Commitment Cost Enhancements Phase 2

Revised Straw Proposal

December 22, 2014

Table of Contents

1. Changes from the straw proposal

Section 6 - The ISO provides additional refinements to the proposed use-limited definition and examples of acceptable sources of use limitations. The ISO also provides clarifications on proposed policy for storage, participating load, geothermal, multi-stage generating resources, and imports.

Section 7 - Some stakeholders have suggested that scheduling coordinators should be allowed to calculate opportunity costs with verification by the ISO. While the ISO does not categorically oppose this, the fact remains that we do not currently have a model or methodology in place to verify, modify, or cap submitted costs. Therefore, this initiative aims to work with stakeholders to develop such a model and provide a consistent approach. The ISO agrees with the numerous stakeholder arguments supporting use of natural gas futures rather than outdated historical prices. The ISO has changed the gas basis in the model to use natural gas futures. Also in response to stakeholder requests, we provide an example of the opportunity cost model update process, clarify that opportunity costs for default energy bids will come from this process, and outline the threshold for triggering a model rerun and what happens if a resource reaches its use limit.

Section 8 – In response to stakeholder requests, the ISO provides a more detailed example of the proposed calculation of transition costs.

Section 9 – As many stakeholders have noted, there is still great regulatory uncertainty around the California Public Utilities Commission’s recent proposed decision for the treatment of greenhouse gas obligations for natural gas providers. The proposed decision defers discussion of several key issues to a later phase not yet announced. The ISO agrees with stakeholders that given the regulatory uncertainty, we propose no policy changes to the treatment of greenhouse gas costs until there is more clarity.

Section 11 – This section was added to address a potential three year review of the default variable operation and maintenance costs and whether to establish default major maintenance adders. The new proposals seek to balance additional administrative burden with priority issues for the market. Only one stakeholder expressed support to review current default operation and maintenance costs. ISO seeks feedback on why the existing default costs may need to be reviewed and whether the stakeholder has taken advantage of a negotiated default cost option. Two stakeholders supported using default major maintenance adders and the ISO is open to additional stakeholder feedback. The ISO also reiterates that major maintenance adders must be based on actual costs as already noted in the tariff.

2. Background

Commitment Cost Enhancements (henceforth referred to as Phase 1) had proposed the calculation of opportunity costs for use-limited resources but there was insufficient time to vet the methodology and business rules. This follow-on stakeholder process, *Commitment Cost Enhancements Phase 2*, is narrowly scoped to continue that discussion and provide additional policy clarifications.

During the winter season of 2013-2014, the ISO energy market experienced abnormally volatile and high natural gas price spikes. The ISO was not able to reflect these price spikes in its resource commitment decisions, which led to inefficient resource dispatch. To address the potential for additional natural gas price spikes for the duration of the winter season, on March 6, 2014 the ISO filed with the Federal Energy Regulatory Commission (FERC) a proposed tariff waiver until April 30, 2014 to take remedial action. In the tariff waiver filing, the ISO also committed to commence a stakeholder process in April to address the issues raised by gas market conditions and to more comprehensively develop an interim solution that can be implemented in fall 2014 if such solutions do not require substantial system changes. FERC granted the ISO's tariff waiver on March 21, 2014.[1]

The ISO started a stakeholder process in April 2014, *Commitment Cost Enhancements Phase 1*, to develop an interim solution to enhance the current options for reflecting resource commitment costs for starting a resource and running at minimum load. The ISO provides two options: 1) the "proxy cost," which updates natural gas prices daily and allows daily bidding up to 100 percent of the calculated proxy cost; and 2) the "registered cost," which updates natural gas prices every 30 days but allows for a fixed, 30-day bid up to 150 percent of the calculated proxy cost. The interim solution modified the current rules by increasing the proxy cost bid cap to 125 percent and eliminating the registered cost option for all resources except those categorized as use-limited resources. The interim solution was approved by the ISO Board of Governors in September 2014 and has been filed at the FERC.[2] Once opportunity costs are implemented for use-limited resources, the registered cost option will be eliminated for all resources.

As Table 1 shows, the *Commitment Cost Enhancements stakeholder* processes are also coordinated with the *Reliability Services* initiative for the development of a more stringent must offer obligation for certain use-limited resources by 2016. The phasing of these design elements for use-limited resources helps incorporate an opportunity cost adder earlier and allows market participants to test and fine tune the calculation before affected use-limited resources have an expanded must offer obligation.

The ISO will also address broader market changes related to bidding rules for energy and commitment costs in the *Bidding Rules Enhancements* initiative. These are longer-term market changes that will require significant market design, settlements, and system changes.

[1] *California Indep. Sys. Operator Corp.*,146 FERC 61,218 (2014).
[2] *California Indep. Sys. Operator Corp.*, FERC docket no. ER15-15, October 1, 2014.

Table 1
Commitment cost-related initiatives

Initiative	Description	Policy start	Status
Commitment Cost Enhancements Phase 1	Interim solution to address natural gas price spikes. Proxy cap increased to 125% and only use-limited on registered.	Q2 2014	Policy complete. Targeted Winter 2014 implementation
Commitment Cost Enhancements Phase 2	Develop opportunity cost adders for use-limited resources and additional clarifications.	Q4 2014	Policy, coordinate implementation with Reliability Services
Reliability Services	Phase 1 focuses on resource adequacy rules and will develop more stringent must offer obligations for use-limited resources.	Q1 2014	Policy, targeted Q1 2016 implementation
Bidding Rules Enhancements	Longer-term changes to energy and commitment cost bidding.	Q4 2014	Policy

There are two additional processes that deserve mention here:

- First, a separate stakeholder initiative, *Natural Gas Pipeline Penalty Recovery*, created to address potential ISO bid cost recovery of operational flow order penalties under specific limited circumstances, has been closed. The ISO was not able to gain unanimous support from natural gas pipeline companies for this policy due to concerns that ISO cost recovery would undermine natural gas reliability. Therefore, the ISO decided not to pursue this policy change. This decision was presented to stakeholders and the Board of Governors at the December 2014 meeting as an informational item.

- Second, on March 20, 2014, the FERC released a notice of proposed rulemaking (NOPR) to address coordination and scheduling practices of the interstate natural gas pipeline companies and the electricity industry.[3] The NOPR provides the natural gas and electricity industries six months to reach a consensus. While the NOPR is not directly related to commitment cost pricing in the ISO market, issues discussed there may overlap with the ISO's commitment cost-related stakeholder initiatives.

3. Schedule for policy stakeholder engagement

The proposed schedule for the policy stakeholder process is listed below. We have omitted the issue paper since the issue was already discussed under *Commitment Cost Enhancements Phase 1*.

[3] http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf

Date	Event
Wed 10/29/14	Straw proposal posted
Wed 11/12/14	Stakeholder call
Wed 11/19/14	Stakeholder comments due
Mon 12/22/14	Revised straw proposal posted
Tue 1/6/15	Stakeholder call
Tue 1/13/15	Stakeholder comments due on revised straw proposal
Tue 2/3/15	Draft final proposal posted
Tue 2/10/15	Stakeholder call
Tue 2/24/15	Stakeholder comments due on draft final proposal
Thu/Fri 3/26-3/27/15	Board of Governors meeting

4. Initiative scope

This initiative was created to develop a methodology and the business rules to calculate opportunity costs for use-limited resources. In doing so, it is necessary to first clarify the current use-limited definition, the process for submitting documentation and qualifying for use-limited status, and modeling those use limitations as opportunity costs.

This initiative also clarifies additional commitment cost-related issues such as transition costs, greenhouse gas costs, and related business practice manual changes. Transition costs are costs incurred by multi-stage generators when transitioning from one configuration to another. They can also be thought of as start-up costs when "starting" a new configuration. *Commitment Cost Enhancements Phase 1* did not make any changes to transitions costs. In this initiative we reevaluate the current calculation of transition costs and how they are similar to start-up costs for non-multi-stage generators.

The *Commitment Cost Refinements, 2012* stakeholder process[4] incorporated greenhouse gas costs into commitment costs for those resources subject to California's greenhouse gas program. This initiative considers additional greenhouse gas compliance on natural gas suppliers.

Business practice manual changes will be necessary to clarify the current policy as well as support new policy developed in this initiative. Though changes to the business practice manuals do not require FERC approval and have a separate change process, this revised straw proposal discusses those changes to help stakeholders track closely related issues.

The remainder of this paper is divided into the following sections. Section 5 summarizes all of the proposals. Section 6 clarifies the definition of and process for qualifying for use-limited status. Section 7 details the opportunity cost methodology and related process and business rules. Section 8 aligns the treatment of multi-stage generator transition costs with start-up

[4] http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx

costs. Section 9 considers extending the greenhouse gas costs to thermal resources not subject to California's greenhouse gas program. Section 10 discusses the business practice manual changes in progress and references additional changes that need to be made pursuant to policy developed in this stakeholder initiative. Section 11 discusses a potential review of default variable operation and maintenance costs and default major maintenance adders. Section 12 discusses next steps.

5. Summary of proposals

Table 2 summarizes the changes by topic, and whether it is new policy or clarifications to the existing business practice manuals (BPMs).

Table 2
Summary of proposals

Topic	Change	Type of change*
Use-limited definition	Revised definition and new flag	Policy (and change BPM)
	Application process for use-limited status including documentation	Existing BPM clarifications
Opportunity cost	Types of opportunity costs that can and cannot be modeled	Policy
	Modeling methodology	Policy
	Process for updating the model	Policy
Transition costs	Clarify calculation used in start-up costs	Existing BPM clarifications
	New methodology to account for transition costs	Policy
Greenhouse gas costs	Allow all thermal resources to incorporate a greenhouse gas cost	Policy
Costs for non-thermal resources	Clarify that non-thermal resources may use the "fuel cost" field to reflect certain costs	Existing BPM clarifications
Major maintenance adder	Clarify the documentation required for and methodology to calculate major maintenance adders and responsible parties.	Existing BPM clarifications

*The *type of change* category only reflects whether the topic is new policy or only requires clarification to an existing business practice manual section. It does not determine whether the policy changes will be detailed in the tariff or in a business practice manual. Consistent with the existing FERC-approved ISO tariff, the ultimate tariff language may mention the new policy and provide relevant details in a business practice manual.

6. Use-limited definition

Use-limited resources cannot operate continuously because of environmental, operational, or other non-economic limits. Consequently, the ISO provides for a separate treatment of these resources in accordance with their approved limitations. *Commitment Cost Enhancements Phase 1* clarified that use-limited status is separate from resource adequacy as shown in the first column of Table 3 (pending FERC approval).[5] Therefore, non-resource adequacy resources can also apply for use-limited status. While some resources are deemed use-limited under the tariff, all others must apply for use-limited status.[6]

The ISO proposes to further modify the use-limited definition to what is presented in the second column.[7] These clarifications will greatly benefit the subsequent calculation of opportunity costs. In addition, the ISO will separately identify resource adequacy capacity that will be exempt from the requirement to bid their capacity.

Table 3
Existing and proposed use-limited capacity definition

Existing	Proposed
A resource that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously. This definition is not limited to Resource Adequacy Resources. A Use-Limited Resource that is a Resource Adequacy Resource must also meet the definition of a Resource Adequacy Resource.	Capacity with operational limitations or restrictions established by statue, regulation, ordinance, or court order that cannot be optimized by the appropriate ISO commitment process without allowance for opportunity costs.

First, the ISO proposes to refer to use-limited *capacity* rather than resources.[8] This more accurately reflects the fact that a single resource may have both use-limited and non-use-limited capacity or the resource may only be designated use-limited for certain parts of the year. For example, a combined heat and power resource may have use-limited capacity above its regulatory must-take capacity but not below it. Another resource may have an air permit limiting its capacity's run hours only during the summer months.

[5] *California Indep. Sys. Operator Corp.*, FERC docket no. ER15-15, October 1, 2014.
[6] Based on tariff section 40.6.4.1, hydroelectric generating units, proxy demand resources, reliability demand response resources, and participating load, including pumping load, are deemed to be use-limited.
[7] Policy change.
[8] Policy change.

The limitations accepted by the ISO must be statutory, regulatory, based on an ordinance, due to a court order or operational in nature. They cannot be economic or contractual. The ISO cannot provide an exhaustive list of what the acceptable limitations are but Table 4 below provides illustrative examples.[9] The ISO is seeking feedback from stakeholders on whether the explanations below provide enough guidance.

Table 4
Sample of use limitation sources and examples

Acceptable?	Source	Non-exhaustive list of examples
Yes	Statutes, regulations, ordinances, or court order	• Such as from Air Quality Management Districts, California Energy Commission, Local Regulatory Authorities, etc. ○ This limitation is largely environmental and most commonly in the form of an air permit. For example, emissions limitations with an absolute limit (cannot pay to emit more and would incur a penalty), wildlife/natural resource management, noise restrictions, etc.
	Operational	• Limited due to the actual design of the resource. ○ This limitation is largely applicable to hydro, pumped storage, participating load, and combined heat and power. For example, limited reservoir storage capacity or interruption of host functions for combined heat and power capacity above the regulatory must-take capacity, etc.
No	Contractual	• Limitations based on a power purchasing or tolling agreements
	Economic	• To reduce wear and tear • Staffing constraints or lack of investment • Avoid purchasing more credits, allowances, etc. to manage emissions (*e.g.*, South Coast Air Quality Management District allows purchase of additional permits rather than a strict limit) • Did not procure fuel (potentially because it was expensive)
	Fuel limitation	• Variable energy resource ○ Such as wind and solar without storage, geothermal

The limitations may be statutory, regulatory, based on an ordinance or court order (such as an air permit from a local regulatory authority) or operational (such as supporting a thermal host for combined heat and power resources) but must be non-economic (*i.e.*, not based on contractual obligations or other economic decisions such as staffing requirements).

The next important change in the proposed definition explicitly points out the limitation in the ISO's commitment time horizon and why an opportunity cost should be calculated. The ISO

[9] BPM change supporting new policy.

commits long-start resources in the day-ahead (integrated forward market) and medium- and short-start resources in the short-term unit commitment and short- and fast-start resources in the real-time unit commitment. The day-ahead commitment horizon is currently a single day. Therefore, long-start resources committed by the day-ahead may have an opportunity cost if the applicability of the limitation[10] is longer than this time horizon. For medium-start resources, the resource may have an opportunity cost if the applicability of the limitation is longer than the time horizon for the short-term unit commitment period. For short- and fast-start resource the appropriate time horizon is the real-time unit commitment period. This standard is applicable to Energy Imbalance Market (EIM) entities seeking use-limited status and intertie resources that are dynamic transfers. No other intertie resources can apply for use-limited status.

A use-limitation is different from a fuel limitation. For example, a gas-fired resource with an air permit limiting run hours to 200 per month could physically continue to run more than this limit. Since the run hours are restricted, it is most optimal to only run the resource during the most profitable 200 hours per month. The use-limited capacity has an opportunity cost if it is run in less profitable hours reflecting the foregone profits (*i.e.*, forgone greater benefit to the ISO system). Since the ISO commitment software cannot optimize the resource over the month without opportunity cost adders, we currently do not automatically generate bids for the resource but instead allow scheduling coordinators to bid in accordance with a submitted use plan.[11] Similarly, hydro resources may be limited by a combination of storage capacity and fish and wildlife restrictions.

On the other hand, wind, solar, and geothermal resources (all without storage) run only when the fuel (*i.e.*, energy source) is available. While these generators may have some level of control (*e.g.,* feathering blades) and can submit decremental bids, the fuel supply cannot be optimized by the scheduling coordinator (*e.g.,* wait to use the fuel at a later time in order to maximize profits and system benefit). Therefore, these resources do not inherently have opportunity costs.

The ISO clarifies that designation of "use limited" in the ISO market is not a reflection on how this term is used in other forums (*e.g.*, California Public Utilities Commission) or a judgment on the actual statute, regulation, ordinance, court order, or operational characteristic. For example, if the California Public Utilities Commission uses its own definition of "use limited" to grant resource adequacy capacity, the ISO does not change this designation. The ISO respects the Commission's designation and then applies the ISO's rules applicable to resource adequacy

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[10] The ISO is using the term "applicability" to mean the time frame under which the limitation applies and not the run time limitation. For example, a resource has an air permit that limits its operation to 200 hours per month. The applicability is the month whereas the run time limitation is 200 hours. Since a month is clearly greater than the real-time optimization, this resource may apply for use-limited status.

[11] Most resources with a resource adequacy designation have a must offer obligation to bid that capacity into the market or else the ISO automatically generates a bid. Use-limited resources are exempt from automatic bid insertion unless there is a residual unit commitment availability bid or residual unit commitment schedule for a resource without a corresponding economic bid or self-schedule. Changes under the *Reliability Services* initiative will address must offer obligations for use-limited resources. See: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReliabilityServices.aspx

capacity obligations (such as a must offer obligation) for participation in the ISO markets. The resource can additionally apply for use-limited status in the ISO market if it meets the criteria in the proposed definition. Therefore, the ISO can have the following four types of capacity: 1) resource adequacy and use-limited; 2) resource adequacy and not use-limited; 3) not resource adequacy and use-limited; and 4) not resource adequacy and not use-limited.

Similarly, if the resource has an air permit limiting its operation, the ISO does not question the premise or content of the air permit. However, the ISO will have requirements for providing documentation and validating that sufficient information is provided to the ISO. The ISO can deny use-limited status if the resource has not submitted the appropriate or complete documentation.

Table 5 below is partially reproduced from the *Reliability Requirements* business practice manual. Text copied from the manual is in black and bolded text in blue reflect changes to the use-limited categorization under the proposed definition. The table provides general non-binding guidelines regarding the scope of use-limited status.

The first two changes under **gas-fired resources** with limited fuel storage and environmental restrictions clarify that approval of use-limited status means the limitation cannot be modeled by the ISO optimization without opportunity cost adders because it runs over a single day.

Hydro resources and participating load (including pumping load) will all remain “deemed use-limited” capacity under the proposed definition.

As noted above, **wind and solar** generators will not be considered default use-limited capacity under the proposed definition. However, tariff section 40.6.4.3.4 exempts them from automatic bid insertion in the day-ahead and real-time markets. This section is currently in the use-limited discussion in the tariff. The ISO proposes to retain this exemption but move it to an appropriate section in the tariff so that it is not subsumed under the use-limited definition.[12] Impact on Resource Adequacy designation is discussed below in Section 6.1.

Qualifying facilities (QFs) with existing QF contracts (grandfathered Public Utility Regulatory Policies Act contracts) under the ISO tariff are categorized as regulatory must-take resources, a type of self-scheduling, and are exempt from the standard capacity product availability standard reporting requirements related to resource adequacy capacity. This largely negates the need for additional use-limited status. Since the resources are self-scheduled, there is no opportunity cost. Similarly, QFs that are 20 MW or less are also entitled to regulatory must-take status and would not qualify for use-limited status. QFs with amended QF contracts will be treated as non-use-limited capacity unless they qualify otherwise under the proposed definition. Qualifying facilities that have signed the Net Scheduled Participating Generator Agreement are discussed below in the combined heat and power description. Impact on resource adequacy designation is discussed below in Section 6.1 Regulatory must-take capacity that is also resource adequacy capacity will be exempt from the bidding obligation.

[12] Policy change.

Proxy demand and reliability demand response resources are deemed use-limited by the tariff and the ISO does not propose any changes to this status. Reliability demand response resources do not have non-zero start-up or minimum load costs and therefore do not have commitment cost-related opportunity costs. Proxy demand resources may have shut-down costs and minimum load costs that the ISO may consider. However, both can have energy-based opportunity costs. The ISO would only calculate these costs to include in a default energy bid if these resources were mitigated as part of the market power mitigation process. But since demand response is not subject to mitigation, there is no need for the ISO to calculate these costs. Proxy demand resources can directly reflect opportunity cost in the energy bids up to the offer cap and reliability demand response resources are already required to bid in near the offer cap.

Combined heat and power resources that are bit subject to an existing QF contract (grandfathered Public Utility Regulatory Policies Act contract) but have signed a Net Scheduled Participating Generator Agreement can have the capacity used to support a thermal host designed as regulatory must-take, which will be exempt from the offer obligation. Tariff section 4.6.10 determines the maximum regulatory must-take capacity. Above this amount, the resource can apply to be treated as use-limited capacity if it can demonstrate that the ISO's co-optimize of non-regulatory must-take capacity would unduly interfere with the operation of the thermal host or undermine regulatory policy objectives concerning efficiency or greenhouse gas emissions.[13] Impact on resource adequacy designation is discussed below in Section 6.1.

Nuclear resources under the ISO tariff are also categorized as regulatory must-take resources. Similar to QFs, the ISO proposes to remove nuclear units from the use-limited designation. Impact on resource adequacy designation is discussed below in Section 6.1. These resorUces will also be exempt from the must offer obligation.

The last four rows have been added to the original table and assumes none of the generation types are QFs subject to existing QF contracts. As noted above, **geothermal** resources' fuel source is limited in the same way that wind and solar are and do not qualify for default use-limited status. As circumstances change, these resources may apply for use-limited capacity designation via the same process as other resources.

If **storage** resources can be fully optimized by the ISO within the optimization time horizon, then they do not qualify as use-limited. This does not apply to storage resources such as participating load or pumped storage (and are already deemed use-limited). The ISO understands from the California Energy Storage Alliance (CESA) that modern storage devices (*e.g.,* fly wheels) are not yet large enough to charge or discharge beyond the current ISO optimization time horizon of a single trade date in the day-ahead. If this should change in the future, these storage resources may apply for use-limited status like any other resource with an

[13] Addendum to Draft Final Proposal, Regulatory Must-Take Generation stakeholder initiative, April 30 2012, California ISO. http://www.caiso.com/Documents/Addendum_DraftFinalProposal-RegulatoryMust-TakeGeneration.pdf

acceptable limitation. Impact on resource adequacy designation is discussed below in Section 6.1

We seek stakeholder feedback on how to address potential limitations for **biomass, landfill gas, and other resources** not discussed. Thus far, stakeholders have not objected to the ISO's classifications. These resources will not be default use-limited but may apply for such status based on the acceptable limitations.

Lastly, only **dynamic transfers** are allowed to apply for use-limited status. All other intertie resources cannot be considered use-limited.

Table 5
Use-limited categorization changes under proposed definition

Resource type	**Use-limited (Yes/No)**	**Proposed changes**
Gas-Fired (Steam)	No	**None**
Gas-Fired (Combined Cycle)	No	**None**
Gas-Fired (GT with limited fuel storage)	Yes	**Not use-limited if can be optimized by ISO**
Gas-Fired (GT without limited fuel storage)	No	**None**
Gas-Fired with environmental restrictions that constraint its operation	Yes	**Not use-limited if can be optimized by ISO**
Hydro-Large Storage	Yes/No - although Hydro with large amount of storage may have more flexibility to generate on demand and thus may not be use-limited in a manner similar to a run-of-the river, downstream water flow and water-release needs and other environmental conditions may dictate output so as to warrant Use-Limited status	**None. This category should also include participating load, including pumping load.**
Hydro-Small Storage/Small Conduit	Yes	**None**
Hydro-Run of the River	Yes	**None.**
Wind	Yes	**Not default use-limited. Do not have to bid in DAM (40.6.4.3.4). Assume same treatment in RTM.**
Solar	Yes	**Not default use-limited. Do not have to bid in DAM (40.6.4.3.4). Assume same treatment in RTM.**

Resource type	Use-limited (Yes/No)	Proposed changes
Nuclear	Yes	**Not use-limited – regulatory must-take.**
QF	Yes	1. **With existing QF contract** – not use-limited. Is already considered regulatory must-take. 2. **Is 20 MW or less -** not use-limited. Is already considered regulatory must-take. 3. **With amended QF contract** – not default use-limited. May apply based on proposed definition. 4. **With Net Scheduled Participating Generator Agreement –** see discussion below on combined heat and power
Resource with Contractual Limitation that Limits Availability	No	**This is an overarching requirement, not just under QFs.**
Clarification: Proxy demand and reliability demand response resources	**Yes, per current tariff section 40.6.4.1**	**No commitment-related opportunity cost for RDRR. Both may have energy-related opportunity costs but ISO may not calculate because these resource types are not currently mitigated.**
New: Combined heat and power	**n/a**	**Not use-limited for regulatory must-take capacity; may apply for use-limited status for capacity above regulatory must-take.**
New: Geothermal	**n/a**	**Not default use-limited.**
New: Storage	**n/a**	**Not default use-limited.**
New: Biomass, landfill gas, others	**n/a**	**Not default use-limited.**
Intertie resources	**n/a**	**Only dynamic transfers may apply for use-limited status.**

This proposal does not change the definition or use of the terms "dispatchable" and "non-dispatchable." Under the current paradigm, non-dispatchable use-limited resources include regulatory must-take, regulatory must-run and fuel limited resources such as wind, solar, and some combined heat and power, biomass, hydro, and geothermal units. However, this proposal may eliminate or vastly decrease resources considered non-dispatchable *use-limited* and instead categorize them as non-dispatchable only. As a consequence, resources that have been previously exempt from the residual unit commitment process per tariff section 40.6.4.3.2 may now be subject to it if they have resource adequacy capacity.[14]

In summary, use-limited capacity:

[14] Policy change under the Reliability Services Initiative.

- Is limited by operational limitations or restrictions established by statue, regulation, ordinance, or court order that is not due to economic, contractual, or fuel limitations;
- Cannot be optimized per their limitations because of the ISO's commitment horizon as appropriate for the resource without an opportunity cost adder; and
- Has an opportunity cost.

Today's resources with use-limited designation use the daily start limit field to approximate monthly or annual starts that the ISO optimization cannot model. In future, the ISO expects its opportunity cost methodology to reflect limitations and will subsequently require that resources only use the daily start limit field to reflect actual daily use-limitations.

6.1. Use-limited designation and resource adequacy

As discussed in the tariff stakeholder process for *Commitment Cost Enhancements*, use-limited capacity need not be a resource adequacy resource. Consequently, the ISO proposes that two existing flags in the Master File be used as follows: 1) the use-limited flag will be used for use-limited capacity regardless of resource adequacy status and 2) the must-offer flag will be used more generically (and may be renamed) to indicate that the ISO does not insert a bid regardless of resource adequacy status.[15] The use-limited flag will be used to indicate that the resource has an opportunity cost (and may also be renamed to reflect this use). A single resource may have one, both or none of the flags selected. The *Reliability Services* initiative will establish the criteria for which the ISO uses the no bid insertion flag for both use-limited and non-use-limited resource adequacy capacity.[16]

The December 10, 2014 working group of the *Reliability Services* initiative has proposed the following changes to coordinate with the change in default use-limited status for certain resources.[17] Specifically:

- Continue to exempt regulatory must-take, storage, and variable energy resources from generated bid rules;
- Continue to exempt hydro, pumping load, and non-dispatchable, use-limited resources, and qualifying facilities from residual unit commitment.
  - Wind and solar may need specific provisions that recognize that their residual unit commitment obligation is equal to their day-ahead schedule.

Currently two use-limited resources that do not individually meet the definition of a flexible resource can be combined to meet the flexible resource criteria (Section 40.10.3.2(b)(2)). The ISO does not propose to change this policy.

[15] Policy change.
[16] See http://www.caiso.com/informed/Pages/StakeholderProcesses/ReliabilityServices.aspx
[17] Presentation available at: http://www.caiso.com/Documents/AgendaPresentation-ReliabilityServices-WorkingGroupDec122014.pdf

Lastly, the business practice manual discussion for use-limited resources will be moved out of the Reliability Requirements manual to the Market Operations manual.[18] The separately published Use-Limited Resource Guidebook will be subsumed into the use-limited discussion in the Market Operations manual.[19]

6.2. Current application process

The ISO has made corresponding business practice manual changes to clarify the current application process for use-limited resources. The ISO submitted changes to require an affidavit verifying that each resource categorized as use-limited continues to qualify as such the next calendar year.[20] In addition, the ISO clarifies that a use-limited resource will be considered available 24 hours a day, 7 days a week unless the ISO receives a valid annual or monthly plan.

7. Opportunity costs

The Market Surveillance Committee opinion on the *Commitment Cost Refinements 2012* initiative noted committee members' concern that relying on use plans (*i.e.*, limiting the hours a resource is bid into the market to avoid over-use) could result in inefficient use of a unit's limited starts, run-hours, and energy output.[21] Traditionally, the highest prices and need predictably occurred during on-peak hours. With increasing renewable penetration and the need for flexibility and ramping capability, high prices may occur more frequently during off-peak periods that cannot be anticipated by a use plan.

The Committee concluded that it would be more efficient to allow high start-up and minimum load bids that reflect opportunity costs of operation, which then gives flexibility to the market software to determine if the resource is economic. The Committee presented a methodology to model start-up, run hour, and energy output opportunity costs for gas-fired resources.[22] The ISO developed a prototype model based on this methodology and presented it to stakeholders in *Commitment Cost Enhancements*. Based on stakeholder feedback, there was not enough time to fully develop the methodology and its application for the 2014-2015 winter. Therefore, the ISO allowed use-limited resources to retain use of the registered cost option to reflect opportunity costs until an opportunity cost methodology is implemented.

[18] BPM change pursuant to policy change.

[1919] The guidebook is currently available at: http://www.caiso.com/Documents/Use-LimitedResourceGuideBook.pdf

[20] Existing BPM clarifications. See PRR 787 available at: http://bpmcm.caiso.com/pages/default.aspx

[21] http://www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf

[22] See Market Surveillance Committee meeting documents for November 15, 2013 available at: http://www.caiso.com/Documents/Presentation-MSC-FRACMOO_OpportunityCost-Hobbs.pdf. The opportunity cost methodology for use-limited resources was also discussed in the *Flexible Resource Adequacy Criteria and Must-Offer Obligation* initiative and was originally scheduled to be included in the *Reliability Service* initiative.

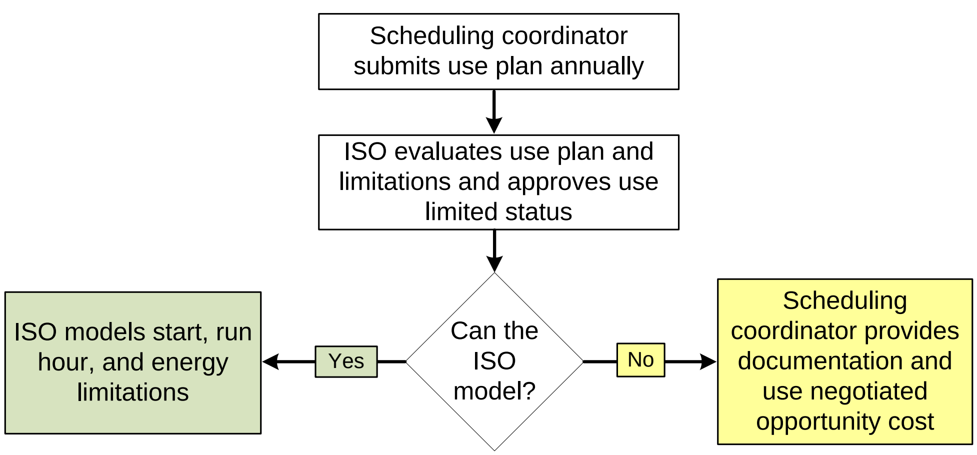
Some stakeholders have suggested that scheduling coordinators should be allowed to submit their own opportunity costs subject to verification. While the ISO does not object to this in principle, the ISO also does not currently have a model or methodology in place to verify, modify, or cap these costs. The modeling methodology described below clearly and transparently provides the input data required to calculate opportunity costs.

7.1. Opportunity costs under proposed definition

Based on the proposed definition, all resources categorized as use-limited capacity have opportunity costs for that capacity. The ISO will not be able to model every type of opportunity cost but will determine if modeling is possible based on reviews of documents submitted as part of the normal use-limited application process. Figure 1 below shows that the ISO will either calculate opportunity costs or work with scheduling coordinators to develop negotiated opportunity cost adders after the ISO has received the documentation needed to evaluate use limitations and has approved the resource's use limited status.[23]

The ISO will evaluate each submission on a case-by-case basis and determine whether the ISO can model the opportunity costs. The ISO expects that its methodology will largely be used by gas-fired resources with clearly defined limitations based on starts, run hours, and energy use, as shown in the green box.

Figure 1
Opportunity costs modeled



Based on conversations with scheduling coordinators, many hydro, participating load, and pumped storage resources develop costs based on sophisticated models that synthesize the

[23] Policy change.

impact of current and projected hydrology data, including snowpack levels, watershed topology and size, and various fish and wildlife restrictions. The ISO will not be able to replicate such a model. Instead, the ISO expects the scheduling coordinator to provide documentation of the modeling methodology for calculating opportunity costs. The resource will then use negotiated opportunity cost adders as approved by the ISO based on the submitted methodology, as depicted by the yellow box. The ISO expects that thermal host needs for combined heat and power and more complicated environmental permits (*e.g.,* Delta Dispatch), as well as mutli-stage generators with use limitations, may also require negotiated opportunity cost adders. Lastly, there may be some resources for which the ISO can model some limitations but not others. The ISO proposes to consider these resources under the negotiated option where the final opportunity cost is a combination of ISO calculated and scheduling coordinator provided data.

7.2. Opportunity cost methodology overview

Table 6 below provides an overview of the major components needed to calculate and utilize the opportunity cost estimates, including the inputs, calculation procedures, outputs, and the usage of the outputs. Under the "inputs" column, the optimization model will rely on use plans provided to the ISO, Master File characteristics,[24] and applicable commitment and variable energy costs to provide a resource- and limitation-specific opportunity cost. This cost is based on calculating the profit (or gross margin) that is foregone in some future interval if one less start, one less operating hour, and/or one less MWh is available, as appropriate. In order for the model to calculate the profit, we will use historical implied heat rates, and recent natural gas and greenhouse gas prices to simulate a distribution of the node-specific locational marginal prices for the resource. For start-up and minimum load opportunity costs, the optimization model will use these inputs to calculate the difference between the profits of two model runs: a base run, and a run in which the start-up or run hour limitations are tightened by one unit. The difference in the objective function (the generating unit's profit) will be the opportunity cost of that resource's limitation. As noted under the "outputs" column, the model will provide for each resource a specific opportunity cost for each limitation it has over a specific period of time (*e.g.*, month or year). Lastly, the opportunity cost will be added to the calculated proxy cost and the 125 percent cap will be applied to both. This is a change from previous discussions where the opportunity cost was added to the proxy cost cap. The change provides resources with the flexibility to reflect forward looking costs but also manage the limitations and current market conditions through bidding.

[24] The model accounts for each resource's minimum run time and minimum down time. It does not consider maximum daily starts if it has a start-up limitation in its use-limitation plan.

Table 6
Opportunity cost methodology overview

Model inputs	Opportunity cost calculation	Model outputs
• Use plan limitations • Unit characteristics • Historical commitment costs • Historical implied heat rate • Natural gas futures • Greenhouse gas prices	Unit commitment optimization model over future time period (*e.g.*, month) based on simulated node-specific LMPs.	Separate resource specific opportunity costs for start-up, minimum load, and energy, as appropriate. Used as an adder and will have 125% proxy cap applied to it.

The subsections below discuss each of the columns in Table 6 in greater detail.

7.2.1. Model inputs

This section discusses resource characteristics and market inputs to the optimization model.

The ISO will rely on submitted use plans to determine the resource's limitation(s). The ISO will also use Master File characteristics such as the minimum load and maximum capacity of the resource. The variable energy cost will be based on the average heat rate, gas price index, greenhouse gas cost, and the O&M adder. For commitment costs, the ISO will use the prior month's calculated proxy start-up and minimum load costs.

Scheduling coordinators will need to know their resource-specific opportunity costs for the month or year prior to the start of that period in order to reflect the costs in their bidding. Therefore the opportunity cost of each limitation will have to be calculated in advance of the time period based on simulated future prices.

The ISO will simulate real-time prices by calculating an implied marginal heat rate at each use-limited resource's pricing node (Pnode) based on real-time energy prices from the same time period the previous year. Each interval's and location's LMP is assumed to reflect the heat rate of a marginal unit, and that heat rate can be inferred from the prices of gas and emissions allowances at that time and place. This procedure will allow the implied heat rate to inherently capture real-time price volatility which will then be used to forecast prices for the current time period. For example, if the ISO is estimating November 2013 prices, we will use November 2012 real-time energy prices, greenhouse gas costs, and daily natural gas prices. This will generate an implied heat rate for every real-time interval, which will then be used to forecast November 2013 real-time energy prices for a given resource.

Implied heat rate, $ImpHR_{i,t-1}$, will be determined as follows:

$$\mathrm{Im}\,pHR_{i,t-1} = \frac{LMP_{i,t-1}}{NatGasP_{l,t} + (GHGas_{t-1} * EmRate)}$$

Where

$\mathrm{LMP}_{\mathrm{i,t\text{-}1}}$	is the real time energy price at pnode *i* from the previous year's period, *t-1.*
$\mathrm{GHG}_{\mathrm{t\text{-}1}}$	is the greenhouse gas allowance price from the previous year's period, *t-1*.
EmRate	is the emissions rate per MMBtu of gas, which is $.053165\mathrm{mtCO_2e/MMBtu}$
$\mathrm{NatGasP}_{\mathrm{l,t\text{-}1}}$	is the daily natural gas price from the region *l* of pnode *i* of the previous year's period, t-1

To simulate the energy prices, the implied heat rate is multiplied by the sum of: (1) the average natural gas prices of the preceding month; and (2) the greenhouse gas costs multiplied by the unit's emissions rate. The ISO's preliminary analysis showed that there was little difference between using the futures versus the daily spot prices for the period of analysis. However, we agree with stakeholders that natural gas futures will reflect the most current conditions.[25] The ISO will continue to leverage its current process to calculate the monthly gas prices used in the registered cost option and publish this information on OASIS.[26] Monthly futures are available on a long term-basis (*e.g.,* monthly over a 10 year horizon) and the ISO will average futures for each day it was traded. As discussed below, the ISO will plan to update the gas futures use in the model once every quarter. See section 7.2.5 for more details on the modeling process.

The ISO proposes to use forecasted 15-minute real-time prices in the model because unit commitment and de-commitment decisions are made based on that price. By the time this initiative is implemented, the ISO will have a history of at least one year's worth of 15-minute real-time prices to use in the modeling for ISO resources and may need to estimate these prices for Energy Imbalance Market resources (though there are currently no use-limited resources from the Energy Imbalance Market). Previously the ISO had proposed a 10 percent adder to account for the difference in forward looking 15 minute prices, which are used to make commitment decisions, and the market binding 15 minute prices, and any other forecast error that may result in lower forecasted energy prices. We now propose to remove the adder since we are proposing to apply the 125 percent proxy cap to the final opportunity cost.

Simulated 15-minute real-time energy prices will be generated as follows:

$$LMPi,t = ImpHR_{i,t-1} * \left(NatGasF\ _{l,t} + (GHGasF_t * EmRate)\right)$$

Where:

[25] Policy change. The ISO is reviewing this proposed change to determine whether using natural gas price futures as an input to the opportunity cost calculation would create any new Commodity Futures Trading Commission (CFCT) compliance considerations.
[26] BPM change.

$LMP_{i,t}$ is the forecasted real time price at pnode *i* for interval *t*

$ImpHR_{i,t-1}$ is the calculated implied heat rate at pnode *i* from the previous year's period, *t-1*

$NatGasF_{l,m}$ is the average natural gas futures for the analysis month for region *l*

$GHGasF_{t,m}$ is the average greenhouse gas allowance price of the analysis month.

$EmRate$ is the emissions rate per MMBtu of gas, which is $.0530731\ mtCO_2e/MMBtu$

7.2.2. Opportunity cost calculation

The ISO will develop a model to optimally commit and dispatch each resource given its use-limitations and operational constraints against generation node-specific forecasted real-time prices over a given time period. The difference in profit from changes in dispatch due to each limitation will be the calculated opportunity cost. This section discusses how the ISO will calculate opportunity costs for start-up, run hour, and energy limitations.

7.2.2.1. Start-up limitations

Resources with limited starts will have a start-up opportunity cost calculated for the modeled time period, (*e.g.*, month or year). Since the affected variables in the optimization are binary variables (0-1), the opportunity cost is calculated as the difference between the profits of two model runs: a base run, and a run in which the start-up limitations are tightened by one (or more) unit(s) over the study time period. The difference in the objective function (the generating unit's profit) will be the opportunity cost of that resource's limitation.

Further analysis can be conducted on whether this basic approach is sufficient or if it is appropriate to use an average over more runs, because the calculated opportunity cost might be volatile. Take for example a resource with 15 starts per month. Three opportunity costs can be calculated. One based on the difference in profits with 15 and 14 starts; the second based on the difference in profits with 14 and 13 starts; the third based on the difference in profits with 13 and 12 starts. The average of all three opportunity costs will be the final calculated opportunity cost which can then be incorporated into start-up costs. Yet another methodology will average the difference in profits between 16 and 14 starts. The precise methodology can be refined with stakeholder input.

7.2.2.2. Run hour limitations

Resources with a limitation on operation hours per time period will have a run time opportunity cost calculated for the modeled time period, (*e.g.*, month, year). Similar to the start-up opportunity cost, run hour limitations are also binary. The run time opportunity cost will be determined by comparing maximized profits from all run hours to one less run hour. As noted above, there may be modifications to this basic approach.

7.2.2.3. Energy generation limitations

Resources with a maximum generation level per time period will have an opportunity cost calculated for the last megawatt hour of generation. Since this is not a discrete decision in the optimization model (continuous versus binary variable), the shadow value on this constraint is the opportunity cost of the last megawatt. Therefore this will only require one model run. The shadow value on this constraint is in $/MWhs so this cost will be added on to the variable energy cost component used in calculating the default energy bid, shifting the entire curve upward by the $/MWh shadow value. Energy limitations may also be appropriately reflected in the minimum load cost.

Opportunity costs currently used in negotiated default energy bids will be replaced with costs calculated through this process.

7.2.3. Model outputs

The calculated opportunity costs will be an adder to the calculated proxy costs for start-up and minimum load. The 125 percent proxy cap will be applied to the sum of the opportunity cost and calculated proxy cost. The scheduling coordinators will then be able to bid in start-up and minimum load costs up to the combined cap for each limitation.

7.2.4. Initial results

The ISO developed a prototype that is a unit commitment optimization model based on the proposed methodology presented by the Market Surveillance Committee to calculate the opportunity cost for start-up, energy, and run hour limitations. The prototype is a work in progress. See Section 7.2.5 for additional considerations and expected improvements.

The prototype simulated 2013 prices based on 2012 historical data. The accuracy of the forecast was compared to 2013 actual prices. Next, the forecasted prices were used to dispatch five sample use-limited resources to calculate the opportunity costs. The opportunity costs were then added to the appropriate commitment cost to compare with historical dispatch of the resource. Overall, the methodology produced opportunity costs that significantly helped resources to stay within their use-limitations.

7.2.4.1. Simulated future real-time prices

The ISO applied the methodology outlined above to simulate 2013 real-time energy prices, based on the implied heat rates for 2012. The two sets of price distribution charts below compare the simulated 2013 real time energy prices to the actual real time energy prices at a northern (Figure 2 through

Figure **4**) and a southern (

Figure **5** through Figure 7) node.

Overall, the methodology produced reasonable distributions for 2013 energy prices in both the north and the south. In both locations, there is a small percentage of hours (less than 5%) where the simulated price is significantly higher than the actual price. This is attributed to inconsistent congestion patterns from one year to the next. All else being equal, higher congestion will lead to higher implied heat rates and higher prices. The opposite is also true.

If the methodology was to systematically overstate or understate prices, this would possibly translate into biases in the estimated opportunity costs. The behavior of simulated and actual price distributions will be monitored to assess whether such systematic differences arise in the future.

Figure 2
North node: price distribution curves for 2013 real-time energy prices, all

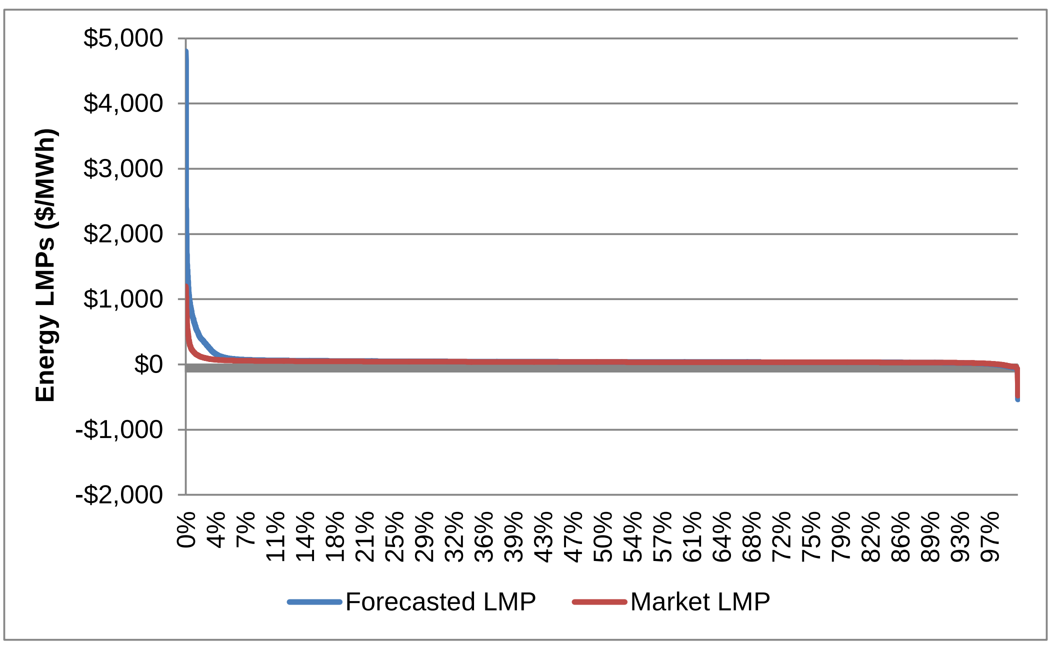


Figure 3
North node: price distribution curves for 2013 real-time energy prices, <5%

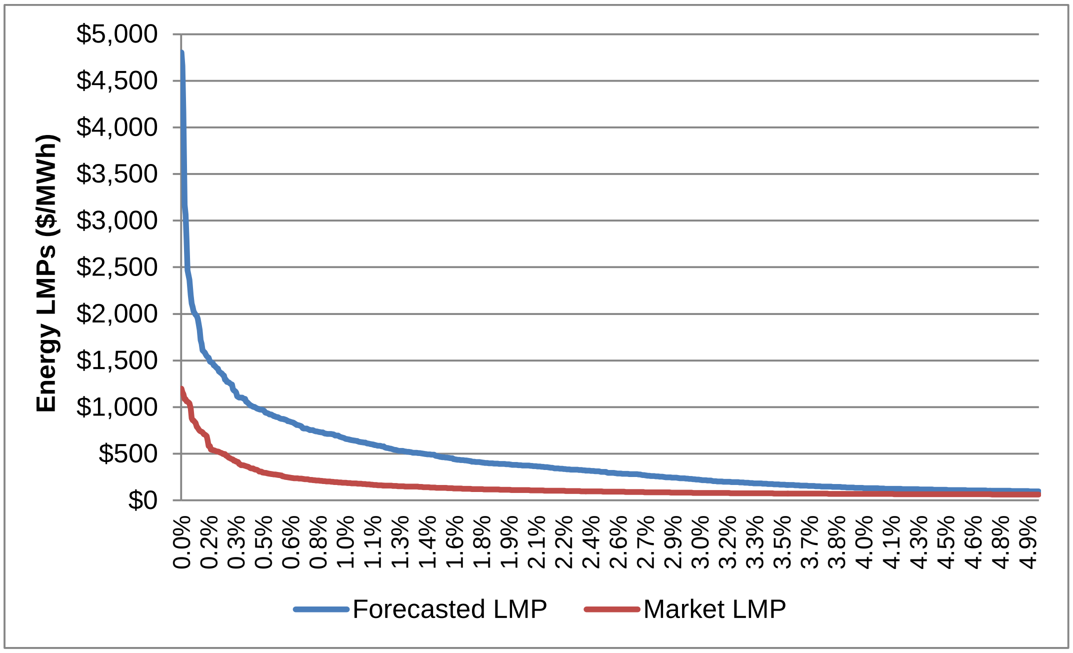


Figure 4
North node: price distribution curves for 2013 real-time energy prices, >95%

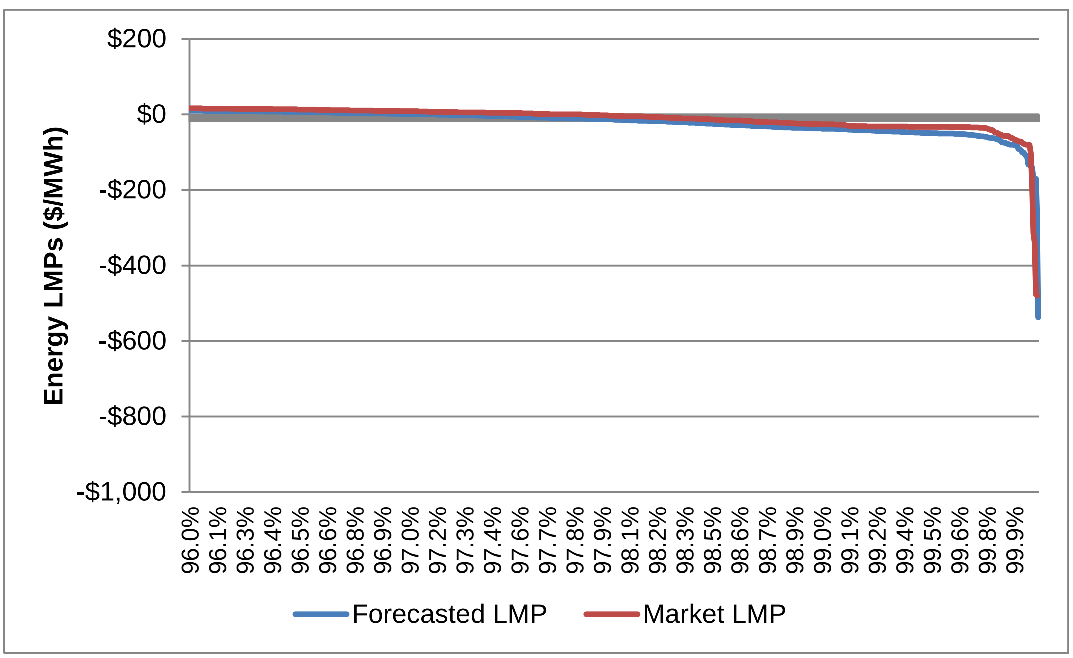


Figure 5
South node: price distribution curves for 2013 real-time energy prices, all

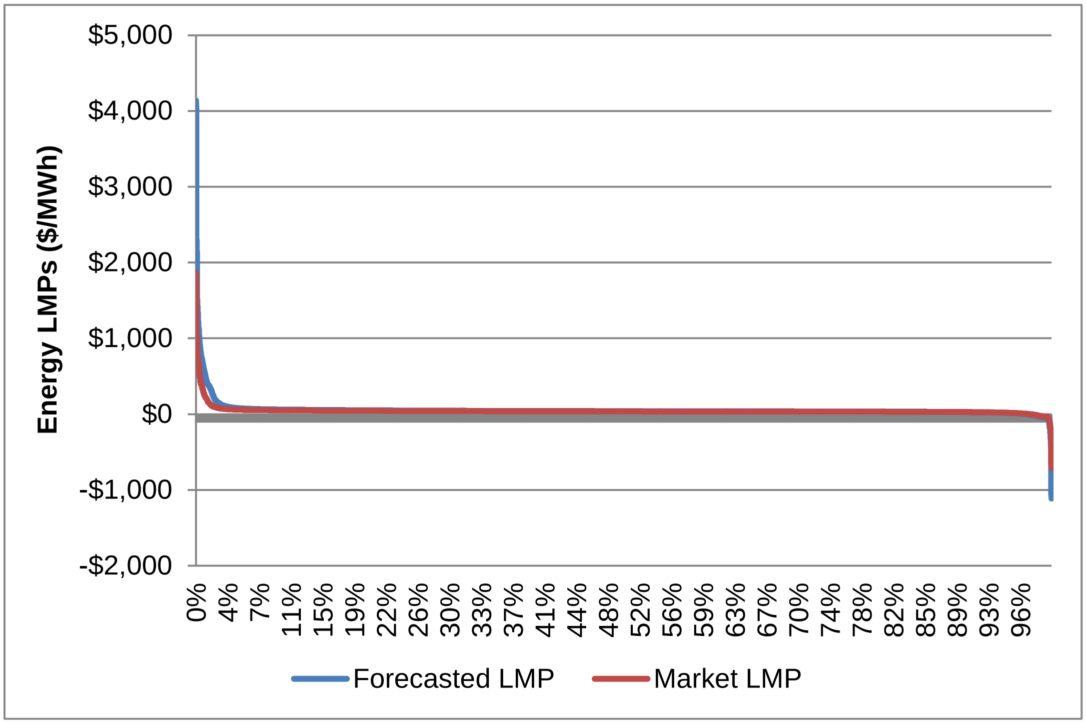


Figure 6
South node: price distribution curves for 2013 real-time energy prices, <5%

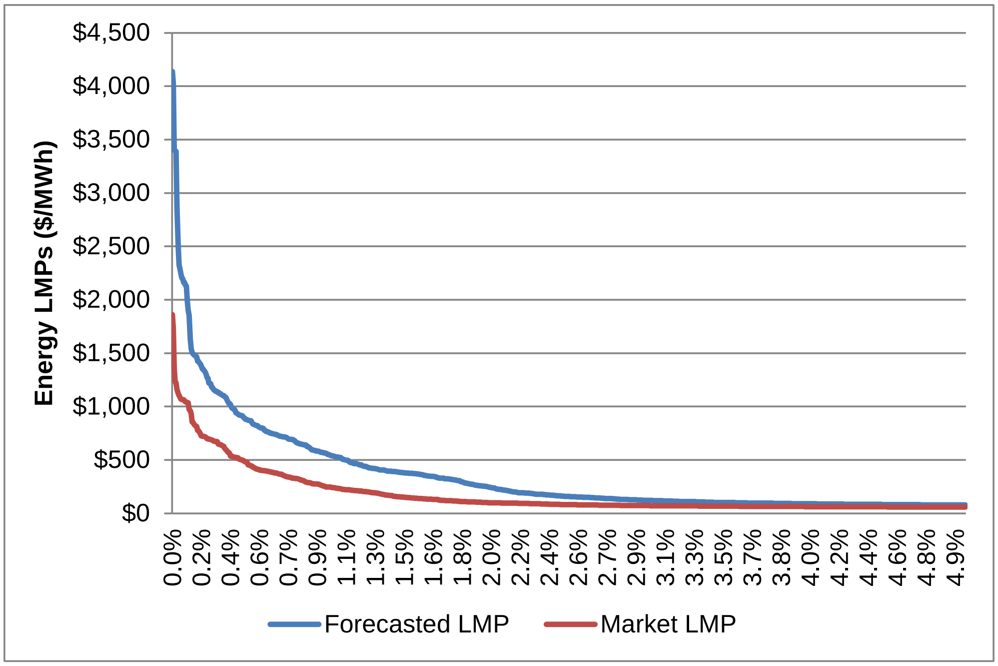
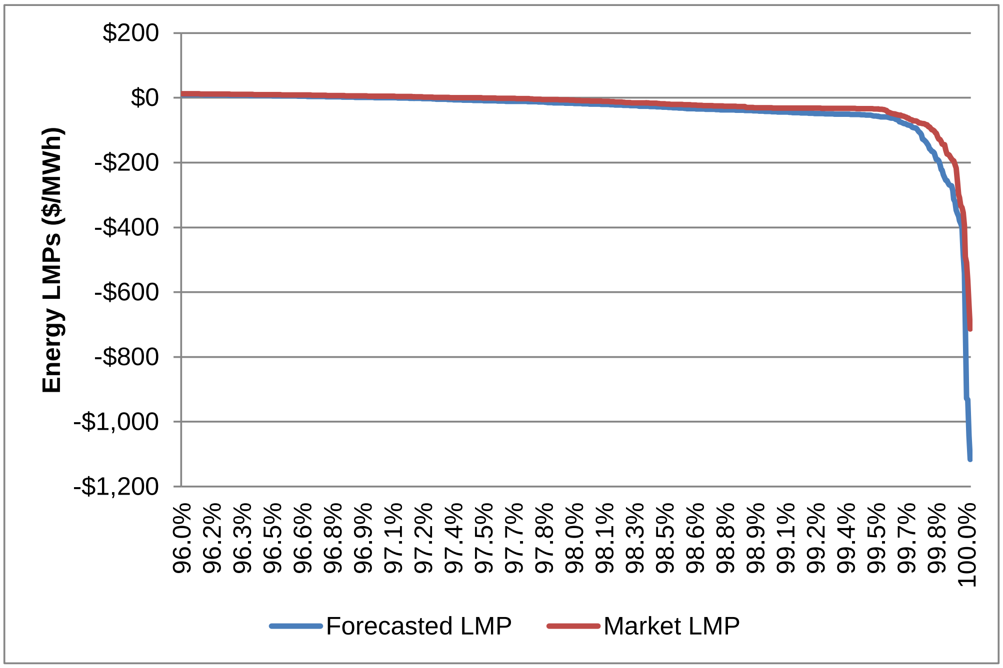


Figure 7
South node: price distribution curves for 2013 real-time energy prices, >95%



7.2.4.2. Opportunity cost calculation and back-casting

The ISO calculated the opportunity costs for five dispatchable, natural gas-fired use-limited resources. Of those, only two had non-zero opportunity costs. For these units the ISO conducted a back-cast analysis to compare how they would have been dispatched with and without the calculated opportunity costs. For Resource 1, we first assume that the resource has start-up and minimum load costs of 100 percent of proxy (*i.e.,* calculated proxy costs). This is a conservative assessment because this is more restrictive than the proxy cap of 125 percent. We then calculated the opportunity cost of the resource's monthly limitations based on the 2012 implied heat rates and monthly natural gas and greenhouse gas costs per our methodology above. Resource 1 has both a monthly start-up and run hour limitation and each was analyzed separately.[27] Based on the generated real-time prices, there were opportunity costs for both limitations. As discussed in Section 7.2.4.1, simulated and actual real-time prices were very close but diverged slightly as the locational marginal prices were higher in 2012, likely due to higher overall congestion.

[27] The actual number of starts and run hours are not provided to protect the confidentiality of the resource.

For the back-cast, we simulated two cases: one with and one without opportunity costs. In the first case, we removed the use limitations and dispatched the resource against actual 2013 prices, again assuming start-up and minimum load cost of 100 percent proxy and no opportunity cost. In the comparison case, we included the use-limitations and added the entire calculated opportunity costs for start-up and minimum load to 100 percent of their respective proxy costs.

Table 7 below compares the two cases for Resource 1 for every month. The data is presented as the percentage of starts or run hours to its respective limitation. For example, in column [1A] for January, the resource would have used 188 percent of the allowed starts. On the other hand in column [1C], the addition of the full opportunity cost for start-ups reduced the number of starts to 63 percent of allowed starts, showing that the calculated cost is providing enough flexibility to ensure the resource does not violate its use limitations. Similarly, the run hour percentages without opportunity costs under column [1B] are higher than the percentages under column [1D].[28]

The opportunity cost is provided as a cap so the resource's scheduling coordinator can bid in lower start-up and minimum load costs to manage limitations. In this case, the scheduling coordinator would likely lower the start-up and minimum load costs below the level allowed, assuming it was behaving competitively.

Table 7
Resource 1: sample comparison of opportunity cost impact

	100% Proxy cost only		100% Proxy cost with opportunity cost	
	Percent of start-up limitation used	Percent of run hour limitation used	Percent of start-up limitation used	Percent of run hour limitation used
	[1A]	[1B]	[1C]	[1D]
Jan	188%	24%	63%	11%
Feb	338%	50%	100%	26%
March	225%	31%	25%	4%
April	325%	53%	13%	3%
May	250%	47%	38%	23%
June	100%	17%	0%	0%
July	138%	19%	0%	0%
August	275%	61%	25%	7%
September	150%	21%	0%	0%
October	313%	51%	63%	29%
November	150%	29%	13%	1%
December	225%	43%	25%	6%

[28] Note that the simulation to calculate run hour limitation opportunity costs produced non-zero values in only some months. However, all of the percentages in column [1B] in Table 7 are below 100 percent because dispatch was lower using 2013 actual real-time prices than simulated 2012 real-time prices.

Repeating the process for Resource 2, the data in Table 8 show very similar results to Resource 1 with a few notable exceptions. First, the percent of start-ups used in column [2C] exceeds 100 percent in the first three months. Since our analysis is conservatively based on only 100 percent of proxy plus opportunity costs, results will likely change if the scheduling coordinator bids up to 125 percent of proxy costs. However, if this reflected a significant change in market conditions, the ISO may rerun the model, as discussed in the next section. Second, the percentages for run hour limitation used in column [2D] for March and December are higher than the percentages for the same months in column [2B]. This difference can be explained by the interplay between start-ups and run hour limitations in the optimization. For these months, and for other months as well, the calculated opportunity cost was zero for run hour limitations but non-zero for start-up costs. Since the start-ups were more binding, the unit commitment in the rerun case with opportunity costs kept the unit online to avoid having to incur the high start-up costs again. This results in greater use of the allowed run hour limitation in the rerun case. Nonetheless, the percentages are all below 100 percent.

Table 8
Resource 2: sample comparison of opportunity cost impact

	100% Proxy cost only		100% Proxy cost with opportunity cost	
	Percent of start-up limitation used	Percent of run hour limitation used	Percent of start-up limitation used	Percent of run hour limitation used
	[2A]	[2B]	[2C]	[2D]
Jan	150%	50%	105%	47%
Feb	110%	41%	105%	40%
March	155%	55%	110%	58%
April	115%	35%	40%	25%
May	85%	46%	35%	19%
June	55%	37%	40%	23%
July	105%	50%	30%	27%
August	105%	87%	80%	67%
September	110%	46%	85%	45%
October	125%	58%	90%	50%
November	85%	41%	45%	26%
December	105%	63%	30%	72%

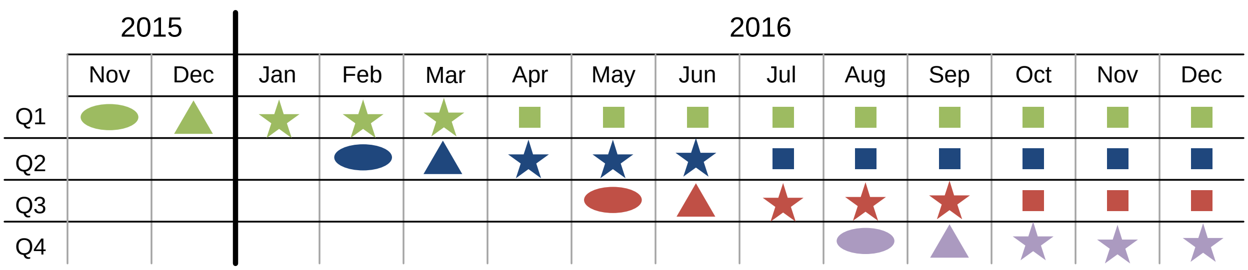
7.2.5. Additional considerations for the optimization model and process

The ISO is improving its current prototype. The model currently can reflect monthly limitations and we expect to be able to expand that to an annual optimization as well. The ISO is evaluating whether it can model rolling annual periods.

The ISO will not be able to model multi-stage generating resources. However, our preliminary review of use-limited resources and their limitations did not find this to be a significant drawback. In the first series of resources reviewed, we found the limitations for the resource complicated enough that it may be more appropriate to use negotiated opportunity costs as proposed in this initiative. In the second series of resources, we found limitations on starts of the plant, rather than each configuration. The ISO can model plant-level starts. Therefore, the ISO's proposed methodology can largely capture the limitations in conjunction with the additional 25 percent bidding headroom.

The ISO is currently proposing to refresh the model quarterly by updating the natural gas price futures. Table 9 below provides an example of the natural gas futures update process. Calculating the opportunity costs used in the first quarter (Q1) of 2016 starts with averaging the natural gas futures traded in November 2015 (shown as a green oval). The averaged gas prices will be used in the model runs conducted in December 2015 (shown as a green triangle). The resultant opportunity costs are used by Scheduling Coordinators in January through March 2016 (shown as green stars). If the limitation is only for a portion of the quarter, then no opportunity costs is calculated beyond this time horizon. If the limitation is longer than a quarter, then the costs calculated for time beyond the first quarter is advisory only (shown as green squares). The advisory opportunity costs may be revised during the next model run for the second quarter or if there is an intra-quarter rerun. The process for the second quarter (Q2), repeats starting in February 2016 (shown as the same shapes in blue).

Table 9
Sample opportunity cost update process



= ISO to average futures for each trade date available.
= ISO to calculate opportunity costs.
= ISO to use calculated opportunity costs.
= ISO to use as advisory opportunity costs.

If the limitations fall between two quarterly runs, the ISO will rerun the analysis. For example, a resource has an air permit only from June through August. The ISO will calculate June's opportunity costs during the second quarter and July's and August's costs during the third quarter.

More frequent updates may be appropriate if there are:

- Significant system or network changes that tend to increase congestion or prices (*e.g.*, the outage of a direct current transmission line or prices have increased by more than 25 percent cumulatively) for greater than two weeks. The ISO may then need to rely on its D+2 reliability forecasts to have a better reflection of new system conditions as historical heat rates will not be able to capture the outage. This intra-quarter rerun may be conducted for an impacted area, resource, or market-wide. No rerun will be conducted if the change occurs within two weeks of the start of the next quarterly rerun.
- Natural gas prices increase appreciably from what was assumed in the original model runs (*e.g.*, greater than 25 percent cumulatively). This intra-quarter rerun may be conducted for an impacted fuel region or market-wide. No rerun will be conducted if the change occurs within two weeks of the start of the next quarterly rerun.
- Significant Master File or use plan changes that impact how the resource is modeled (*e.g.*, change in an air permit or rerates of Pmin) that will impact the resource for longer than two weeks. This rerun is for a specific resource. No rerun will be conducted if the change occurs within two weeks of the start of the next quarterly rerun. Generally if there is another established process to address the resource's changes then an opportunity cost model rerun is not warranted. For example, if the resource has an outage, this should be managed via the ISO's existing process for handling outages.

Table 10 below (split across three pages) provides an example comparing the daily and cumulative increase or decrease in the gas price index over the natural gas future prices used in the opportunity cost model for a first quarter model run. Column [A] shows illustrative monthly natural gas price futures for fuel region PGE2 as compared to the historical daily gas price index used in the day-ahead market in column [B].[29] The daily change between these two sources is shown in column [C] with a maximum increase of 464 percent. Column [D] is the cumulative increase or decrease. For example, the 22 percent increase shown for January 8 is the average of all the daily changes (shown in column [C]) for January 1 through 8. The highest cumulative increase is 49 percent. The ISO proposes to base the threshold to rerun during the quarter on the cumulative percentage increasing above 25 percent (this occurs on February 3 in the illustrative example). This is to reduce administrative burden and in recognition that some gas price spikes (or congestion or other factors) may be transient and that the additional headroom provided by the proxy cost option should absorb these changes.

[2929] The ISO will use monthly granularity for gas price futures. The day-ahead gas price index will have a one-day lag unless updated via the gas price spike manual process.

Table 10
Illustrative example of daily and cumulative changes in natural gas prices

	Natural gas futures to be used in opportunity cost model	Actual GPI for PGE2	Daily increase (decrease) of GPI from futures	Cumulative increase (decrease) of GPI from futures
	[A]	[B]	[C]	[D]
			=([B] - [A]) / [A]	*average of [C]*
1/1/2014	$4.20	$4.99	19%	19%
1/2/2014	$4.20	$4.99	19%	19%
1/3/2014	$4.20	$5.10	21%	20%
1/4/2014	$4.20	$5.15	23%	20%
1/5/2014	$4.20	$5.15	23%	21%
1/6/2014	$4.20	$5.15	23%	21%
1/7/2014	$4.20	$5.27	25%	22%
1/8/2014	$4.20	$5.30	26%	22%
1/9/2014	$4.20	$5.16	23%	22%
1/10/2014	$4.20	$4.97	18%	22%
1/11/2014	$4.20	$4.82	15%	21%
1/12/2014	$4.20	$4.82	15%	21%
1/13/2014	$4.20	$4.82	15%	20%
1/14/2014	$4.20	$5.02	20%	20%
1/15/2014	$4.20	$5.13	22%	20%
1/16/2014	$4.20	$5.19	24%	21%
1/17/2014	$4.20	$5.27	25%	21%
1/18/2014	$4.20	$5.13	22%	21%
1/19/2014	$4.20	$5.13	22%	21%
1/20/2014	$4.20	$5.13	22%	21%
1/21/2014	$4.20	$5.13	22%	21%
1/22/2014	$4.20	$5.21	24%	21%
1/23/2014	$4.20	$5.40	29%	22%
1/24/2014	$4.20	$5.51	31%	22%
1/25/2014	$4.20	$5.50	31%	22%
1/26/2014	$4.20	$5.50	31%	23%
1/27/2014	$4.20	$5.50	31%	23%
1/28/2014	$4.20	$5.53	32%	23%
1/29/2014	$4.20	$5.55	32%	24%
1/30/2014	$4.20	$5.78	38%	24%
1/31/2014	$4.20	$5.96	42%	25%

	Natural gas futures to be used in opportunity cost model	Actual GPI for PGE2		Daily increase (decrease) of GPI from futures	Cumulative increase (decrease) of GPI from futures
	[A]	[B]		[C]	[D]
				=([B] - [A]) / [A]	*average of [C]*
2/1/2014	$4.18	$5.80		39%	25%
2/2/2014	$4.18	$5.80		39%	25%
2/3/2014	$4.18	$5.80		39%	26%
2/4/2014	$4.18	$6.84		64%	27%
2/5/2014	$4.18	$8.62		106%	29%
2/6/2014	$4.18	$23.58		464%	41%
2/7/2014	$4.18	$7.76		86%	42%
2/8/2014	$4.18	$7.13		71%	43%
2/9/2014	$4.18	$7.13		71%	44%
2/10/2014	$4.18	$7.13		71%	44%
2/11/2014	$4.18	$8.26		98%	45%
2/12/2014	$4.18	$6.65		59%	46%
2/13/2014	$4.18	$6.02		44%	46%
2/14/2014	$4.18	$6.03		44%	46%
2/15/2014	$4.18	$6.15		47%	46%
2/16/2014	$4.18	$6.15		47%	46%
2/17/2014	$4.18	$6.15		47%	46%
2/18/2014	$4.18	$6.15		47%	46%
2/19/2014	$4.18	$6.19		48%	46%
2/20/2014	$4.18	$6.49		55%	46%
2/21/2014	$4.18	$6.91		65%	46%
2/22/2014	$4.18	$7.97		91%	47%
2/23/2014	$4.18	$7.97		91%	48%
2/24/2014	$4.18	$7.97		91%	49%
2/25/2014	$4.18	$7.54		80%	49%
2/26/2014	$4.18	$5.96		43%	49%
2/27/2014	$4.18	$6.01		44%	49%
2/28/2014	$4.18	$6.29		50%	49%

	Natural gas futures to be used in opportunity cost model	Actual GPI for PGE2		Daily increase (decrease) of GPI from futures	Cumulative increase (decrease) of GPI from futures
	[A]	[B]		[C]	[D]
				=([B] - [A]) / [A]	*average of [C]*
3/1/2014	$4.15	$6.61		59%	49%
3/2/2014	$4.15	$6.61		59%	50%
3/3/2014	$4.15	$6.61		59%	50%
3/4/2014	$4.15	$8.62		108%	51%
3/5/2014	$4.15	$7.47		80%	51%
3/6/2014	$4.15	$6.12		47%	51%
3/7/2014	$4.15	$5.66		36%	51%
3/8/2014	$4.15	$5.59		35%	51%
3/9/2014	$4.15	$5.59		35%	50%
3/10/2014	$4.15	$5.59		35%	50%
3/11/2014	$4.15	$5.56		34%	50%
3/12/2014	$4.15	$5.56		34%	50%
3/13/2014	$4.15	$5.53		33%	49%
3/14/2014	$4.15	$5.37		29%	49%
3/15/2014	$4.15	$5.32		28%	49%
3/16/2014	$4.15	$5.32		28%	49%
3/17/2014	$4.15	$5.32		28%	48%
3/18/2014	$4.15	$5.57		34%	48%
3/19/2014	$4.15	$5.45		31%	48%
3/20/2014	$4.15	$5.44		31%	48%
3/21/2014	$4.15	$5.43		31%	47%
3/22/2014	$4.15	$5.37		29%	47%
3/23/2014	$4.15	$5.37		29%	47%
3/24/2014	$4.15	$5.37		29%	47%
3/25/2014	$4.15	$5.41		30%	47%
3/26/2014	$4.15	$5.61		35%	46%
3/27/2014	$4.15	$5.49		32%	46%
3/28/2014	$4.15	$5.47		32%	46%
3/29/2014	$4.15	$5.53		33%	46%
3/30/2014	$4.15	$5.53		33%	46%
3/31/2014	$4.15	$5.53		33%	46%

Note that not all significant changes may trigger a rerun or a resetting of opportunity costs. For example, if natural gas prices are lower than what was modeled (and therefore reduces market prices and costs), the ISO may not need to rerun the model outside of the normal quarterly process since the calculated opportunity cost is provided as a *bid cap*. Therefore, the resource could bid lower to manage its use limitations within the quarter.

The ISO expects scheduling coordinators to adjust their bids up to the total cap in accordance with good utility practice. Units with resource adequacy obligations should be bid in so that the limitations can be maximally used in a rational and operationally useful manner. The ISO is providing this additional bidding flexibility but since the opportunity cost is only updated once a quarter, we expect scheduling coordinators to adjust their bids to reflect current market conditions within reasonable bounds.

The *Reliability Services* initiative will develop availability incentive mechanism rules around a more stringent must offer obligation that may entail reporting of when use limitations are exhausted (*e.g.,* declaring an outage related to use limitations). Based on the second revised straw proposal, resource adequacy resources that have use-limitations will have the following exemptions, available on a monthly basis:[30]

- *If the resource has an ISO calculable opportunity cost in their minimum load, start-up, or default energy bid costs, the ISO will allow the resource to be exempted from the availability incentive mechanism once its use-limitation is reached in that month and the resource has put in the appropriate outage card. The ISO will not allow resources with a calculable opportunity cost to submit outages to manage their resource limitations.*
- *If the ISO determines the resource has non-calculable "negotiated" opportunity cost, then a resource will be allowed to manage its use limitation with outage cards and be exempted for the availability incentive mechanism during these outage periods.*

8. Transition costs

This topic only applies to multi-stage generators.

Transition costs are a type of start-up cost specific to multi-stage generators. Transitions costs can be thought of as the costs to "start" a configuration (or conversely the cost savings to "shut down" a configuration). The ISO maintains the separate terminology to differentiate between changes in configuration when the resource is already on versus plant-level start-up, which turns the resource "On" or "Off" per the ISO tariff definitions. A plant-level start reflects an operational need to validate a physical start and adherence to certain physical parameters such as inter-temporal constraints for the plant, versus the configuration. Otherwise, they are the same.

[30] Bentley, C., *Reliability Services Second Revised Straw Proposal*, Section 6.10: Use-limited resources and the availability incentive mechanism, October 22, 2014,p. 48-49.

8.1. Transition cost business practice manual changes

The ISO will clarify Attachment H of the Market Instruments business practice manual.[31] This can be accomplished without any policy changes and will largely preserve the current calculation of transition costs.

The ISO will clarify that resources with an approved major maintenance adder, the adder from the highest start-able configuration below the non-start-able configuration, will be added to the non-start-able configuration for the purposes of calculating the transition cost. This clarification is needed to prevent negative calculations from missing data.

8.2. Transition cost policy changes

The ISO proposes the following policy changes and clarifications to transition costs. The ISO expects to make corresponding business practice manual changes.

A transition cost is a type of start-up cost

The ISO will clarify that the transition cost is the cost to transition between multi-stage generator configurations when the resource is already "On." It is the ISO's understanding that the transition cost reflects the fuel input to transition from one configuration to another. The fuel input is based on the resource's actual unit-specific performance parameters, as required in tariff section 30.4.1.1.1. Since the transition is a start-up, there is no transition cost when transitioning to a lower configuration just like there is no start-up cost when shutting down.[32] Stakeholders should comment on whether the ISO's interpretation is correct and if there are any other costs that should be considered in transition costs.

Start-up costs can reflect major maintenance adders

The ISO will allow major maintenance costs for each configuration to be reflected in the start-up cost for each configuration. The ISO calculates a start-up cost for each configuration regardless if the resource can start directly into that configuration or not.

Table 11 below is reproduced from the sample transition cost calculation spreadsheet posted on the ISO website.[33] The figure shows a four configuration resource that can start directly into configurations 1 and 3 but not into 2 or 4. The fields in yellow are based on information provided by the scheduling coordinators (or otherwise stored in the Master File). The ISO expects the data provided for the heat input, configuration Pmin and configuration start-up time to reflect the resource's actual unit-specific performance parameters and may be different for each configuration. On the other hand, the monthly GPI (gas price index), GHG (greenhouse

[31] Existing BPM clarifications. The change has not been made at the time of this straw proposal publication.

[32] However, there are resources that have explicit shut-down costs.

[33] "See Multi Stage Generating Resource Transition Cost Validation Sample Spreadsheet v2" available at: http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx

gas) price and emission rate and the GMC (grid management charge) are the same for all configurations. The 10 percent cost adder in the last column is a calculation embedded in the spreadsheet. Lastly, the major maintenance adder column should be populated based on costs submitted to and approved by the ISO pursuant to the processes and rules in Appendix L of the Market Instruments business practice manual (incorporating the recent changes to be made as discussed in Section 10). Once the major maintenance adders have been approved, they will be stored in the Master File.

Table 11
Current sample start-up cost calculation for multi-stage generator

STEP 1:	Calculate proxy start-up values for each configuration, and apply a 10% adder											
	The values in cells highlighted in yellow are supplied by the SC.											
		Configuration Proxy Start-Up Costs – For validation of rule 1 ONLY										
	Enter Configuration IDs	Configuration	Start-able	Heat Input (MMBtu)	Monthly GPI ($/MMBtu)	Monthly GHG Price	GHG Emission Rate	Major Maint. Adder	Configuration Pmin	Config Startup Time	GMC	Cost + 10%
	Config 1	1 - Startable	Y								0.3626	$ -
	Config 2	2	N		$0.00	$0.00	0				0.3626	$ -
	Config 3	3 - Startable	Y		$0.00	$0.00	0				0.3626	$ -
	Config 4	4	N		$0.00	$0.00	0				0.3626	$ -

Eliminate cost boundary rules

Currently the ISO relies on two separate rules to bound transition costs:

> Rule 1: Constrains the transition costs along each feasible path from offline to each configuration such that their sum is between 100 percent and 125 percent of the cost (plus 10 percent) associated with starting up directly to that configuration.
>
> Rule 2: Limits transition costs between configurations such that the sum of nested transition costs is between 100 percent and 125 percent of the direct transition.

The ISO proposes to eliminate both rules.[34] Instead, the transition and start-up costs will be calculated and treated as follows:[35]

- A start-up cost is incurred when a resource is turned "On." If a resource is already On but incrementing between configurations, it may incur a transition cost.
- The ISO will calculate a start-up cost for each configuration based on quantifiable and verifiable costs, related to physical parameters of the resource. The start-up cost may include a major maintenance adder per configuration. If the scheduling coordinators

[34] Policy change.
[35] Policy change.

cannot provide such information for a particular configuration, then that configuration will have the same costs and/or parameters as the next lowest verifiable configuration.

- The ISO clarifies that even configurations that cannot be directly started (referred to as "non-start-upable" configurations) can have verifiable physical parameters and/or costs that are used to calculate the total start-up cost. The start-up costs for a non-start-upable configuration is only used to calculate the transition cost and will not be used to calculate a start-up cost to turn the unit "On." Again, should the scheduling coordinator not (or cannot) provide such information, the parameters and/or of the next lowest verifiable configuration will be used.
- Costs for increasing configurations must be increasing. For example, the total start-up cost for configuration 2 must be equal to or greater than configuration 1.
- Scheduling coordinators may bid up to 125 percent of the total start-up cost for each configuration on a daily basis but costs must be increasing for increasing configurations.
- Transition costs will be calculated as the difference between the "To" and the "From" configuration start-up costs.
- The ISO is not proposing to calculate costs for a downward transition. Unlike minimum load costs, once the resource has started, the start-up cost has been incurred.
- These changes will require new bidding and verification functionality.

The ISO reviewed a sample of multi-stage generator transition costs. The tables below reflect the two most common variations. Table 12 shows the proposed calculation for a resource with distinct peakers or steam turbines and Table 14 shows a resource with duct firing and distinct peakers or turbines.

Unit A in Table 12 has four configurations, all of which are directly startable. In this example, a new configuration entails starting a new peaker or steam turbine. Therefore, most of the costs and physical parameters approximately double as the configurations increase. The ISO expects that all the columns in yellow are verifiable costs and/or verifiable physical parameters of the resource. For example, the ISO should be able to verify the heat input, start-up energy, configuration Pmin, and start-up time for each configuration. Additionally through its existing process, the ISO expects to verify the major maintenance adder for each configuration. The non-highlighted columns are costs that remain the same for all configurations and are provided by the ISO such as the daily gas price index. The last two columns in blue calculate the total proxy cost and the total cost at the 125 percent bid cap. Note that the costs are increasing with increasing configurations. When scheduling coordinators bid, the bid for higher configurations should be greater than or equal to lower configurations.

Table 12
Proposed start-up cost calculation: peaker or steam turbine

Config IDs	Configuration	Start-able	Heat Input (MMBtu)	Start-up energy (MWh)	Daily GPI ($/MMBtu)	Energy Price Index ($/MWh)	GHG Price	GHG Emission Rate	Major Maint. Adder	Config Pmin	Config Startup Time	GMC	Cost	Cost x 125%
UnitA_1	1 - Startable	Y	80	20	$4.00	$1.00	$12.00	0.053963	$250	50	20	$0.38	$645	$806
UnitA_2	2 - Startable	Y	160	20	$4.00	$1.00	$12.00	0.053963	$550	100	20	$0.38	$1,320	$1,650
UnitA_3	3 - Startable	Y	240	20	$4.00	$1.00	$12.00	0.053963	$1,000	150	20	$0.38	$2,145	$2,681
UnitA_4	4 - Startable	Y	320	20	$4.00	$1.00	$12.00	0.053963	$1,500	200	20	$0.38	$3,020	$3,775

Assuming that the scheduling coordinator bid at the 125 percent proxy cap and transitioning to all configurations is feasible, Table 13 shows the possible transition costs. The transition costs are calculated as the difference between the "To" configuration and "From" configuration start-up cost shown in Table 12. For example, the bid for configuration 1 is $806 and for configuration 2 is $1,650 as shown in the last column of Table 12. If the resource transitions from configuration 1 to 2, it would incur an additional $844 in transition costs shown in the first row, second column of Table 13, which is the difference between the two configuration start-up bids. In total when the resource is in configuration 1 it incurs only the start-up for configuration 1. After it transitions, it would only incrementally incur the transition cost to configuration 2. There are no transition costs from a higher to a lower configuration or if the resource stays in the same configuration.

Table 13
Proposed transition cost calculation: peaker or steam turbine

		"To" configuration			
		UnitA_1	UnitA_2	UnitA_3	UnitA_4
"From" configuration	UnitA_1		$844	$1,875	$2,969
	UnitA_2			$1,031	$2,125
	UnitA_3				$1,094
	UnitA_4				

Unit B in Table 14 also has four configurations but only the first and the third can be directly started. In this example, configurations 2 and 4 reflect duct firing. Therefore, the costs do not double from configuration 1 to 2 or from 3 to 4. Instead, there is a small incremental increase in the costs due to the change in the configuration Pmin but the heat input and major maintenance costs do not increase from the startable configurations. Unlike starting a new piece of equipment, it is the ISO's understanding that in order to access the duct firing capability, the resource needs to increase its energy output from the Pmin of configuration 1 (200 MW) through to the Pmin of configuration 2 (250 MW) and would be paid for the energy produced in the dispatchable portion of configuration 1 (between 200 and 249 MW). In this way, there is likely no additional fuel input for reaching duct firing that has not been accounted for in the energy to ramp into the duct firing configuration. The ISO is seeking stakeholder feedback on its understanding.

The ISO expects that all the columns in yellow are verifiable costs and/or verifiable physical parameters of the resource. For example, the ISO should be able to verify the heat input, start-up energy, configuration Pmin, and start-up time for each configuration. Additionally through its existing process, the ISO expects to verify the major maintenance adder for each configuration. The non-highlighted columns are costs that remain the same for all configurations and are provided by the ISO such as the daily gas price index. The last two columns in blue calculate the total proxy cost and the total cost at the 125 percent bid cap. Note that the costs are increasing with increasing configurations. When scheduling coordinators bid, the bid for higher configurations should be greater than or equal to lower configurations.

Table 14
Proposed start-up cost calculation: duct firing

Config IDs	Configuration	Start-able	Heat Input (MMBtu)	Start-up energy (MWh)	Daily GPI ($/MMBtu)	Energy Price Index ($/MWh)	GHG Price	GHG Emission Rate	Major Maint. Adder	Config Pmin	Config Startup Time	GMC	Cost	Cost x 125%
UnitB_1X1	1 - Startable	Y	1,500	20	$4.00	$1.00	$12.00	0.053072	$11,590	200	60	$0.38	$18,604	$23,254
UnitB_1X1DF	2	N	1,500	20	$4.00	$1.00	$12.00	0.053072	$11,590	250	60	$0.38	$18,613	$23,266
UnitB_2X1	3 - Startable	Y	2,500	20	$4.00	$1.00	$12.00	0.053072	$23,180	400	60	$0.38	$34,869	$43,586
UnitB_2X1DF	4	N	2,500	20	$4.00	$1.00	$12.00	0.053072	$23,180	450	60	$0.38	$34,878	$43,598

Assuming that the scheduling coordinator bid at the 125 percent proxy cap and transitioning to all configurations is feasible, Table 15 shows the possible transition costs. The transition costs are calculated as the difference between the “To” configuration and “From” configuration start-up cost shown in Table 14. For example, the bid for configuration 1 is $23,254 and for configuration 2 is $23,266 as shown in the last column of Table 14. If the resource transitions from configuration 1 to 2, it would incur an additional $12 in transition costs shown in the first row, second column of Table 15, which is the difference between the two configuration start-up bids. In total when the resource is in configuration 1 it incurs only the start-up for configuration 1. After it transitions, it would only incrementally incur the transition cost to configuration 2. There are no transition costs from a higher to a lower configuration or if the resource stays in the same configuration.

Table 15
Proposed transition cost calculation: duct firing

		"To" configuration			
		UnitA_1	UnitA_2	UnitA_3	UnitA_4
"From" configuration	UnitA_1		$12	$20,331	$20,343
	UnitA_2			$20,319	$20,331
	UnitA_3				$12
	UnitA_4				

9. Greenhouse gas costs

In response to Assembly Bill 32, California's Air Resources Board established the state's market-based cap-and-trade program to reduce greenhouse gas emissions. "Covered entities," such as thermal generators, emitting more than 25,000 metric tons of carbon dioxide equivalents (MTCO2e) per year are required to comply. The program began on January 1, 2013 with phased compliance obligations for different parts of the economy. Thermal electric generating sources have already begun compliance.

Starting January 1, 2015, natural gas suppliers will also be considered covered entities for the amount of gas delivered to California end-users, net of the amount delivered to existing covered entities.[36]

The ISO currently allows covered entities to reflect greenhouse gas costs in commitment costs. Thermal resources that have not reached the 25,000 MTCO2e threshold cannot include a greenhouse gas cost or will have to voluntarily enroll in the cap-and-trade program. When natural gas suppliers become covered entities, the greenhouse gas costs incurred may be passed on to natural gas-fired generators that do not meet the emission threshold. Therefore, all natural gas-fired resources will have greenhouse gas costs. Correspondingly, the ISO proposes to allow all natural gas-fired resources to reflect greenhouse gas costs in commitment costs. This assumes that greenhouse gas costs are *not* reflected in the gas price indices used.[37]

The California Public Utilities Commission is currently assessing the impact of greenhouse gas compliance on natural gas suppliers.[38] On November 18, 2014 the Commission released a non-binding proposed decision that defers several key issues from the current Phase 1 process to Phase 2 of the proceeding.[39] The schedule for Phase 2 has not been released. It is also unclear whether the gas price indices in future will reflect greenhouse gas costs.

The outcome of this proposal will impact commitment cost and opportunity cost calculations. However, given the current regulatory uncertainty, the ISO proposes no policy changes until there is clearer direction from the Commission. The ISO needs more regulatory clarity in order to propose market design changes that will be acceptable to the Federal Energy Regulatory Commission.

[36] California Public Utilities Commission, *Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge*, Rulemaking 14-03-003, July 7, 2014, p. 3.
[37] Policy change.
[38] See California Public Utilities Commission, Rulemaking 14-03-003, filed March 13, 2014.
[39] California Public Utilities Commission, Proposed Decision, Decision Resolving Phase 1 Issues and Addressing the Motion for Adoption of Settlement Agreement,, Rulemaking 14-03-003, November 18, 2014.

10. Additional business practice manual clarifications

Costs for non-thermal resources

The ISO has submitted to the FERC a tariff amendment to allow reflection of fuel or fuel-equivalent costs for non-natural gas-fired resources.[40] The ISO will make a corresponding clarification in the Market Instruments manual that non-thermal resources will be allowed to use the "fuel cost" field in the Master File to reflect non-fuel costs, such as pumping costs for pumped storage resources.[41] The ISO recognizes that much of the ISO's systems were created with thermal resources in mind and that some categories do not specifically meet non-thermal resources' needs.

Major maintenance adders

The ISO will make a clarification in Appendix L of the Market Instruments manual outlining the documentation required and the methodology used to calculate major maintenance adders.[42]

11. Other issues

Default variable operation and maintenance costs - The ISO is approaching the three year review period for default variable operation and maintenance costs, which became effective on April 1, 2012. Only one stakeholder desired a review but it is unclear whether the stakeholder has taken advantage of or fully completed the negotiated cost option. Devoting time and resources to the three year review should be prioritized against other ISO activities in this and other initiatives. We would appreciate stakeholder feedback on whether conducting the three year review will be valuable or necessary given that the ISO is not aware of any concerns regarding the current values and the proposed proxy cost option will have an increased head room up to 125 percent on *all costs*, not just natural gas.

Default major maintenance adders – The ISO is contemplating ways to reduce the administrative burden on ISO and stakeholder resources by proposing to establish default values for major maintenance adders. Many scheduling coordinators only have access to contracts such as power purchase agreements as supporting documentation when applying for these adders. These costs may not necessarily reflect actual operational costs but rather a negotiated price. The ISO proposes to use default values when the scheduling coordinator cannot or does not provide supporting documentation for alternative values. The ISO would apply this to both non- and multi-stage generating resources.

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[40] *California Indep. Sys. Operator Corp.*, FERC docket no. ER15-15, October 1, 2014. Section 30.4.1.1.2 Non-Natural Gas-Fired Resources.

[41] Existing BPM clarifications. The change has not been made at the time of this straw proposal publication.

[42] Existing BPM clarifications. See PRR 782 available at: http://bpmcm.caiso.com/pages/default.aspx

Clarification on major maintenance adders – The ISO reiterates that if scheduling coordinators submit power purchase agreements, service agreements or other contractual arrangements as documentation for major maintenance adders, they must be based on estimates of reasonable actual major maintenance costs. This is already detailed in the tariff in section 30.4.1.1.4.

12. Next Steps

The ISO will discuss this straw proposal with stakeholders on a conference call on January 6, 2015. Stakeholders should submit written comments by January 13, 2015 to ComCosts2@caiso.com.