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I. Introduction and purpose

This stakeholder process is being initiated to enhance the ISO’s modeling of the electrical system (i.e., network model) for operating the ISO controlled grid through its market process used for dispatching and scheduling resources on the grid. These changes will improve the ISO’s modeling of electrical flows throughout the Western Interconnection, which will result in improved reliability and market solutions.

On September 8, 2011, a system disturbance in Arizona caused cascading outages and blackouts through Arizona, Southern California, and the Baja peninsula portion of Mexico, which affected the following five balancing authorities: ISO, Arizona Public Service Company (APS), Imperial Irrigation District (IID), Western Area Power Administration-Lower Colorado (WALC), and Comision Federal de Electricidad (CFE). The outage resulted in the loss of more than 7,000 MW of firm load. In the ISO, all of the San Diego area lost power. ISO markets were temporarily suspended and prices were set administratively. Markets were not fully restored to normal operations until about 12 hours later.

Given the severity and rapid propagation of the outages, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) conducted an inquiry to determine the causes of the outages and develop recommendations to prevent such events in the future. Following review of data, on-site visits at entities involved in the outages, and interviews and depositions, FERC and NERC issued a joint staff report in April 2012 that found that certain aspects of systems within the Western Interconnection were not operated in a secure state. The joint report offered 27 findings and recommendations for improvement. The findings and recommendations apply to various aspects of the operation of the Western Interconnection.

Two of these findings and recommendations in the joint report are the subject of this stakeholder process. The ISO is considering them together because both address the need for greater visibility and modeling of external networks leading to reliable real-time operation. The findings are: Finding 2 – Lack of Updated External Networks in Next-Day Study Models and Finding 11 – Lack of Real-Time External Visibility: Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. The two findings and recommendations are set forth in their entirety in Table 1.

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3 The disturbance occurred at about 3:27 p.m., leading to power outages at 3:38 p.m., and the ISO market was fully restored at 4:00 a.m.
Table 1
FERC/NERC Joint Staff Report Findings and Recommendations
September 8th Event

| Finding 2 – Lack of Updated External Networks in Next-Day Study Models: When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs’ next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems. | Recommendation 2: TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs. |
| Finding 11 – Lack of Real-Time External Visibility: Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors’ systems. | Recommendation 11: TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS. |


BA = Balancing Authority
BPS = Bulk Power System
RC = Reliability Coordinator
RTCA = Real-Time Contingency Analysis
TOP = Transmission Operators
SOL = System Operating Limit

In Finding 2, the joint staff report determined there was a failure to effectively share and coordinate next-day studies within the Western Interconnection. Although the Western Electricity Coordinating Council (WECC) reliability coordinator receives some next-day study data, the joint staff report found that there was a need for greater sharing of such data among transmission operators and balancing authorities.

In Finding 11, the joint staff report found that entities lacked sufficient real-time situational awareness of their neighbors. While many transmission operators had the appropriate tools for internal analysis, the joint staff report found that improvements should be made to deal with external contingencies.
The modeling improvements resulting from this stakeholder initiative will improve the reliability of the ISO grid and market solution accuracy. For the ISO, ensuring reliability and operating efficient markets are inter-dependent. For example, the ISO uses the market to reliably manage congestion on its transmission system and in turn account for transfers and uses of the grid so that we can achieve a reliable and efficient market dispatch. Resources on the ISO grid are dispatched and scheduled through the ISO markets. Only in exceptional circumstances does the ISO dispatch resources outside of its market processes. Therefore, the feasibility and accuracy of the market solution is an important element in the ISO’s ability to operate the system reliably. To do this, it is essential we increase the accuracy of our day-ahead and real-time market solutions. As the September 8th event demonstrated, events outside of the ISO can significantly impact the reliability of the ISO grid and market operations. Therefore, the ISO’s efforts to improve reliability and market operations encompass improved modeling of our surrounding balancing authority areas and incorporating that information in the market models. This aligns with Finding 2 and Finding 11, and related recommendations, in the joint staff report.

While this initiative seeks to improve modeling of areas external to the ISO, we will in the first instance rely on data that exists with the WECC reliability coordinator. To the extent neighboring entities wish to share more information, we look forward to and appreciate further cooperation.

II. Plan for stakeholder engagement

The proposed schedule for stakeholder engagement is provided below. In April, we brought our initial ideas to the ISO’s Market Performance and Planning Forum. Typically we publish an issue paper to discuss the scope of the stakeholder process but since the recommendations in the FERC/NERC joint staff report are already clear, the ISO is presenting this straw proposal for stakeholder review.

<table>
<thead>
<tr>
<th>Date</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wed 4/10/13</td>
<td>Presentation at Market Performance and Planning Forum</td>
</tr>
<tr>
<td>Tue 6/11/13</td>
<td>Straw proposal posted</td>
</tr>
<tr>
<td>Tue 6/18/13</td>
<td>Stakeholder call</td>
</tr>
<tr>
<td>Tue 6/25/13</td>
<td>Stakeholder comments due</td>
</tr>
<tr>
<td>Mon 7/22/13</td>
<td>Revised straw proposal posted</td>
</tr>
<tr>
<td>Tue 7/30/13</td>
<td>Stakeholder in-person meeting</td>
</tr>
<tr>
<td>Mon 8/5/13</td>
<td>Stakeholder comments due on revised straw proposal</td>
</tr>
<tr>
<td>Thu 9/10/13</td>
<td>Draft final proposal posted</td>
</tr>
<tr>
<td>Tue 9/17/13</td>
<td>Stakeholder call</td>
</tr>
<tr>
<td>Tue 9/24/13</td>
<td>Stakeholder comments due on draft final proposal</td>
</tr>
<tr>
<td>Thu-Fri 11/7-8/13</td>
<td>November Board of Governors meeting</td>
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</tbody>
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III. Scope of initiative

Given the recommendations in the FERC and NERC joint staff report, the ISO’s ultimate goal in this stakeholder initiative is to improve reliability and market solution accuracy. The ISO can achieve this by accurately modeling day-ahead and real-time conditions inside and outside of the ISO to minimize the impact of loop flows. Loop flows can be particularly challenging to manage if they create a significant divergence from day-ahead schedules. Within the WECC, loop flows occur naturally because of the difference between scheduled flows over contract paths and the resultant physical flows that abide by Kirchhoff’s circuit laws. However, loop flows can be countered through heightened situational awareness from accurate day-ahead and real-time market solutions. For the ISO, increased awareness and improved modeling can help decrease the use of exceptional dispatch to manage real-time flows. Improved modeling should also tend to reduce real-time congestion offset charges. This is accomplished by reducing the amount of schedules awarded in the day-ahead market that are infeasible in real-time because of loop flows. These infeasible schedules, including physical schedules and virtual schedules, result in real-time congestion offset because generation on either side of the constraint causing the infeasibility has to be dispatched up in the real-time market at a relatively higher price and dispatched down at a relatively lower price.

To meet our goal and effectuate the recommendations by the joint staff report, the ISO will enhance its full network model (FNM). The FNM is the logical point of change because it provides a detailed and accurate representation of the power system for operational purposes. It contains both physical and commercial data for the reliable and efficient operation of our day-ahead market (including the integrated forward market and residual unit commitment process), the real-time market, and the congestion revenue rights auction and allocation process. The FNM includes:

- ISO physical transmission system reflecting planned outages for each market;
- ISO generation and pumped storage resources reflecting planned outages for each market;
- ISO loads;
- Balancing authority areas embedded or adjacent to ISO;
- Resources external to ISO;
- Resources using dynamic schedules or pseudo-ties;
- Groupings of generation or loads to reflect commercial arrangements; and
- Aggregation of generation or load pricing nodes for bidding and settlement purposes.

The FNM expansion project is being undertaken to enhance the ISO’s modeling of its system independent from implementation of the Energy Imbalance Market (EIM).

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5 See the Full Network Model Business Practice Manual at:
http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Managing%20Full%20Network%20Model

accuracy. Table 2 below lists four major objectives of this stakeholder process and the activities to support them. The objectives and activities seek to address reliability concerns while still respecting each balancing authorities’ current operations and processes.

Table 2
Objectives and Activities for Full Network Model Expansion

<table>
<thead>
<tr>
<th>Objectives</th>
<th>Activities to support objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Accurate loop flow modeling</td>
<td>1) New scheduling point and load aggregation point definitions</td>
</tr>
<tr>
<td>• Enhanced security analysis</td>
<td>2) Enforce constraints for both scheduled and physical flow</td>
</tr>
<tr>
<td>• Better analysis and outage coordination</td>
<td>3) Include variables in high voltage direct current transmission modeling</td>
</tr>
<tr>
<td>• Accurate high voltage direct current modeling</td>
<td></td>
</tr>
</tbody>
</table>

Expansion of the FNM will take place in phases, conditioned on the availability of data such as telemetry and outage information. The ISO will focus in the first instance on the balancing authority areas surrounding the ISO to accurately account for loop flow and get reasonably accurate state estimator solutions. The ultimate goal is to improve the modeling of the entire WECC.

To accurately model the loop flow from balancing authority areas modeled in the FNM through the ISO’s system in the day-ahead and real-time markets, the ISO will develop “base schedules” for supply and demand. These base schedules will be reflected as fixed schedules in the market optimization software. For example, in the day-ahead market, the ISO will establish base schedules for demand based on the demand forecast for these balancing authority areas obtained from the WECC Reliability Coordinator. The ISO will either obtain base schedules for supply directly from the relevant balancing authority area or will estimate them by distributing the demand, net of tagged scheduled interchanges, to supply resources in each balancing authority area using generation distribution factors, normalized for known outages, also obtained from the WECC Reliability Coordinator. Similarly, the ISO will derive base schedules in the real-time market in a similar fashion for future intervals beyond the next trading hour; however, the ISO will use more accurate information for the current trading hour from the state estimator solution for these areas.

IV. Activity 1: new scheduling point and load aggregation point definitions

The ISO’s scheduling points are currently at the ISO interties. Scheduling points are used by scheduling coordinators to submit physical and virtual bids and schedule energy and ancillary services for imports and exports in the day-ahead and real-time markets. With the expansion of
the FNM to include surrounding balancing authority areas, the ISO proposes to create scheduling points for: (1) imports from and exports to balancing authority areas that are modeled in the FNM, and (2) imports from and exports to external balancing authority areas that are not modeled in the FNM. We will discuss each scenario.

For external balancing authority areas that are modeled in the FNM, the ISO will define a scheduling point as a generation aggregation point of all supply resources in the respective balancing authority areas. The import and export schedules from bids that are submitted at these scheduling points and that clear the market will be distributed to the relevant supply resources of the balancing authority areas using generation distribution factors. Import and export schedules will be distributed as incremental and decremental adjustments, respectively, to the relevant base schedules. The generation distribution factors will be based on historical patterns derived from the state estimator solution, normalized for known outages; alternatively, the generation distribution factors can be derived from day-ahead and hour-ahead schedules provided by external balancing authority areas. The distribution of the import/export schedules to the relevant supply resources is required to obtain a network solution (power flow solution) for the entire FNM to accurately represent loop flows in enforcing transmission constraints in the ISO and the ISO interties. These schedules will be settled at the aggregate locational marginal price of the respective generation aggregation point.

For external balancing authority areas that are not modeled in the FNM, the ISO will define scheduling points at the FNM boundary at each intertie with the FNM. These scheduling points are similar to the existing scheduling points at the ISO interties, which will be replaced with the relevant generation aggregation points after the surrounding balancing authority areas are included in the FNM. The import and export schedules from bids that are submitted at these boundary scheduling points and that clear the market will be modeled as algebraic power injections at a generic system resource connected to the FNM through the relevant intertie. These schedules will be settled at the LMP of the respective boundary scheduling point.7

Dynamic resources can exist within a modeled balancing authority area or at the FNM boundary. A dynamic resource is registered with the ISO and assigned a unique resource ID registered in the ISO’s Master File; it is modeled with the same level of detail, telemetry, and revenue quality meter requirements as internal generating resources. Dynamic resources may participate in the day-ahead market, as well as in the 15-minute and 5-minute real-time markets. Static intertie bids may be submitted at scheduling points in the day-ahead market, as well as in the 15-minute real-time market, but they may not participate in the 5-minute real-time market. No resource or resource ID is required for static intertie bids or schedules. Table 3 below summarizes the types of import/export bids in the ISO markets.

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7 If the FNM encompasses the entire WECC, there would be no need for these boundary scheduling points or the associated generic system resources.
Table 3
Modeling of intertie bids

<table>
<thead>
<tr>
<th>For balancing authority areas included in the FNM:</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Intertie bids from dynamic resources are modeled at detailed</td>
</tr>
<tr>
<td>registered resources with unique resource IDs</td>
</tr>
<tr>
<td>• Static intertie bids are modeled at the relevant generation</td>
</tr>
<tr>
<td>aggregation point without resource IDs</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FNM boundary:</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Intertie bids from dynamic resources are modeled at detailed</td>
</tr>
<tr>
<td>registered resources with unique resource IDs</td>
</tr>
<tr>
<td>• Static intertie bids and compensating injections are modeled at</td>
</tr>
<tr>
<td>simple generic system resources without resource IDs</td>
</tr>
</tbody>
</table>

Although resource IDs are not required for static intertie bids, the ISO proposes to use a “transaction ID” that will serve as a surrogate resource ID in order to uniquely identify these bids and any resultant schedules. Table 4 below shows the bid information that will be used to determine the transaction ID. Unlike the resource ID, the transaction ID will not be registered in the Master File, but it will be generated when bids are submitted and will persist through the ISO market systems, from bid validation through market clearing and settlements. The transaction ID will help the ISO identify bids and schedules, honor contract paths by enforcing scheduling limits, and facilitate intertie schedule tagging, without the need to register an unbounded number of resources in the Master File. Furthermore, the use of a transaction ID as the main means of bid and schedule identification will present a minimal change to market participants’ existing systems since it can simply replace the existing resource ID.

Table 4
Transaction ID details

<table>
<thead>
<tr>
<th>Category</th>
<th>Detail</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market ID</td>
<td>Day-ahead market or real-time market, trading day or trading hour</td>
</tr>
<tr>
<td>Scheduling Coordinator ID</td>
<td>Same as today</td>
</tr>
<tr>
<td>Location ID</td>
<td>Resource ID, scheduling point, load aggregation point, or trading hub</td>
</tr>
<tr>
<td>Bid Type</td>
<td>Physical or virtual, supply (import) or demand (export), firm/non-firm, etc.</td>
</tr>
<tr>
<td>Intertie ID for physical import/export bids</td>
<td>Used for schedule tagging and scheduling limit constraints</td>
</tr>
</tbody>
</table>
As an exception, for static intertie bids associated with resource adequacy capacity, existing transmission contracts, transmission ownership rights, or other contractual agreements, it will still be necessary to register a system resource in the Master File with a resource ID to link these bids to their respective contract information.

For load, each balancing authority area modeled in the FNM will have defined a load aggregation point and, similar to generation, the ISO will use historical default load distribution factors to distribute the demand forecast throughout the balancing authority area.

Figure 1 below shows a simplified example of FNM expansion. The ISO is shown in the lower left and it is connected to two modeled balancing authority areas (BAA$_1$ and BAA$_2$). A generation aggregation point composed of G$_1$ and G$_2$ is defined as the scheduling point for BAA$_1$. Similarly, a generation aggregation point composed of G$_3$ and G$_4$ is defined as the scheduling point for BAA$_2$. A load aggregation point composed of L$_1$ and L$_2$ is defined for BAA$_1$, and a load aggregation point composed of L$_3$ and L$_4$ is defined for BAA$_2$. The demand forecast of each balancing authority area is distributed to the loads in the respective load aggregation point using default load distribution factors. Similarly, import/export schedules at the scheduling point of each balancing authority area are distributed as incremental/decremental changes on the base schedules of the resources that compose the respective generation aggregation point using default generation distribution factors. Lastly, the example shows two system resources G$_5$ and G$_6$. These resources are used to model compensating injections and import/export bids from/to external balancing authority areas that have not yet been modeled in the FNM. Note that G$_5$ is connected to the FNM through an intertie with BAA$_1$.

**Figure 1**

**Full Network Model Expansion Example**
With these elements defined within the FNM, the ISO will be able to get a much more accurate power flow solution based on day-ahead schedules and real-time dispatch. The expanded model will also allow scheduling coordinators to submit physical or virtual import or export bids at each of the new scheduling points.

V. Activity 2: enforce constraints for both scheduled and physical flow

As mentioned above, WECC entities use both scheduled and physical flows. The ISO proposal under this initiative is to use a dual approach that will respect both scheduled and physical flows. This, in conjunction with improved modeling of day-ahead and real-time conditions, will help to minimize and manage loop flows.

The ISO proposes to enforce two constraints on each ISO intertie in the day-ahead and real-time markets to manage transmission congestion. The first constraint is based on the scheduling limit for the intertie declared in intertie bids. This will ensure that contract paths are honored and will be used for tagging intertie schedules. In enforcing the constraint, the ISO will net physical import and export energy schedules against each other. The entire schedule or award will be constrained (i.e., no shift factors). Ancillary services, on the other hand, because they require firm transmission and would not be simultaneously dispatched for energy in both directions, will not be netted. For example, a regulation down (export capacity) will not net against upward ancillary services (import capacity). Furthermore, transmission capacity reserved for ancillary services awards will not create counter flow transmission capacity for energy schedules. These scheduling limit constraints will not be different than the constraints that are currently enforced on ISO interties.

The second constraint is based on the physical limit for an intertie based on actual power flow contributions from all resource schedules in the FNM. This second constraint includes both physical and virtual import/export energy schedules in the integrated forward market. Only physical import/export energy schedules are considered in the residual unit commitment and the real-time market. This is consistent with the ISO’s implementation of FERC Order 764 where virtual intertie schedules are only considered in the integrated forward market and only the physical intertie schedules that clear the residual unit commitment have the obligation to submit tags. Unlike the scheduling limit, the schedule contributions toward the physical limit will be based on the power transfer distribution factors calculated from the network topology so that we can accurately model loop flows.

The scheduling and physical limits constraints collapse to the same constraint in the case of some radial interties in the current FNM, where the power transfer distribution factors are all 1 or 0 for these interties, but they need to be differentiated in the expanded FNM.
VI. Activity 3: Include variables in high voltage direct current transmission modeling

The ISO currently models the Trans Bay Cable high voltage direct current (HVDC) transmission line in the FNM. Since the line is internal to the ISO, the modeling is simplified so that the load at the rectifier station is equal to the generation at the inverter station, using logical resources at each converter station. Furthermore, that load and generation are fixed in the market. The ISO proposes to enhance its current model for HVDC transmission for those lines for which the ISO has and does not have direct operational control. We discuss each scenario.

For HVDC links where the ISO has direct operational control (e.g., Trans Bay Cable), the ISO proposes to replace the fixed algebraic injections at the converter stations with free variables (i.e., without a cost in the objective function). The ISO would no longer fix the two power injections, but will still constrain them to be equal to each other by enforcing a balancing constraint. As an additional measure of accuracy, the ISO can even approximate the associated DC losses in that balancing constraint. Furthermore, the magnitude of the algebraic power injections would be limited by the HVDC link’s capacity allowing omnidirectional power flow.

For HVDC links where the ISO does not have direct operational control (e.g., Pacific DC Intertie, InterMountain-Adelanto), the ISO proposes a similar model with algebraic injection variables at the converter stations constrained by a balancing constraint. However, in these cases the injections will be limited by the algebraic sum of all associated import and export schedules that declare the use of the HVDC link in the corresponding bids. Furthermore, the injections will be limited by applicable transmission rights. Verified tags for intertie schedules on the HVDC links would provide a hedge for the locational marginal price difference between the inverter and rectifier stations, in effect exempting these schedules from marginal loss and marginal congestion charges between these stations since the associated energy is flowing on the HVDC link as opposed to the AC network.

VII. Market clearing

This section describes the market clearing process that will use the expanded FNM. The process involves the following steps:

1) The ISO will first determine base schedules for each external balancing authority area prior to each day-ahead or real-time market run. This process involves distributing the demand forecast for each balancing authority area to load nodes using the respective default load distribution factors. Similarly, the demand forecast net of any scheduled interchanges (e.g., day-ahead schedules with the ISO or other balancing authority areas, prior to the real-time market) will be distributed to the resources in each balancing authority area based on historical generation patterns using generation distribution factors, or based on the state estimator solution in the real-time market. The base schedule determination will include information about resource and transmission
outages and other relevant data to the extent available. In real-time market, the base schedules for the ISO are the day-ahead schedules.

2) The ISO will then run an AC power flow with net interchange control for each balancing authority area to maintain its net schedule interchange. A distributed load slack will be used to distribute transmission losses in each balancing authority area. The resultant adjusted base schedules will be used as a reference in the subsequent market run.\(^8\)

3) The ISO will then run its market performing congestion management for the ISO network and ISO interties.\(^9\) Import and export schedules from bids at aggregate scheduling points that that clear the market will be modeled as incremental and decremental market adjustments, respectively, on the base schedules of the associated resources. The ISO market solution will ignore the impact of transmission losses in external balancing authority areas on the locational marginal prices.\(^10\)

**VIII. Data coordination**

The ISO intends to rely on as much existing information as possible to expand the FNM in a timely manner. The ISO will rely on existing WECC databases and resources but may have to estimate or extrapolate data that is missing, incomplete, or not appropriately formatted. This may require significant effort. Therefore, the ISO would appreciate and welcome neighboring balancing authorities to share data with the ISO in order to improve the collective modeling. The ISO intends to follow a phased approach of data collection, with neighboring balancing authority areas being the first priority and with a goal towards full WECC modeling.

The following six data sets represent our priority list for FNM expansion likely derived from WECC Reliability Coordinator data:

1. Net interchange schedules (default information from Western Interconnection Interchange Tool)
2. Demand forecasts
3. Generation
4. Load and generation distribution factors
5. Generation and transmission outages
6. Telemetry

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\(^8\) The process for determining and calculating adjusted base schedules is slightly different for EIM Entity BAAs in the RTM and it is described in detail in the EIM straw proposal.

\(^9\) Congestion management is also an option for EIM Entity BAAs in the RTM.

\(^10\) With the exception of EIM Entity BAAs in the RTM.
IX. Next Steps

The ISO will discuss this straw proposal with stakeholders during a teleconference to be held on June 18, 2013. Stakeholders are encouraged to submit written comments by June 25, 2013 to FNM@caiso.com.