10 minute ancillary reserves are procured primarily to meet NERC and WECC operating reserve requirements.[29]   As mentioned above, reserves in WECC must cover either the single largest contingency or 5 percent of load served by hydro and 7 percent of load served by thermal and be comprised of 50 percent spinning and 50 percent non-spinning reserves.[30]

For NERC standard TOP-007-0 R2, 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 the IROL purpose. Use of these reserves is more complicated when addressing a system operating limit violation under the WECC SOL standard. 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 from other ISOs/RTOs that stranded ancillary services, even if procured sub-regionally, are an operational challenge.

The main point is that 10 minute ancillary services are procured to comply with completely different NERC and WECC standards than the WECC SOL standard. 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 WECC SOL standard is a dynamic need based on the post-contingency flows.   Creating smaller ancillary service subregions is a very rough way to target the flow-based need under WECC SOL standard.

6.3.   Exceptional dispatch

Exceptional dispatch is used to compensate for and supplement stranded ancillary services. Specifically for the WECC SOL standard, 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 respond to a contingency within the 30 minute limit. Exceptional dispatches are issued based on operator experience and judgment about the effectiveness of particular units. The units selected are not 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 are not tested. Therefore, without an actual contingency occurring, we will not know whether the unit selected was effective in maintaining reliability. Manual operations are prone to both under- and over-procurement but typically leans towards more conservative actions.

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[29] For example, WECC standard BAL-STD-002-0 B.WR1
[30] WECC standard BAL-STD-002-0

6.4.   MOC constraints

MOC constraints are used to identify the minimum generation capacity needed to address a reliability requirement. They are largely used to address the WECC SOL standard but are also deployed to address non-flow-based, procedural, and outage related constraints on the system. While MOC constraints are an improvement over exceptional dispatch because they introduce a systematic approach that can be included 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 MOC constraints pre-define a small geographic footprint where units may be most effective but retain this static definition regardless of where the contingency occurs and the post-contingency topology. Third, the MOC constraint only commits units to their Pmin. The energy output above Pmin will be optimized in the market. Therefore, the MOC constraints do not have a marginal contribution to the LMPs (the energy bids above Pmin may have). Most importantly, without an actual contingency occurring, we will not know whether the constraint was effective in maintaining reliability.

6.5.   Reliability challenges in current mechanisms

Table 4 below summarizes the ISO's current mechanisms to address the WECC SOL standard. 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 under the WECC SOL standard.

Table 4
Reliability comparison of ISO 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[31]	WECC operating reserve requirements[32]	System-wide	Partially – deliverability issues because not flow-based and granularity
Exceptional dispatch	As specified in ISO tariff[33]	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

For 10 minute contingency reserves, the basis for procurement is not the WECC SOL standard but rather other NERC/WECC standards that specify operating reserve capacity as noted in column [B]. 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 the WECC SOL standard when possible and appropriate. However, the capacity procured is not tested for deliverability and therefore cannot fully meet the flow-based requirements under the WECC SOL standard (column [E]).

Exceptional dispatch can be used for several reasons specified in the ISO tariff and has been used to address the WECC SOL standard (column [B]). The technical paper attached to the previous ISO issue paper (as well as reproduced in Figure 2 below) 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 the WECC SOL standard.[34] Therefore, a significant portion of exceptional dispatches were used to address this specific reliability standard. 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 the units can provide the correct ramping capability within the 30 minute time limit but the units procured are not tested for deliverability. Since the amount of capacity procured is not optimized, we cannot definitively say that we have procured the "right" amount of capacity to address the WECC SOL standard. In fact, without a

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[31] WECC standard BAL-STD-002-0 B.WR1.
[32] WECC standard BAL-STD-002-0 B.WR1.
[33] See ISO tariff such as Section 34.9.
[34] Measured in MWhs of exceptional dispatch volume. See Contingency Modeling Enhancements Issue Paper, March 11, 2013, Technical Paper attachment, p. 3.

contingency actually occurring, we cannot say whether we have over- or under-procured (column [E]).

For MOC constraints, the main purpose is to address the WECC SOL standard but some are used for non-flow based constraints (such as those related to voltage support) as shown in column [B]. Each MOC constraint has a predefined static location and list of units (columns [C] and [D]). However, MOC constraints are only partially effective in addressing the WECC SOL standard because the units within the constraint are only moved to their Pmin. Most importantly, the MOC constraint definition is static while the need is dynamic and depends on the post-contingency topology.

6.6.   Efficiency challenges in current mechanisms

In addition to reliability challenges, exceptional dispatch and MOC 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. Our definition of efficiency also includes market efficiency where pricing signals reflect need, operationally desirable characteristics are valued, and reliability is maintained via lowest cost. Table 5 compares the efficiency of the ISO's current mechanisms to meet the WECC SOL standard.

Table 5
Efficiency comparison of ISO mechanisms to meet WECC SOL standard

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
MOC 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 WECC SOL standard) so there may be deliverability limitations in real-time as shown in Column [C]. On the other hand, exceptional dispatches and MOC 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 very likely efficiently dispatched post-contingency because the operator has selected (to the

best of his or her knowledge) a highly effective unit with no deliverability constraints that can meet the 30 minute time limit. MOC 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 the LMP, 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 MOC constraint does not value fast response directly because it does not differentiate the ramping capabilities of the units within the constraint.

The Federal Energy Regulatory Commission (FERC) has directed the ISO in several instances to reduce reliance on exceptional dispatches and increase market-based solutions.[35] This includes using market-based solutions to address system needs as well as developing appropriate compensation via LMPs or through other market signals. In summary, more efficient procurement of the most effective resources will improve reliability. To the extent we can leverage the market in procuring needed capacity and compensate those resources, we will be increasing the overall effectiveness of the ISO markets.

6.7.   Potential solutions considered

The ISO's current procurement of 10 minute reserves at first glance could potentially provide a model to address the WECC SOL standard. 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 (faster response) resources than needed for the WECC 30 minute SOL standard. However, as explained in Section 6.2, the ISO's current ancillary services are procured to meet a system capacity requirement rather than the flow-based requirement under the WECC SOL standard. In an attempt to address the flow-based requirement, some stakeholders have suggested procurement of 30 minute reserves at a subregional level assuming that smaller regions will provide greater granularity. This is a false premise. The only way to accurately evaluate whether the WECC SOL standard is 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 err on the side of over-procurement in order to ensure reliability. The lack of a 30 minute product in the current ISO market does 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 efficiently.

In our review of other ISOs and RTOs, the closest proxy they have to the WECC's SOL standard is NERC standard TOP-007-0 R2 (see

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[35] See for example 126 FERC ¶ 61,150 and 128 FERC ¶ 61,218.

Table 1), which also has a 30 minute time limit for IROL violation. We have found that 30 minute reserves in those markets are not expressly procured to meet this NERC standard and that primary 10 minute reserves and manual operations are the first line of defense. While the ISO also has these options, it does not have firm load shedding and reserve sharing opportunities. In summary, the ISO has a more stringent reliability standard to meet but fewer effective tools with which to meet it.

The issue paper introduced a preventive-corrective constraint to address the WECC SOL standard. 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 MOC constraints, provide greater compensation through LMPs and may likely result in a separate capacity payment for resources (both generation and demand response) that help meet the reliability standards.[36] The major concepts discussed in the technical attachment were introduced to stakeholders at the last 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.

7. Preventive-Corrective Market Optimization Model

7.1.   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[37]. 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, we will

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[36] While some level of exceptional dispatch is needed in every market, minimizing such manual operations and preferably replacing them with optimized solutions improves reliability.

[37] 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.

have a more advanced market 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 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[38].

Without this preventive-corrective model in production, currently the ISO has to meet the SOL standard by enforcing minimum online capacity constraints (MOCs) or through manual exceptional dispatches. The ISO estimated the SOL related exceptional dispatches through operator logs[39], and showed the volume (MWhs) by month in 2012 in Figure 2. 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.[40] The cost estimate is shown in Figure 3. 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 2
SOL Related Exceptional Dispatch Volume in 2012 (Thousands of MWhs)

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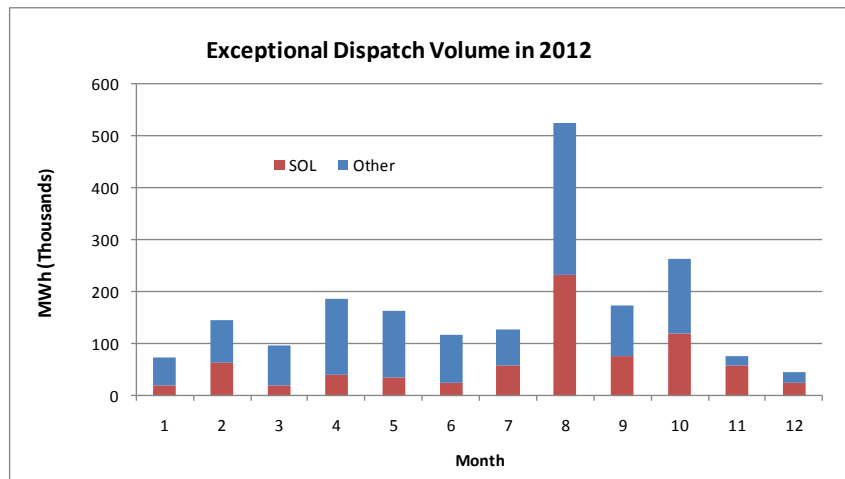
[38] James McCalley, EE553, Steady-state analysis, Class 18: security constrained OPF, Iowa State University, http://home.eng.iastate.edu/~jdm/ee553/SCOPF.pdf
[39] The numbers shown in Figure 2 may over or under estimate the actual volume of SOL related exceptional dispatches due to the complexity of analyzing operator logs.
[40] 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 3
SOL Related Exceptional Dispatch Cost in 2012 (Million dollars)
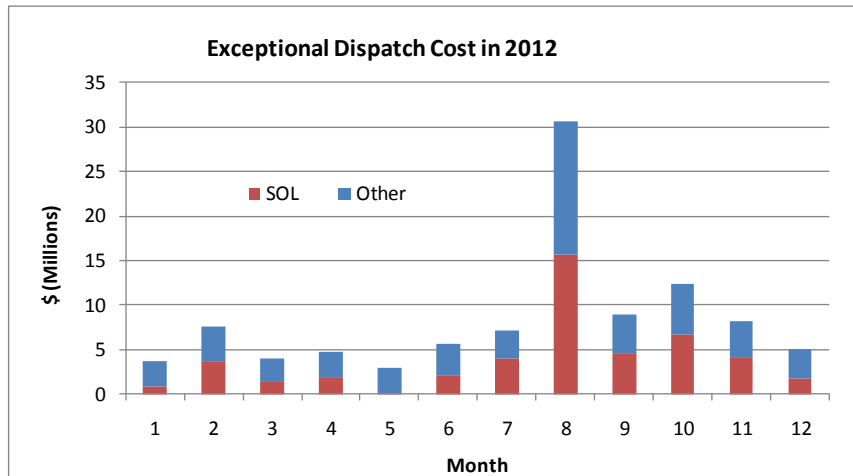
The ISO proposes to enhance the contingency model in the market optimization to handle the post contingency corrective actions. With the contingency model enhancement (CME), the market optimization advances from a pure preventive mode to a preventive-corrective mode, where both pre contingency dispatches 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.

7.2.   Preventive-corrective market optimization

In this section, we will first review the power system security framework, and then discuss the modeling enhancement to the market optimization. For simplicity and ease of understanding, we use 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.

7.2.1. 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 4.

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

- 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.

Figure 4
Power System Security Study Framework
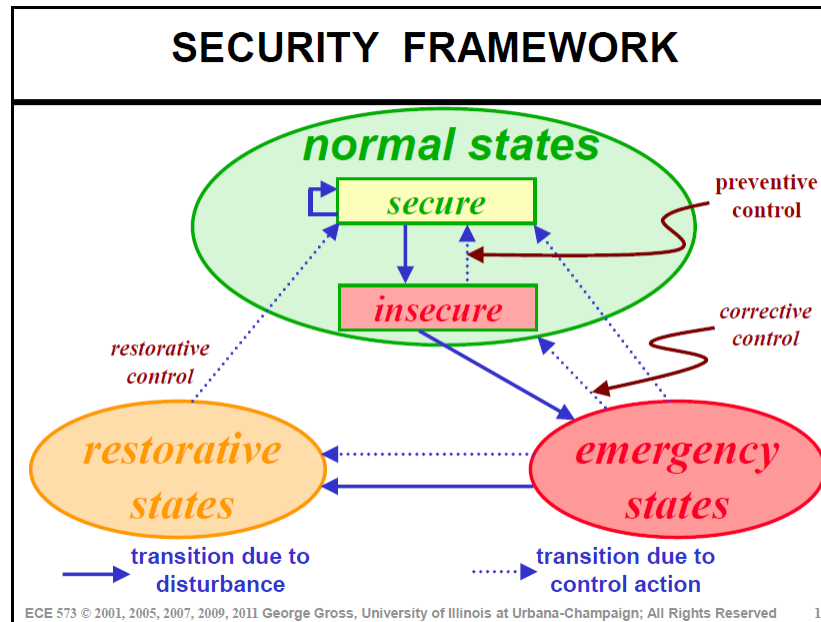
Implementing the security framework into the Energy Management System (EMS) can provide the operators online security analysis functionality to closely monitor, assess and control system security.

7.2.2. Preventive market optimization

Section 7.2.1 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. See Section 12 for a list of nomenclature used in this paper.

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.

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 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

$$\sum_{i=1}^{n} SF_{l,i}^{k}\left(P_i^k - L_i\right) \leq \overline{FL_l^k}$$

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[41]. 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[42] 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.

7.3. 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. NERC reliability standard NERC TOP-007-0 R2 and WECC reliability standard TOP-007-WECC-1 R1 require the ISO to transition the system back to a secure state within 30 minutes after the system disturbance. These reliability standards require the system to be not only 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 5.

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

Figure 5
SCIT Pre-contingency rating and post-contingency rating
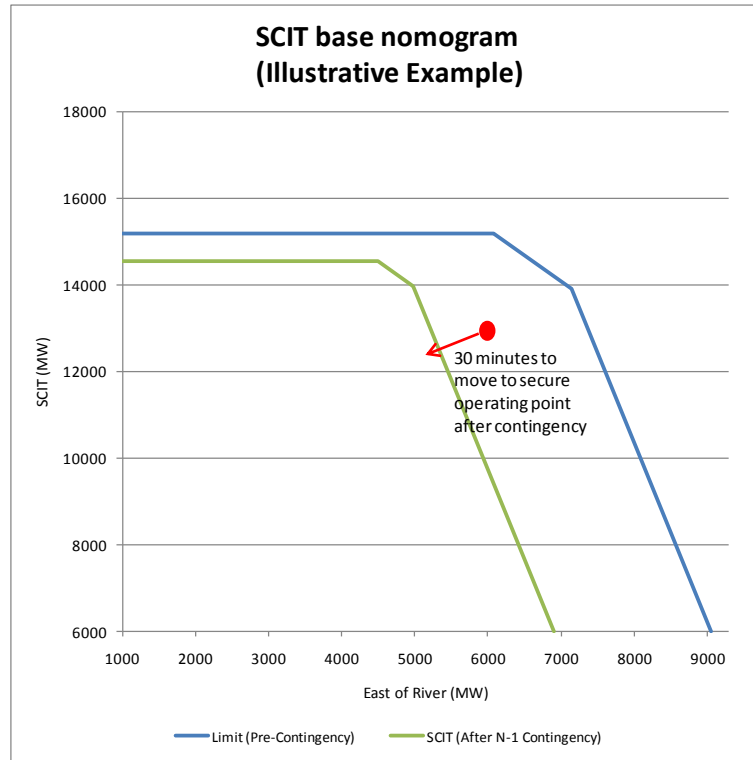
If all elements are in service, the normal SCIT nomogram limit (SOL) is the blue curve. If the system operates inside the blue curve, it is N-1 secure. Assume that pre contingency, the system is operating at the red dot with 13,000 MW flow on SCIT and 6,000 MW flow on East of River. Suddenly, one of the SCIT lines trips. With one element out of service, the new SCIT nomogram limit is the green curve. To comply with the NERC and WECC standards, 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, we need to reduce the 30-minute timeframe to the practical available response time in the preventive-corrective model. In this paper, we will assume this time to be *T*. The corrective re-dispatch may or may not involve operating reserve deployment depending on the relevant NERC and WECC reliability standards.

7.3.1. 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.

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

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

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

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

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

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

$RCD(P^0) \leq \Delta P^{kc} \leq RCU(P^0), \forall kc = K+1, K+2, \cdots, K+KC$ 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 is not ΔP^{kc}, but the more economic solution from re-dispatching resources without the corrective capacity awards. This design 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.

We will specifically discuss the power balance constraint and transmission constraint in the corrective contingency cases 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, we enforce 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.

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 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 the time frame.

7.3.2. 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 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

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

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.

We will demonstrate the meaning and appropriateness in the following section through examples.

7.4.   Examples

In this section, we will go through 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.

7.4.1. 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 trips, and next N-1 secure SOL for branch A-B is 350 MW. The load is 1200 MW at node B.

Figure 6
A two-node system with three generators
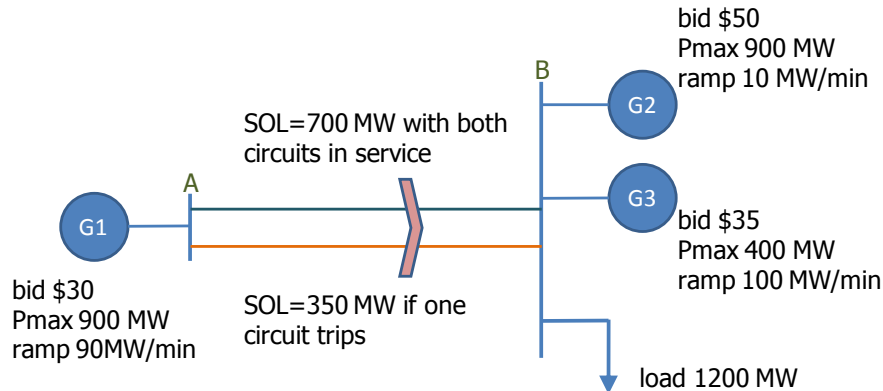
We will compare the following models:

- 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 6. 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 6, load energy payment is 1,200 MW*$50=$60,000. Note that the convention of the revenue column in Table 6 is that revenue is positive, and payment is negative. That is why the load revenue is –$60,000 in Table 6. 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 6
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 (A→B)	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 7. 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 7, 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.[43] 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.

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[43] 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 7
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
CRR (A→B)	350	N/A	N/A	$20	N/A	$7,000	N/A

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 8. 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 8. As described in section 7.3, for each corrective contingency case, we calculate 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 dec'ed 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 8
Preventive-corrective solution and LMCP compensation

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

Table 9
Preventive-corrective model settlement

Resource	MW	LMP	Bid cost	Revenue	Profit/uplift
Total gen energy	1,200	N/A	$47,000	$46,000	$3,750
Total gen capacity	350	N/A	N/A	$2,250	$2,250
Load	1,200	$50	N/A	–$60,000	–$2,250
CRR (A→B)	700	$20	N/A	$14,000	N/A

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 10.

As shown in Table 9, Load energy payment is still 1,200 MW*$50=$60,000, and CRR revenue is 700 MW*$20 = $14,000. Load energy payment is just enough to cover the total generation and CRR revenue: $46,000+$14,000–$60,000=$0. However, we need additional payment to cover the corrective capacity revenue. To maintain the ISO's revenue neutrality, the ISO needs to collect $2,250 uplift cost from load. The uplift cost to load in the preventive-corrective example is higher than that in the strong preventive example because the CRR sold quantity has been adjusted down to 350 MW in the strong preventive model. If the CRR sold quantity stays at 700 MW as in the preventive-corrective example, the strong preventive model would have to uplift $7,000 cost to load to cover the CRR revenue.

Table 10
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

7.4.2. 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 11. 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 12. Load energy payment is still 1,200 MW*$50=$60,000, and CRR revenue is still 700 MW*$20=$14,000. The ISO needs $7,000 uplift to load to main revenue neutrality. Among the $7,000 uplift, $4,000 is to cover the corrective capacity revenue, and the rest $3,000 is to cover CRR revenue: $49,000+$14,000–$60,000=–$3,000.

Table 11
Preventive-corrective solution and LMCP compensation with G3 out of service

Gen	Energy in base case			
	P^0	LMP	λ^0	μ_{AB}^0
G1	550	$30	$50	$0
G2	650	$50	$50	$0
G3	0	$50	$50	$0
	Corrective Capacity in contingency *kc*=1			
Gen	ΔP^1	LMCP^1	λ^1	μ_{AB}^1
G1	−200	$0	$20	−$20
G2	200	$20	$20	−$20
G3	0	$20	$20	−$20

Table 12
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	−$7,000
CRR (A->B)	700	$20	N/A	$14,000	N/A

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

bid 400 MW @ $35
ramp 10 MW/min
500 MW @ $50
ramp 80 MW/min

SOL=700 MW with all
circuits in service

bid $30
Pmax 900 MW
ramp 90MW/min

SOL=350 MW if one
circuit is out of service

bid $31
Pmax 700 MW
ramp 1 MW/min

Ref bus   load 1200 MW
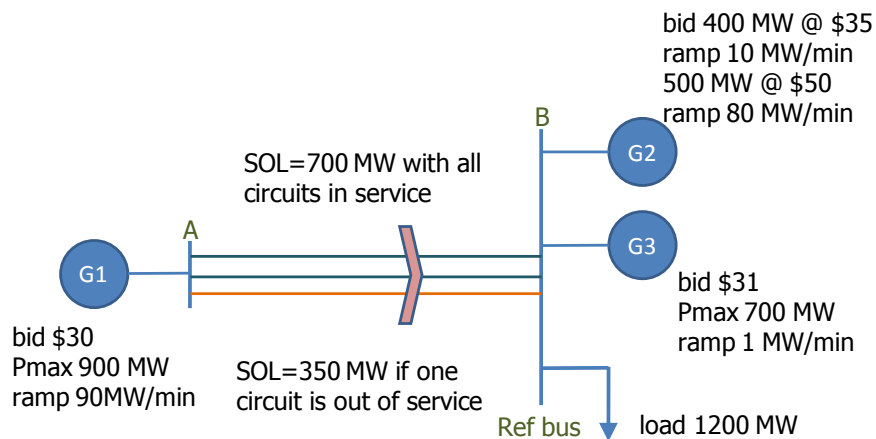
Table 13
Preventive-corrective solution and LMCP compensation with G2 having dynamic ramp rate

Gen	Energy in base case			
	P^0	LMP	λ^0	μ_{AB}^0
G1	700	$30	$31	−$0.43
G2	218.57	$31	$31	−$0.43
G3	281.43	$31	$31	−$0.43
	Corrective Capacity in contingency *kc*=1			
Gen	ΔP^1	LMCP^1	λ^1	μ_{AB}^1
G1	−350	$0	$0.57	−$0.57
G2	330	$0.57	$0.57	−$0.57
G3	20	$0.57	$0.57	−$0.57

Table 14
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	−$886
CRR (A->B)	700	$1	N/A	$700	N/A

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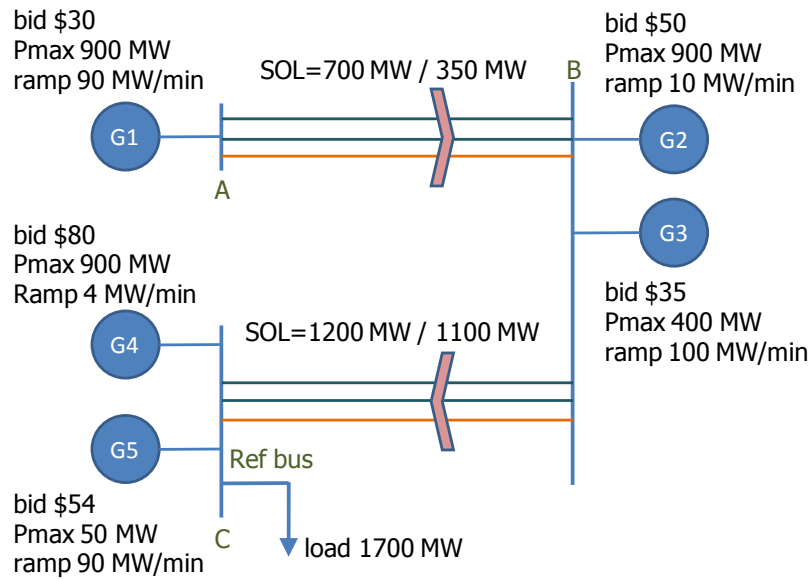
- from 217.57 MW to 400 MW, ramp 182.43 MW in 182.43/10 = 18.24 minutes,
- from 400 to 540.56, ramp 140.56 MW in 140.56/80=1.76 minutes,

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 14. Load energy payment is 1200*31=$37,200, and CRR revenue is 700*1=$700. The ISO needs $886 uplift to load to main revenue neutrality. Among the $886 uplift, 350*0.57=$200 is to cover the corrective capacity revenue, and the rest $686.2 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.

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

bid $30
Pmax 900 MW
ramp 90 MW/min

bid $50
Pmax 900 MW
ramp 10 MW/min

SOL=700 MW / 350 MW

B

G1

G2

A

G3

bid $80
Pmax 900 MW
Ramp 4 MW/min

bid $35
Pmax 400 MW
ramp 100 MW/min

SOL=1200 MW / 1100 MW

G4

G5

Ref bus

bid $54
Pmax 50 MW
ramp 90 MW/min

C

load 1700 MW

Table 15
Preventive-corrective solution and LMCP compensation with two SOLs

Gen	Energy in base case				
	P^0	LMP	λ^0	μ^0_{AB}	μ^0_{BC}
G1	700	$30	$80	−$5	−$19
G2	150	$50	$80	−$5	−$19
G3	350	$50	$80	−$5	−$19
G4	470	$80	$80	−$5	−$19
G5	30	$80	$80	−$5	−$19
	Corrective Capacity in contingency kc=1				
Gen	ΔP^{kc}	LMCP	λ^1	μ^1_{AB}	μ^1_{BC}
G1	−350	$0	$15	−$15	$0
G2	200	$15	$15	−$15	$0
G3	50	$15	$15	−$15	$0
G4	80	$15	$15	−$15	$0
G5	20	$15	$15	−$15	$0
	Corrective Capacity in contingency kc=2				
Gen	ΔP^{kc}	LMCP	λ^2	μ^2_{AB}	μ^2_{BC}
G1	0	$0	$11	$0	−$11
G2	−150	$0	$11	$0	−$11
G3	50	$0	$11	$0	−$11
G4	80	$11	$11	$0	−$11
G5	20	$11	$11	$0	−$11

Table 16
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	−$6,350
CRR (A→B)	700	$20	N/A	$14,000	N/A
CRR (B→C)	1,200	$30	N/A	$36,000	N/A

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 dec'ed 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 16. Load energy payment is 1,700 MW*$80=$136,000, and CRR revenue is (700 MW*$20)+(1,200 MW*$30)=$50,000. The load energy payment exactly covers the generation revenue and CRR revenue: $86,000+$50,000–$136,000 = $0. The generation corrective capacity revenue $6,350 will be uplifted to load to main the ISO's revenue neutrality.

8. Summary of reliability and market efficiency benefits

The ISO is dedicated to ensuring the reliability of the grid by adhering to applicable NERC and WECC standards. The WECC SOL standard presents an operational challenge to secure the appropriate level of reliability when the post-contingency topology is dynamic. Table 17 below (partially reproduced from Table 4) 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 WECC SOL standard 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 17
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[44]	WECC operating reserve requirements[45]	System-wide	Partially – deliverability issues because not flow-based and granularity
Exceptional dispatch	As specified in ISO tariff[46]	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 18 (partially reproduced from Table 5) compares each mechanism based on market efficiency where pricing signals reflect need, whether operationally desirable characteristics are valued, and reliability is maintained via lowest cost. As compared to the other mechanisms, the preventive-corrective constraint is more efficient on all counts.

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[44] WECC standard BAL-STD-002-0 B.WR1.
[45] WECC standard BAL-STD-002-0 B.WR1.
[46] See ISO tariff such as Section 34.9.

Table 18
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 WECC SOL standard because it considers the flow-based nature of the requirement. This reliability benefit also reflects not dropping firm load, which is implicit in the WECC SOL standard (because the standard does not allow firm load drop except as we have noted in an extreme emergency). Exceptional dispatch and MOC 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 5 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 the WECC SOL standard needs. 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 is not what the WECC SOL standard requires. 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 the SOL violation. 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 in the WECC SOL standard. 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 7, 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.

9. Additional ISO proposals

After consideration of stakeholder comments and internal discussion, the ISO provides the following proposals.

9.1. Eligibility to count towards corrective capacity

9.1.1. Resources eligible to count as corrective capacity

The types of resources eligible to provide corrective capacity include:

- generating units (online and offline),
- demand response,
- system resources also certified to provide ancillary services; and
- participating load/pumped storage

These resources will be included in the preventive-corrective constraint to the extent they:

- Have an energy bid (*i.e.*, is not self-scheduled, but can be offline if fast start resource);
- Have sufficient ramping capability as determined by the preventive-corrective constraint;

- Can meet the time requirements as determined by the preventive-corrective constraint;
- Is appropriately located to address an SOL violation as determined by the preventive-corrective constraint;
- Are not on the list of resources not eligible for corrective capacity.

Resources with an operating reserve award are eligible to provide corrective capacity as well.

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 constraint as on other constraints and products in the IFM today. However, only physical supply will be used to meet the constraint in RUC (which is consistent with the design features of the proposed FERC Order 764 compliance).[47] The corrective capacity awards will be re-optimized in the real-time based on changing market conditions.

ISO seeks to coordinate to the greatest extent possible this proposal with other market changes and impacts and align market designs. For example, the proposed constraint will utilize the current 10 minute operating reserves and does not duplicate that procurement. We will ensure that when multiple products are used, only the correct marginal value is reflected. The constraint also has many similarities to the current flexible ramping constraint and the proposed flexible ramping product.[48] Table 19 below summarizes the similarities and differences between the preventive-corrective constraint, flexible ramping constraint and product.

Table 19
Efficiency comparison of mechanisms to meet WECC SOL standard

Capacity type	Objective	Pre-contingency	Post-contingency
Preventive-corrective constraint	Prepare for contingencies pursuant to WECC TOP-007	• Procure in IFM, RUC, FMM, and RTD • Capacity reserved for contingencies	Use corrective capacity
Flexible ramping constraint	Address net load variability/uncertainties	• Procure in real-time at 15 minute granularity • Use capacity as needed • Should not overlap with preventive-corrective	Use flexible ramping capacity
Flexible ramping product *(initiative in progress)*	Address net load variability/uncertainties	• Procure in IFM, FMM, and RTD • Use capacity as needed • May overlap with preventive-corrective	Use flexible ramping capacity

Both the current flexible ramping constraint and the flexible ramping product are capacity procurements separate from operating reserves and corrective capacity. This is because the flexible ramping constraint and product aims to address net load variability/uncertainties while

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[47] See the FERC Order 764 stakeholder initiative (which was approved by the ISO Board in May 2013) at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx
[48] See the flexible ramping product stakeholder initiative (which is currently on hold) at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

operating reserves and corrective capacity are to cover contingencies. Currently, the flexible ramping constraint is only procured at a 15 minute granularity. Should the capacity be released to address net load variability, it may not be reprocured in time to address a contingency. Similarly, the preventive-corrective constraint will procure capacity needed for a contingency that would not be released to address net load variability. The main concern is the procurement timescale of both constraints and thus the ISO proposes that there will be no overlap in the procurement of the preventive-corrective and flexible ramping constraints.

On the other hand, the flexible ramping *product* will be in RTD like the preventive-corrective constraint and it would be possible to overlap these two capacity types. The degree of overlap (*i.e.*, whether 100% of the flexible ramping product capacity can count towards the preventive-corrective constraint) may be determined as the ISO gains more experience with both in the market.

In terms of converting the capacity to energy, following a contingency, both the flexible ramping constraint and product will be deployed to help the system to recover. On the other hand, when the flexible ramping product is deployed in the RTD market to deal with net load variability/uncertainties, operating reserves and corrective capacity will not be deployed. These two capacities will be used to protect against the next contingency.

9.1.2. Resources <u>not</u> eligible to count as corrective capacity

The following resources are not eligible to provide corrective capacity (*i.e.,* intertie resources that cannot provide ancillary resources):

- Intertie resources that cannot provide ancillary services
- Any portion of a resource that is self-committed
- Capacity procured under the flexible ramping constraint

9.1.3. Dispatch of corrective capacity

In the event of contingency, ISO operations will utilize the real-time contingency dispatch (RTCD) to access corrective capacity. Note that this does not bar ISO operations from utilizing exceptional dispatch for this or any other tariff-approved reason should the operators need to. The corrective capacity dispatched via RTCD will be considered contingency energy for settlement purposes. Also note that ISO operations are not prohibited from utilizing non-corrective capacity resources to address a contingency (see above for other resources).

9.2.   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). The LMCP is calculated as the shadow price of constraint in question multiplied by the shift factor plus the nodal price.

9.3. 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.

9.4. Settlement of corrective capacity

Corrective capacity is awarded in the day-ahead market and the constraint is re-optimized in the 15 and 5 minute real-time markets. Settlement of corrective capacity will occur for the day-ahead market and the 15 minute real-time market (FMM) pursuant to FERC Order 764 compliance and in RTD.

9.5. Bid cost recovery

This section assumes that changes under the RIMPR 1 and BCR mitigation measures initiative is in effect. Payments and charges from corrective capacity (LMCP x MW award) will be included in bid cost recovery calculations for bid cost recovery eligible resources, per market. Bid cost recovery eligible resources are defined in the ISO tariff. This shall also apply to offline resource. Note that a self-committed resource is not eligible to provide corrective capacity.

9.6. Economic buy-back and no pay provisions

Since the preventive-corrective constraint will be re-optimized in the real-time market, an economic buy-back can occur in the real-time. Real-time buy-back will be the product of the real-time LMCP and the real-time imbalance corrective capacity. This is similar to the settlement of buy-back of energy today. A buy-back of corrective capacity likely indicates that the unit is more valuable for energy than it is for corrective capacity.

A "no pay" charge rescinds day-ahead and real-time corrective capacity award payments to the extent that the resource awarded the corrective capacity does not fulfill the requirements associated with that payment. A "no pay" charge exists for operating reserves and the application to corrective capacity will be similar. The corrective capacity No Pay rescinds corrective capacity payment when one of the following conditions occurs:

Condition	Description
Undispatchable Capacity Two types: availability limited and ramp	**Availability-Limited Capacity** – If a resource's capacity is de-rated in Real-Time and cannot provide enough energy once the awarded AS is called upon, the total amount of previous corrective capacity Awards and Schedules may not be available in Real-Time for Dispatch due to the availability limitation. **Ramp-Limited Capacity** – Corrective capacity is required to be delivered in 30 minutes. If a resource does not have the 30-minute or less Ramp Rate capability

limited	(determined by its Start-Up Time and Ramp Rate curve) in Real-Time to deliver the corrective capacity was awarded or scheduled, then a portion of the corrective capacity is not available due to the Ramp Rate limitations on the resource.
Undelivered Capacity	If Energy from a resource's corrective capacity Award or Schedule is dispatched pursuant to a real-time contingency dispatch, then that resource is responsible for delivering at least 90% of the Expected Energy attributed to that dispatched corrective capacity in order to avoid a No Pay charge. This applies to offline generators that do not come online.
Unavailable Capacity	No Pay charges apply when corrective capacity is unavailable because it is converted to Energy without Dispatch Instructions from CAISO. Uninstructed Deviations in Real-Time may cause corrective capacity to be unavailable to CAISO as Operating Reserve
Declined Instruction	This section will apply only to Non-Dynamic System Resources capable of providing Spinning or Non-Spinning Reserve. Non-Dynamic System Resources respond to Dispatch Instructions with an "Accept", "Partial" or "Decline" response. When a Non-Dynamic System Resource partially accepts or declines a Dispatch Instruction to convert awarded corrective capacity to energy pursuant to a real-time contingency dispatch, No Pay applies to the amount not delivered

The requirements dictate that the resource awarded the corrective capacity payment must either convert that capacity into energy if dispatched in real-time pursuant to a real-time contingency dispatch or keep that capacity unloaded and available for a potential dispatch for energy in real-time pursuant to a real-time contingency dispatch. If the resource fails to fulfill these requirements, then it is not entitled to its full corrective capacity payment.

It is possible for a unit to be awarded both operating reserve capacity and counted towards corrective capacity. In the event the unit is in any of the conditions noted above, the No Pay provision will adhere to the following priority from first to be assessed a No Pay to the last. Note that this is the reverse order of dispatch priority for the corrective capacity.

No Pay priority (for rescinding payment)	Dispatch priority
1. Corrective capacity 2. Non-spin 3. Spin	1. Spin 2. Non-spin 3. Corrective capacity

9.7.   Bid in ramp rates

The ISO believes that a ramp rate is a physical characteristic of a resource as reflected in the Master File. Therefore, the ISO proposes to remove bid in ramp rate functionality from the market. In the event of a physical operating capability change, a resource could still change its ramp rate in SLIC.

The ISO has greatly improved the modeling of resources in the market (such as multi-stage generating resources) since the market start-up so additional flexibility to change ramp rates is no longer needed. Removing this functionality would also minimize gaming or manipulation opportunities in the market as ramping capability increases in value. Removing the ability to bid

in ramp rates does not mean the ISO does not value ramping capability. On the contrary, the preventive-corrective constraint (as well as other proposals such as the flexible ramping product) aims to value ramping capability explicitly in the market. The preventive-corrective constraint and other proposals can only be effective if we can minimize or eliminate gaming or manipulation opportunities. We are open to making refinements to the Master File if necessary to reflect ramp rates under normal operating conditions versus emergency conditions.

9.8.   Cost allocation

This constraint will help the ISO meet a WECC-wide standard. Procuring corrective capacity will prevent firm load shedding in case of a contingency per the WECC SOL standard. Since the constraint will also be procured based on flow, we find it appropriate to allocate the cost of the capacity to measured demand on a MWh basis. This should send the appropriate market signals to motivate load to contract with units that can provide economic corrective capacity. Some stakeholders maintain that costs for corrective capacity should be allocated on a regional basis. This argument seems to be based an assumption of where the corrective capacity is physically located. However, the many reliability and market efficiency benefits mentioned above will broadly benefit the ISO system. As an analogy, the ISO's current transmission cost allocation reflects this idea of broad benefits by allocating the costs of transmission upgrades ≥200 kV across the ISO footprint, regardless of the physical location of the line. Though there are local benefits, the constraint will also help maintain the ISO's import capability, which benefits the system as a whole. It would be difficult and potentially not even feasible to parse out the local versus system benefits the corrective capacity constraint involves. Therefore, we propose to allocate the costs of the corrective capacity constraint to measured demand ISO-wide.

9.9.   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, that 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.

9.9.1. 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,[49] is the available effective energy supply 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 7 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.

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[49] 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 7
Real-Time Supply of Counterflow to *Preventive-Constraint* from Fringe Competitive
Suppliers and Potentially Pivotal Suppliers
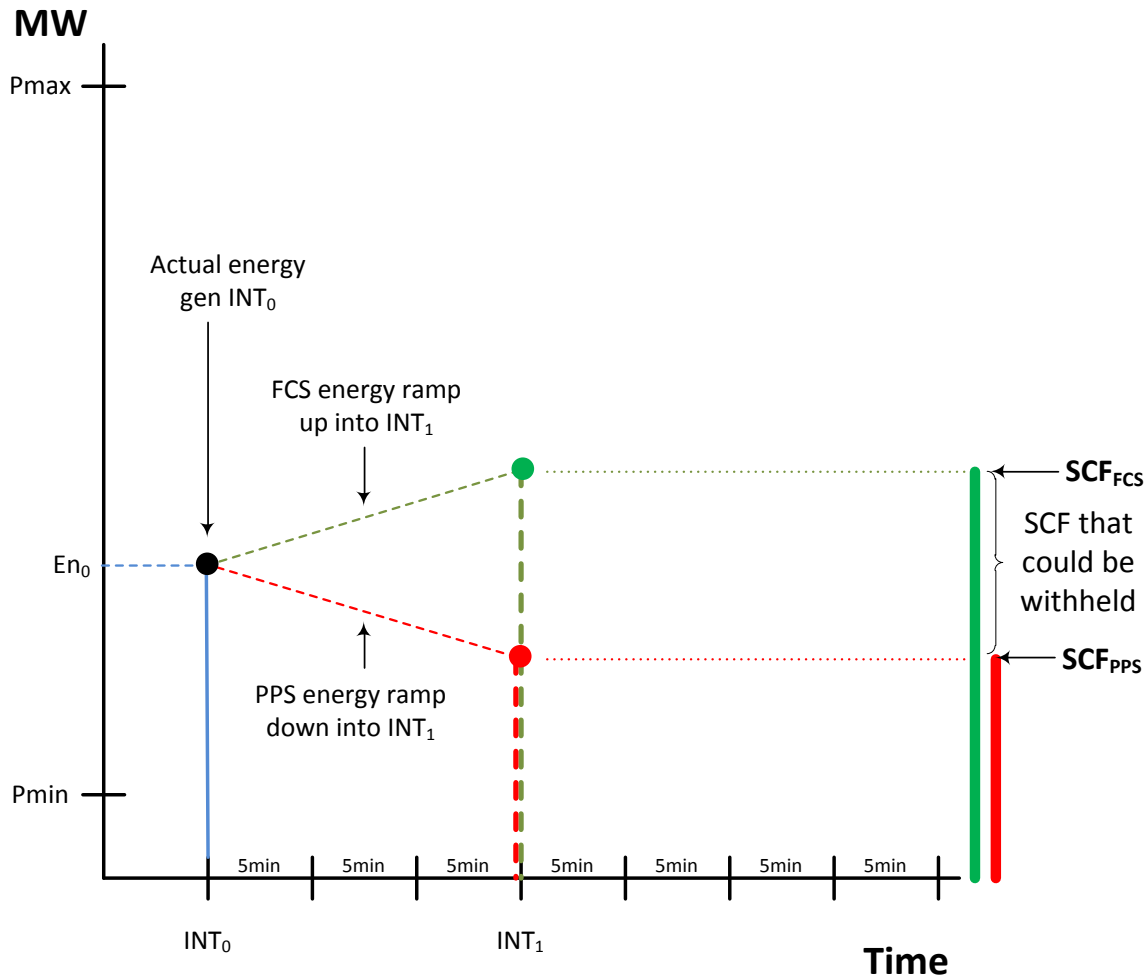
For a potentially pivotal supplier the calculation considers how much SCF the resource could withhold. In the 15 minutes from INT_0 to INT_1 the resource could ramp down to the red dot. The *solid red* line is the minimum SCF the resource must provide and is the SCF used in the RSI calculation if the 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:

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

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

The effective ramp rate may differ when ramping upwards (RR_i^u) versus ramping downwards (RR_i^d).[50] 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:

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

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[50] 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.

9.9.2. 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:

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

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

Figure 8 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[51] 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:

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

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

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

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[51] 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.

the *red* line. 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_o as RR_i^u is in Equation 8.

Equation 9:

$$SCF_k^{pps} = \sum_i -SF_{kc,i} * \begin{bmatrix} max(En_o - RR_i^d * 15,\ EnerMin_i) \\ +min(RR_i^{u2} * 20,\ EnerMax_i) \end{bmatrix}$$

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

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 8 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 8.

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 8
Real-Time Supply of Counterflow to *Corrective-Constraint* from Fringe Competitive
Suppliers and Potentially Pivotal Suppliers
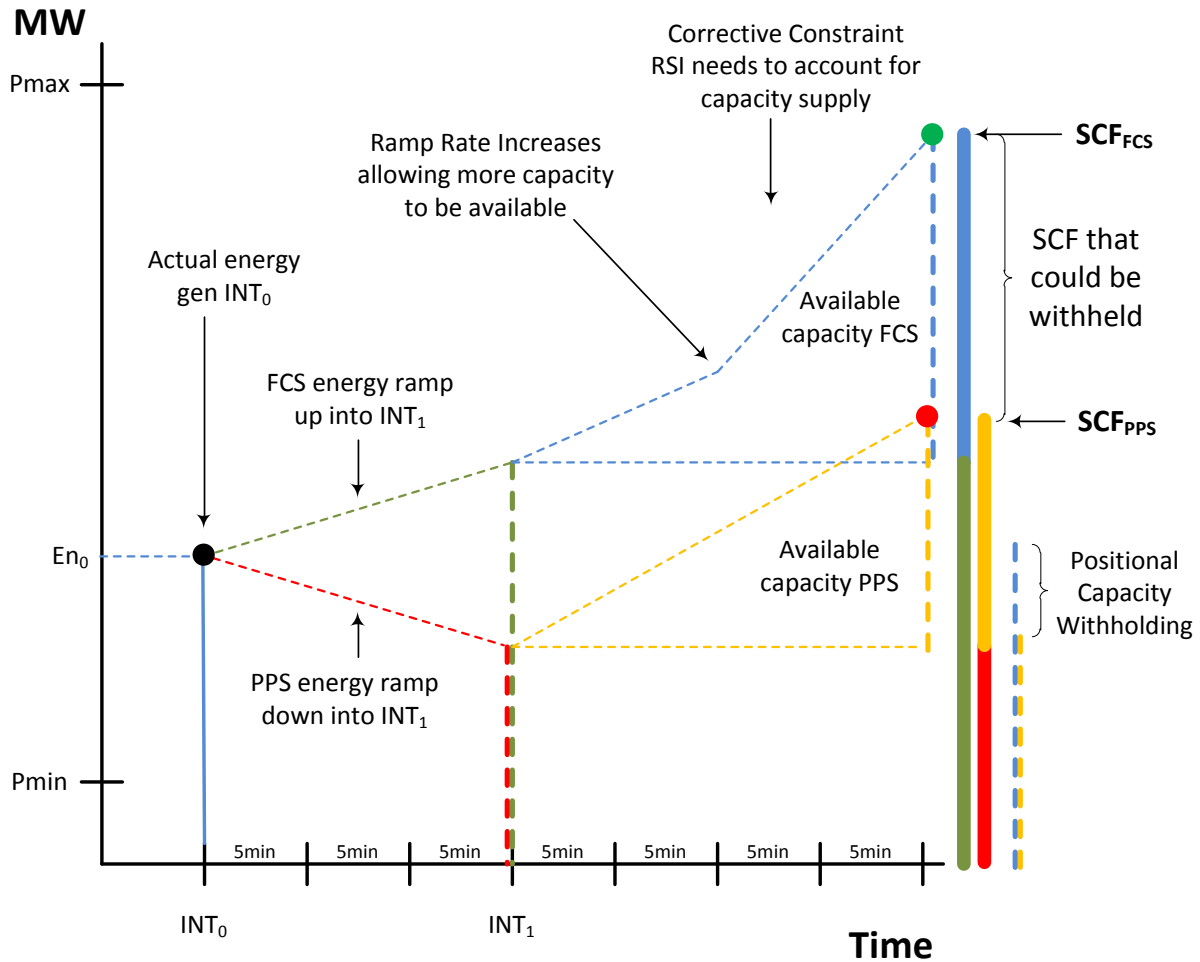
The RSI for Preventive constraints will have to be updated to account for net corrective capacity awards in Real-Time.[52] The maximum available capacity able to provide SCF to the preventive constraint will have to be reduced by the corrective capacity award. This is similar to how it is reduced for spin and non-spin awards, as shown in Equation 10.

Equation 10:

$$EnerMax_i = MaxCap_i - Derate_i - OR_i - RU_i - \mathbf{\textcolor{red}{CC_i}}$$

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[52] The net corrective capacity to account for would be in excess of capacity used for operating reserves.

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:

$$EnerMax_i = MaxCap_i - Derate_i - RU_i$$

9.9.3. 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.

9.9.4. 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.

There are two alternate approaches to consider for calculating the SCF to corrective constraints from potentially pivotal suppliers. In the first approach the SCF could be calculated in the same manner as is currently done for preventive constraints.

However, if a resource is committed (say, it is self-scheduled in the strong case or it is committed in the MPM run in the weaker case) it is then not possible to economically withhold the corrective capacity from that resource. There are no explicit offers for corrective capacity – the offer is implicit in that any energy that is offered into the market with an economic bid can be procured as corrective capacity. From this perspective, it would be over counting the amount of SCF that could be withheld if all the available energy and corrective capacity from the three potentially pivotal suppliers is removed.

An alternative would be to calculate the amount of corrective capacity that can be supplied from minimum load levels (plus the minimum load energy) if the resource is self-scheduled[53] (stronger case) or committed in the MPM run (weaker case).

An interesting implication of this line of reasoning is that the same principle may hold for minimum load (or self-schedule) energy in the preventive constraint RSI calculation. For example, if a resource from a potentially pivotal supplier is self-scheduled to minimum load, the minimum load energy cannot be physically or economically withheld in that market run. Thus, it may be more appropriate to not withdraw minimum load energy from the available SCF from potentially pivotal suppliers when their resource is self-scheduled[54] or committed in the MPM process.

9.10.   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 the WECC SOL standard. 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.[55]

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). We take these matters very seriously and in fact view LMPM for capacity as a boarder market-wide effort which would include operating reserves and the flexible ramping product. While we have not come to the conclusion that there is market power, we do not want to deploy a constraint that would be vulnerable to potential abuse.

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[53] In the case of self-schedules, the amount of corrective capacity that could be supplied from the self-scheduled output level plus the self-scheduled energy should be include in the SCF calculation.
[54] See footnote 4.
[55] 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

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.

9.11. Grid management charge

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

9.12. Data release

There are current process refinements taking place internal to the ISO to determine whether information on the constraints enforced and contingencies can be provided in a more timely manner via the CAISO Market Results Interface (CMRI). The ISO will update market participants on the progress of this discussion and outcome.

10. Stakeholder feedback

The ISO's responses to stakeholders' written comments and questions can be found at the Contingency Modeling Enhancements webpage.[56] While we have responded to most of the stakeholders' questions or requests, we want to stress, however, that some of the concerns about the preventive-corrective constraint are somewhat misplaced. As we have explained in this revised straw proposal, the WECC SOL standard is a reliability standard the ISO must meet regardless of the probability of a contingency event. Moreover, the preventive-corrective constraint leverages the current preventive only framework and seeks to improve its effectiveness, thereby increasing reliability.

11. Next Steps

We would like stakeholders to provide written comments on any of the above issues including questions or suggestions on this second revised straw proposal.

The ISO will discuss this second revised straw proposal with a focus on the prototype results with stakeholders during the call on March 20, 2014. Stakeholders should submit written comments by March 27, 2014 to ContingencyModeling@caiso.com.

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[56]

http://www.caiso.com/informed/Pages/StakeholderProcesses/ContingencyModelingEnhancements.aspx

12.   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

12.   Nomenclature