California ISO
Shaping a Renewed Future

Renewables Integration Market Vision & Roadmap

Revised Straw Proposal • 8/29/2011

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1 Straw Proposal Revisions

The ISO has revised its approach to the renewable integration phase 2 initiative. The July 6th initial straw proposal cast a vision for broader day-of market design enhancements than majority stakeholders were prepared to address in the timeframe provided. The ISO appreciates the significant challenge and time required for parties to vet wholesale electricity market enhancements needed to integrate variable energy resources. With constructive stakeholder feedback and additional internal input, the ISO determined that incremental market design changes that fully leverage the existing market design features and infrastructure provide a more prudent and cost-effective approach for the short-term and better aligns with the ISO's guiding principles, specifically to adopt enhancements that are cost-effective and implementable by the ISO and its market participants. In addition, the ISO agrees with the many comments stating that any significant changes to the real-time market clearing timeline should be undertaken with careful consideration of interchange scheduling changes that may be adopted within the WECC.

1.1 Statement of Purpose Revisions

The ISO was persuaded by the many comments across industry groups suggesting the process was moving too fast and would not provide adequate time for development and stakeholder review. The Six Cities, for example, suggested the ISO take a more incremental approach to design enhancements. Thus, the ISO is proposing incremental design changes to be developed and implemented between now and 2020, building on enhancements that are already underway for implementation in 2012-13 and emphasizing mid-term solutions that can be implemented in 2013-2015. Long-term solutions after 2015 may include revised market timing, such as a 15-minute real-time market, as conveyed in the ISO initial straw proposal. However, before long-term changes can be implemented, the ISO needs greater clarity on west wide developments, particularly around interchange scheduling and timelines. In addition, more time and empirical evidence will enable the ISO and market participants to better assess the performance of market design modifications implemented between now and 2013, which should help inform future needs and modifications.

1.2 Guiding Principles Revisions

The ISO agrees with the many stakeholders who suggested that cost allocation should be based on cost causation. As recommended by various stakeholders, the ISO incorporated "cost causation" as the seventh guiding principle to recognize that load and resource variability and the associated settlement risks are best managed by those market participants directly responsible for serving load or developing and operating resources.

The ISO was not persuaded by arguments that the ISO or ratepayers are in the best position to manage uncertainty or minimize integration costs. First, neither the ISO nor ratepayers are directly responsible for building, operating, or scheduling resources. Second, inaccurate forecasting and scheduling can create operational uncertainty and add to unit commitment costs. Forecasting and scheduling inaccuracies should be maintained within reasonable bounds by allocating the costs to parties that are best able to improve accuracy.

The ISO was also not persuaded by the "spatial diversity" argument which asserts that for the system as a whole, the variations in resource output will tend to cancel each other and thus mitigate the operational impacts of variability. While such canceling may occur in some hours under certain conditions, the ISO does not believe that depending on spatial diversity to constrain variability would be a prudent way to operate the system. All resource types can contribute to real-time deviations, and would have little incentive to manage such deviations if allowed to deviate at-will without explicit consequences. An important expected outcome of the cost causation principle in the future operating environment is to provide ISO operators with greater operational certainty and predictability, not less. Managing uncertainty and schedule deviation risk must be borne by those that can directly manage the risk through contract terms or by using complementary technologies that add resource flexibility and controllability. Saying this, the ISO recognizes that some market participants may be unable to effectively manage deviation risk and, therefore, it would be more efficient to assign this risk to the contracting party. Thus, the ISO is considering settlement provisions that would enable intermittent resource owners to assign their deviation costs and risk to a third party.

1.3 Market Design Framework Revisions

In revising its market design approach for this renewables integration initiative, the ISO is proposing incremental steps. For discussion purposes and sequencing, the ISO is looking at market design enhancements that evolve across three time periods:

- Short-term: Today to 2013
- Mid-term: 2013 to 2015
- Long-term: 2015 to 2020

The ISO has purposely overlapped the three time periods because this is a market evolution rather than a market transformation, i.e. the periods conveyed do not represent explicit hard "cut over" design phases. Because several short-term enhancements are already in progress and under discussion with stakeholders, the primary focus of this current phase of the initiative is the mid-term period, 2013 to 2015, with an eye on potential long-term enhancements as the needs and the design possibilities become clearer. To set the context for developing the mid-term enhancements, this paper provides a summary description of the short-term enhancements in progress.

1.3.1 Short-term Enhancements

The short-term, today through 2013, is about implementing market enhancements already on the books or already under development. Stakeholders may already be familiar with many of the enhancements, but for convenience, a summary description of what market design enhancements are to be implemented in this period is provided in section 7.1 Short-term Market Enhancements – Today through 2013.

1.3.2 Mid-term Enhancements

The mid-term period, 2013 through 2015, is the immediate and primary focus of this initiative as the detailed planning and development of proposed market enhancements must begin promptly for approval, preparation and implementation by year-end 2012. The proposed market enhancements for this period build on the short-term, with the intent of making refinements commensurate with the size and scope of the renewable integration challenges anticipated in the 2013 to 2015 timeframe. A description of proposed enhancements for the mid-term are detailed in section 7.2 Mid-term Market Enhancements — 2013 through 2015.

1.3.3 Long-term Enhancements

An incremental and evolutionary market design approach enables experience to inform future market design changes based on what is working, or not working, from the short- and mid-term implementation efforts, and based on market developments that occur during the next few years. Based on this experience, the ISO and its stakeholders can more effectively assess whether more significant market design changes are still required. Long-term market enhancements for 2015 through 2020 should be based on this experience and on what changes are happening in the wholesale markets in the west, particularly around west-wide energy trading practices and interchange scheduling timelines and tagging. With this experience and context, the ISO and its stakeholders can consider whether more extensive changes to the market are necessary, including, for instance, implementing a 15-minute real-time market as was discussed in the initial straw proposal. A brief discussion of potential long-term market enhancements, including the forward procurement of capacity to integrate renewable resources, is provided in section 7.3 Long-term Market Enhancements — 2015 through 2020.

1.4 Stakeholder Process for 2011 Revisions

The ISO updated the stakeholder process schedule, which includes ISO deliverables and stakeholder meeting dates, reflecting the revised approach for this initiative. However, the ISO maintains its objective to deliver for Board review a vision and roadmap in December 2011.

2 Introduction

For decades the power industry has operated under a structure of relatively stable technologies and operational practices, and has needed to evolve only to accommodate gradual growth in demand and incremental changes to the supply fleet. With new policy mandates for a cleaner, greener supply fleet, however, significant changes are required in virtually all aspects of industry activity. For several years now the ISO has been proactively assessing the impacts of environmental policy mandates and new technologies and has worked with stakeholders to develop practical approaches to support state policy goals and facilitate the participation of new resource types. The ISO's integration studies have provided important insights into the operational requirements to maintain reliability with high levels of participation by wind and solar resources, and recent market product enhancements have provided the means for new technology types to participate in the ISO's spot markets. Yet more work remains to be done. Although the ISO's comprehensive new market structure implemented in 2009 was designed for flexibility to adapt to such changes, it was largely designed before the ISO or market participants began to grapple with the impacts of large-scale changes to the supply fleet driven by the new environmental policies and emerging technologies. It is therefore necessary and timely to review the current ISO market structure comprehensively, informed by the integration studies and the recent design changes, and determine what further market enhancements are needed to both adapt to and facilitate the coming changes while maintaining the ISO's traditional core functions of providing reliable open-access transmission service and running efficient spot markets.

Against this backdrop the ISO offers this next version of its renewables integration straw proposal as an additional step towards a Renewables Integration Market Vision and Roadmap. Following an extensive stakeholder process described at the end of this document, ISO management intends to present the Vision and Roadmap to the Board of Governors for discussion at its December 2011 meeting. In early 2012 the ISO will initiate stakeholder activities to develop more detailed proposals for market products, like development of a flexi-ramp product, and other market enhancements to be incorporated into the ISO market structure in the mid-term (2013 to 2015) after receiving Board and FERC approval.

This paper provides context, background and guiding principles for this phase of the ISO integration of renewable resources initiative, and offers an initial straw proposal, including some options, for enhancements to the ISO market. Specifically, this paper discusses:

- What the ISO is trying to accomplish in this initiative and by when;
- The principles proposed for assessing the merits of alternative market enhancements;
- A review of the operational challenges associated with high levels of participation by variable energy resources such as wind and solar;

- Incremental market design enhancements for the 2013-2015 timeframe needed to maintain reliability and robust market participation in an environment where there is greater resource diversity and production variability; and
- A proposed schedule of stakeholder activities leading to presentation of the Renewables Integration Market Vision and Roadmap to the ISO Board in December, 2011.

3 Statement of Purpose

The purpose of the Renewables Integration Market Vision and Roadmap initiative is to take a holistic view of to the ISO market and identify incremental enhancements that leverage the existing market and infrastructure to address and facilitate the transformative changes resulting from the state's energy and environmental policies and the emergence of new technologies. This must be done in a manner that maintains the safe and reliable operation of the grid and the stability of the spot markets. The ISO goal is to evolve the existing market structure to:

- Enable ISO operators to efficiently and reliably operate the grid with a more diverse and variable supply portfolio;
- Be flexible to accommodate future changes to energy policy goals and new resource types without requiring further substantial market changes; and
- Resolve known market and performance issues and minimize the need for manual interventions.

Now that California has a 20% and 33% Renewables Portfolio Standard (RPS), as well as Assembly Bill 32 which calls for reductions in greenhouse gas emissions, the ISO is relying on stakeholder input to help the ISO determine the most effective way to evolve the market to meet these objectives. The ISO seeks comments on what specific, incremental changes are necessary to efficiently and reliably operate the grid in an environment where a large number of renewable, variable energy resources are interconnected to the transmission and distribution systems.[1] The significant operational challenge for the ISO is to reliably maintain continuous system balance given the variability of the energy output of variable energy resources, which is caused in large part by the intermittent nature of their fuel source, e.g., solar irradiance and wind energy. Increased variability in the output of the supply portfolio will result in less predictability and, therefore, greater operational uncertainty. The ISO must anticipate and manage this variability to balance supply and demand as well as to meet applicable reliability criteria.

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[1] "Variable energy resources" is the term used by the Federal Energy Regulatory Commission to describe renewable resources that have variable or intermittent production. Variable energy resources is used here as an equivalent term to "intermittent resources". Not all renewable resources eligible under California's renewables portfolio standard are variable energy resources. For example, geothermal, biogas and biomass resources generally follow fixed hourly schedules.

Meanwhile, technological improvements and innovations and state policy targets may enable potentially thousands of megawatts of distributed energy resources to interconnect to the grid at the sub-transmission and distribution level, creating new and unique challenges for system operators to forecast, monitor and reliably operate the grid. The ISO is currently assessing its operational needs under this changed environment, for example, to assess alternative approaches for providing adequate visibility to the real-time performance of these resources. From the perspective of this Vision and Roadmap initiative, the ISO must make sure that the market enhancements being developed here will also accommodate and facilitate the expansion of distributed energy resources as a major contributor to achieving a 33% or greater RPS.

The market vision the ISO develops in collaboration with stakeholders over the next months will be a conceptual outline of market enhancements that the ISO plans to implement in the short-term, today to 2013, and in the mid-term, 2013-2015, with an eye toward the end-state market for 2020. In support of and as a companion to the market vision, the ISO will develop a roadmap to lay out the implementation of short and mid-term changes that will provide the operational characteristics needed from the resource fleet to reliably and cost-effectively integrate renewable, variable energy resources. The roadmap will highlight activities and a timeline for delivering prioritized market design enhancements, but will not contain implementation details for specific market products or other enhancements. Those details will be developed in the next phase of the renewables integration initiative beginning in early 2012, where specific market enhancements and the associated tariff language will be developed in collaboration with stakeholders.

4 Background

California is leading the way to a new greener grid. Approved by the California legislature, SBX1-2 increases the state renewables portfolio standard to 33% by 2020. The ISO, its stakeholders and the state energy and environmental agencies must now determine best approaches to meet public policy goals. Rules, regulations and policies, along with the ISO wholesale electricity market, must align to support the clean energy future envisioned by SBX1-2.[2]

To this end, the ISO is considering refinements to its wholesale electricity market that effectively integrate the operational characteristics of variable energy resources and accommodate the development of many small distributed energy resources. With a clear legislated mandate, the ISO believes it is prudent to assess the market and operational refinements required to reliably operate the grid under a 33% RPS. This must be done even as more specific information on the

[2] SBX1-2 requires California's electric utilities to reach the 33% RPS in three compliance periods. By December 31, 2013, utilities must procure renewable energy products equal to 20% of retail sales. By December 31, 2016, utilities must procure renewable energy products equal to 25% of retail sales, and by December 31, 2020, utilities must procure renewable energy products equal to 33% of retail sales and maintain that percentage in following years.

quantity of renewable resource energy production and the mix and location of renewable resource types develops.

The ISO and its stakeholders have learned a lot over the past few years about future market and operational needs. First, renewable resources will be displacing energy production from in-state gas fired resources. The amount of capacity and energy required from gas-fired resources is a function of the amount of balancing energy and capacity reserves the ISO will need to support a high level of energy production from variable energy resources. The ISO 20% RPS study showed that the displacement from wind and solar resources causes the net load – load minus wind and solar production – to affect energy production from gas-fired units across the day. With a 33% RPS, on some days up to 50% or more of energy production during the peak hours may come from variable energy resources, such as solar (assuming a high in-state development of solar resources). Hence, solar production could substantially displace energy production from gas-fired peaking units.

Second, with a large number of renewable resources displacing energy production from gas-fired resources, the gas-fired fleet will experience increased cycling and will operate more often at minimum operating levels. For instance, the production simulations conducted for the 20% RPS study suggested that combined cycle plants would see a 35% increase in the number of starts compared to the benchmark scenario for 2012. However, the study also shows that conventional gas-fired steam units and simple cycle gas turbines are expected to operate less often and have fewer starts. As we transition from the 20% to the 33% RPS, the ISO will likely need to procure additional capacity and balancing energy. As this shift occurs, the fleet of conventional gas-fired steam units may be needed more often to provide balancing energy, incurring an increased number of start-stop cycles.

Third, wholesale energy prices will be affected because of the changing supply portfolio. Significant numbers of renewable resources integrated into the grid will lead to a reduction in energy market prices in certain hours relative to today. For instance, off-peak energy prices are expected to be lower because of higher wind energy production. Nevertheless, how wind and solar production will affect on-peak prices will depend on the production efficiency and, therefore, cost of gas-fired units that have historically operated during peak hours. In addition, real-time prices may become more volatile, reflecting the energy supply nature of variable energy resources.

Key findings of the 20% RPS study indicated that to successfully integrate renewable resources the ISO will need increased operational flexibility. This will require additional ramping capability, and balancing energy and ancillary services from both generation and non-generation resources. There will also be a need to more frequently mitigate frequency excursions and over-generation conditions.

The ISO expects the results of its 33% RPS study to provide more insights around the quantities of balancing energy, ancillary services, and ramping capability needed to support the integration of many variable energy resources. In the meantime, the 20% RPS study provides a firm foundation for discussing market enhancements needed to satisfy California's future operational and reliability needs under a 33% RPS.

5 Guiding Principles

The seven guiding principles below serve as guideposts for assessing the comparative merits of market enhancements that will be developed in this and future phases of the renewables integration initiative. The ISO goal is to strike a reasonable balance between these principles when assessing design options that may have competing, yet beneficial objectives.

The seven guiding principles for this initiative and their expected outcomes are as follows:

Technology Agnostic

Principle	The ISO market accommodates new resource types based on their performance capabilities, without preference for specific technologies.
Expected Outcomes	✓ Enables any technically capable resource, regardless of technology, to provide services on a level playing field based on performance ✓ Resource technologies are viable based on innovation and competition rather than on resource-specific market rules ✓ Integrates devices that can both produce and consume energy

Transparent

Principle	The ISO market relies on price signals to incent participant behaviors that align with ISO operating needs.
Expected Outcomes	✓ Products are competitively procured through transparent market mechanisms ✓ Procurement targets are transparent and tied to operational needs ✓ Operating constraints are reflected in price signals, minimizing non-market solutions ✓ Prices incent performance from supply and demand that supports operational needs and encourages mitigation of generation variability and congestion ✓ Pricing rules allow transparent allocation of renewables integration costs

Deep and Liquid

Principle	The ISO market attracts robust resource participation.
Expected Outcomes	✓ More economic bids and less self-scheduling ✓ More price responsive demand ✓ Increased participation from resources in other balancing authorities through improved interchange scheduling ✓ Minimal seams issues with neighboring balancing authorities

Durable and Sustainable

Principle	The ISO market ensures an efficient mix of resources to maintain reliability and attracts new investment when and where needed.
Expected Outcomes	✓ Resources are commercially viable through a combination of ISO market revenues and forward contracts ✓ Resource fleet and mix enables the ISO to meet NERC and WECC reliability standards ✓ Resources are incented to enhance availability and performance ✓ Market products and rules are stable ✓ Known real-time market issues are addressed

Flexible and Scalable

Principle	The ISO market easily adapts to new and changing energy policy goals and resource mix.
Expected Outcomes	✓ Establish flexible market design that can accommodate reasonable changes in policies and technologies ✓ Recognize key linkages and coordinate with initiatives and proceedings of state agencies ✓ Compatible with high penetration levels of distributed energy resources

Cost-effective and Implementable

Principle	The ISO market design leverages existing ISO infrastructure, industry experiences and lessons learned.
Expected Outcomes	✓ A market design that is cost-effective to implement for market participants and the ISO ✓ Build on existing functionality and market systems to extent possible ✓ Design leverages the experience of other ISOs/RTOs as to what works and what does not; do not re-invent

Cost Causation

Principle	The ISO market allocates costs based on cost causation
Expected Outcomes	✓ Market participants better manage their load and resource variability ✓ More accurate forecasting and scheduling by market participants reduces operational uncertainty and associated costs

6 Operational Challenges

The ISO is keenly interested in identifying and resolving the lower probability operating conditions under a 33% RPS that will make it difficult for the ISO to balance supply and demand in real time. With the introduction of large numbers of variable energy resources, the ISO is particularly concerned about large, fast ramps that are difficult to forecast. Thus, a key purpose of this initiative is to translate real-time operational challenges into market changes that ensure the system continues to safely and reliably serve demand even under extreme operating conditions.

The ISO anticipates that the majority of new renewable generation capacity needed to satisfy the state's 33% RPS will predominately come from additional variable energy resources such as wind and solar. The key operational characteristic of such resources is the variability of their generation over different time-frames (seconds, minutes, hours) and the uncertainty associated with forecasting their production (i.e., forecast error). As such, the integration of variable energy resources will require increased operational flexibility—notably the capability to provide load following and regulation in wider operating ranges and at ramp rates that are faster than what is generally provided today. Forecast uncertainty associated with wind and solar production increases the need for the reservation of resource capacity to ensure that operational requirements are met in real time. There is also the concern of increased over-generation, a condition where there is more supply from non-dispatchable resources than there is demand. Flexibility will be needed from dispatchable resources to respond to these operational needs. The existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day.

Additionally, certain conventional generators will operate at lower capacity factors because of the increased production from renewable energy resources.

Below is a summary of the key operational challenges the ISO must address, preferably through market solutions, where possible:

6.1 Net Load Following

A core ISO operational and market function is forecasting system load and renewable production in the day ahead and real time. This includes ensuring that sufficient supply resources are committed so that deviations from hourly schedules can be accommodated by those resources under ISO dispatch control. Historically, intra-hour deviations were caused by changes in load, hence the term "load-following". With increased variable energy resource production, the net load-following requirement—i.e., the amount of net load following capacity needed because of load schedule deviations plus variable energy resource deviations—could increase substantially in certain hours because of forecast uncertainty related to wind and solar fuel supply variability.

6.2 Self-scheduling

The empirical analysis from the ISO 20% RPS study demonstrated a shortage of 5-minute net load-following capability in the downward direction when resources are self-scheduled, as compared to offering their actual physical capabilities for economic dispatch. These results were further substantiated by using a production simulation. Hence, the 20% RPS study made clear that the ISO must pursue incentives or mechanisms to reduce the level of self-scheduled resources or increase the operating flexibility of otherwise dispatchable resources.

6.3 Ramping

The ISO must rely on ramping capability to balance the less predictable energy production patterns of variable energy resources, such as that from wind and solar resources.[3] Under-forecasting of demand errors and under delivery of scheduled supply in production require dispatching flexible resources to higher levels and the reverse for over-forecasting of demand errors and over delivery of scheduled supply. The ISO must accurately follow load and minimize inadvertent energy flows. This calls for having ramping capacity in both speed and quantity, which is dictated by how fast and how much variable energy resources' production patterns change. To meet this operational challenge, the ISO needs enough flexible resources committed with sufficient ramping capability to balance the system within the operating hour. This includes having enough

[3] Those variable energy resources that do not have the ability to firm and shape their production output

ancillary services, specifically regulation energy, available to address any second-to-second real-time imbalances between generation and demand.

6.4 Over-generation

Over-generation occurs when there is more generation and imports within a balancing area than load and exports can use. This situation develops after the system operator has exhausted all decremental energy bids available in the imbalance energy market, has pushed all regulating resources to the bottom of their operating range, and has exercised arrangements for out of market purchases for excess energy with neighboring balancing authorities.

When anticipating over-generation conditions, ISO operators will send out a market notice to request additional decremental bids. If insufficient decremental bids are received from scheduling coordinators and the area control error can no longer be maintained within acceptable limits, ISO operators could declare a system emergency. The fundamental causes that precipitate an over-generation condition are:

- A mismatch between scheduled generation and forecasted load;
- Managing must take generation during low load conditions;[4]
- Load and resource forecast errors;
- More imports are scheduled than there is load on the system;
- Excess must take hydro generation and the need to avoid spilling water; and
- Excess unscheduled wind and solar generation.

6.5 Fleet Operations

The increased supply variability associated with the 33% RPS will cause more frequent dispatches and starting and stopping of flexible, gas-fired generators and, therefore, potentially more wear and tear. Lower capacity factors for dispatchable generation combined with potential reduced energy prices under a 33% RPS may result in decreased energy market revenues for the gas-fired fleet in all hours and seasons raising revenue adequacy concerns and the ability to support gas-fired generation resources that are necessary for dispatch flexibility and reliability.

6.6 Inertia and Frequency Response

The ISO is concerned that as variable energy resources displace conventional generation, the system may not have sufficient inertia to maintain system frequency or enough governor response to stabilize system frequency following a grid disturbance. Frequency excursions because

[4] Regulatory must-take generation is defined in ISO Tariff Appendix A- Master Definition Supplement.

of over-generation are possible during periods of high variable energy resource production and low system demand, such as during off-peak hours, weekends and holidays. Specifically, higher than scheduled or expected variable generation production levels can result in over generation conditions and ultimately over-frequency if dispatchable resources are already at their minimum load levels and regulation down capacity has been exhausted. Thus, the ISO believes it is essential for variable energy resources to have the ability to automatically reduce energy output in response to high frequency. This will become an increasingly important attribute as the percentage of variable energy resources in the supply portfolio increases over time.

6.7 Active Power Control

Variable energy resources must have the ability to limit active power output. The ISO's concern is if a line trips that forces a large solar photovoltaic resource off-line, when the line comes back in service, the ISO must have the ability to control the resource's ramp back on the system, i.e. the ISO would not want such a resource to instantaneously ramp its full energy output onto the grid the second the line comes back into service. Thus, ISO operators need the ability to instruct variable energy resources to limit power production, or disconnect from the system, for reasons that include the following:

- Risk of overloads because of congestion;
- Risk of islanding;
- Risk to steady state or dynamic network stability;
- Frequency excursions;
- Routine or forced maintenance; and
- Reconnecting to the system post-contingency

The ISO will further consider what active power control should be required to minimize this reliability impact.

6.8 Loss of Distributed Energy Resources

FERC Order No. 661 A states that a wind resource should not disconnect from the system in the event voltage drops to zero and remains there for as long as 150 milliseconds at the point of interconnection. NERC draft standard PRC-024 extends this requirement to all generators.

Likewise, it is desirable for distributed energy resources to remain connected to the system during fault conditions for the same duration, i.e., 150 milliseconds to maintain power system dynamic stability.[5] It may be possible to mitigate the impact of nuisance tripping during under-

[5] This requirement does conflict with IEEE 1547 standard which requires that inverter-based generation trip off-line for low voltage faults near the generator inverter terminals.

voltage and under-frequency events by expanding a resource's ride-through requirements. One issue created by expanding the ride-through capability is that distributed energy resources must avoid unintentional islanding that can occur when a circuit-level breaker opens.

7 Market Design Framework

This section presents the ISO's proposal for managing the reliability impacts from increasing numbers of variable energy resources and other emerging technologies on the grid and for resolving existing market-design challenges. The ISO is taking an incremental approach to refining its market, with targeted developments over three timeframes, the short-term- today to 2013, the mid-term, 2013 to 2015, and the long-term, 2015 to 2020. The ISO has purposely overlapped the three time periods because the current proposal is a market evolution rather than a market transformation, i.e. the periods conveyed do not represent explicit hard "cut over" phases. The primary focus of the Renewable Integration Phase 2 effort is on the mid-term, 2013 to 2015 and the immediate preparations needed to reliably absorb the anticipated ramp up in the number of variable energy resources in this timeframe. The following section describes what enhancements and features the ISO is proposing within each of the three timeframes, balancing ISO objectives against the stated design principles and prudently taking into consideration market and seams issues in the west.

The enhancements the ISO proposes build on the basic ISO market structure of security constrained unit commitment, economic dispatch and locational margin pricing; these elements of the market are fundamental to aligning market signals with operating needs, grid conditions and the laws of physics and are not anticipated to change with what is being proposed in this initiative.

The remainder of this section describes the ISO market design proposal within each of the three timeframes discussed above.

7.1 Short-term Market Enhancements – Today through 2013

The short-term period, today through 2013, concerns implementing market enhancements already on the books or soon to be developed. Stakeholders may already be familiar with some of these enhancements; however, for convenience, a description of what primary market design enhancements are to be implemented in this time period is provided below, including Table 1, which summarizes the primary day-ahead and day-of market changes in the short-term.

Table 1: Short-term Market Enhancements Summary

Short-term Market Enhancements (Today through 2013)	
Day-ahead Market Proposal	
Energy	
• **External Resources**	
– *Static schedules*	– No modifications proposed at this time
– *Dynamic transfers*	– Implement dynamic transfers policy as approved by FERC (implement 2013)
• **Internal Resources**	–
– *Renewables*	– Implement Regulation Energy Management (implement spring ’12)
– *Conventional &* – *Non-intermittent*	– No modifications proposed at this time
• **Convergence Bidding**	– No convergence bidding at the ties
Ancillary Services	
• **Non-spin**	– No modifications proposed at this time
• **Spin**	– No modifications proposed at this time
• **Regulation**	– No modifications proposed at this time – Procurement targets may increase – Regulation Energy Management implementation (implement spring ’12)
Integration Service	
	– Implement flexiramp constraint with opportunity cost compensation (implement Dec ’11)
RUC	
	– 72-hour RUC implementation (spring ’12) – More granular modeling of VERs and, therefore, more accurate RUC target
Day-of Market Proposal	
Market Closing	
	– T-75-minutes
Energy	
• **External Resources**	
– *HASP*	– No modifications proposed at this time
– *Static schedules*	– No modifications proposed at this time
– *Dynamic transfers*	– Implement dynamic transfers policy as approved by FERC (implement 2013)
• **Internal Resources**	–

– *Renewables*	– No modifications proposed at this time
– *Conventional &* – *non-intermittent*	– Start-up and shutdown profiles – Multi-stage Generator enhancements – Non Generator Resource model (REM implementation)
• **PIRP**	– RIMPR Phase 1 changes (implement fall '12)
• **Convergence Bidding**	– No convergence bidding at the ties
Ancillary Services	
• **Non-spin**	– No modifications to product
• **Spin**	– No modifications to product
• **Regulation**	– No modifications to product – Regulation Energy Management implementation (implement spring '12)
• **Frequency Responsive Reserve**	– TBD. Going to NERC board May 2012
Integration Service	
	– Implement proposed flexiramp constraint (implement Dec '11)

7.1.1 Regulation Energy Management

The ISO's renewable integration studies highlight the potential need for additional procurement of both regulation up and regulation down. As shown in Table 2 below, the ISO estimated in its 20% RPS Study that regulation requirements could increase by almost 40 percent in aggregate during some seasons. This projected requirement is not equally distributed over the operating day: in some hours there may be little additional regulation required, but in others the requirement could be up to three times greater than currently procured to address significant wind and solar ramps.

Table 2: Percentage Increase in Total Seasonal Simulated Operational Capacity Requirements under 20% RPS, 2012 vs. 2006*

	Spring	Summer	Fall	Winter
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

* Note that 2006 is used as a benchmark year to calculate the incremental operational requirements

The ISO's 33% RPS operational simulations suggest continued increases in regulation requirements, with higher regulation ramp rates, depending on where the variable energy resources are located in the west and technology type. The ISO believes that reducing participation barriers now of non-generation resources in regulation markets will help prepare the power system for future operational requirements under a 33% RPS by adding new regulation capability.

The regulation energy management product will allow non-generator resources to bid their capacity into the ISO's regulation market more effectively and consistent with the continuous energy requirements for regulation service set forth in the ISO tariff. Under REM, a non-generator resource may bid or self-schedule capacity equal to four times the maximum energy it can generate or curtail for 15-minutes. The ISO will manage the resource's operating set point. For limited energy storage resources, the ISO will discharge the resource for regulation up and will charge the resource for regulation down. The ISO will use offsetting dispatches of energy from the real-time energy market, if necessary, so that the resource can satisfy its regulation capacity award. For a demand response resource, the ISO will also manage the resource's operating set point within its capacity range to provide regulation service. The ISO will adjust its forecast of demand for the next real-time dispatch interval (7.5-minutes before real-time dispatch) to offset the energy generated or curtailed during the previous interval's regulation energy dispatch.

7.1.2 Dynamic Transfer Policy

Under the dynamic transfer proposed policy approved by the ISO board of governors on May 19, 2011, intermittent resource scheduling across an intertie may reserve more transmission than what the resource is actually using at any particular time given the variable nature of the resource's energy output. [6,7] Thus, energy flowing across an intertie at any particular time may represent a fraction of the actual transfer capability of that transmission path even though market awards may reserve all of the available transmission, causing that transmission path to appear congested. If the ISO better understood how a dynamically scheduled resource's output varies within the operating hour, then the ISO could help minimize the under-utilization of transmission capacity.

To ensure a more efficient dispatch of all ISO resources over the real-time operating horizon, the ISO is filing with FERC a dynamic transfer proposal. This dynamic transfer proposal provided a scheduling option to eligible intermittent resources to submit dynamic schedules to the ISO, for reasons other than price-responsive dispatches or response as regulation reserve, to account for variation in their energy output within the operating hour.[8] This mechanism will allow the ISO to maintain efficient operation of its interties and internal transmission by dispatching other resources that can respond to the availability of transmission, in two ways: (1) the ISO will be

[6] Materials related to the governing board's approval are provided in Attachment G to this filing and are available on the ISO's website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx.

[7] Final Dynamic Transfer Proposal: http://www.caiso.com/Documents/FinalProposal-DynamicTransfers.pdf

[8] Non-intermittent resources already have the ability to report reductions in their availability through the ISO's "SLIC" outage reporting software system. Intermittent resources are also expected to report reductions in their availability that are due to equipment outages or derates, but SLIC is not designed to be able to handle the very frequent changes in meteorological conditions that affect wind and solar generators.

aware of upcoming changes in delivery from the dynamic transfers, and efficiently dispatch other resources to meet system requirements, and (2) if there is at least one separate, dispatchable dynamic transfer using the same intertie, the ISO can dispatch the other dynamic resource to use the available intertie capacity. The policy has been approved by the ISO Board. If approved by FERC, this dynamic transfer scheduling option is anticipated to be implemented by spring 2013.

7.1.2.1 *Dynamic transfer dispatchability requirements and curtailment rules*

When the ISO's market software awards schedules, it considers known transmission constraints, however, conditions can change after the market runs and reliable operations will require schedule changes if necessary. In the event of a real time derate on the designated intertie or other transmission contingency event in close proximity, it is imperative that dynamic resources, either conventional or intermittent resources be "dispatchable" so as to be able to respond immediately to the dynamic interchange schedule (e-Tag) curtailment.[9]

A key issue with the expansion of dynamic import services will be the ability for intermittent resource to be "dispatchable" and to curtail output in defined increments, immediately responsive to orders by the native or attaining balancing authority. In addition to tariff provisions, this curtailment capability may require the use of special operating procedures that reflect an individual resource's characteristics or equipment that facilitates immediate response to such dispatch instructions. To ensure grid reliability and compliance with NERC Interchange standards, this agreement, along with an understanding of the system resource's operating characteristics, is critical if an overload occurs at the Intertie where this resource has a scheduled import.

In the real-time market, the dynamic transfer resource's availability as reported to the ISO (or as observed from telemetry if the SC has not reported the resource's availability) becomes an upper limit on the ISO's dispatch instructions. If a scheduling coordinator submits an economic bid to reduce output below its resource's availability, the ISO's real-time economic dispatch will schedule the resource at or below its availability. The ability of resources to submit economic bids for decremental dispatch below their availability allows market participants to limit their exposure to negative locational marginal prices that can result from congestion, over-supply, or other system conditions, and provides the ISO with increased flexibility for managing these situations.

7.1.3 **Flexible Ramping Constraint**

The ISO has already implemented several measures to reduce the uncertainty of imbalance conditions expected between HASP and RTD. These measures include: 1) improving consistency between the HASP and RTD forecasts, 2) accounting for hourly intertie ramps when scheduling

[9] E-Tagging of dynamic transfers is necessary for compliance with scheduling standards. The ISO is refining our administration of e-Tags for pseudo-ties within the market systems, based on our experience with the pseudo-tie pilots.

hourly intertie energy in HASP, 3) improving the real-time load forecasting tools, and 4) providing improved guidance to the operators regarding HASP and real-time load adjustment practices. Although these measures have yielded improvements, they do not guarantee sufficient operational flexibility to meet the variability and uncertainty of real-time energy imbalances.

Under its current tariff, the ISO is required to ensure that in operating the ISO markets, the ISO takes necessary steps to ensure a feasible and accurate system dispatch that is consistent with good utility practice. As a result, the ISO can rely on nomograms to establish prudent operating margins to ensure reliable operations under conditions of unpredictability and uncontrollability because of flow volatility.

7.1.3.1 *Description*

The proposed flexible ramping constraint relies on an operator-specified quantity of upward ramping capability, by dispatch interval, which affects the RTPD unit commitment and the RTD dispatch for intervals beyond the binding dispatch interval. The flexible ramping constraint will provide the on-line dispatch capability to efficiently follow net load variations. Additionally, the use of the flexible ramping constraint will reduce the need for the ISO to bias the load forecast in HASP.

The quantity of the flexible dispatch capability needed will be determined by operators using tools that will estimate: 1) the expected level of imbalance variability, 2) the uncertainty due to forecast error, and 3) the differences between the hourly, 15-minute average and actual 5-minute load levels. The expected level of historical imbalance variability will consider the statistical pattern of supply variation including expected variation due to scheduled changes in interchange ramp. Uncertainty due to forecast error will also factor in the historical differences between the hour ahead forecast and the actual load. The ISO will publish the quantity of upward ramp capability used in the constraint for each relevant market process (i.e., RTPD and RTD).

Initially, this constraint will only apply to internal generation resources, and demand response resources that are modeled as supply but not to static import or export schedules. The flexible ramp capability will come from capacity that is not already designated to provide regulation or contingency reserve (*i.e.*, spinning or non-spinning reserve), and will not offset the required procurement of said reserves. This capacity will be available for five-minute dispatch instructions from the RTD, and if dispatched above minimum load, will be eligible to set the real-time locational marginal price subject to other eligibility provisions established in the ISO tariff.

7.1.3.2 *Flexible ramping compensation*

If a resource was not awarded ancillary services in the binding 15-minute interval necessary to reserve sufficient upward ramping capability in any interval across the RTPD horizon, an opportunity cost concern can arise. The ISO is proposing to compensate units that are committed under the flexible ramping constraint based on the flexible ramping shadow price. The flexible ramping shadow price is the resource specific cost of the marginal unit that resolves the constraint.

Since RTPD co-optimizes ancillary services and energy across the entire RTPD horizon, the flexible ramping constraint shadow price in the binding RTPD ancillary service settlement interval will be based on the ancillary services opportunity cost and reductions in energy committed even though the energy price is not binding for settlement purposes.

Since it is difficult to decompose the shadow price to determine only the ancillary services portion, which is financially binding in RTPD, the ISO proposes to compensate resources at the flexible ramping shadow price when the constraint is binding in the first interval. Thus, the ISO proposes to compensate for flexible ramping in RTPD since this is where opportunity cost exists because of the interplay with other market service bids. All resources resolving the constraint will be compensated based on the RTPD shadow price in the binding ancillary services interval only. The compensation will equal the product of the ramping megawatt quantity of capacity that the resource was awarded and the flexible ramping constraint shadow price. All resources used to meet the flexible ramping constraint will be compensated even if a specific resource does not have a resource specific opportunity cost. This is because the shadow price reflects the marginal unit's opportunity cost, similar to how the locational marginal price is based upon the marginal unit and not on an individual resource's bid.

7.1.4 Renewable Integration Phase 1 Market Enhancements

Following is a description of the three key proposals that are currently under development and will be up for Board of Governor approval in October 2011 with implementation fall 2012.

7.1.4.1 *Energy Bid Floor*

The ISO spot markets currently requires that economic bids submitted by scheduling coordinators be no greater than the cap of $1,000 per MWh and no less than the floor of -$30 per MWh. Negative bids serve an important function in the spot markets by providing a strong incentive for resources to curtail energy production from previously scheduled levels, and by demand (including exporters) to increase energy purchases when there is excess supply and over-generation. Currently, there is a limited supply of decremental energy bids available to the ISO to economically dispatch sufficient energy curtailment to balance demand, especially in off-peak hours, which will become increasingly susceptible to over-generation as additional intermittent wind resources come on-line.

Although some resources are constrained from providing decremental bids based on contractual and environmental factors, there are other resources that can physically curtail but cannot economically curtail given the current energy bid floor is too high. The current bid floor level of -$30/MWh is not sufficient to compensate reductions in energy output from variable energy resources who receive additional revenue from outside the ISO market for their energy production, preventing these resources from submitting economical decremental bids.

Market design changes to increase the provision of decremental bids are an important element of the present initiative, to improve the ISO's capability to use market-based optimization to manage over-generation conditions, real-time congestion and possibly system ramps in the future. If there are insufficient decremental bids available for dispatch during these conditions, the ISO must issue non-economic instructions (i.e., instructions that are not based on energy bids) for resources to reduce energy supply to balance the system.[10] For many obvious reasons, these non-economic dispatch instructions result in a less efficient system dispatch. Such instructions are determined by the market optimization through the use of market parameters that are outside the allowable range of economic bids, resulting in costs higher than what could have been provided through economic bids.[11] Over the past year, the ISO has faced numerous instances where there were insufficient decremental bids in the market, indicating the need for the ISO to reduce its bid floor sooner rather than later. Over-generation conditions are anticipated to increase with the growing numbers of intermittent resources coming on-line in the next few years, making the need for this change a high priority.[12]

7.1.4.2 *Bid Cost Recovery*

The ISO's is proposing to change its bid cost recovery rules so that netting occurs separately in the day-ahead and real-time markets. This change will provide a stronger incentive for resources to provide economic bids in the real time, which is vital to managing the grid as more variable energy resources come on-line. Today's method of offsetting day-ahead and real-time market outcomes lowers a resource's bid cost recovery amount. This creates a negative alignment between price incentives and desired bidding behavior. In particular, the incentive to submit economic bids over self-schedules in the real time market to protect a resource from a net shortfall in the day-ahead market. Thus, the netting of costs and revenues across day ahead and real time (i.e., the current BCR structure) is at odds with the intent of the proposal to lower the energy bid floor as it runs at cross-purposes with the ISO's efforts to encourage more decremental bids in real-

[10] This section is written from the perspective of supply resources to simplify the discussion. It should be understood, however, that the energy bid floor is also relevant to demand resources, including both internal load and exporters that may be willing to increase their purchases of energy to relieve over-generation if the price were low enough.

[11] For example, New York ISO has noted in comment on the FERC Notice of Inquiry Seeking Comment on the Integration of Variable Energy Resources that negative LMPs in the absence of sufficient decremental bids has caused wind plants to curtail at higher quantities than would have been necessary if the decremental dispatch was conducted through the economic dispatch function of the ISO. (http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/04/NYISO_Cmmnts_VERs_NOI_041510.pdf)

[12] An indication of the frequency of decremental bid insufficiency is found in Table 4-1 in the 20% RPS Study, (http://www.caiso.com/23bb/23bbc01d7bd0.html) which shows the number of 5-minute intervals with negative prices by season and hour of day from April 1, 2009 to June 30, 2010.

time. Revising the current netting methodology for bid cost recovery in the short-term is important for renewable integration and for lessening the incentive to self schedule.

7.1.5 72-Hour Residual Unit Commitment

In the current day-ahead market process, the Residual Unit Commitment (RUC) function extends the amount of generation capacity committed in the integrated forward market, and provides startup instructions to committed units. RUC determines the gap in demand between the ISO forecast and the IFM scheduled load. RUC relies on the security constrained unit commitment algorithm to extend existing commitments, commit new resources, and to honor transmission constraints, outages, etc. Currently the RUC process considers both short start and long start units for the next 24-hour time horizon. Long start units need between five and eighteen hours to start and synchronize to the grid. RUC issues startup instructions to long start units only.

The extremely long start commitment process in production today is a supply commitment process in which ISO operators can manually issue startup instructions to extremely long start generators (ELS). ELS units have a startup horizon greater than 18 hours. ISO operators can manually issue startup instructions based on submitted bids and good utility practices for the next 48 hour (or longer) time horizon by placing a phone call to the unit's scheduling coordinator. ELS units are committed in the extremely long start commitment process up to minimum load.

The current 24-hour day-ahead market commitment window is incapable of effectively utilizing ELS units in the day-ahead to avoid manual dispatch of these units in the real-time market. The current day-ahead market implementation begins committing units less than 24 hours before the trade day. The day-ahead market does not take full advantage of ELS units that are committed and dispatched at the beginning or toward the end of a trade date. These units have startup times greater than 18 hours and are currently susceptible to cycling instead of commitment to provide long-term generation. Modifying the manual extremely long start commitment processes with RUC functionality can incorporate reliable and less expensive generation, and can help to reduce exceptional dispatch in the real-time market. Similarly the long start units, i.e., units with startup time less than 18 hours but longer than four hours, can also be susceptible to uneconomic cycling.

The ISO intends to extend the day-ahead market process to a 72-hour look-ahead for the RUC part of the day-ahead market rather than a single 24-hour look-ahead process. Extending the unit commitment look-ahead process to a configurable 72-hour period allows the optimization solution to evaluate whether the resource is likely to be committed and online during off-peak hours versus cycling the resource based on the next day's load forecast conditions.

The 72-hour RUC, which is an extension of the RUC functionality spanning over a configurable 72-hour period, including the trade date, aims to provide three benefits: 1) an increase in grid reliability by reducing the amount of uneconomic cycling of resources; 2) an increase in economic efficiency by reducing the commitment costs caused by additional start-ups due to uneconomic cycling and 3) optimized commitment decisions of ELS resources.

The 72-hour RUC is achieved by extending the RUC to look ahead over a configurable default 72-hour period (TD+1, TD+2, TD+3). Under the following three cases, this will allow:

1. For extra long start units, i.e., units with startup times greater than 18 hours, if they are committed in the second or third trade day (TD+2, TD+3), 72-hour RUC will propose binding commitment decisions and commitment instructions for the second and/or third trade days;
2. For extra long start unit, i.e., units with startup times greater than 18 hours, if they are committed in the trade day (TD+2) and do not meet the minimum up time, 72-hour RUC will ensure the initial condition to be binding (ON) at the end of the trade day;
3. For units between extra long start and short start time frames, i.e., units with startup times shorter than 18 hours and longer than 4 hours, if committed for the last four hours of the day and they are still on at the end of the day, 72-hour RUC will ensure the initial condition to be binding (ON) at the end of first trade day when running the next days' day-ahead market.

The ability for operators to view (via a GUI) non-binding long start and binding extremely long start units' commitment decisions on TD+2 and initial conditions at the end of TD+2 which will help ensure better, more efficient unit commitment decisions.

In Case 1 above, the commitment decision in the second trade day is binding but the energy and ancillary services bids in the subsequent day-ahead run for the second trade day can still be used to determine the optimal schedule and capacity.

In both Case 2 and 3, above the commitment decision for the second trade day is not binding, only the initial condition is. This will allow the subsequent day-ahead market to ensure the unit is still on at the beginning of the second trade day. However, the commitment decision will still be optimally determined by the subsequent day-ahead market run for the second trade day.

7.1.6 More Granular Variable Energy Resource Forecasting for RUC

Eligible variable energy resources (VERs) have the opportunity to bid or schedule in the day-ahead market. Consequently, the ultimate quantity scheduled from VERs may differ from the ISO forecasted deliveries from VERs. Under the current tariff, the ISO has the authority to adjust the forecasted demand either up or down for such differences by RUC zone where the VERs reside. The ISO intends to increase the granularity of the RUC zones to include VER zones to better capture locational VER forecast variability. To the extent the scheduled quantity for a VER in integrated forward market is less than the quantity forecasted by the ISO, the ISO makes a supply-side adjustment in RUC by using the ISO forecast quantity for the VERs as the expected delivered quantity. However, to the extent the scheduled quantity for VERs in the integrated forward market is greater than the quantity forecasted by the ISO, the ISO makes a demand-side adjustment in the VER zone equal to the difference between the day-ahead market schedules and the ISO forecasted quantity.

The ISO uses a neural-network forecasting service/software to forecast deliveries from VERs based on the relevant forecasted weather parameters that affect the applicable VERs. The ISO monitors and tunes forecasting parameters on an ongoing basis to reduce intermittent forecasting error.

7.1.7 Startup and Shutdown Profiles

The ISO continues to enhance modeling of the startup and shutdown of generating resources to better account for the energy delivered during these periods in the ISO's real-time energy imbalance calculations. In the current implementation, a unit that is starting is assumed to jump to its Pmin at the startup time, and a unit that is shutting down is assumed to jump from Pmin to zero at the shutdown time. To better account for the energy delivered during the startup and shutdown, the ISO plans software enhancements to calculate linear startup and shutdown profiles corresponding to a unit's startup and shutdown ramp times. In cases where the startup and shutdown ramp time is zero, the startup and shutdown ramp will be instantaneous. Figure 1 illustrates the startup profiles for a sample generating unit that requires 30 minutes to ramp from zero MW to Pmin.

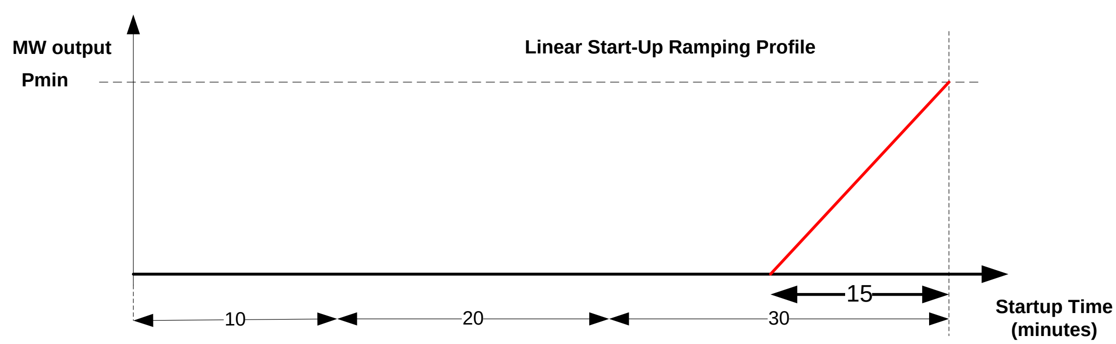

Figure 1: Linear Startup Profile

The Real-Time Unit Commitment (RTUC) application will determine commitment and send the binding instructions. From that point forward and until the startup time expires, RTUC will consider the unit to be in the startup phase and will use the appropriate megawatt value from the unit's profile. The startup profile is provided under an optional generator attribute in the ISO master file and, at the application level, can be "turned-off" if needed. If this feature is turned-off, the application will treat the resource the way it does today when determining the ISO's' imbalance energy needs, i.e. it will "jump" from its current telemetry value to Pmin at the scheduled start-up time and then ramp from there.

7.1.8 Enhanced Contingent/Non-Contingent Operating Reserve Management

ISO operators consistently monitor available operating reserves and take actions to maintain or recover any deficiency. Recovering from a deficiency is generally accomplished by procuring extra real-time contingent operating reserves and or by converting procured day-ahead non-contingent operating reserves to contingent reserves. The consequence of this conversion is that it deprives the 5-minute real-time market of the capacity it needs to meet sudden changes in real-time system conditions. Moreover, under the current design, any time incremental reserves are procured in the 15-minute RTUC process, all reserves on such resources are made contingent reserves even if the award was made in the last hour in STUC and even if the resource was awarded only a small megawatt quantity, regardless if the resource had non-contingent operating reserve awarded in the day-ahead market.

Additionally, under the current design, the ISO attempts to acquire 100% of its operating reserve requirement in the day-ahead market. If part of the procured day-ahead operating reserve is disqualified due to a resource derate or forced outage, the disqualified capacity amount is replaced with a similar amount of operating reserve in the 15-minute RTUC process regardless if the replaced amount is actually needed in real-time based on WECC reliability criteria.

The ISO plans to enhance the way it manages operating reserves. The ISO intends to designate the entire procured operating reserve amount as contingent or non-contingent based on a resource's contingent/non-contingent flag set in the resource's bid. The ISO will use this designation for any procured operating reserve amounts in the day-ahead market. If any additional spin or non-spinning reserves is needed and procured in real-time, only the incremental procurement will be considered contingency-only (today, both the initial and any additional amounts are designated as contingent reserve even if the initial amount procured in day-ahead is non-contingent). With this enhancement, if a resource is flagged as non-contingent in the day-ahead, the amount of spin and non-spinning reserve procured in the day-ahead would remain non-contingent. Alternatively, as the ISO enhances the management of non-contingent reserves in real-time, the ISO may propose changes necessary to maintain the resource's contingent or non-contingent flag status used in day-ahead market when procuring incremental amounts of reserves in real-time to maintain minimum required operating reserves.

The dispatch of the non-contingent and contingent reserves shall be protected against the premature use of the available capacity with contingent capacity being protected at a higher penalty price than non-contingent reserves. This protection scheme will also help in the automatic restoration of previously dispatched reserves.

If the operator calls for a contingency dispatch, then both non-contingent and contingent reserves are available for energy dispatch without any protection of capacity, and the original energy bid prices are used locational marginal pricing calculations for both the contingent and non-contingent amounts.

7.2 Mid-term Market Enhancements — 2013 through 2015

The mid-term period, 2013 through 2015, is the immediate and primary focus of this initiative. To achieve the desired implementation targets in this period, the ISO intends to work with stakeholders to complete the detailed planning and design of proposed market enhancements in time to obtain Board approval by year-end 2012. The market enhancements developed for this period will build on the short-term enhancements in a manner that will enable ISO market and grid operations to manage the size and scope of the renewable integration challenges anticipated in the 2013 to 2015 timeframe.

7.2.1 Introduction

The initial straw proposal contemplated significant enhancements to the ISO real-time market. These enhancements included the creation of a totally new capacity product, Real Time Imbalance Service (RTIS), which would be dispatched, possibly based on economic bids, on a one-minute basis to balance the grid, enabling regulation to be a bi-directional service used for very short-term grid balancing. The initial straw proposal also included an option that would modify the real-time market to a 15-minute energy dispatch and pricing structure and use the RTIS to balance the grid between market runs. The ISO proposed moving to more granular scheduling for intermittent resources, suggesting that RTIS could be a proxy for integration costs.

Stakeholders submitted numerous comments on the initial straw proposal. While there were many positive comments on the ISO proposal, there was a general consensus concerning a mismatch between the scope of the ISO proposal and the compressed timeline for getting to a final proposal in early November. In considering the comments, the ISO realized that it took on more than we – ISO and stakeholders – could manage this year. Rather than completely dropping the initial proposal for the real-time market, the ISO will postpone the discussion of long-term market design changes until next year, focusing on incremental market enhancements that can be implemented with reasonable cost and effort over the next few years.

This does not mean that the ISO has scrapped the ideas behind the more fundamental changes that were proposed in the initial straw proposal. As mentioned above, these concepts deserve further discussion; indeed, the market vision and roadmap to be presented to the Board in December will outline a timeline for proceeding with discussions on long-term market enhancements. However, the market enhancements outlined in this paper and to be implemented in the short-term and mid-term will help develop the experience necessary to assess if more comprehensive market enhancements are needed as were discussed in the initial straw proposal. The proposed short-term and mid-term enhancements will:

- Address existing and anticipated market concerns for the 2013-15 time frame until more comprehensive solutions can be developed; and
- Move the ISO closer to a long-term, flexible market structure envisioned in the earlier paper.

The ISO proposes the following four enhancements to the existing markets and structures for the mid-term, 2013 to 2015. Each is designed to address specific operational and or market needs in alignment with the guiding principles.

- Create a flexi-ramp product;
- Provide variable energy resource forecast updates;
- Allow PIRP resources to submit decremental bids to curtail; and
- Modify the pricing and settlement of hour-ahead interchange schedules.

7.2.2 Flexi-ramp Product

7.2.2.1 *Introduction*

As explained in the section on short-term enhancements, the ISO is currently proposing to institute a flexi-ramp constraint in the real-time market to ensure that sufficient ramping capacity is available for 5-minute real-time economic dispatch. This constraint may mean that some generation, identified as flexi-ramp capacity, is held unloaded in the unit commitment run. For the short-term, the ISO is proposing that resources be compensated based on the "opportunity cost" that resource incurs for capacity that is held unloaded as flexi-ramp capacity, but which could have earned revenue through an ancillary services award and or non-binding energy dispatch. As numerous commentators, including the Market Surveillance Committee (MSC), have noted, this opportunity cost as calculated by the ISO may not actually match the true costs to the generation of having its ramping capacity withheld as flexi-ramp.

One of the principles outlined for this initiative is to use market based products and services to procure what is needed to run the market through competitive processes. That is exactly what the ISO is proposing for the mid-term – to create a product for which suppliers will submit bids to provide and then be paid for providing in a manner that provides incentives to perform as directed. While this goes considerably farther than the flexi-ramp constraint proposed for the short-term, the flexi-ramp product does not go as far the Real Time Imbalance Service (RTIS) of the initial straw proposal. RTIS as envisioned in the previous straw proposal would be like regulation in that it would be dispatched through a separate mechanism from the real-time economic dispatch using only RTIS resources and would not set real-time energy prices. In contrast, the flexi-ramp product proposed here is a capacity-only product whose energy in dispatched in and can set the prices for the real-time dispatch.

The flexi-ramp product proposal differs from the current flexi-ramp constraint proposal in that it would encompass both a flexi-ramp up product and a flexi-ramp down product, comparable in that way to today's regulation up and regulation down products. In contrast, the short-term flexi-ramp constraint only envisions procuring ramping resources to meet upward ramping needs. The mid-term proposal will therefore be an important improvement due to the expected increase in over-generation situations as large amounts of renewable resources are added to the resource mix. The ISO proposal would allow for the up and down flexi-ramp to be different products.[13] Indeed, the amount of each product procured for each operating interval will likely be different.

The ISO recognizes that another important improvement to flexi-ramp as a product is that defining it as a product allows us to consider procuring it in the day-ahead market. Exactly how this will be done will be a topic for further discussion. The ISO believes that procuring flexi-ramp in the day-ahead market will involve coordination between the RUC procurement and the IFM. This is because determining how much flexi-ramp to procure day-ahead requires the ISO to estimate how much variability and ramping needs will exist next day. Unlike RUC, where the procurement target is based simply on the supply gap between resources committed in the IFM and the hourly load forecast for the next day, the estimation of variability and ramping needs does not directly fall out of the demand and supply bids and estimates used in the IFM and the results of the IFM optimization. Instead, a day-ahead flexi-ramp procurement target will require the ISO's best judgment and other information to determine if extra amounts of ramping capability within a defined period should be designated for real-time availability. At the same time, it should be obvious that a portion of the capacity that is on-line due to a RUC commitment may also be able to provide ramping services, and similarly, any flexi-ramp capacity procured day-ahead can also be used as RUC capacity. Since not all capacity will have the same ramping capabilities, the coordination between RUC and day-ahead flexi-ramp procurement will not likely be as simple as each procurement process looking at how much of the other is procured, but will require that the optimization be done together. The required coordination between a day-ahead flexi-ramp procurement and the RUC also suggests that we might want to consider co-optimizing the IFM and RUC in the day-ahead market.

While flexi-ramp product will be similar to other ancillary services that the ISO currently procures, such as spinning and non-spinning reserves and regulation, there is one difference that needs to be addressed. Regulation is dispatched through the EMS system and AGC and the

[13] The ISO envisions that variable energy resources could offer downward flexi-ramp capacity by providing decremental bids associated with their energy self-schedules, which would enhance the ISO's ability to meet downward ramping needs through the real-time economic dispatch without resorting to non-economic curtailment.

dispatch of regulation capacity does not figure into the market clearing price determination. Spinning and non-spinning reserves can set market prices, but are only able to be used (and thus set prices) during contingencies or when critical shortages or emergency conditions are present. Unlike both of those situations, the energy from resources selected for flexi-ramp will be used in the normal RTD runs and will likely be involved in setting prices in most intervals. The extent to which flexi-ramp capacity is dispatched and sets prices in the normal RTD process may need to be managed, however, by introducing a parameter in the market optimization to maintain sufficient flexi-ramp capacity over the RTD time horizon where ramping needs are expected to persist; this will be a topic for further discussion.

Currently, when the market procures ancillary services the optimization considers the capacity bids from the resources, and considers their energy bids only for purposes of optimizing between scheduling each resource for energy or awarding it ancillary services. Importantly, the market does not utilize the energy bids for the purpose of optimizing the cost of dispatching the reserves to provide energy. That is a reasonable mechanism since their energy bids do not set market prices (in the case of regulation) or will only set prices in rare contingency or shortage periods (spin and non-spin). For the procurement of flexi-ramp capacity, however, the ISO would like the market to also consider the cost of dispatching this capacity based on its energy bids. One of the main purposes of the flexi-ramp product is to ensure that there is sufficient ramping capacity on line so that spurious price spikes (i.e., spikes that occur due to shortage of ramping capacity when there is no shortage of energy), do not occur in the RTD. But if the energy bids from the flexi-ramp units are extremely high, either because they were not considered in the procurement of the flexi-ramp capacity or they were raised in the real-time submission after the capacity was procured in the IFM, there could still be significant price impacts in real time as flexi-ramp resources seek to maximally profit from their IFM awards.

Differences in the short-term between a future flexi-ramp product and the proposed flexi-ramp constraint must be resolved. For instance, unlike the short-term flexi-ramp constraint, flexi-ramp product revenues and associated bid costs will likely need incorporation into the bid cost recovery mechanism. Additionally, performance incentives for a flexi-ramp product will need to be incorporated, and a cost allocation method will need to be developed in the spirit of the cost causation principle.

The ISO believes that it is important that those resources receiving capacity payments for providing flexi-ramp have incentives to accurately follow the dispatch instructions issued to them. While the ISO expects all resources to follow dispatch instructions, those receiving payments for standing ready to respond have a greater obligation to respond. Thus, the ISO is considering how to develop effective incentives for flexi-ramp resources to perform as dispatched.

7.2.2.2 *What is the flexi-ramp product?*

The ISO is proposing that the flexi-ramp product will be reserved ramping capacity procured in the day-ahead market and in the real-time market. Procurement will include both up and down quantities, procured as separate products and potentially with different procurement targets, capacity bids and clearing prices.

The actual product being procured will be the amount of ramping capacity, in terms of MW/X mins, that can be delivered in a specific period of time. The ISO sees different possibilities for the time period. One would be five minutes, so the product would be the amount that the resource could move in response to one RTD dispatch. Another possibility would be the amount of ramping capable in ten minutes, which would correspond to the current criterion for other types of ancillary services. The amount could be set at 15 minutes, which would correspond to the time interval in RTPD where the flexi-ramp capacity will be procured in real-time. The ISO seeks stakeholder's comments on which option makes the most sense.

Flexi-ramp resources would have to satisfy a simple qualification and minimum ramp rate level. Units currently certified to provide ancillary service capacity would automatically qualify, and other units that wish to qualify would be evaluated based on their historical ramp rate and dispatch performance. Units would be required to have on-file a registered Pmin, Pmax, and a ramp curve. Units that provide flexi-ramp capacity would submit a bid along with the existing components of a bid. To avoid having a downward constraint from distorting economic dispatch, consideration how variable energy resource curtailment can be used to meet a downward constraint shall be considered.

In real time, the flexi-ramp product would be procured every 15 minutes in the RTPD, similar to the procurement of existing ancillary services. As mentioned above, one difference from the current procurement of spin and non-spin would be incorporating the energy bids into the selection of the flexi-ramp capacity for the purpose of considering the expected cost of dispatching this capacity for energy in the optimization. Since contingency-only spin and non-spin are dispatched only in contingency conditions, the energy bids will have minimal impact on real-time prices and total market costs, since it is less likely that energy from those units would be dispatched. The same does not apply to flexi-ramp capacity. The energy from these units will be included in the real-time energy market, and to the extent that the flexi-ramp capacity is actually needed, it will be dispatched and eligible to set the real-time locational marginal price. For many flexi-ramp units, this will occur much more frequently than the dispatch of a spin or non-spin awarded resource.

To illustrate this point, consider two resources that both offer 12 MW for flexi-ramp. Unit A bids $6 per MW/min for capacity along with a $36 energy bid. Unit B bids $5 per MW/min for capacity, but $240 for energy. Choosing only based on the capacity bid would result in Unit B being chosen at a savings of $12. Moreover, because the optimization does consider the energy bids of resources for purposes of optimally awarding ancillary services versus scheduling the resource to provide energy, Unit B will look even more attractive as a provider of flexi-ramp capacity. However, if we consider the cost of dispatching the resource for energy for a 5-minute period (1/12 of an hour), then Unit B looks less attractive. Either unit would provide 1 MWh of energy during the interval. The energy from Unit A would cost $36, while the energy from Unit B would cost $240, a difference of $204. In this case, even if the probability of dispatching the energy was only 50%, the expected cost of Unit A would be $72 + 50% * $36 = $90. The expected cost of Unit B would be $60 + 50% * $240 = $180.

If the energy costs are taken into consideration when procuring flexiramp, then the meaning of the marginal prices for the flexiramp product needs to be carefully understood. It should be noted that including energy costs may result in flexiramp shadow prices that could be higher level than the shadow price of the load balance equation or the system energy marginal clearing price. Therefore, the settlement implications of considering the energy costs corresponding to flexiramp capacity should be carefully considered and linked to locational marginal prices used to compensate the dispatched flexiramp energy in the 5-min RTD. The ISO seeks stakeholder comments on whether they agree with this assessment, and invites suggestions as to how appropriate optimization and pricing could be done.

Flexi-ramp capacity would also be procured on an hourly basis in the day-ahead market. This will take place in the integrated forward market, but as explained above, would need to be coordinated with the RUC process. The ISO proposes that the procurement of RUC capacity be optimized together with the procurement of flexi-ramp and the other ancillary service products in the integrated forward market. Determining procurement targets for flexi-ramp and RUC must be done together since the capacity procured under each of these mechanisms will generally offset the need for the other resources. The ISO seeks comments on the co-optimization of RUC and flexi-ramp in the day-ahead market. As in the real-time market, the ISO would like the selection of flexi-ramp in the day-ahead markets to evaluate the energy bids as well as the capacity bids. In order for this to be effective, the energy bids used in the optimization should not change from the integrated forward market to the real-time market, at least for the capacity that is awarded flexi-ramp. Otherwise, gaming opportunities arise in which resources could put in a low energy bid in the day-ahead market to ensure they were awarded flexi-ramp capacity payments, but in real-time, could modify those bids to be very high, knowing that there is a good chance that they would be needed in real time to provide energy. Thus, the ISO proposes that for units selected to provide flexi-ramp, their energy bids for the real-time markets cannot exceed the bids submitted to the day-ahead market corresponding to the capacity that was awarded flexi-ramp. The ISO seeks comments on this.

The ISO seeks stakeholder input on how flexi-ramp capacity would fit into the structure of all ancillary services. Specifically, the ISO is interested in how flexi-ramp capacity might be incorporated into the cascading provisions whereby higher-quality ancillary services may be procured to meet the procurement targets for lower-quality services. Under today's cascading provisions, units that can supply regulation can also be chosen for spinning or non-spinning reserves, and units that could provide spin can be selected for non-spinning reserve; however, a unit that can provide only non-spinning reserve cannot be used to provide spinning reserve.

7.2.2.3 *How procurement targets are set*

An important question is how the ISO will determine how much flexi-ramp to procure. Certain aspects of this seem obvious – that the amount procured will likely differ depending on the time of year, time of day and the trajectory of load. Other aspects will be related to the amount of variable energy resources on-line and the potential vulnerabilities that presents with weather disturbances. For example, if there are very few intermittent resources on line, there is little need for flexi-ramp up capacity to meet potential drops in output from the intermittent resources. If, instead, the projection is for large numbers of intermittent resources to be on-line and operating close to their full capacity, there is more need for flexi-ramp up capacity to address the potential of those intermittent resources decreasing their output because of a wind over-speed event or clouds blowing over solar PV facilities. At the same time, there is little need for flexi-ramp down capacity to meet an increase in intermittent resource output, because with the intermittent resources producing near their capacity, there is minimal chance for an increase in intermittent output to cause over-generation.

The ISO proposes to construct models to estimate the statistical variability expected in each period due to the load, intermittent resources and other factors, such as weather forecasts and predicted forecast errors and ramping needs of conventional generation. The ISO proposes to use a 95% confidence interval in selecting the target amounts of flexi-ramp to procure. That is, the ISO would procure sufficient flexi-ramp capacity to manage the expected range of real-time variability in load and resource output that would be exceeded statistically by no more than 5% of the time. The ISO seeks stakeholder comments on the factors that should be used in creating these statistical estimates and whether 95% is an acceptable confidence interval.

7.2.2.4 *How will the cost of flexi-ramp be allocated?*

An important decision is how the cost of flexi-ramp will be allocated. Based on comments received from stakeholders on the initial straw proposal, it is the desire of the ISO and stakeholders that costs should be allocated to those driving the need based on actual performance. While there is majority agreement on the "cost causation" principle, moving beyond the general principle is much harder. The ISO is seeking specific suggestions from stakeholders as to how to formulate cost allocation based on the cost causation principle spelled out in section 5.

To facilitate the discussion of cost allocation, the ISO offers these possibilities:

- Since the procurement target for flexi-ramp is based primarily on a statistical calculation of the expected variability of load and intermittent resources, the cost of flexi-ramp might be allocated to load and supply deviations from integrated forward market schedules or instruction, and renewable resource deviations from their forecast-based schedules.

- Based on comments received on the initial straw proposal, cost would be allocated to all market participants based on their deviations from their scheduled or instructed energy (i.e., their uninstructed deviations). For supply resources this might be measured as:

$$\Delta \text{ Supply} = \text{Supply}_{\text{Actual}} - (\text{Latest DA}_{\text{schedule}} \text{ or } \text{RT}_{\text{self-schedule}} \pm \text{IIE}_{\text{ISO dispatch}})$$

Where:

  - $\text{DA}_{\text{schedule}}$ = Day-Ahead binding energy schedules
  - $\text{RT}_{\text{self-schedule}}$ = the self-schedule submitted into real-time
  - IIE is the Instructed Imbalance Energy from ISO optimal energy dispatches, or AGC signals for regulation (alternatively regulation resources would be excluded)
  - For non-dispatchable resources, IIE would generally be zero unless the market issues a decremental dispatch based on the use of penalty prices for non-economic adjustments
  - Positive supply deviations should be allocated downward flexi-ramp costs, and negative supply deviations should be allocated upward flexi-ramp costs

For load, deviations would be measured as follows:

$$\Delta \text{ Load} = \text{Load}_{\text{Actual}} - \text{Load}_{\text{DASchedule}}$$

Where:

  - $\text{Load}_{\text{DASchedule}}$ = Day-Ahead hourly load schedule
  - Positive load deviations should be allocated upward flexi-ramp costs, and negative load deviations should be allocated downward flexi-ramp costs

- A possible variation is to utilize a two-tier allocation to limit the flexi-ramp rate allocated to the deviation equations above, where the flexi-ramp rate is the total amount of flexi-ramp divided by the maximum of: 1) the sum of the scheduling coordinator's upward obligations and 2) the total amount of energy dispatched from the flexi-ramp upward capacity. The maximum amount allocated to tier 1 would be based on the megawatts of deviation based on the deviation equations above, with any excess amount spread to metered demand.

7.2.2.5 *How to ensure performance?*

Since resources providing flexi-ramp are receiving a capacity payment for standing ready to provide their energy, performance in following instructions is a critical part of providing flexi-ramp. The ISO is proposing that if a resource's response to dispatch instructions are outside a tolerance range, the resource might:

- Forfeit the capacity payment for providing flexi-ramp similar to no-pay;
- Possibly have an additional penalty applied;
- After several incidents of non-performance, the resource would no longer be certified to provide flexi-ramp.

In addition to imposing performance standards, flexi-ramp could also serve as an incentive for all generators to follow dispatch instructions. This would be as a result of the deviation-based allocation methodology which would allocate less flexi-ramp costs to those generators and loads that have smaller deviations.

7.2.2.6 *How are suppliers assured they will be made whole?*

The ISO proposes that a resource's revenues and bid costs associated with flexi-ramp would be included in the bid cost recovery mechanism. This will ensure that in a case where the marginal price is less than a resource's capacity bid, any net overall revenue shortfall would be made up through the bid cost recovery mechanism, in accordance with the applicable bid cost recovery rules.

7.2.3 **Alternative Proposal to a Flexi-ramp Product**

A suggested alternative to a flexi-ramp product is for the ISO to procure more non-contingent spinning reserves. When these capacity resources are in excess relative to actual demand needs and not required to meet the reliability requirements of the grid, these resources could be released into the real-time energy market to provide additional capacity and ramping services. To keep them from dispatch until needed, the ISO could assign a bid adder in the scheduling run. This would ensure that other resources were taken for energy first, and that these non-contingent spinning reserves could be dispatched after all other available resources. This approach has two major issues. First, it likely requires that the ISO treat contingent and non-contingent capacity bids differently, with a constraint on the amount of contingent spinning reserves that could be purchased to ensure a sufficient supply of non-contingent capacity. This likely means different prices for contingent and non-contingent reserves. Second, such a mechanism only provides upward ramping capacity, and does not address the need for downward ramping capacity. This is not a trivial concern given the recent studies which indicate that over-generation is already a problem and likely to increase as more renewable resources interconnect to the grid. The ISO seeks comments on whether such a mechanism would resolve enough of the issues and if easier to implement.

7.2.4 Variable Energy Resource Availability Updates

One of the concepts discussed in the initial straw proposal was improving the ability of intermittent resources to schedule or update their availability. This increased granularity should help the ISO minimize the need for regulation by improving the accuracy of the real time dispatch. Further, if the costs of variability are allocated on a cost causation basis as majority stakeholders seem to agree they should, then intermittent resources will rightly demand the opportunity to update their availability to limit deviations. This concept is hardly radical, but determining what it actually means may prove a more challenging undertaking.

To launch this discussion, it is important to recognize that in the ISO dynamic transfers stakeholder process, intermittent resources located outside of the ISO and utilizing the dynamic transfers option have two methods to update their availability in the real-time market. One option is to have the ISO use a persistence forecast based on the latest telemetry as the instructed dispatch. The other option is to have the dynamically transferred intermittent resource submit its own forecast of availability every 5-minutes and have this forecast returned to its stated availability during the next 5-minute dispatch interval, including downward adjustments if necessary. Dispatch based on stated availability would be the operating point for the next interval and the basis for financial settlement of instructed and uninstructed energy. This option allows the ISO to utilize the transmission capacity at the interties more efficiently, which raises a question as to whether a similar option should be made available to all intermittent resources. The ISO seeks stakeholder comment on this.

A less radical option for intermittent resources is to allow the existing hour-ahead forecast provided 75 minutes before the operating hour to consist of four different forecasts for each of the 15-minute periods within the operating hour. This would allow solar resources to better match their forecast output to the morning and evening ramps, for example. This option would also allow the ISO to adjust its procurement of flexi-ramp for the operating hour. Further, if deviations from the hour-ahead forecast are used to allocate flexi-ramp costs, this option could provide variable resources a method to reduce expected deviations and thus the allocation of costs. This option would obviously be easier to implement than 5-minute availability updates. The ISO seeks stakeholder comment on how this proposal compares to allowing the 5-minute availability updates provided for dynamic transfers and or whether some other timing for availability updates would make better sense. For example, in the initial straw proposal, the ISO suggested that perhaps 15-minutes was an optimal update under the 15-minute real-time market proposal.

7.2.5 Decremental Bidding from PIRP Resources

A primary ISO objective is to maximize the ability of the ISO's real-time economic dispatch to resolve over-generation and congestion using economic bids. Achieving this objective requires incentives to decrease the amount of resources that are either self-scheduled or unwilling to curtail output based on market mechanisms. In Phase 1 of this initiative, the bid floor is being lowered so that more extreme negative real-time prices will during over-generation conditions or congestion caused by excess generation, which in turn will provide an incentive for resources to provide decremental bids. Initially, the ISO proposed in Phase 1 to limit participation in PIRP so that intermittent resources, which currently do not provide economic bids, would participate in the real-time market and be more responsive to price signals. Due to stakeholder comments, the ISO modified the proposal to continue PIRP, but to allocate any uplifts for recovering the costs of PIRP to the scheduling coordinators that have contracted for the energy from renewable resources that are in the PIRP program. Although this modification improves PIRP by assigning program costs more appropriately, it is unlikely to incent real-time market participation by PIRP resources. Therefore, in Phase 2 of the initiative, to provide PIRP resources with both the ability and the incentive to submit decremental bids and respond to the needs of the grid through market mechanisms, the ISO proposes the following modifications:

- A PIRP resource would be allowed to submit a decremental economic bid in conjunction with its usual hour-ahead self-schedule based on the forecast provided by the forecast service provider. The bid submission would not affect the resource's normal PIRP settlement (i.e., the monthly netting of deviations from the hour-ahead self-schedule) in intervals where the ISO market does not dispatch the bid. At this time, the ISO is still considering whether the PIRP resource will be required to submit a new economic bid for each hour in conjunction with its hour-ahead self-schedule, or should it be able to submit a standing bid that is changed less frequently.

- For intervals where the ISO market does dispatch the resource's submitted bid, the resource's deviation from the hour-ahead self-schedule would be removed from the normal settlement and would be settled at the real-time interval price in accordance with the formula specified below.

- Even if the PIRP resource does not submit a decremental economic bid, the resource's hour-ahead self-schedule would be included in the real-time economic dispatch as a generic self-schedule subject to non-economic curtailment in accordance with provisions of the ISO tariff dealing with non-economic adjustment. As a result, if the real-time market runs out of effective economic bids to resolve over-generation or congestion, the PIRP resource could receive a decremental dispatch instruction for one or more real-time intervals, and for such intervals the resource's deviation from its hour-ahead self-schedule would be removed from the normal PIRP settlement and would be settled at the real-time interval price in accordance with the formula specified below. For intervals where the real-time market issues decremental dispatch instructions under non-economic adjustment, the real-time interval price is typically set at the bid floor.

The principle behind the settlement formula for intervals where the real-time market issues a decremental dispatch instruction to the PIRP resource, either based on the resource's submitted economic decremental bid or based on the self-scheduling penalty price under non-economic adjustment, is that the resource should get paid (i.e., pay the negative price) for MWh it actually curtails below its hour-ahead schedule, but then be charged (i.e., get paid the negative price) for MWh above the dispatch instruction level. Under this approach the hour-ahead self-schedule remains as the reference point for deviations, and is settled in the current PIRP manner regardless of whether a decremental instruction is issued.

The proposed settlement formula would work as follows. For any interval where the real-time market issues a DEC instruction to the PIRP resource, let s = hour-ahead self-scheduled MWh, a = actual (metered) MWh, i = instructed MWh (dispatch instruction) and t = the telemetry registered output of the resource that is input to the scheduling run of the real-time market. Then the deviation that would be priced at the locational real-time price would be:

- If a < t (the resource moved up from its telemetry value), then the deviation for settlement at real-time LMP = MIN[MAX(0,s+i-2a),s]

- If a ≥ t (the resource moved down from its telemetry value), then the deviation for settlement at real-time LMP = MIN(s-a, i-a)

Example 1:

Suppose t = 120, s = 100, i = 80, and a = 80. This is the case a < t, so the first formula applies and the deviation = MIN[MAX(0, 20), 100] = 20. In this case the resource is paid (charged the negative price) for exactly following the decremental dispatch, based on the MWh amount by which its actual or instructed output is below its hour-ahead schedule.

Example 2:

Suppose t = 120, s = 100, i = 80, and a = 85. Same as example 1, except that in this case the resource only partially followed the decremental dispatch. This is the case a < t, so the first formula applies and the deviation = MIN[MAX(0, 10), 100] = 10. In this case the resource is paid (charged the negative price) for partially following the decremental dispatch, but its payment is reduced to reflect the fact that it continued to deviate above the instructed level.

Example 3:

Suppose t = 120, s = 100, i = 80, and a = 125. This is the case a > t, so the second formula applies and the deviation = MIN(-25, -45) = -45. In this case the resource is charged (paid the negative price) for ignoring the decremental dispatch and actually increasing its output.

Example 4:

Suppose t = 120, s = 100, i = 80, and a = 0. Same as example 1, except that in this case the resource reduces its output all the way to zero, beyond the level instructed. This is the case a < t, so the first formula applies and the deviation = MIN[MAX(0, 180), 100] = 100. In this case the resource is paid (charged the negative price) for its entire output reduction below its hour-ahead self-schedule.

A resource that fails to follow the decremental instruction is at risk for 1) the greater of its deviation from either the hour-ahead schedule or 2) the instruction it received. As long as the resource is moving in the correct direction, it won't be charged for positive deviation. If it fails to reduce to where it was instructed, the resource loses some payment for not following the decremental instruction. The ISO seeks stakeholder comments on both the general concept and the specific proposed formulas.

7.2.6 Intertie Pricing

A significant ISO concern is price differences between HASP and the real-time market. This difference has contributed to the Real Time Imbalance Energy Offset uplifts. The ISO is proposing to reduce the Real Time Imbalance Energy Offset by suspending convergence bidding at the interties. While this may reduce the problem associated with intertie pricing, it is not a long term solution. The ISO feels that the ultimate solution may have to wait until the west moves to 15-minute interchange scheduling. The 15-minute market in Option A of the previous whitepaper, combined with the rest of the west moving to 15-minute scheduling for the interties would likely be a good solution to this issue, but this change would likely be a ways off.

Such a solution does not appear implementable any time soon. For the interim, the ISO is considering two potential solutions to the issue of pricing at the interties. The first is to take the NYISO approach. The second is to require interties to settle at the ISO real-time price and hourly schedules settle as price takers without any cost recovery during off-peak periods. Each suggestion is explained below.

7.2.6.1 *The NYISO approach*

This discussion is the same as contained in the ISO's Draft Final Proposal on the Impact of Convergence Bidding on Interties, dated July 29, 2011. That paper concluded that the ISO has reviewed NYISO intertie settlement option and as discussed in the straw proposal for the Impact of convergence bidding on Interties, the ISO concluded that the settlement option is not appropriate at this time, because it could not be implemented immediately. However, the ISO now believes that this may be an appropriate time to consider whether such a procedure provides benefits to the ISO and market participants for the interim until a more permanent solution can be devised.

The NYISO schedules imports and exports in an hour-ahead process that is very similar to the ISO's HASP process. The NYISO process/software tool is called RTC. RTC initializes and runs every 15 minutes, looking forward nine 15-minute intervals in time. In addition to scheduling imports, RTC is used to commit quick start units, primarily 10-minute and 30-minute gas turbines. While RTC runs four times an hour, only one of the four runs is currently used to schedule imports and exports. This run is referred to as RTC15 and initializes at the top of the hour and posts 15 minutes after the hour, with schedules for the hour beginning roughly 45 minutes after posting.

If there is no congestion on the external interfaces in the RTC evaluation, RTC will schedule imports and exports, but the price used for settlements will be the real-time price at the relevant proxy bus, computed as the time weighted average real-time price. However, imports scheduled in RTC receive a bid production cost guarantee that if the real-time price is lower than their offer price, they will be paid their offer price. This introduces a potential pay-as-bid element into the market design that is not ideal, but concluded to be necessary to ensure the availability of import supply. The NYISO, like the ISO, is typically a net importer, and is likely to be a net importer during high load conditions when imports may be important for meeting load.

There is no price assurance for exports scheduled in RTC. If the real-time price turns out to be higher than projected in RTC and higher than the price bid by the purchaser for the export, the export buyer has to pay the real-time price for power. The rationale for the absence of any price guarantee is that the scheduling of exports does not benefit New York power consumers and hence there is no basis for them to bear any uplift costs associated with exports. Neither generators nor exporters have volunteered to bear uplift costs to make exporters whole, so there is no price assurance for export transactions.

The exception to interchange prices being determined in real-time is if the interface is constrained in RTC, so that the offer price of the marginal import is lower than the internal New York price (import constrained) or the bid price of the marginal export is higher than the internal New York price (export constrained). If a proxy bus is import constrained and the clearing price in RTC is lower than the real-time price, the import supplier is paid the RTC price, i.e. a price lower than the internal NYISO price. Conversely, if a proxy bus is export constrained the clearing price in RTC is higher than the real-time price, the export buyers pays the higher RTC price. Thus, congestion does not give rise to shortfalls and uplift but contributes to surpluses in the form of real-time congestion rents.

The NYISO does not allow virtual bids on the interties, but it should also be pointed out that the NYISO does not allow nodal virtual bidding at this time. All virtual supply and demand bids are cleared at zonal prices. As a result, the market optimization for liquidating virtual supply and demand and determining internal zonal prices occur at the same timeframe. Further, since the ISO has eliminated virtual bidding on the interties, similar to the NYISO, there would not be a timing disconnect that could cause price discrepancies between virtuals and physicals.

7.2.6.2 *Clear interties at real-time prices during the off-peak period*

The only way to resolve the issue of two different prices is to price the interties on the same basis as the internal nodes in the real-time market. The problem with this is that since interties are generally scheduled on an hourly basis, hourly interchange schedules would be required to be price takers for the hour. Actually, since the HASP process is actually a version of the RTPD which does not set binding energy prices (they are set in the RTD), market participants bidding at the ties would be price takers in all periods of the hour. Until market participants gain experience with such a settlement, the potential risks to import scheduling might be high, limiting imports into California, which could present a reliability problem during on-peak periods.

If this pricing mechanism were initially implemented only for off-peak hours it would give market participants and the ISO a chance to become comfortable with the concept during periods when price volatility is lower, and when the reliability risks of diminished imports is smaller. Also, it is during off-peak hours that much of the uplift charges in the Real Time Imbalance Energy Offset are generated, so this would minimize the problem at the same time. Further, since in these off-peak periods the interties and other nodes would all be priced consistently, it might be possible to allow convergence bidding at the interties during off-peak hours. This would provide another hedging tool for market participants to use to manage the risks they would encounter from being price takers.

7.3 Long-term Market Enhancements — 2015 through 2020

As discussed above, the changes in this revised straw proposal do not indicate that the ISO has abandoned the ideas in the initial straw proposal and that further discussion of the long-term market are required. The market vision and roadmap to be presented to the Board in December will outline a timeline for discussing long-term market design enhancements.

The incremental and evolutionary market design approach presented in this revised straw proposal will enable the ISO and market participants to develop a better understanding and experience for what market enhancements are needed in the future. Based on this experience, the ISO and its stakeholders can more effectively assess whether significant market design are needed, like those presented in the initial straw proposal, or simply additional tweaks and refinements to prepare for the long-term period, 2015 to 2020. Another important element to inform long-term needs is what changes are happening in the wholesale markets in the west, particularly around interchange schedule timelines and tagging. With this experience and context, the ISO and its stakeholders can consider if fundamental changes to the market are necessary, including, for instance, implementing a 15-minute market as was discussed in the initial straw proposal.

7.3.1 Forward Procurement

The discussion above about the new flexi-ramp product, and its predecessor the flexi-ramp constraint, should make clear that to accommodate anticipated variability, the ISO desires the availability of flexible resources in the real-time market. The results of the ISO's 20% RPS Study and the initial results of the 33% RPS Study indicate that the ISO will face a new set of problems moving into the future. As shown in the 20% RPS Study, conventional thermal resources will decrease the number of hours they run and will receive lower payments for energy delivered, leading to energy revenue reductions of up to 39% for some resources. Additionally, these resources will be subject to an increased number of start-ups, by as much as 35%. This indicates that these resources will face higher costs and reduced revenues that could ultimately lead to many of these resources retiring or shutting down if there is revenue inadequacy. Though California is moving to greater energy output from renewable resources, the increased start-ups for conventional resources actually point to an increased need for the capacity and ramping capability from these conventional, thermal resources. For example, the morning and evening ramps in shoulder months pose unique ramping and load following challenges because the only resources online could be baseload and renewable resources. If resources with the required ramping properties retire due to insufficient revenues, then the ISO would be left with limited ramp capability to account for changing supply and demand conditions.

The ISO believes that, as part of the Renewable Integration Market Vision and Roadmap, it is prudent to consider a mechanism that will ensure that sufficient ramping capacity is available to the ISO to maintain grid reliability. Therefore, the ISO will consider a forward market for capacity resources that can provide balancing capacity. This market would focus strictly on ensuring adequate ramping capacity and is not intended to substitute for or replace the CPUC's resource adequacy program. Though the ISO may seek minimum levels of balancing capacity, additional work with the CPUC would be required to assure capacity procured for the ISO's purposes would also qualify for the CPUC's resource adequacy requirements. Though the ISO would not look to implement such a market until 2015-2020, we understand that such an endeavor is complicated and initial steps need to be taken soon to have all matters resolved in the desired timeframe.

8 Stakeholder Process Timeline

Table 3 below outlines the stakeholder process associated with this initiative. The ISO will post a series of papers starting with the day-of market vision, followed by a day-ahead and forward market vision. The paper series concludes with a comprehensive renewables integration market vision and roadmap for presentation and review by the ISO Board on December 15-16, 2011.

Table 3: Renewables Integration Market Vision and Roadmap Initiative Schedule

Schedule	Item
Sep 12, 2011	Stakeholder meeting
Sep 22, 2011	Stakeholder comments due on revised straw proposal
Oct 11, 2011	ISO post draft final market vision & roadmap
Oct 18, 2011	Stakeholder meeting to review draft final market vision & roadmap
Nov 2, 2011	Comments due on draft market vision & roadmap
Nov 16, 2011	ISO post final market vision & roadmap
Nov 17, 2011	MSC final opinion adopted
Dec 15-16, 2011	ISO Board review and presentation