Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: December 6, 2017

Re: **Decision on contingency modeling enhancements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes to enhance the ISO market model to ensure that there is sufficient generation capacity available for dispatch to return electrical flows on transmission facilities to below normal ratings within required timeframes after the unexpected loss of a transmission line. This unexpected loss is referred to as a "transmission contingency."

The ISO market dispatches generation to ensure electrical flows will not exceed emergency transmission system limits immediately after a transmission contingency. However, it currently has the limitation that it does not explicitly model the subsequent need to return electrical flows back to within normal operating limits within required timeframes. Today, this is accomplished through relatively inefficient and inexact constraints – termed "minimum online commitment constraints" – that commit generation in specific areas to meet transmission constraint requirements. These minimum online constraints also have the disadvantage that they do not compensate the generation for the capacity made available by the generator commitments. In addition to minimum online commitments, ISO grid operators use exceptional dispatch to position resources to ensure electrical flows can be returned to within normal transmission limits within the required timeframes in the event of a contingency.

Management proposes to enhance the ISO market to explicitly model resource capacity needed to return flows to normal operating limits in the event of a transmission contingency. This "corrective capacity" would be modeled in both the day-ahead and real-time markets and would receive a locational marginal corrective capacity price. This enhanced modeling will improve the market dispatch, decrease operator reliance on inefficient minimum online commitment constraints, decrease operator out-of-market actions, and appropriately compensate resource capacity the ISO relies on in the event of a transmission contingency.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the proposal to implement the contingency modeling enhancements described in this memorandum dated December 6, 2017; and***
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> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the contingency modeling enhancements described in this memorandum, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Federal Energy Regulatory Commission guidance in any initial ruling on the proposed tariff amendment.***

BACKGROUND

Grid operators must plan operations to ensure reliability, including when faced with contingencies such as changes in system configuration, generation, and load. These reliability requirements are based on North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards. These various standards include the fundamental requirement that generators must be operated at output levels that do not result in electrical flows that exceed transmission limits, even when generation or transmission is unexpectedly lost. Additionally, generators also must be operated at output levels to ensure that if transmission is lost, electrical flows on the remaining transmission can be brought back to normal operating limits within the timeframe allowed under transmission's emergency limit.

Currently, the ISO's market dispatch does not ensure that electrical flows can be returned to within normal transmission limits after a contingency. Instead, grid operators must take out-of-market actions to ensure that the ISO has sufficient capacity to return electrical flows on transmission to within normal limits within the required timeframe specified by NERC and/or WECC (generally 30 minutes). Grid operators do this primarily by relying on relatively inefficient minimum online commitment constraints in the day-ahead market and manual exceptional dispatch.

The minimum online commitment constraints currently used are relatively inefficient at ensuring flows can be brought back to within normal limits within the required timeframes as they merely commit a minimum amount of generation within a defined area. They are set up based on an engineering analysis using assumptions about generation dispatch, system topology, and load levels, but they do not result in the market optimally positioning resources to ensure they can address contingencies. Minimum online commitment constraints pre-define a set of resources that may be effective at addressing certain potential contingencies. ISO grid operators use this static definition for all potential contingencies even though different resources are not equally effective at addressing different contingencies. Most importantly, because commitments are based on conservative offline studies, the resulting commitment is likely not the most efficient use of market resources in maintaining reliability.

Minimum online constraints also may commit a resource out-of-merit and schedule it at its minimum operating level, thereby precluding the resource from setting the locational marginal price and contributing to price formation.[1] In addition, minimum online commitment constraints do not provide explicit compensation to resources for the capacity a resource provides to ensure the system is secure in the event of potential contingencies.

Finally, the Federal Energy Regulatory Commission (FERC) has directed the ISO several times to reduce reliance on exceptional dispatches and increase market-based solutions. This includes using market-based solutions to address system needs as well as developing appropriate compensation via locational marginal prices or through other market signals. Moreover, as part of its recent settlement agreement with FERC and NERC related to the September 8, 2011 pacific southwest blackout, the ISO agreed to commit to implementing its contingency modeling enhancements proposal to ensure that the ISO market procures the appropriate resources to ensure its balancing area's ability to recover from a contingency and be ready for the next contingency as soon as possible, but no longer than 30 minutes following the contingency event.

PROPOSAL

Management proposes implementing the contingency modeling enhancements functionality to explicitly model and price the corrective capacity needed to return electrical flows to within normal limits within a specified timeframe following a transmission contingency. The enhancements will enable the market models to efficiently calculate the required amounts and locations of corrective capacity and represent the value of that capacity through a locational marginal capacity price. Explicitly modeling corrective capacity in the day-ahead and real-time markets will avoid potentially unnecessary unit commitments that minimum online commitment constraints would otherwise make and will ensure the ISO balancing area is optimally positioned in the event of a contingency.

The contingency modeling enhancements will calculate the expected electrical flows after a transmission contingency and efficiently dispatch resources to bring flows back to within the transmission's normal limits within the period of time the transmission can be operated at its emergency rating. The modeling minimizes total production costs by considering each resource's ramp rate and effectiveness on the potentially overloaded transmission.

Under the proposed enhancements, each pricing node on the system will have a locational marginal capacity price in addition to the locational marginal energy price it currently has. Generation and demand response will receive the locational marginal capacity price for corrective capacity. The locational marginal capacity price reflects a resource's opportunity cost of being held back from producing energy, its costs to be dispatched up out of merit to be at an output where it can more rapidly ramp, or the marginal congestion cost savings of reducing flows on a transmission line. The

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[1] In some scenarios, after the unit is committed, the market may dispatch it above its minimum operating level, making it eligible to set the locational marginal price.

proposal does not include separate bids for corrective capacity, as these costs are calculated based on energy bids. The locational marginal capacity price is a market clearing price similar to energy prices. As a result, resources earn profits through locational marginal capacity prices that are greater than their specific costs.

The locational marginal capacity price will be non-zero when there is not enough effective unloaded capacity on the system to position the system, without making any changes to the economic energy dispatch, to return flows to within normal limits after a contingency. In this scenario, the need for corrective capacity will be binding and the market will change resources' energy dispatch to free up effective capacity. This adds costs to the dispatch which are reflected in non-zero locational marginal capacity prices.

However, sufficient effective unloaded capacity may be available on the system to address potential contingencies without making any changes to the economic energy dispatch. In this scenario, the need for corrective capacity will not be binding and will not add costs to the dispatch. This will be reflected in zero dollar locational marginal capacity prices.

The corrective capacity constraint will modify the calculation of locational marginal prices by adding a new congestion cost component reflecting the need for corrective capacity. This will increase locational marginal prices charged to load to cover the cost of corrective capacity payments when the need for corrective capacity is binding. The local market power mitigation calculations will also be modified to reflect the need for corrective capacity.

In a prototype analysis of market results, Management used a typical stressed day to compare the results of the minimum online commitment constraint to the proposed contingency modeling enhancements. The analysis found that the minimum online commitment requirements were conservatively defined relative to the actual need based on market results. The contingency modeling enhancements were able to address the reliability criteria with fewer commitments. The analysis further showed that on typical stressed days, the contingency modeling enhancement constraints often do not bind. This means that the contingency modeling enhancements will assure the ISO grid operators that the market has evaluated reliability criteria and found that the criteria has been met, without incurring additional costs due to conservative additional commitments. Without the contingency modeling enhancements, ISO grid operators would continue to rely on the inefficient minimum online commitment constraints to meet the reliability criteria.

Management also analyzed the potential impacts the contingency modeling enhancements could have on the ISO congestion revenue rights market. ISO staff used a prototype of the contingency modeling enhancements functionality to study stressed system conditions and evaluate a period of parallel operations. The analysis showed that the corrective capacity constraints did not bind often, indicating that there is a low likelihood of it binding after implementation. Therefore, Management expects minimal impacts to the congestion revenue rights market. As a result, Management proposes no changes to the congestion revenue rights allocation and auction. Instead, Management proposes to change the settlement of the congestion revenue rights so that the product does not settle congestion related to corrective capacity. Market participants will nominate or bid for congestion revenue rights to normal and preventive congestion as they do today. The market will award a product that only settles on normal and preventive congestion. Only settling the normal and preventive congestion is justified because, in this design, the corrective capacity constraints would not be modeled by the congestion revenue rights auction and incorporated into its prices.

POSITION OF THE PARTIES

Stakeholders, with the exception of Southern California Edison, generally support Management's proposal to explicitly model corrective capacity constraints in the market rather than relying on the relatively inefficient out of market operator actions used today. They believe it will result in more efficient procurement and dispatch of the most effective resources to meet system operating limits.

However, some stakeholders have remaining concerns about certain aspects of the proposal. These concerns are discussed below.

A stakeholder comment matrix is included as Attachment A. The Market Surveillance Committee provided a formal opinion on Management's proposal and is included as Attachment B.

Modeling constraints with greater than 30 minute temporal requirements

PG&E and DMM do not support the ISO implementing contingency modeling enhancements for system operating limits with greater than 30-minute corrective timeframes. The ISO had proposed a relatively late modification to implement the contingency modeling enhancements functionality for timeframes longer than 30 minutes. PG&E and DMM made the point that the scope of design changes expands when extending the 30-minute model to facilities with four-hour corrective time requirements and that these changes warrant further evaluation. Management agrees and has removed this from the proposal.

Potential benefits

The Six Cities, SCE, and DMM question the benefit in implementing this policy. They question the need for these enhancements because the ISO currently achieves a transmission feasible dispatch using exceptional dispatches and minimum online commitments as a supplement to the day-ahead market. While DMM is generally supportive of the enhancements, DMM points out that the prototype analysis of market results, described above, shows the corrective capacity constraints in the market will likely not bind frequently. Thus, they question the need for the functionality.

In response, Management believes that instead of relying on manual reviews, determinations, and interventions, all of which have inherent inaccuracies, the contingency modeling enhancements will enable the ISO to achieve an efficient, optimized transmission-feasible market solution. The proposal provides efficient price signals for corrective capacity through locational marginal prices. The results of the ISO's technical analysis indicate a robust solution with clear reliability and efficiency benefits over manual exceptional dispatches and minimum online commitment constraints.

SCE is concerned that the proposal will increase the cost that electricity consumers have to pay when temporal constraints are binding. In response, Management notes that the market objective is to lower the overall production cost of operating the system given its many reliability constraints. The proposal holds the potential to greatly reduce both out-of-market exceptional dispatches and unpriced minimum online commitment constraints. Over the long run, reductions in use of these inefficient tools will lower the overall production cost of operating the system and allow the value of energy and capacity to be appropriately represented in locational prices.

Congestion revenue rights

SCE, Powerex, and DC Energy are concerned that the congestion revenue rights settlement proposal will not provide a complete hedge to holders of congestion revenue rights. Management proposes to make minimal changes to congestion revenue rights settlement because it has found through its prototype analysis that the temporal constraints are expected to rarely bind in the day-ahead market. This obviates the need for a congestion revenue rights product that hedges congestion caused by the need for corrective capacity. However, Management commits to monitor and report the amount, if any, of congestion in the day-ahead market due to corrective capacity constraints and will pursue congestion revenue right changes if it becomes significant.

Capability to bid in corrective capacity

Suppliers support the proposal but believe it should include provisions for separate bids for corrective capacity. As described earlier in this memorandum, Management believes the proposed capacity pricing calculated based on energy bids reflects the costs of providing corrective capacity. In addition, separate bids for corrective capacity would introduce significant complexity into the design of the corrective capacity product including introducing market power concerns requiring complicated local market power mitigation design.

The Market Surveillance Committee agrees with Management's rationale for not implementing bidding capability in the real-time market but has noted in its opinion several potential adverse impacts of not implementing bidding capability in the day-ahead market. Although the Market Surveillance Committee agrees that the benefits of the contingency modeling enhancements justify its implementation under the current proposal, they note that the lack of day-ahead market bidding poses a risk of distorting the incentives for resources to submit bids in the day-ahead market. This risk can arise if day-ahead schedules for corrective capacity chronically clear at a zero price or otherwise well below real-time prices for corrective capacity, or below day-ahead spin and non-spin reserve prices. As a result, resources without a resource adequacy must-offer obligation may have an incentive to not submit bids to the real-time market. While Management acknowledges this risk, we believe it is small. Given the uncertainty and likely infrequency of the corrective capacity binding in the real-time market, Management does not believe there is a significant incentive for resources to risk foregoing day-ahead market revenues in order to secure corrective capacity payments. Therefore, Management finds that this limited risk does not justify the additional complexity and implementation cost of adding corrective capacity bidding to the proposal.

Despite the concerns raised in the Market Surveillance Committee's opinion, the Market Surveillance Committee supports deferring bidding on day-ahead corrective capacity until a future initiative in which Management could develop a capacity bidding and market power mitigation approach. Management will closely monitor whether the contingency modeling enhancements result in disincentives for resources to bid into the day-ahead market and commits to reconsider adding bidding functionality in the event this occurs.

CONCLUSION

Management requests the ISO Board of Governors approve the changes described above. The contingency modeling enhancements will reduce operator reliance on the inefficient minimum online commitment constraints, decrease out-of-market actions, improve the market dispatch, and expose the value of corrective capacity in the system.