



California ISO

**Generator Contingency & RAS Modeling  
Draft Final Proposal**

**July 25, 2017**

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## Revision History

Date	Revision
06/30/2017	Initial Release
07/25/2017	Updated Section 4, revising the Energy Imbalance Market Governing Body’s authority to include providing advisory input on those aspects of the proposal relating to the real-time market.

## 1. Executive summary

The ISO operators currently manage constraints impacted by generator contingencies and remedial action scheme operation outside the market through manual intervention or in the market using static nomograms which approximately represent the constraint. Neither approach is optimal because each relies on human judgement and untimely operating condition assumptions. The proposed market design changes to recognize the impact of generator contingencies and remedial action scheme operation in the market will result in the most efficient and reliable generation dispatch by using the latest available information in the security constrained economic dispatch and not relying on manual intervention or operating condition assumptions.

Currently, the security constrained economic dispatch only considers loss of transmission elements in its contingency modeling. However, the transmission system may be constrained due to the loss of generation alone or due to remedial action scheme operation. The transmission system relies on an already large and increasing amount of remedial action scheme armed generation because these schemes are a cost effective and reliable method of increasing the transfer capability of transmission systems. The ISO intends to update the security constrained economic dispatch to:

- (1) model generation loss in the dispatch, and
- (2) model transmission loss along with subsequent generation/load loss due to remedial action scheme (RAS) operation in the dispatch.

The proposed changes result in an update to the congestion component of the locational marginal price so that it considers the cost of positioning the system to account for generator contingencies and remedial action scheme operations. A remedial action scheme connected generator will potentially receive higher energy prices than generators not connected to a remedial action scheme at the same bus because a remedial action scheme connected generator does not contribute to binding emergency limits.<sup>1</sup> While under certain scenarios the generator may receive a higher price for its energy, the constraint allows the dispatch to potentially use less expensive generation reducing overall production cost.

This initiative proposes market design changes that will impact generation dispatch in the market. The proposed changes can be used to model the loss of generation, a reliability issue that can require generation dispatched in certain locations in order to protect transmission elements for the loss of another generator.<sup>2</sup> The same functionality can be used to model generation loss due to remedial action scheme operation, which can increase the dispatch of lower cost generation efficiently through the market.<sup>3</sup>

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<sup>1</sup> This behavior is shown in Section 6.4.1.2.

<sup>2</sup> This behavior is shown in Section 6.4.2.1.

<sup>3</sup> This behavior is shown in Section 6.4.1.1.

## 2. Scope of initiative

This initiative is focused on required enhancements to the day ahead market, real time market, and energy imbalance market to support generator contingencies. The final proposal should result in an economic dispatch that will respect all emergency limits after the loss of a generating unit or after remedial action scheme operation without the need for out-of-market intervention.

This initiative will not focus on the system response and state after the loss of a generating unit and subsequent deployment of contingency reserves.

The initiative's objectives are to:

- (1) Allow for the benefits of increased transmission capability while protecting the transmission system for remedial action scheme events;
- (2) Pre-dispatch generation such that transmission lines will not overload if a generator event or remedial action scheme event were to occur; and
- (3) Price the contribution to congestion for generators on remedial action schemes versus generators not on remedial action schemes.

### 3. Stakeholder Comments and changes to this proposal

In this initiative, the ISO has focused its efforts on ensuring transmission security immediately after generation loss (including due to remedial action scheme operation). This focus allowed the ISO to develop a methodology that realizes the benefits of remedial action schemes in the market, while also addressing issues that carry higher reliability risk. Stakeholders generally supported this approach because it will reduce out of market actions by modeling the cost of certain constraints in the market. DC Energy, Pacific Gas and Electric (PG&E), Powerex, Western Power Trading Forum (WPTF), and the Division of Market Monitoring (DMM) supported the proposed approach.

In its comments on the revised straw proposal, PG&E suggested that the ISO should also make its remedial action scheme modeling approach general enough to include dropping load or reconfiguring the transmission system by switching elements in addition to dropping generation. After reviewing remedial action scheme logic, the ISO agrees with PG&E that the ISO's proposed methodology should also be used to model remedial action schemes that drop load or reconfigure the transmission system. The functionality aligns with the ISO's goals of ensuring transmission security and reducing out-of-market actions.

Stakeholders also support the ISO's proposal to directly model the generator and remedial actions scheme contingencies in the congestion revenue rights market. PG&E suggested that the ISO update its congestion revenue rights market generation distribution factor calculation methodology to be based on the monthly average share of committed capacity. The ISO maintained its proposal to directly model the contingencies in the congestion revenue rights market, eliminated the previously discussed alternatives, and adjusted its generation distribution factor calculation methodology to align with PG&E's suggestion.

The Division of Market Monitoring demonstrated a potential consequence of the congestion revenue rights market granularity difference from the day-ahead market. It explains, however, that this is not caused by the ISO's proposed design of generator contingency and remedial action scheme modeling, but rather caused by the ISO's current congestion revenue rights market design. It shows the potential opportunity for market participants to receive higher payments on congestion revenue rights that would be valued lower in auction when a generator contingency or remedial action scheme is only modeled for a portion of the month in the day-ahead market. The ISO reviewed potential remedial action schemes and only found a few that may not be enabled, and therefore not enforced, for the entirety of a month; the rest will be enabled and enforced all month.

PacifiCorp submitted comments principally targeted at the implementation of the policy discussed in the revised straw proposal. The ISO will work with stakeholders on these items in the implementation stage of the initiative. PacifiCorp also questioned how the initiative would interact with ancillary services. As discussed in the revised straw proposal, the purpose of the initiative is to reserve transmission capacity for the loss of generation; the formulation does not procure generation capacity and therefore is not intended to ensure performance of generation reserves.

The Six Cities asked the ISO to clarify why the proposed revisions in the modeling would be optional for energy imbalance market entities. The ISO applies the same algorithm for dispatch optimization in all balancing authority areas participating in the energy imbalance market. As proposed, energy imbalance market entities could choose which generator or remedial action scheme contingencies, or any at all, they wish to enforce in that optimization. This follows the existing practice of allowing energy imbalance market entity operations engineers to interact with ISO operations engineers in determining constraints to enforce in their areas.

In response to the revised straw proposal, Southern California Edison (SCE) reiterated that it does not support using the proposed methodology to model remedial action schemes in the market. SCE states that it could lead to (1) unjustified revenue for remedial action scheme resources, (2) false incentives for network upgrades, and (3) distortions in the interconnection process. SCE does find merit in the approach for modeling generator contingencies, but seeks more information about the impact on congestion revenue rights and the impact of virtual bidding.

As discussed previously,<sup>4</sup> the ISO maintains that the price formation for the remedial action scheme generator is justified because it appropriately values the generator's contribution to congestion on the system and results in the most efficient dispatch of the resource. The ISO's markets are designed to determine the most efficient scheduling and dispatch of resources. CAISO market prices are a mechanism for incentivizing the resources that currently exist to participate in the market and to perform in the way that maximizes consumer and supplier (total) surplus while maintaining grid reliability. The methodology does not provide false incentives for network upgrades because it is the ISO and the transmission owner that decide the appropriate network upgrades, whether they be remedial action schemes or conventional transmission infrastructure, based on interconnection reliability studies. Finally, the ISO sees no distortions to the interconnection process because it will continue to base its interconnection decisions on the results of reliability studies and fixed infrastructure costs. When studies indicate that the system can no longer support generation participating in remedial action schemes, it will require the development of other transmission upgrades.

The ISO made the following changes to address stakeholder comments:

- (1) In **Section 6.5**, the ISO proposed to use its methodology to also model remedial action schemes that drop load or reconfigure the transmission system.
- (2) In **Section 6.9**, the ISO expanded its discussion on virtual bidding considerations to clarify the real-time settlement of day-ahead positions.
- (3) In **Section 6.11.3**, the ISO proposed to track the generator and remedial action scheme contingency impact on real-time congestion imbalance offset going forward after implementation.
- (4) In **Section 6.12.3**, the ISO proposed to directly model the generator and remedial action scheme contingencies in the congestion revenue rights market.
- (5) In **Section 6.12.3**, the ISO proposed a methodology for calculating congestion revenue rights market generation distribution factors based on historical unit commitments.

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<sup>4</sup> Section 6.5, Generator Contingency & RAS Modeling Revised Straw Proposal



- (6) In **Section 6.12.3**, the ISO analyzed the potential impact that granularity differences between the congestion revenue rights market and the day-ahead market may have on the proposed congestion revenue rights market generation distribution factor.
- (7) In **Section 6.12.3**, the ISO clarified that it will follow existing practices for enforcing generation contingencies in the congestion revenue rights market.

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## 4. Stakeholder engagement

As described in more detail below, this CAISO has revised its proposed plan for seeking approval and input on this initiative from the EIM Governing Body. The policy issues that this initiative addresses are within the scope of and will affect the ISO's Energy Imbalance Market where a participating EIM entity wishes to enforce generator or remedial action scheme contingencies within its EIM entity area.

Accordingly, Management plans to seek approval under the EIM Governing Body's primary authority for the element of this initiative that proposes to allow an EIM Entity the option to enforce generator or remedial action scheme contingencies within its EIM balancing authority area. The approach of dividing the initiative into separate components is consistent with the guidance in section II.B. of the *Guidance for Handling Policy Initiatives within the Decisional Authority or Advisory Role of the EIM Governing Body*. That document addresses how to proceed when an initiative contains a severable component that CAISO management would plan to file for approval whether or not another components or components are approved. In such a case, it states that "...any severable EIM-specific element should be separated after the conclusion of stakeholder review and directed to the EIM Governing Body for decision. The severable EIM-specific element (alone) should be directed to the EIM Governing Body as part of primary authority. The remainder of the initiative should be classified according to the applicable rules.

In the version of the draft final proposal issued on June 30, 2017, the CAISO stated that the EIM Governing Body would not have any role, however, in connection with the remainder of the proposal, because the remainder does not govern participation in the entire real-time market, but only the ISO balancing authority area portion of the real-time market. Upon further consideration, the CAISO has concluded that it would be appropriate for the EIM Governing Body to have the opportunity to provide advisory input on those aspects of the proposal relating to the real-time market, given that the resulting changes to the real-time market needed to accommodate this functionality would ultimately apply to any EIM Entities that may choose to adopt this functionality for their balancing authority area. For this reason, the CAISO has updated the draft final proposal issued on June 30, 2017, with changes only to this Section 4. As revised, Management plans to present to the EIM Governing Body for any potential advisory input those aspects of this proposal relating to the real-time market that are not already within the EIM Governing Body's primary approval authority. This advisory input is in addition to the EIM Governing Body's primary approval authority as described in June 30, 2017 draft final proposal. This is the only change that has been made to the June 20, 2017 draft final proposal.

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

Date	Event
Wed 04/19/2016	Issue paper
Mon 04/25/2016	Stakeholder conference call
Fri 05/13/2016	Stakeholder comments due on issue paper
Mon 11/07/2016	Revised Issue Paper & Straw proposal posted
Tue 11/15/2016	Stakeholder conference call
Fri 12/02/2016	Stakeholder comments due on revised issue paper & straw proposal
Wed 03/15/2017	Revised straw proposal posted
Wed 03/22/2017	Stakeholder conference call
Wed 04/05/2017	Stakeholder comments due on revised straw proposal
Fri 06/30/2017	Draft final proposal posted
Fri 07/07/2017	Stakeholder conference call
Fri 07/14/2017	Stakeholder comments due on draft final proposal
September 2017	Energy Imbalance Market Governing Body
September 2017	Board of Governors

## 5. Background & issues

The ISO must ensure feasible dispatches. To do so, the ISO has two mandates when faced with generation and/or load loss:

- (1) The system must be secure after the loss of a generation/load element alone or in combination with a transmission element due to remedial action scheme operation, and
- (2) The system must be secure after the loss of a generation/load element alone or in combination with a transmission element due to remedial action scheme operation and the subsequent deployment of contingency reserves.

This proposal focuses on system security immediately after the loss of a generation/load element alone or in combination with a transmission element due to remedial action scheme operation.

### 5.1. Discussion

Among its many reliability requirements, the ISO must ensure a secure dispatch that considers the system condition immediately after a generator contingency. This section discusses the appropriate system condition immediately after any single contingency.

Evaluations for transmission security include planning for the potential loss of generation. The market enforces transmission security today, but it does not consider generator contingencies (i.e., loss of generation). Currently, the ISO evaluates and ensures transmission security for loss of generation outside of the market. As discussed below, by not modeling generator contingencies, the market could produce a transmission insecure dispatch considering the impact of the loss of a generating unit. In **Section 5.1.2**, we evaluate what the market does today, the resulting issue, and what a desirable dispatch would achieve.

Remedial action schemes are a cost effective and reliable method of increasing the transfer capability of transmission systems. Remedial action schemes are physical/software systems integrated into the transmission system that detect predetermined system conditions and automatically take corrective actions such as automatically tripping generation if a transmission line is forced out. The ISO currently has more than 19,800 MW of remedial action scheme arm-able generation on its system. Evaluations for transmission security include planning for the loss of transmission along with immediate loss of associated generation such as could occur due to remedial action scheme operation.

Currently, the ISO evaluates and ensures transmission security for remedial action scheme operation outside of the market. As discussed below, by not explicitly modeling remedial action schemes in its security constrained economic dispatch, the market may be pricing in congestion where no congestion really exists and may be inaccurately reflecting the locational cost of supply. In **Section 5.1.5**, we evaluate what the market does today, why that may be leaving room for more production cost savings, and what a desirable dispatch would achieve. In **Section 5.1.6**, we evaluate another example of what the market does today, why that may not

be accurately reflecting the locational cost of supply, and what a desirable dispatch would achieve.

#### 5.1.1. N-1 security including potential loss of generation

All transmission operators, including the ISO, must plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 contingency planning) in accordance with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and local reliability requirements. N-1 contingency planning means that the dispatch must not overload any transmission lines given the loss of any one element (N-1) or combination of elements that are simultaneously removed from service. The ISO accomplishes this by establishing and operating within system operating limits.<sup>5</sup>

Most system operating limits are straightforward and, once derived, can be directly modeled in the market system; the market uses these limits to produce a security constrained economic dispatch. Others are more complex and the ISO relies on operations engineering studies of near term system conditions to ensure that a reasonable mix of available generation and transmission in certain areas are sufficient to ensure N-1 security. For these complex system operating limits, operators additionally watch the real-time conditions and make generation dispatch adjustments out-of-market to ensure N-1 security through real-time.

A secure transmission system must be able to withstand credible transmission contingencies as well as credible generation contingencies.<sup>6</sup>

#### **Transmission security for transmission contingencies**

Transmission loss obviously has an immediate impact on the transmission system.

The ISO market system currently ensures that for the loss of a transmission element, all elements of the remaining system will be below emergency transmission ratings.

With the addition of the market changes resulting from the *Contingency Modeling Enhancements* initiative, the ISO market system will ensure that for the loss of a transmission element, no element of the remaining system will be over its emergency rating and that there is enough ramping capability to return transmission elements below a dynamic post-contingency system operating limit within 30 minutes.

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<sup>5</sup> NERC Reliability Standard TOP-002-2.1b (R6)

<sup>6</sup> Credibility is an industry term that generally means a contingency is likely or plausible (independent of how critical or harmful the contingency may be, which is determined separately). The ISO's determination of credibility is not based solely on regulatory standards, but takes a holistic view of credibility that includes engineering studies and operator experience based on system conditions at the time of a contingency. See generally [NERC Reliability Concepts](#) and [Peak Reliability SOL Methodology for the Operations Horizon](#).

### Transmission security for generator contingencies

Generation loss also has an immediate impact on transmission system flows. While generation loss does not change the network topology of the system, it could dramatically impact flows and even cause operating limit exceedances and violations.

The ISO has not yet added the functionality to model generation loss within its security constrained economic dispatch because until recently, remedial action schemes were not as prevalent in the system. The loss of a generating unit in certain areas could result in flows over transmission elements above emergency ratings as the system responds.

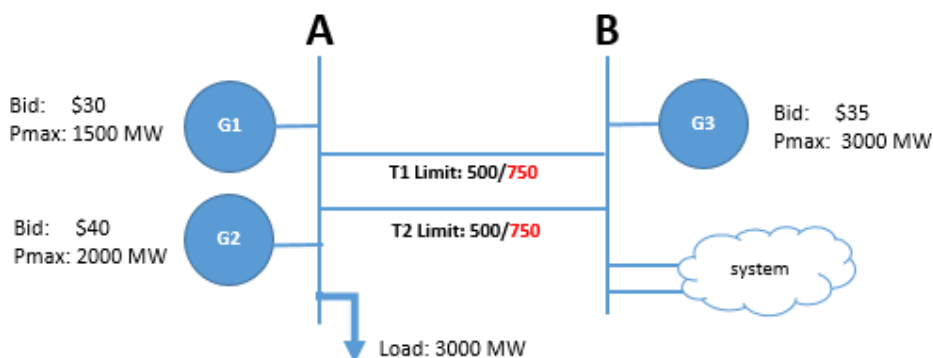
#### 5.1.2. Insecure transmission given the potential loss of generation

The following example illustrates how the market could produce an insecure dispatch if it does not consider the loss of generation.

#### Market dispatch that does not consider generation loss

A market that does not consider generation loss produces a transmission insecure dispatch that requires operator intervention to maintain reliability.

We show a transmission path overload above its emergency rating after the loss of a generator if the system operator does not engage in out-of-market corrections to the dispatch.



Currently, the market will only schedule generation that results in a transfer of 750 MW between A and B because security constraints require the dispatch to account for the loss of T1 or T2. The market enforces a 750 MW emergency limit on transmission line T1 for the loss of transmission line T2.<sup>7</sup> The total normal transfer limit from B to A is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from B to A is 1500 MW (750 MW on T1 plus 750 MW on T2); however, to protect for the loss of T2, a post-contingency emergency transfer limit from B to A of 750 MW is enforced today.

<sup>7</sup> In this particular scenario, enforcing the emergency rating on T1 for the loss of T2 yields the same dispatch as additionally enforcing the emergency rating on T2 for the loss of T1. In these scenarios, the ISO may only model one of the two contingencies because it yields the same dispatch and congestion.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the current market dispatch.

Generator	Energy Bid	Energy Award
G1	\$30	1500
G2	\$40	750
G3	\$35	750

Given the system setup and bidding behavior, the market dispatches the cheapest energy on G1 up to its pmax of 1500 MW followed by the next cheapest energy from G3. The emergency transfer limit 750 MW enforced from B to A for the loss of T2 binds, and the market dispatches G2 for the remaining 750 MW necessary to serve 3,000 MW of load.

750 megawatts flow from B to A which respects the 1000 MW normal transfer limit and the 750 MW emergency transfer limit.

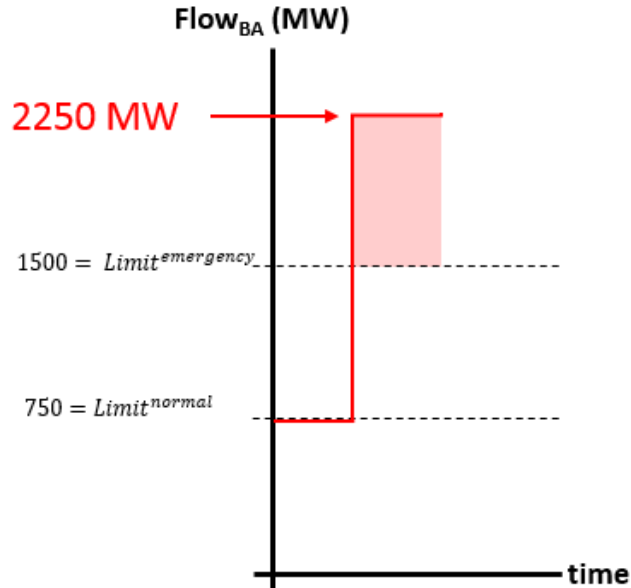
Path Flow		
Contingency	Pre-Contingency Flow <sub>BA</sub> (MW)	Post-Contingency Flow <sub>BA</sub> (MW)
Loss of T2	750	750
Loss of G1	750	<b>2250</b>

While this dispatch is secure for the loss of transmission line T2, it is not secure for the loss of generator G1. Assuming the total generation loss is made up from the rest of the system, if the system were to lose generator G1, an additional ~1500 MW would flow from B to A. This brings the total flow on the path to 2250 MW (750 MW pre-contingency flow plus the additional 1500 MW of generation required to meet load at A). The path from B to A would be well above its emergency rating given the potential loss of generator G1, which is not an N-1 secure dispatch and would therefore require manual intervention.



The image below shows the flow from B to A for the loss of G1 given the current market dispatch.

Figure 1: Flow on path B to A for loss of G1 given current market dispatch



Given the loss of the generator G1 at A, path AB would be loaded above its emergency rating of 1500 MW. A secure dispatch would ensure that path AB does not load above its emergency rating given a single contingency event. The dispatch that achieves this goal is shown below.

**Market dispatch that does consider generation loss**

A market that does consider generation loss produces a transmission secure dispatch that does not require operator intervention to maintain reliability.

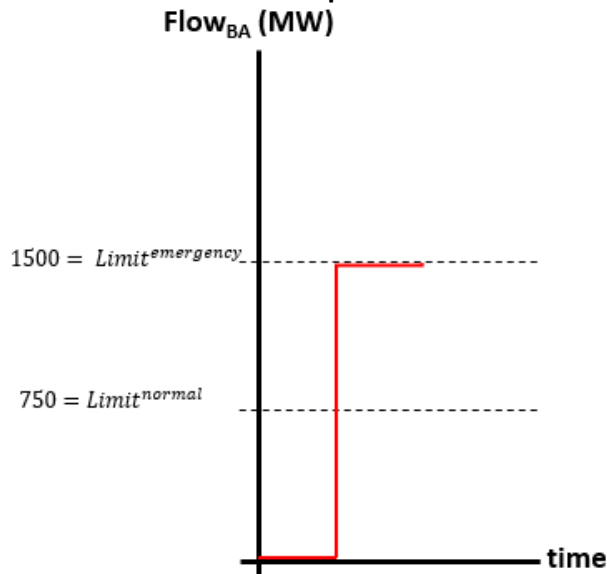
We now add the generator contingency into the set of contingencies.

Generator	Energy Bid	Energy Award
G1	\$30	1500
G2	\$40	1500
G3	\$35	0

The secure dispatch places generator G2 at 1500 MW to ensure that post contingency flows from B to A do not exceed 1500 MW after the loss of generator G1. Assuming the total generation loss is made up from the rest of the system, the 1500 MW emergency rating on path AB does not bind for the generator contingency, but ensures post contingency flows would be less than or equal to 1500 MW. The 750 MW emergency rating on T1 does not bind for the loss of T2. The normal rating on Path AB does not bind.

The acceptable dispatch does not allow the flow from B to A for the loss of G1 to be greater than the emergency rating on the path. The image below shows the flow from B to A for the loss of G1 with an acceptable market dispatch. Note that flows stay below the emergency rating on the path.

**Figure 2: Desirable flow on path B to A for loss of G1**



### 5.1.3. Background on generator interconnection and remedial action scheme installations

The process to include a generator on a remedial action scheme is determined during the generation interconnection process. It is an infrastructure development decision based on system reliability, deliverability, and infrastructure cost. Expected energy prices are not considered.

When a new generator is connected to the grid, the ISO and participating transmission owners conduct power flow and transient stability studies to determine if the new generator will contribute to any reliability violation in operating the bulk electric system. If any potential violation is found, the ISO provides potential mitigation solutions such as building new lines, adding capacitors, installing new remedial action schemes, or curtailing generation in the area. Similarly, the ISO evaluates and determines the transmission upgrades needed for generation deliverability. If an existing remedial action scheme in the area is the most cost effective solution to mitigate a potential overload, the new generator will be required to finance and then use that remedial action scheme. In performing its generator interconnection studies, the ISO only considers the fixed infrastructure costs and not expected energy market prices.

Currently, all new or modified remedial action scheme upgrades are considered Reliability Network Upgrades (RNUs) and the interconnection customer is reimbursed up to \$60,000/MW for all its assigned RNU costs within five years of the commercial operation date. Generators are reimbursed for network upgrades by the participating transmission owner. This means that the interconnection customer does not pay for transmission needed to mitigate the potential congestion. The ISO bases the decision on which transmission solution to require on system reliability, deliverability, and fixed infrastructure cost.

### 5.1.4. Prevalence of remedial action schemes on the system

Transmission systems in the western interconnection rely on an already large and increasing amount of arm-able remedial action scheme generation. Where remedial action schemes are not reflected in the market, price signals for the actual locational cost of supply can be muted.

Remedial action schemes are a cost effective and reliable method of increasing the transfer capability of transmission systems. Remedial action schemes have been historically utilized to increase a transmission system's capability to transmit remotely located hydroelectric generation long distances from load centers. They are now also being utilized to increase the grid's ability to transmit renewable generation that is remotely located long distances from load centers. Unfortunately, it is often the case that the realized benefits of the remedial action schemes are managed outside the market through operator intervention. This is not optimal.

Total generation-drop-related remedial action scheme installations have the capability to arm up to approximately 19,800 MW of generation. Northern California installations have the capability to arm up to 8,600 MW with a maximum single contingency loss of approximately 1,450 MW. Southern California installations have the capability to arm up to 11,200 MW with a maximum single contingency loss of approximately 2,300 MW. While remedial action schemes only arm the maximum capacity under certain system conditions (and it is highly unlikely that most or all

arm-able remedial action scheme capacity is armed at one time), these numbers indicate the prevalence of remedial action schemes on the system. The term “arm-able” here means that the generation to be dropped at a given time is dependent on transmission system flows. Generally, when transmission flows in an area of the system are highest, the maximum amount of generation will be armed in that area. These conditions are the conditions that the ISO proposes to protect for in this initiative. If conditions on the system are not such that generation would be armed, it is unlikely that the generator and remedial action scheme constraints would bind. At some point during the day, one area of the system may have fully armed generation while another area of the system will not have generation armed at all. When conditions are such that no generation would be armed, it is unlikely that the generator and remedial action scheme constraints would bind. As such, the largest potential generation that could be dropped due to a remedial action scheme would present a significant impact on the system and is therefore important regardless of the aggregate level armed in the system at a given time.

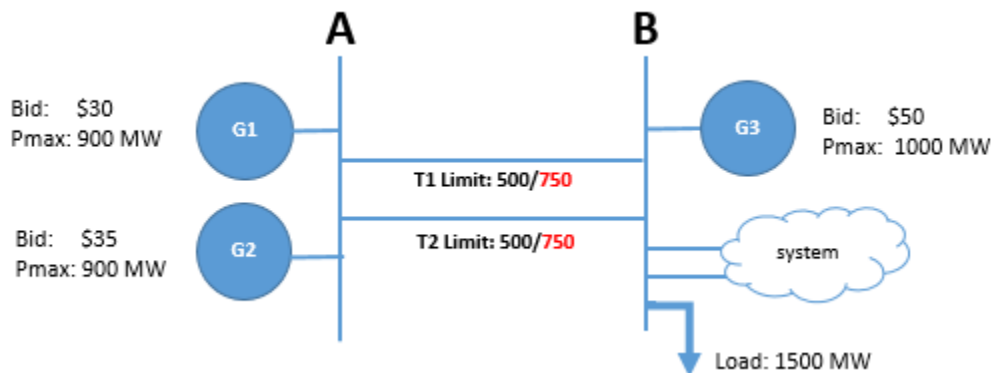
5.1.5. Production cost savings realized when modeling RAS generation loss

Many of the remedial action schemes in the system involve the loss of a transmission element along with the subsequent loss of all or a portion of generation. If not explicitly modeled in the market, the ISO may be producing a higher production cost dispatch due to certain constraints. If the ISO gains the capability to model the loss of generation, it could explicitly model remedial action schemes in the market, which would be optimal.

**Market dispatch that does not consider RAS generation loss**

Let us start with how the market behaves today. The market does not consider RAS generation loss, determines a dispatch yielding a higher production cost, and requires operator intervention to achieve the benefits from the remedial action scheme.

In this example, the market does not produce the lowest production cost dispatch without operator intervention, because it is inaccurately modeling congestion. Assume a remedial action scheme is defined such that for the loss of transmission line T2, generator G1 will trip offline with the loss of generation made up from the system at B.



Currently, the market enforces a 750 MW emergency limit on transmission line T1 for the loss of transmission line T2. The total normal transfer limit from A to B is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from A to B is 1500 MW (750 MW on T1 plus 750 MW on T2); however, given the loss of T2, an emergency transfer limit from A to B of 750 MW is enforced today.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the current market dispatch.

Generator	Energy Bid	Energy Award
G1	\$30	750
G2	\$35	0
G3	\$50	750

Given the system setup and bidding behavior, the market dispatches 750 MW of the cheapest energy on G1. The emergency transfer limit of 750 MW enforced from A to B for the loss of T2 binds, and the market dispatches G3 for the remaining 750 MW necessary to serve 1,500 MW of load.

750 megawatts flow from A to B which respects the 1000 MW normal transfer limit and the 750 MW emergency transfer limit.

Path Flow		
Contingency	Pre-Contingency Flow <sub>BA</sub> (MW)	Post-Contingency Flow <sub>BA</sub> (MW)
Loss of T2	750	750
Loss of T2 & RAS loss of G1	750	0

While this dispatch is secure for the loss of transmission line T2, there is a RAS associated with the loss of T2 that is unaccounted for in the market dispatch. A remedial action scheme is defined such that for the loss of transmission line T2, generator G1 will trip offline.

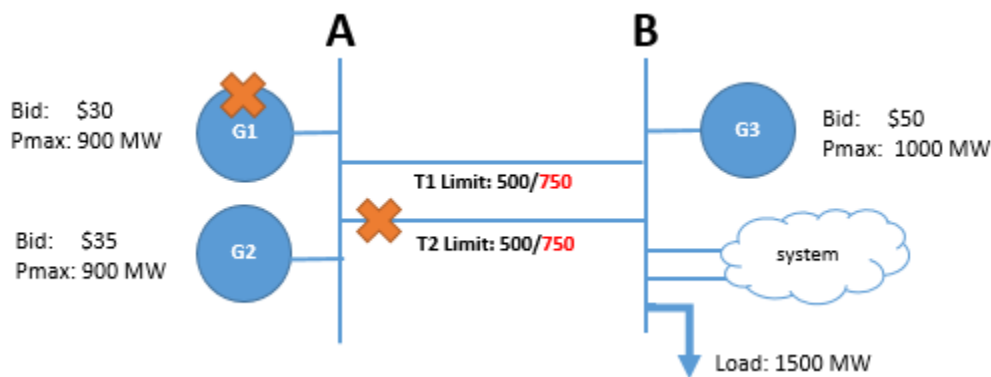
As shown in the Path Flow table above, the loss of transmission line T2 and subsequent remedial action scheme loss of generator G1 would result in transmission line T1 to be loaded under its emergency rating (0 MW). The market could have dispatched the cheaper generator G2 higher in the base case if the RAS was modeled in the market.

This dispatch yields a production cost of \$22,500 + \$37,500 = \$60,000.

**Market dispatch that does consider RAS generation loss**

A market that does consider RAS generation loss determines the optimal dispatch yielding a lower production cost without the need for operator intervention.

Below, a contingency is defined as the loss of T2 along with the loss of generator G1. With this capability, the ISO does not enforce the loss of T2 alone because the contingency does not reflect the actual system operation.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit between A and B is 1500 MW (750 MW on T1 plus 750 MW on T2); however, given the preventive loss of T2+G1, an emergency transfer limit between A and B of 750 MW will be enforced.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the desired market dispatch.

Generator	Energy Bid	Energy Award
G1	\$30	900
G2	\$35	100
G3	\$50	500

The market dispatches the cheapest energy on G1 up to its pmax of 900 MW followed by the next cheapest energy from G2. The normal transfer limit between A and B of 1000 MW binds, and the market dispatches G3 for the remaining 500 MW necessary to serve 1,500 MW of load.

1,000 MW flows between A and B in the base case, and only 100 MW flows between A and B in the remedial action scheme preventive case. Note that the remedial action scheme constraint does not bind at 750 MW because only 100 MW would flow between A and B after the potential loss of T2 and remedial action scheme operation that removes G1 from service.

Path Flow		
Contingency	Pre-Contingency Flow <sub>BA</sub> (MW)	Post-Contingency Flow <sub>BA</sub> (MW)
Loss of T2 & RAS loss of G1	1000	100
<i>Note: Loss of T2 alone no longer enforced because it does not reflect the actual system operation.</i>		

As shown in the Path Flow table above, the loss of transmission line T2 and subsequent remedial action scheme loss of generator G1 would result in transmission line T1 to be loaded under its emergency rating (100 MW). The market dispatched the cheaper generator G2 higher in the base case since the remedial action scheme was correctly modeled in the market.

This dispatch yields a production cost of  $\$27,000 + \$3,500 + \$25,000 = \$55,500$ , which is lower than today's dispatch production cost of \$60,000.

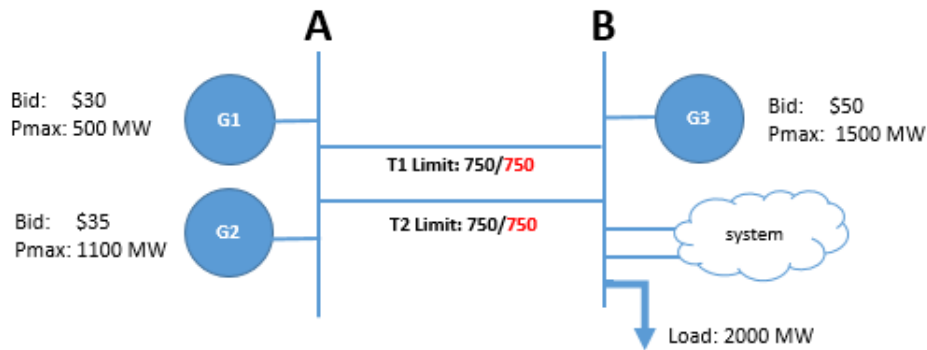
5.1.6. Accurate pricing of generation associated with remedial action schemes

Many of the remedial action schemes in the system involve the loss of a transmission element along with the subsequent loss of all or a portion of generation. If not explicitly modeled in the market, the resulting costs may not be accurately reflected in the locational marginal price. If the ISO market gains the capability to model the loss of generation, it could accurately price generation associated with remedial action schemes in the market.

**Market dispatch that does not consider RAS generation loss**

A market that does not consider remedial action scheme generation loss may suppress energy prices.

For example, here we show the emergency limit binding, but because the remedial action scheme is not modeled in the market, congestion charges for both G1 and G2 are equal.



The total normal transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2). The total emergency transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the loss of T2, an emergency transfer limit between A and B of 750 MW will be enforced. In this example, the transmission system is designed such that there is no additional transfer capability on T1 or T2 above normal limits.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the desired market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	\$30	500	\$35
G2	\$35	250	\$35
G3	\$50	1250	\$50

The market dispatches the cheapest energy on G1 up to its pmax of 500 MW followed by 250 MW of the next cheapest energy from G2. The transmission constraint of 750 MW for the loss of T2 binds, and the market dispatches G3 for the remaining 1250 MW necessary to serve



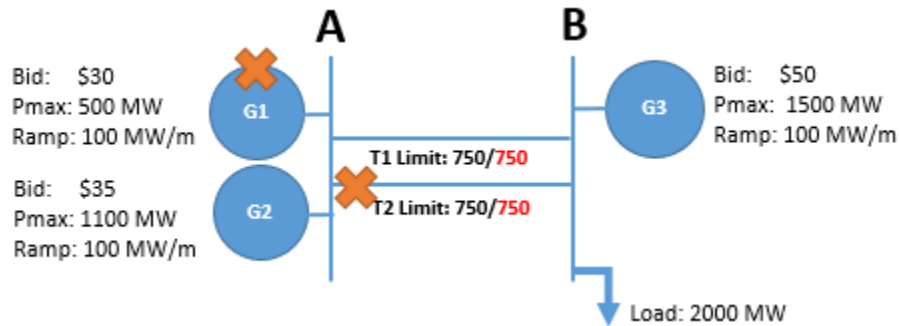
2,000 MW of load. In this example, the preventive constraint for the loss of T2 binds with a shadow cost of \$15.

Both G1 and G2 are charged \$15 of congestion associated with the binding transmission constraint, and both generators receive a \$35 energy price.

**Market dispatch that does consider RAS generation loss**

A market that does consider remedial action scheme generation loss allows for accurate pricing of generation associated with remedial action schemes.

In this example, we show the emergency limit binding, but because the remedial action scheme generator is not contributing to preventive case congestion, it is not charged for that congestion.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2). The total emergency transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the loss of T2+G1, an emergency transfer limit between A and B of 750 MW will be enforced. In this example, the transmission system is designed such that there is no additional transfer capability on T1 or T2 above normal limits.

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the desired market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	\$30	500	\$50
G2	\$35	750	\$35
G3	\$50	750	\$50

The market now dispatches the cheapest energy on G1 to its pmax of 500 MW followed by 750 MW of the next cheapest energy from G2. The remedial action scheme constraint limit from A to B of 750 MW binds, and the market dispatches G3 for the remaining 750 MW necessary to serve 2,000 MW of load.

1,250 MW flow between A and B in the base case, and 750 MW flow between A and B in the RAS preventive case. Note that the remedial action scheme constraint binds at 750 MW because a full 750 MW would flow from A to B after the potential loss of T2 and remedial action scheme operation that removes G1 from service, all of which is being produced by G2.

Only G2 contributes to the remedial action scheme constraint congestion, therefore, only G2 is charged the \$15 in congestion from A to B. G1 is charged the same amount in congestion as any other generator that is not contributing to the congestion (G1 and G3 are charged \$0 in congestion from A to B).

## 5.2. Existing strategies for reliable operations

The following rules are not modeled in the market leading to a less efficient and less reliable dispatch:

- (1) Given a generator loss, all transmission facilities must be below emergency ratings.
- (2) Given a transmission line loss, plus a generation loss due to remedial action scheme operation, all transmission facilities must be below emergency ratings.

The ISO achieves N-1 transmission security for the loss of generation today; however it often achieves this through manual intervention.

ISO operators rely on real-time contingency analysis tools and custom displays to constantly monitor the potential for generator contingencies that may push the system outside of operating limits and take manual action if necessary to keep the system within applicable limits. Assessing and ensuring N-1 security for generation contingencies requires a mix of offline studies, manual review, analysis, and out-of-market intervention.

ISO operations engineers also use remedial action scheme nomograms in limited areas of the system where it is possible to model for the loss of generation due to remedial action scheme operation. This method can only be used in certain areas of the system, requires full network model changes, relies on stale shift factors that may not be reflective of current system conditions, and can only monitor a limited portion of the system as opposed to ensuring all transmission elements do not overload for the operation of the remedial action scheme. In other areas of the system, operators de-activate single transmission contingencies related to the remedial action scheme, adjust path ratings, and manually monitor and adjust flows on the particular path throughout the day.

All strategies the ISO currently uses to achieve N-1 transmission security for the loss of generation suffer from the inefficiencies associated with manual review, analysis, and out-of-market intervention. The market will gain efficiency and pricing accuracy by implementing market design changes that produce an economic dispatch that respects all emergency limits after the loss of a generating unit alone or due to remedial action scheme operation without the need for out-of-market intervention. These market design changes will reduce inefficiencies associated with manual review, analysis, and out-of-market intervention.

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## 6. Proposal

This section describes a preventive constraint used to enable the market to model and price for the immediate impact of remedial action scheme operation on the transmission system. The purpose of this methodology is to ensure that the transmission system is below emergency ratings immediately after the loss of transmission and associated remedial action scheme generation loss; because reliability standards do not allow for any corrective timeframe in which to resolve these potential overloads, this methodology also allows for no corrective timeframe.

The N-1 preventive contingency model also can be expanded to enforce generation contingencies or simultaneous transmission and generation contingencies in preventive mode. The generation contingency is a G-1 contingency event and the simultaneous transmission and generation contingency is an N-1 transmission contingency with a remedial action scheme that trips one or more generating resources. The differences between the two types of contingency models are as follows:

	<b>Preventive (G-1 or N-1+RAS)</b>	<b>Preventive-Corrective (N-1-1)</b>
Contingency element	<ul style="list-style-type: none"> <li>▪ Transmission Line</li> <li>▪ Generation</li> <li>▪ Transmission+Generation</li> </ul>	<ul style="list-style-type: none"> <li>▪ Transmission Line</li> </ul>
Corrective action	Generation loss distribution	Re-dispatch
Corrective time period	Immediate	20-30mins
Post-corrective transmission limits	Emergency limits on all transmission elements	N-1-1 limit (lower than base case limit) on affected transmission corridor; emergency limits on other transmission elements
Contingency reserve dispatch	No	No

The base case is solved simultaneously with all contingencies in preventive mode and all contingencies in corrective mode, co-optimizing all commodities such as energy and ancillary services.

### 6.1. Modeling power flow for loss of generation

Before describing how to model for the loss of generation in the security constrained economic dispatch, it is helpful to first look to how planning and operations engineers study for the loss of generation in power flow studies today.

All analyses related to generator contingencies and remedial action scheme contingencies examine the resulting transmission system flows compared to emergency ratings of transmission facilities. The goal of the analyses is to determine the appropriate amount of transmission capacity to reserve on transmission lines to account for the change in flows caused by the loss of generation.

The ISO regional transmission planning engineers perform long-term studies where they analyze the potential for overloads given generator and remedial action scheme contingencies in stressed system conditions. In these studies the planning engineers model generation loss by removing a generator from service and spreading its generation to other frequency response capable generators on the system in accordance with applicable study criteria. The studies spread the generation to simulate the response of the system and observe the resulting flows on transmission lines. These studies utilize a generation distribution factor based on governor status, maximum generator output, and the units committed on the system.

The ISO operations planning engineers perform short-term studies where they analyze the potential for overloads given generator and remedial action scheme contingencies based on upcoming system conditions, outages, and assumptions of generator commitment status and output. In these studies, the operations engineers account for generation loss by removing a generator from service and spreading its generation to other frequency response enabled generators on the system in accordance with applicable study criteria. The studies spread the generation to simulate the response of the system and observe the resulting flows on transmission lines. These studies utilize a generation distribution factor based on governor status, maximum generator output, assumptions of the units committed on the system, and assumptions of the generator output.

The ISO real-time operations engineers also perform ad-hoc real-time studies where they analyze the potential for overloads given generator and remedial action scheme contingencies based on real-time system conditions, outages, generator commitment status, and generator output. They use the Real-Time Contingency Analysis (RTCA) tool to perform this study. The RTCA spreads the generation to simulate the response of the system and observe the resulting flows on transmission lines. These studies utilize a generation distribution factor based on governor status, maximum generator output, units committed on the system, and generator output.

The RTCA tool alerts operators when it detects an overload condition and operators take out-of-market action. The RTCA is a reactionary mechanism: it detects the real-time condition based on the current dispatch produced by the market, and operators react to potential problems.

All of these studies assume a generation distribution factor to simulate the system response to the loss of generation. This factor is the vehicle to distribute the lost generation across the system so one can determine the amount of power flowing on transmission elements after the loss of generation.

As discussed further below, we intend to utilize this same technique in modeling for the loss of generation in the security constrained economic dispatch. This will ensure that the pre-contingency dispatch pattern produced by the market will not violate operating criteria and ISO operations will no longer need to take reactionary out-of-market actions to meet reliability criteria.

## 6.2. Reserving transmission capacity for potential loss of generation

The generator contingency and remedial action scheme modeling proposal discussed below for the day-ahead and real-time markets reserves *transmission capacity* to account for the change in flows caused by the loss of generation. When generation is lost, the system has an immediate response whereby all frequency response enabled resources on the system automatically increase their output to compensate for the load and supply imbalance. The loss of the generator and the system response to the loss of the generator creates dramatically different flows on the system in the post-contingency state. The purpose of this initiative is to ensure that if the contingency were to happen, the resulting flows would not be greater than the emergency ratings on any transmission elements in the system. The proposal seeks to reserve enough *transmission capacity* in the right places to ensure that no transmission element would be loaded above its emergency rating if the contingency were to occur. This proposal does not reserve generation capacity.

## 6.3. Proposal Formulation

### 6.3.1. Notation

The following notation will be used throughout:

$i$	node index
$m$	transmission constraint index
$k$	preventive contingency index
$g$	generation contingency index
$o_g$	node index for generator outage under generation contingency $g$
$N$	total number of nodes
$M$	total number of transmission constraints
$K$	total number of preventive contingencies
$K_g$	total number of generation contingencies
$S_{FR}^k$	set of supply resources with frequency response capability
$^k$	superscript denoting preventive post-contingency values
$^g$	superscript denoting generation post-contingency values
$\sim$	superscript denoting initial values from a power flow solution
$\forall$	for all...
$\Delta$	denotes incremental values
$u_i$	commitment status of generating resource $i$ (0: offline, 1: online)
$G_i$	generation schedule at node $i$
$G_{i,\min}$	minimum generation schedule at node $i$
$G_{i,\max}$	maximum generation schedule at node $i$
$L_i$	load schedule at node $i$
$C_i$	energy bid from generation at node $i$
$\mathbf{G}$	generation schedule vector
$g(\mathbf{G})$	power balance equation
$h_m(\mathbf{G})$	power flow for transmission constraint $m$
$F_m$	power flow limit for transmission constraint $m$
Loss	power system loss

$LPF_i$	loss penalty factor for power injection at node $i$
$SF_{i,m}$	shift factor of power injection at node $i$ on transmission constraint $m$
$GDF_{o_g,i}$	generation loss distribution factor of generation contingency $g$
$LMP_i$	locational marginal price at node $i$
$\lambda$	system marginal energy cost (shadow price of power balance constraint)
$\mu_m$	shadow price of transmission constraint $m$
$\delta_{o_g,i}$	Binary parameter (0 or 1) that identifies the generator node with generator outage under generation contingency $g$

### 6.3.2. Simplifying assumptions

To simplify the mathematical formulation solely for the purpose of presentation, the following assumptions are made:

- There is a single interval in the time horizon, thus inter-temporal constraints are ignored.
- There is a single Balancing Authority Area, thus Energy Imbalance Market Entities and Energy Transfers are ignored.
- Imports and exports are ignored.
- Unit commitment costs and variables are ignored, thus it is assumed that all generating resources are online and all Multi-State Generators are fixed in a given state.
- Load bids are ignored, thus load is scheduled as a price-taker at the load forecast.
- The energy bids cover the entire generating resource capacity from minimum to maximum.
- There is a single energy bid segment for each generating resource.
- Ancillary services are ignored.

### 6.3.3. Mathematical formulation

The mathematical formulation of the complete preventive contingency optimization problem is as follows:

$$\min \sum_{i=1}^N C_i (G_i - G_{i,\min}) \quad (a)$$

subject to:

$$g(\mathbf{G}) = 0 \quad (b)$$

$$h_m(\mathbf{G}) \leq F_m, \quad m = 1, 2, \dots, M \quad (c)$$

$$h_m^k(\mathbf{G}) \leq F_m^k, \quad \begin{cases} m = 1, 2, \dots, M \\ k = 1, 2, \dots, K \end{cases} \quad (d)$$

$$G_i^g = G_i + GDF_{o_g,i} \cdot G_{o_g}, \quad \begin{cases} i = 1, 2, \dots, N \\ g = 1, 2, \dots, K_g \end{cases} \quad (e)$$

$$h_m^g(\mathbf{G}^g) \leq F_m^g, \quad \begin{cases} m = 1, 2, \dots, M \\ g = 1, 2, \dots, K_g \end{cases} \quad (f)$$

$$G_{i,\min} \leq G_i \leq G_{i,\max}, \quad i = 1, 2, \dots, N \quad (g)$$

Where:



(a) is the objective function comprised of the bid cost for energy.

(b) is the power balance constraint in the base case, which can be linearized around the base case power flow solution as follows:

$$g(\mathbf{G}) \equiv \sum_{i=1}^N (G_i - L_i) - Loss \cong \sum_{i=1}^N \frac{(G_i - \tilde{G}_i)}{LPPF_i} = 0$$

(c) is the set of transmission constraints in the base case, which can be linearized around the base case power flow solution as follows:

$$h_m(\mathbf{G}) \cong \tilde{h}_m(\tilde{\mathbf{G}}) + \sum_{i=1}^N SF_{i,m} (G_i - \tilde{G}_i) \leq F_m, \quad m = 1, 2, \dots, M$$

(d) is the set of transmission constraints in each preventive contingency case, which can be linearized around the base case power flow solution as follows:

$$h_m^k(\mathbf{G}) \cong \tilde{h}_m(\tilde{\mathbf{G}}) + \sum_{i=1}^N SF_{i,m}^k (G_i - \tilde{G}_i) \leq F_m^k, \quad \begin{cases} m = 1, 2, \dots, M \\ k = 1, 2, \dots, K \end{cases}$$

where the shift factors reflect the post-contingency network topology and the transmission power flow limits are the applicable emergency limits.

(e) is the generation loss distribution in the generation contingency state, which is assumed lossless and pro rata on the maximum online generation capacity from supply resources with frequency response capability, ignoring associated capacity and ramp rate limits. This value approximates the system response to loss of generation closely to how the system will actually behave. This value is used only to model flows placed on transmission in the contingency case, and is aligned with current operations engineering study practices:

$$GDF_{o_g,i} = \begin{cases} -1 & i = o_g \\ 0 & i \notin S_{FR} \wedge i \neq o_g \\ \frac{u_i G_{i,\max}}{\sum_{i \in S_{FR}, i \neq o_g} u_i G_{i,\max}} & i \in S_{FR} \wedge i \neq o_g \end{cases}, \quad \begin{cases} i = 1, 2, \dots, N \\ g = 1, 2, \dots, K_g \end{cases}$$

(f) is the set of transmission constraints in each generation contingency case, which can be linearized around the base case power flow solution as follows:

$$h_m^g(\mathbf{G}^g) \cong \tilde{h}_m(\tilde{\mathbf{G}}) + \sum_{i=1}^N SF_{i,m}^g (G_i^g - \tilde{G}_i) = \tilde{h}_m(\tilde{\mathbf{G}}) + \sum_{i=1}^N SF_{i,m}^g (G_i + GDF_{o_g,i} G_{o_g} - \tilde{G}_i) \leq F_m^g, \quad \begin{cases} m = 1, 2, \dots, M \\ g = 1, 2, \dots, K_g \end{cases}$$

where the shift factors reflect the post-contingency network topology, which can be different than the base case if the contingency definition includes a transmission outage, and the transmission power flow limits are the applicable emergency limits.

(g) is the set of the resource capacity constraints in the base case.

**Locational marginal prices**

The locational marginal prices are as follows:

$$LMP_i = \frac{\lambda}{LPF_i} - \sum_{m=1}^M SF_{i,m} \mu_m - \sum_{k=1}^K \sum_{m=1}^M SF_{i,m}^k \mu_m^k - \sum_{g=1}^{K_g} \sum_{m=1}^M \left( SF_{i,m}^g + \delta_{o_g,i} \sum_{i=1}^N SF_{i,m}^g GDF_{o_g,i} \right) \mu_m^g,$$

$$i = 1, 2, \dots, N$$

Where:

$$\delta_{o_g,i} = \begin{cases} 1 & i = o_g \\ 0 & i \neq o_g \end{cases}, \quad \begin{cases} i = 1, 2, \dots, N \\ g = 1, 2, \dots, K_g \end{cases}$$

Therefore, the marginal congestion contribution from a binding transmission constraint in a generator contingency to the locational marginal price at the node of the generator outage includes the impact of the assumed generation loss distribution.

A generator modeled in a generator contingency receives appropriate compensation taking into account its contribution to total production cost. The transmission constraint shadow prices are zero for constraints that are not binding in the base case or the relevant contingency case.

**Generator flow factors**

Similar to how a traditional “shift factor” represents the control variable’s contribution to a particular constraint ( $SF_{i,m}$  and  $SF_{i,m}^k$ ), we can summarize a generator’s contribution to the generator preventive constraint cost for a particular monitored element as a “generator flow factor” (GFF) in order to simplify the locational marginal price calculation in the examples presented in this paper.

The GFF, or contribution to the generator contingency preventive constraint, is:

$$GFF_{i,m}^g = SF_{i,m}^g + \delta_{o_g,i} \sum_{i=1}^N SF_{i,m}^g GDF_{o_g,i}$$

The GFF for the all generators that are not the contingency generator ( $i \neq o_g$ ) simplifies to the network topology shift factor because each generator’s  $\delta_{o_g,i} = 0$ :

$$GFF_{i,m}^g = SF_{i,m}^g + \delta_{o_g,i} \sum_{i=1}^N SF_{i,m}^g GDF_{o_g,i} = SF_{i,m}^g + (0) \sum_{i=1}^N SF_{i,m}^g GDF_{o_g,i}$$

$$GFF_{i,m}^g = SF_{i,m}^g \quad \forall i \neq o_g$$

The GFF for the generator that is the contingency generator ( $i = o_g$ ) simplifies as follows:

$$GFF_{o_g,m}^g = SF_{o_g,m}^g + \delta_{o_g,i} \sum_{i=1}^N SF_{i,m}^g GDF_{o_g,i}$$

$$GFF_{o_g,m}^g = SF_{o_g,m}^g + (1) \sum_{i=1}^N SF_{i,m}^g GDF_{o_g,i} = SF_{o_g,m}^g + SF_{o_g,m}^g \cdot GDF_{o_g,i} + \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g GDF_{o_g,i}$$

$$GFF_{o_g,m}^g = SF_{o_g,m}^g + SF_{o_g,m}^g \cdot (-1) + \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g GDF_{o_g,i}$$

$$GFF_{o_g,m}^g = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g GDF_{o_g,i}$$

This generator flow factor simplifies the locational marginal price calculation in the examples below. All generators not part of the generator contingency definition ( $i \neq o_g$ ) are charged  $GFF_{i,m}^g$  (simplified above to the network topology shift factor  $SF_{i,m}^g$ ) multiplied by the shadow cost of the generator contingency constraint ( $\mu_m^g$ ). The generator on contingency ( $i = o_g$ ) is charged  $GFF_{o_g,m}^g$  multiplied by the shadow cost of the generator contingency constraint ( $\mu_m^g$ ). It represents the total impact on the monitored element from all of the locations on the system to where the optimization distributes the lost generation.

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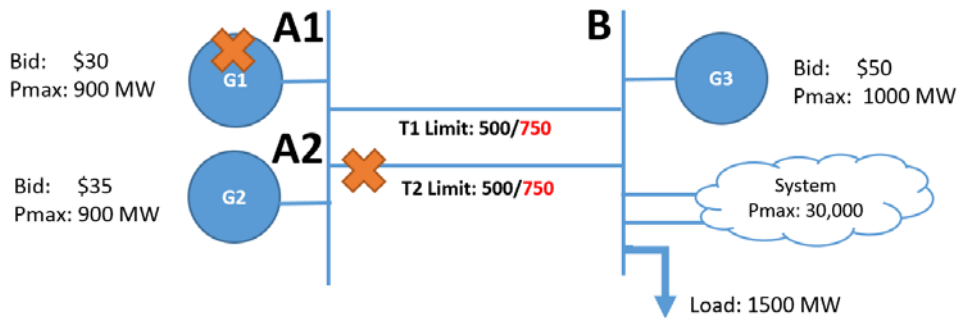
## 6.4. Examples

### 6.4.1. Secure transmission after remedial action scheme operation

The three examples below illustrate how the remedial action scheme preventive constraint solution methodology impacts market dispatch, price formation, and settlement while ensuring the system is within its emergency limits immediately after a transmission loss and associated remedial action scheme generation loss. Each example has slightly different resource definitions and/or bidding behaviors.

#### 6.4.1.1. Example 1 (normal limit binds)

In this example, we show the normal limit binding while the remedial action scheme preventive constraint does not bind, thereby showing that the remedial action scheme generator that still contributes to base case congestion is charged for base case congestion.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit between A and B is 1500 MW (750 MW on T1 plus 750 MW on T2); however, given the simultaneous preventive loss of T2 and G1, an emergency transfer limit between A and B of 750 MW will be enforced.

#### Bids & Awards

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	\$30	900	\$35
G2	\$35	100	\$35
G3	\$50	500	\$50

The market dispatches the cheapest energy on G1 up to its pmax of 900 MW followed by the next cheapest energy from G2. The normal transfer limit between A and B of 1000 MW binds, and the market dispatches G3 for the remaining 500 MW necessary to serve 1,500 MW of load.

**Modeled Flows**

1,000 MW flow from A to B in the base case and the normal constraint binds. Only 125 MW flow from A to B in the remedial action scheme preventive case, which does not bind. Note that the remedial action scheme preventive constraint does not bind because only 125 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

Base case flows from A to B are calculated:

$$\begin{aligned} \text{Flow}_{AB}^0 &= \text{G1 Energy Award} \cdot (\text{SF}_{A1,AB}^0) + \text{G2 Energy Award} \cdot (\text{SF}_{A2,AB}^0) + \text{G3 Energy Award} \cdot (\text{SF}_{B,AB}^0) \\ 1,000 \text{ MW} &= 900 \cdot (1) + 100 \cdot (1) + 500 \cdot (0) \end{aligned}$$

Base case flows of 1,000 MW are less than or equal to the normal transfer capability on the path and the constraint binds at a shadow cost ( $\mu_{AB}^0$ ) of \$15.

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from A to B and consequently its contribution to this constraint's cost is calculated as a Generation Flow Factor ("GFF"):

$$GFF_{A1,AB}^{RAS} = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (1) \cdot \frac{900}{31,900} + (0) \cdot \frac{1,000}{31,900} + (0) \cdot \frac{30,000}{31,900} = 0.028213$$

Remedial action scheme preventive case flows from A to B are calculated:

$$\begin{aligned} \text{Flow}_{AB}^{RAS} &= \text{G1 Energy Award} \cdot (\text{GFF}_{A1,AB}^{RAS}) + \text{G2 Energy Award} \cdot (\text{GFF}_{A2,AB}^{RAS}) + \text{G3 Energy Award} \cdot (\text{GFF}_{B,AB}^{RAS}) \\ 125 \text{ MW} &= 900 \cdot (0.028213) + 100 \cdot (1) + 500 \cdot (0) \end{aligned}$$

Remedial action scheme preventive case flows of 125 MW are less than the emergency transfer capability on the path, given the remedial action scheme operation, and the constraint does not bind. There is a shadow cost ( $\mu_{AB}^g$ ) of \$0.

**Price Formation**

Generator G1 is charged for its contribution to the congestion from A to B ( $SF_{A1,AB}^0$ ). In this example, it is charged congestion on the energy that flows on the binding normal constraint. Because bus A has a network topology shift factor of 1 ( $SF_{A1,AB}^0$ ) to the constraint, all of the energy (G1 Energy Award  $\cdot (SF_{A1,AB}^0) \cong 900$  MW) is charged  $\mu_{AB}^0$  in congestion.

Generator G2 is charged the \$15 in congestion from A to B because its full output has a network topology shift factor of 1 to the normal constraint ( $SF_{A1,AB}^0$ ). Generator G1 is charged approximately the same amount in congestion as any other generator that is contributing to the congestion (G1 and G2 are charged \$15 in congestion from A to B), while G3 which contributes nothing to the normal constraint ( $SF_{B,AB}^0$ ) is not charged.

Note that the contribution factors to the remedial action scheme preventive constraint ( $GFF_{i,AB}^{RAS}$ ) did not impact the energy prices because it had no shadow cost.

Generator (i)	$\lambda^0$	Normal		Loss of G1+T2		LMP
		$SF_{i,AB}^0$	$\mu_{AB}^0$	$GFF_{i,AB}^{RAS}$	$\mu_{AB}^{RAS}$	
G1	\$50	1	\$15	0.028213	\$0	\$35
G2	\$50	1	\$15	1	\$0	\$35
G3	\$50	0	\$15	0	\$0	\$50

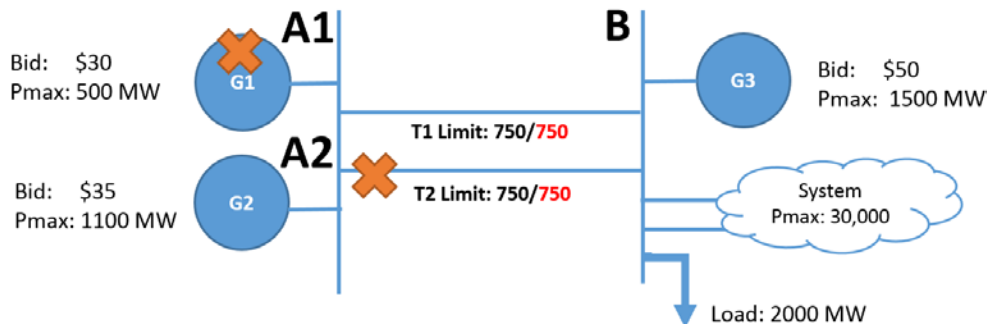
Both G1 and G2 contribute to the normal limit congestion, therefore, both are charged the \$15 in congestion from A to B.

**Settlement**

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	\$35	900	\$31,500	\$31,500
G2	\$35	100	\$3,500	\$3,500
G3	\$50	500	\$25,000	\$25,000
Load B	\$50	-1500	-\$75,000	-\$75,000
Energy & Capacity				-\$15,000
CRR <sub>AB</sub>	\$15	750		\$11,250
Market Net				-\$3,750

6.4.1.2. Example 2 (Emergency limit binds)

In this example, we show the emergency limit binding, but because the remedial action scheme generator is minimally contributing to preventive case congestion, it is only charged a small amount for that congestion.



As shown using orange X's above, a remedial action scheme is defined such that if T2 is lost, G1 will be tripped offline. The total normal transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2). The total emergency transfer limit between A and B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the simultaneous preventive loss of T2 and G1, an emergency transfer limit between A and B of 750 MW will be enforced. In this example, the transmission system is designed such that there is no additional transfer capability on T1 or T2 above normal limits.

**Bids & Awards**

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	\$30	500	\$49.49
G2	\$35	733	\$35
G3	\$50	767	\$50

The market dispatches the cheapest energy on G1 up to its pmax of 500 MW followed by the next cheapest energy from G2. The remedial action scheme preventive constraint transfer limit from A to B of 750 MW binds because of a 733 MW contribution to flow from G2 plus the additional contribution from the portion of the lost generator that was distributed to node A2 of 17 MW (733+17=750). The market dispatches G3 for the remaining 750 MW necessary to serve 2,000 MW of load.



**Modeled Flows**

1,233 MW flow from A to B in the base case, and 750 MW flow from A to B in the remedial action scheme preventive case. Note that the remedial action scheme preventive constraint binds at 750 MW because a full 750 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

Base case flows from A to B are calculated:

$$\begin{aligned} \text{Flow}_{AB}^0 &= \text{G1 Energy Award} \cdot (\text{SF}_{A1,AB}^0) + \text{G2 Energy Award} \cdot (\text{SF}_{A2,AB}^0) + \text{G3 Energy Award} \cdot (\text{SF}_{B,AB}^0) \\ 1,233 \text{ MW} &= 500 \cdot (1) + 733 \cdot (1) + 767 \cdot (0) \end{aligned}$$

Base case flows of 1,233 MW are less than the normal transfer capability on the path and the constraint does not bind.

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from A to B and consequently its contribution to this constraint's cost is calculated as:

$$GFF_{A1,AB}^{RAS} = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (1) \cdot \frac{1,100}{32,600} + (0) \cdot \frac{1,500}{32,600} + (0) \cdot \frac{30,000}{32,600} = 0.033742$$

Remedial action scheme preventive case flows from A to B are calculated:

$$\begin{aligned} \text{Flow}_{AB}^{RAS} &= \text{G1 Energy Award} \cdot (GFF_{A1,AB}^{RAS}) + \text{G2 Energy Award} \cdot (GFF_{A2,AB}^{RAS}) + \text{G3 Energy Award} \cdot (GFF_{B,AB}^{RAS}) \\ 750 \text{ MW} &= 500 \cdot (0.033742) + 733 \cdot (1) + 767 \cdot (0) \end{aligned}$$

Remedial action scheme preventive case flows of 750 MW are less than or equal to the emergency transfer capability on the path, given the remedial action scheme operation, and the constraint binds at a shadow cost ( $\mu^{RAS}_{AB}$ ) of \$15.

**Price Formation**

Generator G1 is charged for its contribution to the congestion from A to B. In this example, it is charged for the portion of its output that was distributed to bus A using the pro-rata distribution (the impact of the distributed generation is represented as the generator flow factor  $GFF^{RAS}_{A1,AB}$ ). Because node A1 has a network topology shift factor of 1 ( $SF^g_{A1,AB}$ ) to the constraint, all of the portion of energy distributed to bus A (G1 Energy Award  $\cdot (GFF^{RAS}_{A1,AB}) \cong 17$  MW) is charged  $\mu^{RAS}_{AB}$  in congestion.

Generator G2 is charged the \$15 in congestion from A to B because its full output has a network topology shift factor of 1 ( $SF^g_{A2,AB}$ ) to the constraint in the remedial action scheme preventive constraint. G1 is charged approximately the same amount in congestion as any other generator that is not contributing to the congestion (G1 and G3 are charged ~\$0 in congestion from A to B), while G2 which contributes its full output to the remedial action scheme preventive case congestion is charged \$15.

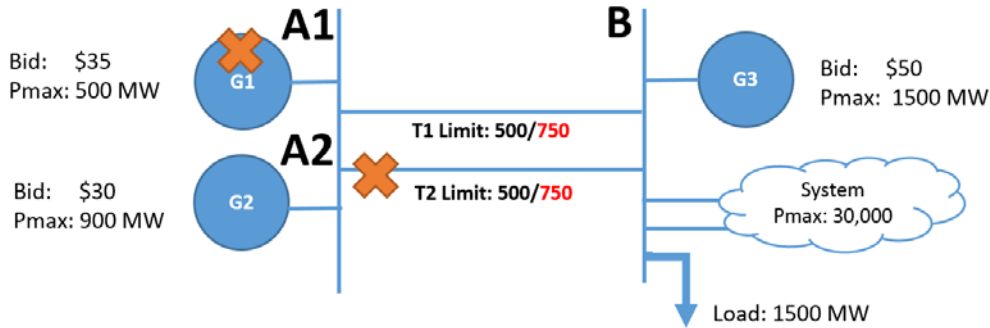
Generator (i)	$\lambda^0$	Normal		Loss of G1+T2		LMP
		$SF^0_{i,AB}$	$\mu^0_{AB}$	$GFF^{RAS}_{i,AB}$	$\mu^{RAS}_{AB}$	
G1	\$50	1	\$0	0.033742	\$15	\$49.49
G2	\$50	1	\$0	1	\$15	\$35
G3	\$50	0	\$0	0	\$15	\$50

**Settlement**

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	\$49.49	500	\$24,745	\$24,745
G2	\$35	733	\$25,655	\$25,655
G3	\$50	767	\$38,350	\$38,350
Load B	\$50	-2000	-\$100,000	-\$100,000
Energy & Capacity				-\$11,250
CRR <sub>AB</sub>	\$15	750		\$11,250
Market Net				\$0

6.4.1.3. Example 3 (Both normal and emergency limits bind)

In this example, we show the normal limit binding and the remedial action scheme preventive constraint binding, thereby showing that the remedial action scheme generator that still contributes to base case congestion is charged for base case congestion. However, because it is minimally contributing to preventive case congestion, it is minimally charged for that congestion.



As shown using orange X's above, a remedial action scheme is defined such that if transmission line T2 is lost, generator G1 will be tripped offline. The total normal transfer limit from A to B is 1,000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from A to B is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the simultaneous preventive loss of T2 and G1, an emergency transfer limit between A and B of 750 MW will be enforced.

**Bids & Awards**

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	\$35	257	\$35
G2	\$30	743	\$30
G3	\$50	500	\$50

The market dispatches 743 MW of the cheapest energy from G2. The RAS preventive constraint transfer limit from A to B of 750 MW binds, and the market dispatches 257 MW of the next cheapest generation from G1. The base case normal transfer limit between A and B of 1000 MW binds, and the market dispatches the remaining 500 MW necessary to serve 1,500 MW of load from G3.

1,000 MW flows from A to B in the base case, and 750 MW flows from A to B in the remedial action scheme preventive case. Note that the remedial action scheme preventive constraint binds at 750 MW because a full 750 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

**Modeled Flows**

1,000 MW flow from A to B in the base case, and 750 MW flow from A to B in the remedial action scheme preventive case. Note that the remedial action scheme preventive constraint binds at 750 MW because a full 750 MW would flow from A to B after the loss of T2 and remedial action scheme operation that removes G1 from service; all of which is modeled as being produced from bus A.

Base case flows from A to B are calculated:

$$\begin{aligned} \text{Flow}_{AB}^0 &= \text{G1 Energy Award} \cdot (\text{SF}_{A1,AB}^0) + \text{G2 Energy Award} \cdot (\text{SF}_{A2,AB}^0) + \text{G3 Energy Award} \cdot (\text{SF}_{B,AB}^0) \\ 1,000 \text{ MW} &= 257 \cdot (1) + 743 \cdot (1) + 500 \cdot (0) \end{aligned}$$

Base case flows of 1,000 MW are less than or equal to the normal transfer capability on the path and the constraint binds at a shadow cost ( $\mu_{AB}^0$ ) of \$15.

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from A to B and consequently its contribution to this constraint's cost is calculated as:

$$GFF_{A1,AB}^{RAS} = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g GDF_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (1) \cdot \frac{900}{32,400} + (0) \cdot \frac{1,500}{32,400} + (0) \cdot \frac{30,000}{32,400} = 0.027778$$

Remedial action scheme preventive case flows from A to B are calculated:

$$\begin{aligned} \text{Flow}_{AB}^{RAS} &= \text{G1 Energy Award} \cdot (GFF_{A1,AB}^{RAS}) + \text{G2 Energy Award} \cdot (GFF_{A2,AB}^{RAS}) + \text{G3 Energy Award} \cdot (GFF_{B,AB}^{RAS}) \\ 750 \text{ MW} &= 257 \cdot (0.027778) + 743 \cdot (1) + 500 \cdot (0) \end{aligned}$$

Remedial action scheme preventive case flows of 750 MW are less than or equal to the emergency transfer capability on the path, given the remedial action scheme operation, and the constraint binds at a shadow cost ( $\mu_{AB}^{RAS}$ ) of \$5.

**Price Formation**

Because both G1 and G2 contribute to the normal limit congestion, they are charged \$15 in congestion from A to B. G2 additionally contributes to the remedial action scheme preventive constraint congestion, and is therefore charged an additional \$5 in congestion from A to B. G1 is charged a total of \$15 in congestion while G2 is charged a total of \$20 in congestion from A to B. G3 does not contribute to congestion from A to B, so it does not receive a congestion charge.

Generator G1 is charged for its contribution to the congestion from A to B mostly due to the normal constraint, but also minimally due to the remedial action scheme preventive constraint. Generator G1’s full output is charged  $\mu^{0}_{AB}$  due to its contribution to the binding normal limit. It is also charged the congestion related to the remedial action scheme preventive constraint ( $\mu^{RAS}_{AB}$ ) for the portion of its output that was distributed to bus A using the pro-rata distribution (the impact of the distributed generation is represented as the generator flow factor  $GFF^{RAS}_{A1,AB}$ ). Because bus A has a network topology shift factor of 1 ( $SF^g_{A1,AB}$ ) to the constraint, all of the portion of energy distributed to bus A (G1 Energy Award  $\cdot (GFF^{RAS}_{A1,AB}) \cong 7$  MW) is charged  $\mu^{RAS}_{AB}$  in congestion.

Generator G2 is charged a total of \$20 for its contribution to the congestion from A to B due to the normal constraint ( $\mu^{0}_{AB}=\$15$ ) and the remedial action scheme preventive constraint ( $\mu^{RAS}_{AB}=\$5$ ). Generator G2’s full output is charged  $\mu^{0}_{AB}$  due to its contribution to the binding normal limit. Generator G2 is also charged  $\mu^{RAS}_{AB}$  in congestion from A to B because its full output has a contribution factor of 1 ( $GFF^g_{A2,AB}$ ) to the constraint in the remedial action scheme preventive constraint.

Generator G1 is charged for its total contribution to congestion, mostly through its contribution to the normal constraint, but also minimally due to the remedial action scheme preventive constraint. Generator G2 is charged for its total contribution to congestion through both the normal constraint and the remedial action scheme preventive constraint.

Generator (i)	$\lambda^0$	Normal		Loss of G1+T2		LMP
		$SF^0_{i,AB}$	$\mu^0_{AB}$	$GFF^{RAS}_{i,AB}$	$\mu^{RAS}_{AB}$	
G1	\$50	1	\$15	0.027778	\$5	\$35
G2	\$50	1	\$15	1	\$5	\$30
G3	\$50	0	\$15	0	\$5	\$50

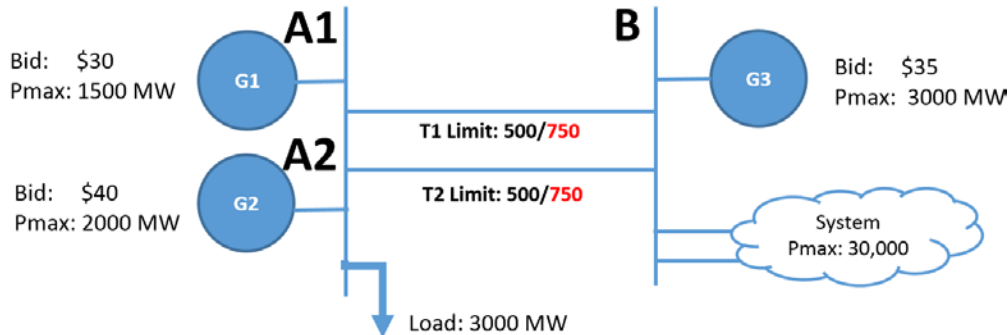
**Settlement**

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	\$35	257	\$8,995	\$8,995
G2	\$30	743	\$22,290	\$22,290
G3	\$50	500	\$25,000	\$25,000
Load B	\$50	-1500	-\$75,000	-\$75,000
<b>Energy &amp; Capacity</b>				-\$18,715
CRR <sub>AB</sub>	\$20	750		\$15,000
<b>Market Net</b>				-\$3,715

6.4.2. Secure transmission after generator loss

6.4.2.1. Example 1 (Emergency limit binds for loss of generation)

In this example, we show the emergency limit binding for the loss of a generator. Here, we examine the interplay between today’s transmission constraints and the proposed generator contingency constraints. This example shows that the loss of generation modeled as proposed may be more limiting than the loss of transmission in an area of the system by enforcing both types of contingencies in the market.



The total normal transfer limit from B to A is 1,000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from B to A is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the preventive loss of T1, an emergency transfer limit from B to A of 750 MW will be enforced. We also enforce a generator contingency preventive constraint to protect the path from B to A for the potential loss of each generator (G1, G2, and G3); this constraint has a total emergency transfer limit of 1,500 MW (750 MW on T1 plus 750 MW on T2).

**Bids & Awards**

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	\$30	1500	\$35.29
G2	\$40	1414	\$40
G3	\$35	86	\$35

The market dispatches the cheapest energy on G1 up to its pmax of 1,500 MW followed by the next cheapest energy from G3. To protect for the loss of G1, the generator contingency preventive constraint transfer limit from B to A of 1,500 MW binds, and the market dispatches G2 for the remaining 1,414 MW necessary to serve 3,000 MW of load.

**Modeled Flows**

**Base case.** 86 MW flow from B to A in the base case. Base case flows from B to A are calculated:

$$\begin{aligned} \text{Flow}_{BA}^0 &= \text{G1 Energy Award} \cdot (\text{SF}_{A1,BA}^0) + \text{G2 Energy Award} \cdot (\text{SF}_{A2,BA}^0) + \text{G3 Energy Award} \cdot (\text{SF}_{B,BA}^0) \\ 86 \text{ MW} &= 1500 \cdot (0) + 1414 \cdot (0) + 86 \cdot (1) \end{aligned}$$

Base case flows of 86 MW are less than the normal transfer capability of 1,000 MW on the path and the normal constraint does not bind.

**Transmission line T1 contingency.** 86 MW flow from B to A in the preventive case protecting for the loss of T1. Flows are calculated:

$$\begin{aligned} \text{Flow}_{BA}^{T1} &= \text{G1 Energy Award} \cdot (\text{SFT}_{A1,BA}^{T1}) + \text{G2 Energy Award} \cdot (\text{SFT}_{A2,BA}^{T1}) + \text{G3 Energy Award} \cdot (\text{SFT}_{B,BA}^{T1}) \\ 86 \text{ MW} &= 1500 \cdot (0) + 1414 \cdot (0) + 86 \cdot (1) \end{aligned}$$

Preventive case flows of 86 MW are less than the emergency rating on the path and the constraint does not bind.

**Generator G1 contingency.** 1,500 MW flow from B to A in the generator contingency preventive case protecting for the loss of G1. Flows are calculated:

$$\begin{aligned} \text{Flow}_{BA}^{G1} &= \text{G1 Energy Award} \cdot (\text{GFF}_{A1,BA}^{G1}) + \text{G2 Energy Award} \cdot (\text{GFF}_{A2,BA}^{G1}) + \text{G3 Energy Award} \cdot (\text{GFF}_{B,BA}^{G1}) \\ 1,500 \text{ MW} &= 1500 \cdot (0.942857) + 1414 \cdot (0) + 86 \cdot (1) \end{aligned}$$

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$\text{GFF}_{A1,BA}^{G1} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \text{GDF}_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{2000}{35,000} + (1) \cdot \frac{3,000}{35,000} + (1) \cdot \frac{30,000}{35,000} = 0.942857$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,500 MW are less than or equal to the emergency rating on the path and the constraint binds at a shadow cost ( $\mu_{BA}^{G1}$ ) of \$5.



**Generator G2 contingency.** 1,439 MW flow from B to A in the generator contingency preventive case protecting for the loss of G2. Flows are calculated:

$$\text{Flow}^{G2}_{BA} = G1 \text{ Energy Award} \cdot (\text{GFF}^{G2}_{A1,BA}) + G2 \text{ Energy Award} \cdot (\text{GFF}^{G2}_{A2,BA}) + G3 \text{ Energy Award} \cdot (\text{GFF}^{G2}_{B,BA})$$

$$1,439 \text{ MW} = 1500 \cdot (0) + 1414 \cdot (0.956522) + 86 \cdot (1)$$

As shown in the formulation section above, the system's response to G2's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G2's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$\text{GFF}^{G2}_{A2,BA} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \text{GDF}_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{1500}{34,500} + (1) \cdot \frac{3,000}{34,500} + (1) \cdot \frac{30,000}{34,500} = 0.956522$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,439 MW are less than the emergency rating on the path and the constraint does not bind.

**Generator G3 contingency.** 77 MW flow from B to A in the generator contingency preventive case protecting for the loss of G3. Flows are calculated:

$$\text{Flow}^{G3}_{BA} = G1 \text{ Energy Award} \cdot (\text{GFF}^{G3}_{A1,BA}) + G2 \text{ Energy Award} \cdot (\text{GFF}^{G3}_{A2,BA}) + G3 \text{ Energy Award} \cdot (\text{GFF}^{G3}_{B,BA})$$

$$77 \text{ MW} = 1500 \cdot (0) + 1414 \cdot (0) + 86 \cdot (0.895522)$$

As shown in the formulation section above, the system's response to G3's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G3's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$\text{GFF}^{G3}_{B,BA} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \text{GDF}_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{1500}{33,500} + (0) \cdot \frac{2,000}{33,500} + (1) \cdot \frac{30,000}{33,500} = 0.895522$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 77 MW are less than the emergency rating on the path and the constraint does not bind.

**Price Formation**

Generator G1 is charged for its contribution to the congestion from B to A. In this example, it is charged for the portion of its output that was distributed to bus B using the pro-rata distribution. Because node B has a network topology shift factor of 1 ( $SF_{B,BA}^{G1}$ ) to the constraint, all of the portion of energy distributed to bus B (G1 Energy Award  $\cdot$  ( $GFF_{A1,BA}^{G1} \cong 1414$  MW) is charged  $\mu_{BA}^{G1}$  in congestion.

Generator G3 is charged for its contribution to the congestion from B to A because it has a contribution factor of 1 ( $GFF_{B,BA}^{G3}$ ) to the path for the transmission preventive constraint that binds at a shadow cost ( $\mu_{BA}^{G3}$ ) of \$5.

For generators G2 and G3, the generator flow factors representing the impact on the path of the portions of their output distributed to the various buses in the system were calculated ( $GFF_{A2,BA}^{G2}$  and  $GFF_{B,BA}^{G3}$ ) but not used because the constraints did not bind.

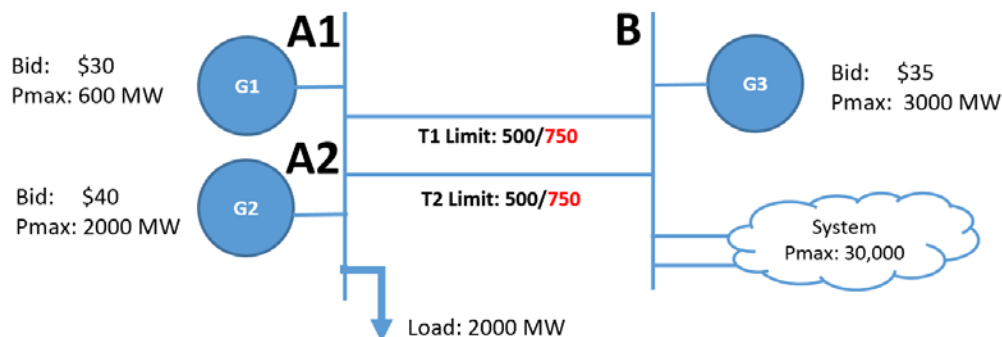
Generator (i)	$\lambda^0$	Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3		LMP
		$SF_{i,BA}^0$	$\mu_{BA}^0$	$SF_{i,BA}^{T1}$	$\mu_{BA}^{T1}$	$GFF_{i,BA}^{G1}$	$\mu_{BA}^{G1}$	$GFF_{i,BA}^{G2}$	$\mu_{BA}^{G2}$	$GFF_{i,BA}^{G3}$	$\mu_{BA}^{G3}$	
G1	\$40	0	\$0	0	\$0	0.942857	\$5	0	\$0	0	\$0	\$35.29
G2	\$40	0	\$0	0	\$0	0	\$5	0.956522	\$0	0	\$0	\$40
G3	\$40	1	\$0	1	\$0	1	\$5	1	\$0	0.895522	\$0	\$35

**Settlement**

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	\$35.29	1500	\$52,935	\$52,935
G2	\$40	1414	\$56,560	\$56,560
G3	\$35	86	\$3,010	\$3,010
Load A	\$40	-3000	-\$120,000	-\$120,000
Energy & Capacity				-\$7,495
CRR <sub>BA</sub>	\$5	750		\$3,750
Market Net				-\$3,745

**6.4.2.2. Example 2 (Emergency limit binds for loss of transmission)**

In this example, we show the emergency limit binding only for the loss of a transmission line even though we enforce a generator contingency for all three generators. Here, we examine the interplay between today’s transmission constraints and the proposed generator contingency constraints. This example shows that the loss of transmission, as modeled today, may be more limiting than the loss of generation in an area of the system by enforcing both types of contingencies in the market.



The total normal transfer limit from B to A is 1,000 MW (500 MW on T1 plus 500 MW on T2). The total emergency transfer limit from B to A is 1,500 MW (750 MW on T1 plus 750 MW on T2); however, given the preventive loss of T1, an emergency transfer limit from B to A of 750 MW will be enforced. We also enforce a generator contingency preventive constraint to protect the path from B to A for the potential loss of each generator (G1, G2, and G3); this constraint has a total emergency transfer limit of 1,500 MW (750 MW on T1 plus 750 MW on T2).

**Bids & Awards**

Generators G1, G2, and G3 submit the following bids and receive the following energy awards given the enhanced market dispatch.

Generator	Energy Bid	Energy Award	LMP
G1	\$30	600	\$40
G2	\$40	650	\$40
G3	\$35	750	\$35

The market dispatches the cheapest energy on G1 up to its pmax of 600 MW followed by the next cheapest energy from G3. To protect for the loss of T1, the preventive constraint transfer limit from B to A of 750 MW binds, and the market dispatches G2 for the remaining 650 MW necessary to serve 2,000 MW of load.

**Modeled Flows**

**Base case.** 750 MW flow from B to A in the base case. Base case flows from B to A are calculated:

$$\text{Flow}_{BA}^0 = \text{G1 Energy Award} \cdot (\text{SF}_{A1,BA}^0) + \text{G2 Energy Award} \cdot (\text{SF}_{A2,BA}^0) + \text{G3 Energy Award} \cdot (\text{SF}_{B,BA}^0)$$

$$750 \text{ MW} = 600 \cdot (0) + 650 \cdot (0) + 750 \cdot (1)$$

Base case flows of 750 MW are less than or equal to the normal transfer capability of 1,000 MW on the path and the normal constraint does not bind.

**Transmission line T1 contingency.** 750 MW flow from B to A in the preventive case protecting for the loss of T1. Flows are calculated:

$$\text{Flow}_{BA}^{T1} = \text{G1 Energy Award} \cdot (\text{SF}_{A1,BA}^{T1}) + \text{G2 Energy Award} \cdot (\text{SF}_{A2,BA}^{T1}) + \text{G3 Energy Award} \cdot (\text{SF}_{B,BA}^{T1})$$

$$750 \text{ MW} = 600 \cdot (0) + 650 \cdot (0) + 750 \cdot (1)$$

Preventive case flows of 750 MW are less than or equal to the emergency rating on the path and the constraint binds at a shadow cost ( $\mu_{AB}^{T1}$ ) of \$5.

**Generator G1 contingency.** 1,316 MW flow from B to A in the generator contingency preventive case protecting for the loss of G1. Flows are calculated:

$$\text{Flow}_{BA}^{G1} = \text{G1 Energy Award} \cdot (\text{GFF}_{A1,BA}^{G1}) + \text{G2 Energy Award} \cdot (\text{GFF}_{A2,BA}^{G1}) + \text{G3 Energy Award} \cdot (\text{GFF}_{B,BA}^{G1})$$

$$1,316 \text{ MW} = 600 \cdot (0.942857) + 650 \cdot (0) + 750 \cdot (1)$$

As discussed in Section 6.3.3, the system's response to G1's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G1's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$\text{GFF}_{A1,BA}^{G1} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \text{GDF}_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{2000}{35,000} + (1) \cdot \frac{3,000}{35,000} + (1) \cdot \frac{30,000}{35,000} = 0.942857$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,316 MW are less than the emergency rating on the path and the constraint does not bind.

**Generator G2 contingency.** 1,388 MW flow from B to A in the generator contingency preventive case protecting for the loss of G2. Flows are calculated:

$$\text{Flow}^{G2}_{BA} = G1 \text{ Energy Award} \cdot (\text{GFF}^{G2}_{A1,BA}) + G2 \text{ Energy Award} \cdot (\text{GFF}^{G2}_{A2,BA}) + G3 \text{ Energy Award} \cdot (\text{GFF}^{G2}_{B,BA})$$

$$1,388 \text{ MW} = 600 \cdot (0) + 650 \cdot (0.98214) + 750 \cdot (1)$$

As discussed in Section 6.3.3, the system's response to G2's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G2's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$\text{GFF}^{G2}_{A2,BA} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \text{GDF}_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{600}{33,600} + (1) \cdot \frac{3,000}{33,600} + (1) \cdot \frac{30,000}{33,600} = 0.98214$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 1,388 MW are less than the emergency rating on the path and the constraint does not bind.

**Generator G3 contingency.** 690 MW flow from B to A in the generator contingency preventive case protecting for the loss of G3. Flows are calculated:

$$\text{Flow}^{G3}_{BA} = G1 \text{ Energy Award} \cdot (\text{GFF}^{G3}_{A1,BA}) + G2 \text{ Energy Award} \cdot (\text{GFF}^{G3}_{A2,BA}) + G3 \text{ Energy Award} \cdot (\text{GFF}^{G3}_{B,BA})$$

$$690 \text{ MW} = 600 \cdot (0) + 650 \cdot (0) + 750 \cdot (0.92025)$$

As discussed in Section 6.3.3, the system's response to G3's lost generation is distributed to each node on the system pro-rata based on each node's cumulative pmax. Generator G3's contribution to flows on the path from B to A and consequently its contribution to this constraint's cost is calculated as:

$$\text{GFF}^{G3}_{B,BA} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \text{GDF}_{o_g,i} = \sum_{\substack{i=1 \\ i \neq o_g}}^N \text{SF}_{i,m}^g \frac{G_{i,max}}{\sum_{i \neq o_g} G_{i,max}} = (0) \cdot \frac{600}{32,600} + (0) \cdot \frac{2,000}{32,600} + (1) \cdot \frac{30,000}{32,600} = 0.92025$$

The other GFF's are equal to the network topology shift factors.

Generator contingency preventive case flows of 690 MW are less than the emergency rating on the path and the constraint does not bind.

**Price Formation**

Generator G3 is charged for its contribution to the congestion from B to A because it has a shift factor of 1 ( $SF^{T1}_{B,BA}$ ) to the path for the transmission preventive constraint that binds at a shadow cost ( $\mu^{T1}_{AB}$ ) of \$5.

For all generators in generator contingencies, while the generator flow factors representing the impact of the portions of their output of which were distributed to the various buses in the system were calculated ( $GFF^{G1}_{i,BA}$ ,  $GFF^{G2}_{i,BA}$ , and  $GFF^{G3}_{i,BA}$ ) the constraints did not bind.

Generator (i)	$\lambda^0$	Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3		LMP
		$SF^0_{i,BA}$	$\mu^0_{BA}$	$SF^{T1}_{i,BA}$	$\mu^{T1}_{BA}$	$GFF^{G1}_{i,BA}$	$\mu^{G1}_{BA}$	$GFF^{G2}_{i,BA}$	$\mu^{G2}_{BA}$	$GFF^{G3}_{i,BA}$	$\mu^{G3}_{BA}$	
G1	\$40	0	\$0	0	\$5	0.942857	\$0	0	\$0	0	\$0	\$40
G2	\$40	0	\$0	0	\$5	0	\$0	0.98214	\$0	0	\$0	\$40
G3	\$40	1	\$0	1	\$5	1	\$0	1	\$0	0.92025	\$0	\$35

**Settlement**

Generator/ Load	LMP	Energy Award	Energy Payment	Total Revenue
G1	\$40	600	\$24,000	\$24,000
G2	\$40	650	\$26,000	\$26,000
G3	\$35	750	\$26,250	\$26,250
Load A	\$40	-2000	-\$80,000	-\$80,000
Energy & Capacity				-\$3,750
CRR <sub>BA</sub>	\$5	750		\$3,750
Market Net				\$0

## 6.5. Methodology not limited to only generation-drop based remedial action schemes

In its comments on the revised straw proposal, PG&E suggested that the ISO should make its remedial action scheme modeling approach general enough to include load drops or reconfiguring the transmission system by switching elements (in addition to generation drops). After reviewing remedial action scheme logic, the ISO is convinced that its methodology should also be used to model remedial action schemes that drop load or reconfigure the transmission system. The functionality is aligned with the ISO's proposed design.

To model for the loss of load due to remedial action scheme operation, the methodology will spread the net energy lost or gained in the contingency using the generation distribution factors. A remedial action scheme that trips 1,000 MW of generation and 500 MW of load will result in the spread of only 500 MW to each node on the system according to its generation distribution factor. A remedial action scheme that trips 1,000 MW of generation and 1,500 MW of load will result in the spread of 500 MW of load to each node on the system according to its generation distribution factor. This functionality aligns with the operational characteristics of remedial action schemes, and the proposed methodology handles the scenarios using the appropriate modeling of the elements lost and the net energy lost or gained.

To model for reconfiguration of the transmission system by switching elements in addition to dropping generation and/or load, the ISO's proposed methodology will use the post-contingency shift factors to show the impact on the system. These reconfigurations can be defined as part of the contingency definition itself. This functionality aligns with the operational characteristics of remedial action schemes and the proposed methodology handles the scenarios using the appropriate modeling of the elements lost or gained on the system to derive the correct shift factors to be used in the optimization.

## 6.6. Price formation and economic signals

The proposed approach provides the appropriate locational marginal price for each generator on the system. On any path in the system, there are two constraints to protect for: (1) normal operating limits and, (2) in the event of a contingency, emergency limits. The approach described above simply models the transmission system as it will electrically behave. In the examples above, all generation will place flows on the path under normal conditions while only the non-remedial action scheme generator will place flows on the line in the contingency condition. A generator that would not contribute to an emergency limit binding on a particular path (because it would not be online after the contingency) does not contribute to the emergency limit congestion. As such, the generator should not be charged for this congestion. While the two generators are at the same physical location, they are in two very different electrical locations based on electric system characteristics.

Stakeholders point to the potential higher locational marginal price for a generator on a remedial action scheme and interpret it as valuing the participation in remedial action schemes higher than normal participation. While the outcome is true, it should rather be thought of as *appropriately valuing each generator's contribution to congestion* on the system. A generator

that would not contribute to congestion should not be charged for that congestion. A generator on a remedial action scheme simply would not contribute congestion toward the emergency limit on the nearby path;<sup>8</sup> and because of this, the security constrained economic dispatch can increase its use of cheaper generation behind the constraint, lowering overall production cost. While two generators at the same physical location may receive two different locational marginal prices, each price represents each generator's actual contribution to congestion, and each price is aligned with each generator's dispatch.

Stakeholders also express concern that this pricing enhancement could lead to an unnecessary incentive for new remedial action schemes. But the locational marginal price is not providing a signal for generators to invest in remedial action scheme additions. As discussed in **Section 5.1.3**, the grid operator and participating transmission owner decide to require a remedial action scheme based on system reliability, deliverability, and fixed infrastructure cost and not expected energy market prices. The proposed changes to the day-ahead and real-time markets merely allow the market to reflect the electrical characteristics of the installed system.

### 6.7. Constraint selection criteria

Similar to how preventive transmission constraints are enforced in the market as needed to reliably manage the system based on engineering analysis and outage studies today, the ISO will enforce preventive generator and remedial action scheme constraints in the market as needed to reliably manage the system based on engineering analysis and outage studies.

### 6.8. Enforce constraints in all markets

The ISO proposes to enforce these contingencies in the integrated forward market for the financial outcome where virtual bids are used just like physical bids, in the residual unit commitment for the operational outcome, and finally in the real-time market.

### 6.9. Virtual bidding considerations

Virtual bids in the integrated forward market will have the same impact on the generator and remedial action scheme preventive constraints as on other constraints and products in the integrated forward market today. Virtual demand and supply at a generator or remedial action scheme contingency node will be treated as an injection or withdrawal where the net injection or withdrawal at the node is reflected in generation vector  $G^g$ . This treatment is consistent with the current treatment of a virtual bid's impact on transmission constraints today.

In its comments on the revised straw proposal, SCE asked for clarity on whether generator contingency constraints would apply to virtual bids. Specifically, if there are only virtual bids, and no physical bids, at the location of the physical generator in the day-ahead market, should

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<sup>8</sup> The remedial action scheme generator does however contribute to certain congestion on the system in the form of small increases to flows on all emergency constraints after the generation loss is distributed across the system. This phenomenon is shown in the proposal through the calculation of the generator flow factors.



the physical generator contingency constraint be enforced even without the physical generator being committed under the proposal?

SCE is concerned that scheduling the system in the day-ahead market for potential loss of virtual supply may be inappropriate. Allowing virtual supply/demand to participate at the generator node is appropriate because the intent of virtual bidding is to better predict real-time conditions. In order to prevent gaming and support convergence between the day-ahead and real-time market, the ISO will treat the virtual supply the same as physical supply. The ISO will enforce the contingency on the generator node regardless of whether it receives physical or virtual bids at the node. Other ISOs that currently model generation loss in their real-time markets are currently seeking enabling the functionality in their day-ahead markets to prevent virtual traders from gaming the generator contingency node due to the modeling difference between the two markets. In the day-ahead market, virtual bids will be charged for the congestion caused by the generator contingency by receiving the appropriate energy price. The virtual bids will then be liquidated in the real-time market.

There would be an issue if the ISO did not consistently enforce the contingency in both the day-ahead and real-time markets. If the contingency was not applied to the generator node in the day-ahead market, a virtual bidder at the location would receive a higher energy price in the day ahead because it would not be charged for transmission congestion caused by the contingency. If the contingency is then applied in the real-time market, the energy price would be lower due to the congestion charge and the virtual supply would buy back at a lower energy price in the real-time market.

As discussed at the May 5, 2017 Market Surveillance Committee meeting, the ISO must ensure that the generator contingency node receives the appropriate real-time settlement of day-ahead positions by enforcing the constraint in both markets regardless of if there is virtual or physical supply at the node.

## 6.10. Energy imbalance market considerations

The policy issues that this initiative addresses are within the scope of and will affect the ISO's energy imbalance market where an EIM Entity wishes to enable the functionality within its balancing area.

The ISO will make the generator and remedial action scheme preventive constraint feature available to EIM Entities. Any EIM Entity can work with the ISO to enforce generator or remedial action scheme contingencies if it would like to model more accurately the production cost of the scheme in the security constrained economic dispatch.

### 6.11. Impact on real-time congestion imbalance offset

In response to the revised issue paper and straw proposal, PG&E expressed concern over potential revenue inadequacy in the real-time market caused by changes in the modeled commitment between the day-ahead and real-time markets.

#### 6.11.1. The proposed model may impact real-time congestion imbalance offset

The ISO recognizes that a difference in generation distribution factors between the day-ahead and real-time market caused by changes in the commitment pattern between the two markets may positively or negatively impact real-time congestion imbalance offset. While the ISO understands that real-time congestion imbalance offset is not necessarily a bad thing and can be considered a cost of providing system reliability, it still feels that the concern at least warrants an analysis of the potential impact this policy may have on real-time congestion imbalance offset.

A similar phenomenon exists today when ISO market operators lower transmission ratings in the real-time market to protect for new threats to reliability. When limits are lower in the real-time market than they were in the day-ahead market, and the constraints are binding, there is no counter-party buy-back of the excess generation schedules; instead, the market incurs real-time congestion imbalance offset.

Similarly, the generator and remedial action scheme constraints reserve a certain amount of transmission capacity in the day-ahead market based on the resources committed in the day-ahead market. When the real-time market solves, the generator and remedial action scheme constraints will reserve either more or less transmission capacity based on the resources committed in the real-time market. In the event that the constraint reserves more transmission capacity in the real-time market, it is equivalent to lowering the transmission limits in the real-time market, and the ISO may incur real-time congestion imbalance offset.

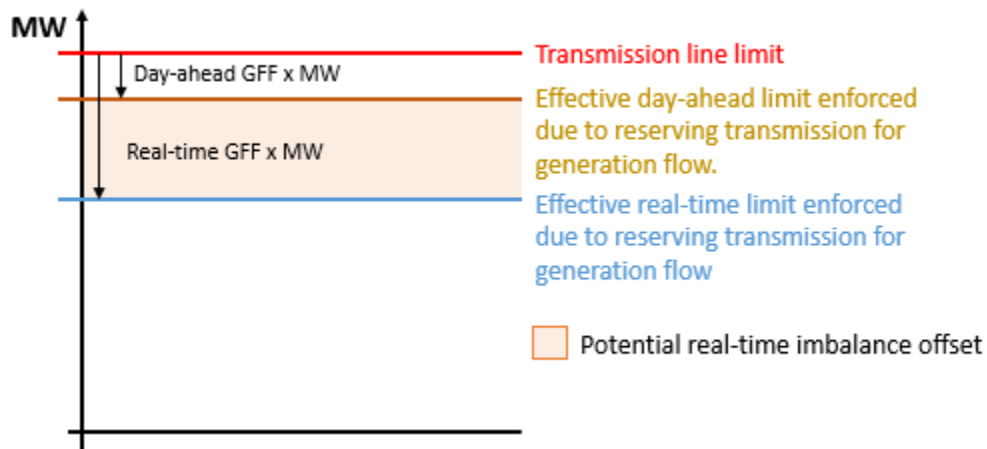


Figure 3: Illustration of different quantities of transmission reserved on a constraint in the day-ahead and real-time markets

### 6.11.2. Analysis on potential impact

The ISO analyzed the potential impact on real-time congestion imbalance using actual market data for the time period from January 2016 through January 2017. The ISO calculated the differences in generation flow factors between the day-ahead market and fifteen-minute market based on actual unit commitments. Using the calculated generation flow factors from the day-ahead market and fifteen-minute market, the ISO calculated how much transmission would need to be reserved in each market on each constraint to account for a large remedial action scheme generation loss. For each constraint, the difference between the fifteen-minute and day-ahead transmission reservation multiplied by the constraint's fifteen-minute market shadow price is the estimated real-time congestion imbalance impact from changing generation flow factors.

Over the 12 month study period, we found that the estimated net real-time congestion imbalance from all constraints caused by differences in day-ahead and fifteen-minute market generation flow factors was a \$148,341 surplus.

Over the 12 month study period, 51% of the observations positively impacted the real-time congestion imbalance offset account (added money to the account), while 49% of observations negatively impacted the real-time congestion imbalance offset account (subtracted money from the account).

In practice not all binding constraints would be in a generator contingency or remedial action scheme case. This means that not all the constraints would be affected by changes in the generation distribution factors as implicitly assumed when netting all the imbalances. The ISO therefore calculated the gross negative real-time congestion imbalance, i.e. summed only the negative imbalances, to provide a bookend to the analysis. The calculated gross negative impact was \$44,609 over the 12 month study period.

Given the results of the analysis, the ISO believes that this is a low-risk issue that does not require any further policy development.

### 6.11.3. Proposal to measure impact going forward

In its comments on the revised straw proposal, PG&E thanked the ISO for its analysis on the potential impact this initiative would have on real-time congestion offset. While the analysis addressed previous concerns, PG&E now asks that the ISO track the real-time congestion offset impact going forward after implementation. The ISO will track the impact going forward after implementation and publish those results for stakeholders.

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## 6.12. Congestion revenue rights considerations

The ISO proposes to directly model the generator contingency constraints in the congestion revenue rights market model the same way it proposes to model the generator contingency constraints in the day-ahead and real-time market.

The proposed changes to the day ahead and real time markets will impact the congestion revenue rights allocation and auction processes. Design changes will allow generators and load to hedge potential incurred congestion charges.

### 6.12.1. The CRR market does not currently model the new constraints

The ISO proposes to address potential revenue inadequacy in the CRR market that would be caused by a simultaneous feasibility test (SFT) in the CRR auction and allocation process that does not model the new generator contingency constraints introduced in this initiative. This potential revenue inadequacy would be introduced solely due to this initiative, and as such should be resolved as part of this initiative.

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

When the generator contingency constraints are added to the security constrained economic dispatch, the market will reserve transmission capacity to account for the potential loss of generation. Similar to the current security constrained economic dispatch, a single dispatch will produce feasible flows considering transmission constraints in the base case as well as in the transmission contingency cases. However, for a given generator contingency, the dispatch that is feasible for the base case and transmission contingencies may no longer be feasible for the generator contingency. The security constrained economic dispatch determines the appropriate amount of transmission capacity to reserve to account for the generator contingency. The SFT for CRRs must take into account the transmission flows resulting from the generator

contingencies. Net congestion rents may change when the ISO reserves transmission capacity to protect for the generator contingencies.

The ISO proposes to adjust the CRR auction and allocation appropriately to recognize the mechanics of the new day-ahead market constraints and maintain revenue adequacy.

### 6.12.2. Demonstration of the issue

While the example is slightly exaggerated, the easiest way to demonstrate the potential for revenue inadequacy if the ISO does not directly model the new generator contingencies in the CRR allocation and auction is to examine the example from **Section 6.4.2.1** above.

**Day-ahead market result.** Recall the results that the day-ahead market produces when modeling the potential loss of T1, G1, G2, and G3. Note that the **contingent loss of G1** causes the path from B to A to bind at its emergency limit of 1,500 MW. When this contingency binds, it results in the market reserving 1,414 MW of transmission capacity from B to A (in other words, the market only schedules 86 MW across a path that has a 1,500 MW emergency limit).

Contingency:		Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3			
Monitored:		BAFlow<1000		BAFlow<750		BAFlow<1500 (binds)		BAFlow<1500		BAFlow<1500			
Generator (i)	$\lambda^0$	$SF_{i,BA}^0$	$\mu_{BA}^0$	$SF_{i,BA}^{T1}$	$\mu_{BA}^{T1}$	$GFF_{i,BA}^{G1}$	$\mu_{BA}^{G1}$	$GFF_{i,BA}^{G2}$	$\mu_{BA}^{G2}$	$GFF_{i,BA}^{G3}$	$\mu_{BA}^{G3}$	LMP	Award
G1	\$40	0	\$0	0	\$0	0.942857	\$5	0	\$0	0	\$0	\$35.29	1500
G2	\$40	0	\$0	0	\$0	0	\$5	0.956522	\$0	0	\$0	\$40	1414
G3	\$40	1	\$0	1	\$0	1	\$5	1	\$0	0.895522	\$0	\$35	86

The market awards a 1,500 MW schedule from G1 to load, a 1,414 MW schedule from G2 to load, and an 86 MW schedule from G3 to load. It reserves 1,414 MW of transmission capacity from B to A for the potential loss of generator G1.

The market collects a net \$7,495 in congestion revenue (1,500 MW x \$4.71 + 1,414 MW x \$0 + 86 MW x \$5.00 = \$7,495).

**CRR market result without generator contingencies modeled.** The results below show the CRR market result if the CRR market is not enhanced to model the generator contingencies. Assuming that market participants ask for as many CRRs as can be injected at all locations and withdrawn at the load, the CRR market does not reserve any transmission capacity for the potential loss of generation. Note that the **contingent loss of T1** causes the path from B to A to bind at its emergency limit of 750 MW. The CRR market does not reserve any extra transmission capacity to account for the potential loss of generation.

Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored Element:		BAFlow<1000	BAFlow<750 (binds)	BAFlow<1500	BAFlow<1500	BAFlow<1500	
Generator (i)	Ask	$SF_{i,BA}^0$	$SF_{i,BA}^{T1}$	$GFF_{i,BA}^{G1}$	$GFF_{i,BA}^{G2}$	$GFF_{i,BA}^{G3}$	Award
G1	1500 G1->L	0	0	Not Enforced	Not Enforced	Not Enforced	1500
G2	1500 G2->L	0	0	Not Enforced	Not Enforced	Not Enforced	750
G3	3000 G3->L	1	1	Not Enforced	Not Enforced	Not Enforced	750

The CRR market awards a 1,500 MW CRR from G1 to load, a 750 MW CRR from G2 to load, and a 750 MW CRR from G3 to load. It reserves 750 MW of transmission capacity from B to A for the potential loss of transmission line T1 as currently modeled as an N-1 contingency.

If these CRRs were to be settled at the difference in the marginal congestion component in the day-ahead market, they would collect \$10,815 (1,500 MW x \$4.71 + 750 MW x \$0 + 750 MW x \$5.00 = \$10,815).

Recall from above that the day-ahead market only collects a net \$7,495 in congestion revenues. The CRR settlement will leave the CRR balancing account short by **\$3,320** (\$7,495 in day-ahead market collections minus \$10,815 in disbursements equals a \$3,320 shortfall).

It is clear from the example that the CRR market must model the generator contingencies in order to remain revenue adequate.

### 6.12.3. Proposed enhancements to the CRR market

The ISO proposes to add the generator and remedial action scheme constraints into the CRR market in the same way it proposes to add the constraints to the day-ahead market. The CRR market will thus limit CRR flows on transmission lines to respect expected post-contingency power flows given the potential loss of generation on the system. There are no proposed changes to the objective function.

#### 6.12.3.1. Generator and remedial action scheme transmission constraints

During the simultaneous feasibility test, transmission constraints will be enforced. The ISO will attempt to make these transmission constraints, to the extent possible, consistent with the transmission constraints that are enforced in the day-ahead market. For generator and

remedial action scheme type contingencies, the transmission constraints that are used in the simultaneous feasibility test are the emergency ratings of transmission lines and transformers.

<p>Flow Constraints for each constraint, <math>g</math></p>	$\sum_{i=1}^N X_i \cdot GFF_{i,g} \leq \text{hourly}TTC_g$	<p><math>GFF_{i,g}</math> is the generator flow factor (calculated as the aggregate impact on the constraint from the locations where the injection is distributed) for the <math>i^{th}</math> control variable on the <math>g^{th}</math> generator/RAS constraint. Hourly <math>TTC_g</math> is the limit for the <math>g^{th}</math> constraint. <math>X_i</math> is the MW quantity of CRRs awarded.</p>
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Similar to the generator flow factor calculation used in the day-ahead and real-time market, the CRR market will use a calculated generator flow factor based on the CRR full network model and derived generation distribution factors. Recall that  $o_g$  is the contingency generator (or in this case the contingency generator node):

$$GFF_{i,g} = SF_{i,g} \quad \forall i \neq o_g$$

$$GFF_{i,g} = \sum_{\substack{i=1 \\ i \neq o_g}}^N SF_{i,g} GDF_{o_g,i} \quad i = o_g$$

We define the generator distribution factor (GDF) in the next section.

**6.12.3.2. Generation distribution factor calculation methodology**

In its comments, PG&E suggested that the ISO seek a generation distribution factor calculation methodology to use in its congestion revenue rights market that would be an accurate representation of the factors that the resource would experience from hour to hour in the day-ahead market. The ISO agrees that it should base its generation distribution factor calculation methodology on committed capacity rather than production, and utilize a historical monthly and seasonal average.

The ISO thus proposes to use the following methodology to calculate generation distribution factors per generator or remedial action scheme contingency, per resource, per month, per time-of-use period.



$$GDF_{o_g,i} = \begin{cases} -1 & i = o_g \\ 0 & i \notin S_{FR} \wedge i \neq o_g \\ \left(\frac{1}{N}\right) \cdot \sum_{t \in H} \left( \frac{u_{i,t} \cdot G_{i,max,t}}{\sum_{i \in S_{FR}, i \neq o_g} (u_{i,t} \cdot G_{i,max,t})} \right) & i \in S_{FR} \wedge i \neq o_g \end{cases}$$

Where,

*H* is the set of hours in the season (or month) in the time period of interest (e.g. peak or off-peak),

*N* is the number of hours in *H*

*t* is the hour within *H*

*u<sub>i,t</sub>* is the unit commitment status in hour *t*

The ISO will use the previous year's seasonal average generation distribution factor in its annual allocation/auction process and the previous year's monthly average generation distribution factor in its monthly allocation/auction process.

#### 6.12.3.2.1. Accuracy of the methodology

The ISO runs the congestion revenue rights market for two time periods: peak and off-peak. For each of these periods, the ISO only uses one transmission system model and similarly proposes to use a representative generation distribution factor for each time-of-use period, for each resource, for each generator and remedial action scheme contingency. The difference between the two congestion revenue rights market models and the varying hour-to-hour day-ahead market model commonly leads to revenue imbalance. The ISO sought to discover how accurate its congestion revenue rights market generation distribution factors would have been when compared to actual day-ahead market generation distribution factors for the time period from January 2016 through January 2017.

Over the 12 month study period, the ISO found that the 94.7% of day-ahead market hours had resource generation distribution factors within 0.005 of the generation distribution factor that would have been modeled in the congestion revenue rights market. 97.3% of day-ahead market observations were within 0.01 of the generation distribution factor that would have been modeled in the congestion revenue rights market. Finally, 99% of day-ahead market observations were within 0.02 of the generation distribution factor that would have been modeled in the congestion revenue rights market.

Given the results of the analysis, the ISO is comfortable with the accuracy of the proposed generation distribution factor methodology.

#### 6.12.3.2.2. Impact on revenue imbalance

The ISO analyzed the potential impact on congestion revenue rights revenue inadequacy using actual market data for the time period from January 2016 through January 2017. The ISO

applied the methodology described above to calculate generation distribution factors that would have been used in the congestion revenue rights market for peak and off-peak periods. The ISO calculated the differences in generation flow factors between the congestion revenue rights market and the day-ahead market based on actual unit commitments. Using the calculated generation flow factors from each market, the ISO calculated how much transmission would have been reserved in each market on each constraint to account for a large remedial action scheme generation loss. For each constraint, the difference between the congestion revenue rights market and day-ahead market transmission reservation multiplied by the constraint's day-ahead market shadow price is the estimated congestion revenue rights imbalance impact from generation distribution factors that vary between the two markets.

Over the 12 months modeled, the ISO estimates that the potential net imbalance from all constraints caused by differences in congestion revenue rights market and day-ahead market generation flow factors was a \$199,352 deficit.

Over the 12 months modeled, 39% of the observations positively impacted imbalance account (added money to the account), 45% of observations negatively impacted the imbalance account (subtracted money from the account), and 16% of the observations had no impact on the imbalance account.

Given the results of the analysis, the ISO views the potential for revenue imbalance due to the introduction of generation distribution factors as negligible, and is therefore comfortable using the generation distribution factor methodology proposed above.

#### **6.12.3.3. Contingency enforcement**

The ISO will enforce generator and remedial action scheme contingencies that are expected to be enforced in the day-ahead market in the appropriate month, and time of use. The decision of which contingencies to protect for will be made through the existing outage planning process that occurs during the CRR market set-up today.

In the annual CRR process, the ISO will enforce generator and remedial action scheme contingencies that are expected to be enforced in the day-ahead market in the appropriate season and time of use as of the time that the annual CRR FNM is released.

The Division of Market Monitoring demonstrated a potential consequence of the congestion revenue rights market granularity difference from the day-ahead market. It shows the potential opportunity for market participants to receive higher payments on congestion revenue rights that would be valued lower in auction when a generator contingency or remedial action scheme is only modeled for a portion of the month in the day-ahead market. The ISO reviewed potential remedial action schemes and only found a few that may not be enabled, and therefore not enforced, for the entirety of a month; the rest will be enabled and enforced all month. In the past three years, remedial action schemes were not physically enabled/disabled coincident with the start of a month on only two occasions. The majority of the remedial action schemes the ISO intends to model are enabled all year. As is current practice today, the ISO operations engineering team plans to work with participating transmission owners to coordinate the cut-

in/cut-out of the few remedial action schemes that may not be enabled coincident with the start of a month.

As it relates to enforcement of generator contingencies in the congestion revenue rights market, the ISO will make decisions on which contingencies to enforce through the existing outage planning process that occurs during the congestion revenue rights market set-up today. If the engineering team finds a scenario requiring the enforcement of generator contingencies in a given month, it will communicate this with the congestion revenue rights team as it does today. The congestion revenue rights team will follow its existing rules for deciding whether it is necessary to model the contingency in the congestion revenue rights market.

**6.12.3.4. Settlement**

The CRRs will clear the same way they do today in both the allocation and auction; the only difference being the amount cleared will respect the generator contingency flow constraint discussed in this section. The CRRs will settle against day-ahead market congestion the same way they do today.

Below we use the same example from above to demonstrate how the CRR market will award CRRs once it models for the potential loss of generation.

**CRR market result with generator contingencies modeled.** The results below show the CRR market result if the CRR market is enhanced to model the generator contingencies. Assuming that market participants ask for as many CRRs as can be injected at all locations and withdrawn at the load, the CRR market now reserves capacity for the potential loss of generation. Note that the **contingent loss of G1** causes the path from B to A to bind at its emergency limit of 1,500 MW. The CRR market reserves 1,414 MW of transmission capacity on the path from B to A, which accounts for the potential loss of G1.

Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored:		BAFlow<1000	BAFlow<750	BAFlow<1500 (binds)	BAFlow<1500	BAFlow<1500	
Generator (i)	Ask	$SF_{i,BA}^0$	$SF_{i,BA}^{T1}$	$GFF_{i,BA}^{G1}$	$GFF_{i,BA}^{G2}$	$GFF_{i,BA}^{G3}$	Award
G1	1500 G1->L	0	0	0.942857	0	0	1500
G2	1500 G2->L	0	0	0	0.956522	0	1414
G3	3000 G3->L	1	1	1	1	0.895522	86

The CRR market awards a 1,500 MW CRR from G1 to load, a 1,414 MW CRR from G2 to load, and an 86 MW CRR from G3 to load. It reserves 1,414 MW of transmission capacity from B to A for the potential loss of generator G1.

If these CRRs were to be settled at the difference in the marginal congestion component in the day-ahead market, they would collect \$7,495 (1,500 MW x \$4.71 + 1,414 MW x \$0 + 86 MW x \$5.00 = \$7,495).

Recall from above that the day-ahead market collects a net \$7,495 in congestion revenues. The CRR settlement will leave the CRR balancing account neutral (\$7,495 in day-ahead market collections minus \$7,495 in disbursements equals a \$0 account balance).

## 7. Next steps

The ISO will discuss the issue paper with stakeholders during a teleconference to be held on July 7, 2017. Stakeholders should submit written comments by July 14, 2017 to [InitiativeComments@caiso.com](mailto:InitiativeComments@caiso.com).