Variable Operations and Maintenance Cost Review

Straw Proposal

December 19, 2019

California Independent System Operator

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1 Executive Summary

The efficient and effective operation and maintenance of generating resources is crucial to the reliability of the energy system of the Western United States. Accordingly, the California Independent System Operator must establish an accurate cost recovery mechanism for the costs associated with these activities in our markets. The current ISO framework to account for operations and maintenance (O&M) costs has sufficed for over a decade but needs improvement to meet the challenges of a changing resource base characterized by increased variability in operating profile and diversity of technologies. In this straw proposal, the ISO proposes a plan to improve the existing O&M cost recovery mechanism by updating our definitions for O&M cost components, changing the composition of the variable operations and maintenance (VOM) adder, and expanding the major maintenance adder (MMA) process with a new default maintenance adder.

The ISO performs bid mitigation to ensure that our markets are competitive and thus provide low-cost electricity to consumers. The Federal Energy Regulatory Commission requires the ISO to mitigate bids to an estimate of a generating resource's marginal costs. A critical input to this estimate is a generator's O&M costs. The current framework the ISO uses to estimate these costs is through a VOM adder (expressed in $/MWh) which is applied based on the generator's technology type and through an MMA (expressed in $/start or $/run-hour). While only the VOM adder has default values defined in ISO Tariff, the values for both adders can be negotiated with the ISO on a resource-specific level.

Over the past year, during which the ISO issued an initial O&M cost report and held five technology-specific working groups on O&M costs, the ISO determined that the current O&M cost framework could be improved. Specifically, the definitions for the current VOM and MMA adders can be improved by having clear definitions of their constituent cost components; this will ease the estimation and negotiation of their values. Additionally, these adders combine dissimilar cost components and can reasonably be expected to grow stale over time.

To address these concerns, the ISO is issuing this straw proposal for stakeholder consideration and feedback. Defining the O&M cost components, including how to differentiate between fixed and variable O&M costs, underlies the rest of the proposal and is thus the first component of our proposal. The ISO proposes to update to the VOM adder, which will be redefined as only a variable operations (VO) adder. Through the VO adder, market participants can recover operations costs such as consumables that have a clear relationship to MWh production. The ISO then proposes to allow market participants to recover *all* of their variable maintenance costs through a new default maintenance adder in lieu of the current MMA. Similar to the VO adder, the default maintenance adder would be calculated on a technology-specific level and can be included in default energy bids, default minimum load costs, and/or default start-up costs depending on how the variable maintenance costs are incurred. The proposed definitions of the O&M cost components and detailed steps of the proposed calculation of the default maintenance adder comprise the bulk of this straw proposal.

The ISO encourages stakeholders to consider this straw proposal and to participate in the stakeholder call on January 6, 2019. Written comments on this straw proposal can be submitted by January 20, 2020.

2 Introduction

The variable operations and maintenance (VOM) adder and major maintenance adder (MMAs) currently allow market participants to recover their operation and maintenance costs. The ISO includes these adders in the resource's "proxy costs", which mirror the three parts of market participants' energy bids: default energy bids (DEBs), minimum load costs, and start-up costs. These proxy costs are used for various purposes in the ISO markets such as local market power mitigation, generating bids when none have been submitted, and, for minimum load costs and start-up costs, for capping market participants' minimum load and start-up bids.

Figure 1 shows the current framework of this cost recovery mechanism. The VOM adder is included in DEBs under the variable cost-based methodology as shown in the blue box in Figure 1 below. The VOM adder is also included in minimum load costs under the Proxy Cost option shown in red below. MMAs are included in minimum load costs and start-up costs under the Proxy Cost option as shown in red and green.

Figure 1 – Current Cost Recovery Framework in ISO Markets

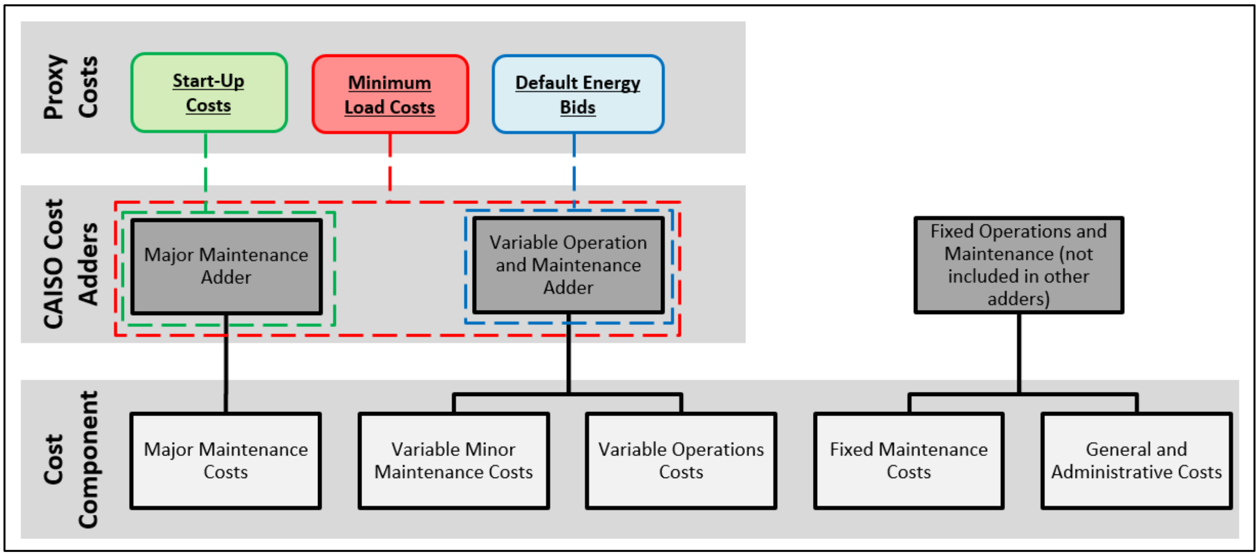

Figure 1 also includes one further level of detail showing which cost components are currently included in each adder. The MMA is comprised of major maintenance costs and the VOM adder is comprised of variable minor maintenance costs and variable operations costs. Fixed maintenance costs, and general and administrative costs are also included in the framework; however, these costs are not included in either the VOM or the MMAs.

2.1 Background

The ISO initially established the VOM adder values as part of a stakeholder initiative in 2012. Prior to 2012, the ISO had only two VOM adders: one for peaker units and one for non-peaker units. To establish the adder values, the ISO engaged an external consultant, Utilicast LLC., to analyze cost estimates from a variety of external sources and propose estimates on a generation technology-specific level. These are the cost estimates that the ISO currently uses as default adders in the ISO markets, *i.e.* generation technologies receive a pre-determined $/MWh VOM value to be included in their DEBs and minimum load costs. If market participants find that the default values are inadequate, they are able to negotiate VOM adder values with the ISO, pursuant to ISO Tariff section 39.7.1.1.2.

Around this time, the ISO introduced MMAs as part of the Commitment Cost Refinements 2012 stakeholder initiative. Potomac Economics, Ltd. (referred to here as Potomac), was engaged to propose a framework for how major maintenance costs could be recovered. Major maintenance costs, like costs incurred for major equipment overhauls, are incurred in large dollar-value increments and possibly irregularly. However, these costs are a direct result of the operation of a generating resource to produce electricity and are thus marginal costs recoverable in the ISO energy markets. These costs were expected to be incurred based on the number of hours a generating resource is online and/or how many times a generating resource starts up in a given time period.

As described in the draft final proposal for the Commitment Cost Refinements 2012, the ISO and Potomac planned on creating default MMAs using "publically available data, experience with development and monitoring of major maintenance cost adders in other markets, and information provided by the ISO and ISO market participants."[1] Market participants were generally supportive of the concept of MMAs but were concerned about the data requirements and difficulty of calculating default MMAs. Based on this feedback, the ISO determined that market participants may negotiate generating resource-specific MMAs and thus the default MMA value would effectively be set to zero.

2.2 Recent Efforts

In 2012, the ISO committed to review the VOM adder values once every three years.[2] The ISO performed an internal review of the adder values in 2015 and did not change the adder values.

In 2018, the ISO conducted a more extensive review of the VOM adder values after another three years with the current VOM adder values and numerous MMA negotiations had passed. The ISO published a report on December 26, 2018[3] and held a stakeholder call on January 8, 2019 to propose the updated VOM adder values. Nexant, Inc. was engaged to evaluate the adders based on ISO definitions of VOM and related costs. Feedback from market participants related to these efforts focused on the lack of formal Tariff definitions of VOM and related cost components to support the ISO and Nexant's proposed adder values. Market participants also found the proposed values for some technology types to be too low or insufficient to adequately cover the resource's variable operations and maintenance costs.

In response to these comments, the ISO drafted definitions of some of the cost components related to the VOM adder and held five technology-specific workshops with market participants to discuss these definitions in July 2019. Market participants provided helpful feedback on the nature of their operations and maintenance activities and on the draft definitions. They noted that there are more variable

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[1] http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostRefinements.pdf
[2] http://www.caiso.com/Documents/2012-01-13_ER12-806_OM_Cost_Values_Amendment.pdf
[3] http://www.caiso.com/Documents/VariableOperationsandMaintenanceCostReport-Dec212018.pdf

operations costs than just consumable materials; that most variable maintenance costs are incurred based on run-hours (e.g. creep, corrosion, erosion, oxidation, rubs/wear, foreign object damage) and start-ups (e.g. thermal, mechanical, or high-cycle fatigue); and that the distinction between major and non-major maintenance activities is challenging and possibly arbitrary.

3 Issues Related to Variable Operations and Maintenance Costs

With the experience and information gained during last year's efforts to update the VOM adder, the ISO summarizes the issues it has identified in the subsections below. An explicit description of the issues will also aid in understanding the rationale for the proposed solution to these problems.

3.1 Issue 1: Need for better definitions

The definitions of the components for operations and maintenance costs may lack some clarity. For market participants, this leads to challenges in applying for MMAs and negotiated VOM adders. For the ISO, this leads to difficulty in quantifying the components of the default VOM adder and processing applications in a consistent and efficient manner.

Since the VOM adder was developed, the ISO has not explicitly defined its cost components because the need had not arisen. However, since the VOM adder was developed, the generation mix in the Western Electricity Coordinating Council (WECC) area has evolved and become more volatile. The higher level of operating variability creates a need to specifically define which costs truly are variable and thus recoverable.

The electric industry more broadly also lacks standardized definitions of these costs that are tailored to meet our purposes. For example, the FERC System of Accounts includes O&M costs but the definition is not suited to ISO requirements: namely, a definition that would help in determining which operations and maintenance activities are variable (and thus recoverable through the ISO energy markets). Additionally, FERC accounts are intended to have some flexibility to allow for diversity in the asset management strategies of generating resource owners.

The lack of clear definitions for VOM costs components can also impact the calculation of the $/MWh VOM adder values. Without a clear definition of which O&M costs are variable, the ISO cannot develop a detailed methodology to calculate the VOM adder. For example, precise definitions would be integral to a "bottom-up" calculation methodology. Since creating an exhaustive list of VOM costs is not practical without a formal definition, the ISO cannot make targeted adjustments to individual components of the adder over time.

Another issue with the lack of definitions arises in negotiating custom VOM adder values as well as MMAs. When the ISO and market participants negotiate a VOM adder or MMA, there is not a reference definition to serve as a baseline for negotiations. This could create inconsistency between what market participants submit as costs eligible for a VOM adder or MMA.

A specific difficulty encountered in negotiations for VOM adders and MMAs is separating out variable minor maintenance and major maintenance costs. As shown in Figure 1 above, variable minor maintenance costs are included in the VOM adder while major maintenance costs are included in the MMA. However, the ISO does not have a clear definition of what constitutes major versus minor maintenance costs. When a proposed definition was offered in July 2019, a number of stakeholders expressed concern over differentiating between major versus minor maintenance costs. The methods that were considered as differentiators included using the scope of the maintenance, isolating certain equipment areas as major or minor, and the length of the outage required.

3.2 Issue 2: Combining dissimilar cost components

The variable operating and variable minor maintenances costs included in the current implied definition of VOM intermingles two dissimilar cost components leading to practical difficulties. Variable operations (VO) costs, which the ISO understands is mostly comprised of consumables[4], typically represent physical materials which are consumed in the production of electricity. The physical reality of this process allows for a clear connection between the cost of consumables and the amount of MWh produced by a generating resource. However, variable minor maintenance costs are not as easily traced to variable electricity production due to them involving both labor and parts and the materials used during maintenance not being consumed in the production process. Accordingly, variable minor maintenance costs are conceptually quite different from VO costs leading to the question of why they are included in the same adder.

While there is no doubt that maintenance costs are incurred as a result of electrical production, how they can be clearly traced to MWh production (as opposed to run-hours or start-ups) is a more difficult proposition. For both variable minor maintenance and major maintenance costs, most costs are incurred in relation to run-hours or start-ups and not directly a result of MWh production. This makes it difficult for the ISO to determine the small component of variable minor maintenance costs which are incurred in relation to MWh. This is further exacerbated by separating maintenance costs out between major and minor as described above.

3.3 Issue 3: Undue burden from previously-proposed VOM adders

The default VOM adder values proposed in December 2018 might unduly burden market participants and the ISO if default values are not an accurate reflection of generating resources' costs.

One key message of the stakeholder feedback on the December 2018 VOM adder proposal is that the default values did not accurately reflect the variable non-fuel costs faced by market participants. Default cost adder values are intended to estimate the costs faced by *most* generating resources, *most* of the time. Stakeholders felt that the proposed values did not achieve this goal. While market participants have the option to negotiate VOM adders with the ISO, inadequate values would lead to an increased number of negotiations which could be unduly burdensome on market participants. An increased burden on

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[4] The ISO understands that there are other variable operating costs other than consumables such as production-based fees and costs associated with the energy needed to cool critical components. The ISO address this issue in the definitions proposed later on in this report.

market participants could lead to increased time, effort, and costs for market participants and the ISO. Based on this concern, the ISO should attempt to determine default VOM adders that accurately estimate the O&M costs faced by generating resources.

3.4 Issue 4: Risk of VOM adders becoming stale over time

Current default VOM adder values may meet market participants' current costs but they will eventually become stale due to changes in costs over time. Without clear definitions and a coherent framework to review against, the ISO will not be able to update them.

O&M costs change over time and thus so should the associated cost recovery mechanism. If the VOM adder values remain at their current levels forever, more and more market participants would turn to the ISO to negotiate custom VOM adder values as O&M costs change. This situation would incent the ISO to update the default VOM adder values. However, in this future scenario, the ISO would be in the same situation it is in today: an inability to make defensible updates to the default values due to the issues described in Issues 1 and 2. Accordingly, maintaining the current VOM at this time will not a long-term solution.

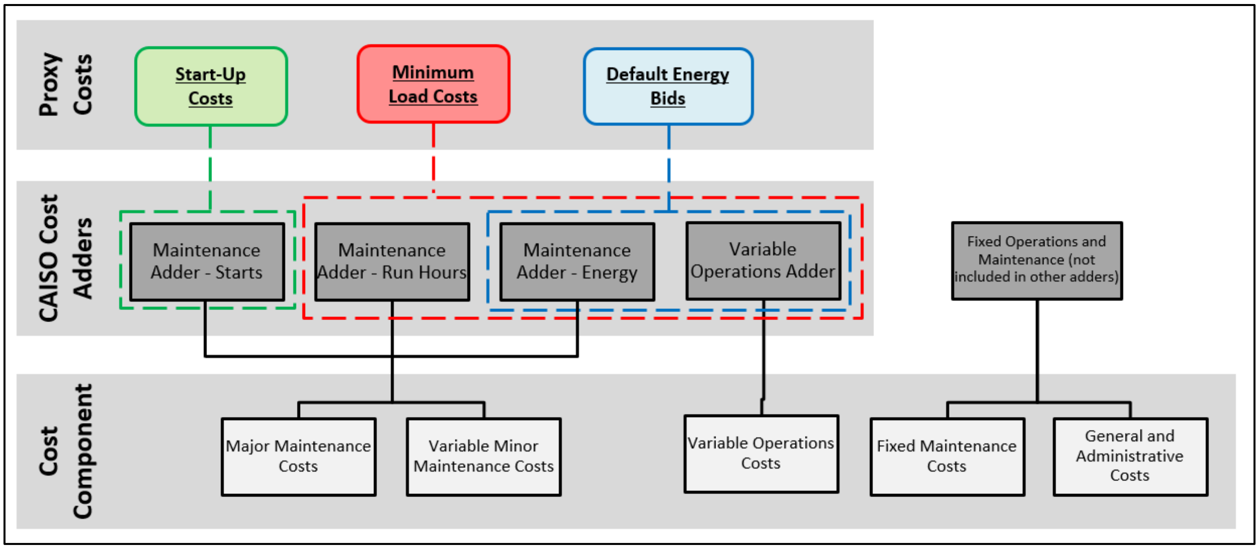
4 Straw Proposal

Given these issues, the ISO believes that the current framework for the VOM and MMA adders needs to be updated. Therefore, the ISO proposes a more comprehensive solution that involves: i) defining the O&M cost components, ii) updating the VOM adder to a VO adder, and iii) changing the MMA to be simply a maintenance adder through which all variable maintenance costs can be considered.

A visual representation of the conceptual framework of the proposal can be seen in Figure 2. Similar to Figure 1, the three proxy costs still exist and are comprised of various O&M costs adders. The framework now includes only one adder for maintenance costs, represented by the three maintenance adder (MA) boxes depending on how these costs are incurred. The maintenance adder for start-ups is comprised of any variable maintenance costs (*i.e.*, both major and minor maintenance costs) that are incurred from starting the unit and is included in SUCs as represented by the green box. Similarly, the maintenance adder for run-hours is comprised of variable maintenance costs incurred from running the unit and is included in minimum load costs as represented by the red box. A maintenance adder for energy is also available for any maintenance costs that incurred in relation to MWh production and is included in both minimum load costs and DEBs (red and blue boxes, respectively). Consistent with current practice, all variable cost adders, including the MA introduced here, can be negotiated with the ISO. The key difference with the current model is that the ISO will develop *default* MAs intended to offset the administrative efforts that may result from the newly proposed framework.

The VOM adder has been modified to a VO adder to be comprised of only VO costs such as consumables. This adder is included in both minimum load costs and DEBs. Fixed O&M costs are not recovered via any adder, which is consistent with marginal pricing principles.

Figure 2 – Proposed Cost Recovery Framework in ISO Markets



In the remainder of this section, the ISO introduces the details and merits of each of the three specific components of our proposal. The goal of this section is to explain what each component entails and how it addresses the issues that the ISO has previously laid out.

4.1 Component A: Establish definitions for the O&M cost components

The following definition relates only to the eligible equipment of a Generating Facility that incurs variable costs. In this context, a Generating Facility is defined as consistent with the ISO Tariff, Appendix A[5].

Variable Operations Costs: Variable Operations costs are the costs of consumables and other costs that vary directly with the electrical production of a Generating Facility, specifically excluding both maintenance and fuel costs. Examples include consumable materials, production-based fees such as royalties paid to landowners, and costs associated with the energy needed to cool critical components.

Previously, the VOM adder used in the ISO markets was not defined adequately to make a clear distinction between variable operations costs (primarily costs of consumables) and variable minor maintenance costs (comprised of maintenance activities not designated as major *and* which are incurred on a $/MWh basis). To avoid this difficult distinction, generators may now reflect $/MWh maintenance costs through the previously proposed Maintenance Adder and may reflect $/MWh variable operations costs through the VO Adder.

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[5] “[a]n Interconnection Customer's Generating Unit(s) used for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Moving forward, a variable operations adder will represent variable operations costs. Because these costs vary directly with the MWh production of a Generating Facility, the adder is expressed as a $/MWh value.

Variable Maintenance Costs: Variable maintenance costs are the costs associated with the repair, overhaul, replacement, or inspection of a Generating Facility that adhere to the following conditions:

1. Such costs must be associated with the electrical production of the Generating Facility such that the costs vary with respect to run-hours, electricity output, and/or the startup of the generating unit.
2. Such costs should reflect going-forward costs that are expected to be incurred within the Lifespan of the unit.

Examples include hot gas path and combustion system inspections and major overhauls. Labor costs associated with maintenance staff that are supplementary to baseline staff (e.g. contractors or reassigned crews) are included in this category. These costs do not include preventative, predictive, or routine maintenance that is not incurred as a result of starting or running the resource. A further discussion of preventative and predictive maintenance can be found in Appendix A.

The ISO proposes this new definition of maintenance costs in an effort to eliminate the distinction and simplify the discussion of major and minor maintenance costs. Grouping both types of maintenance together in one adder eliminates the need to arbitrarily define maintenance scope, categorize equipment and components, and define length of outage, among other contentious points.

The ISO is considering adding the following condition to the definition of variable maintenance costs but would like to specifically solicit stakeholder feedback on this condition:

> Such costs should not represent significant upgrades to the unit or significantly extend the life of the unit.

One important implication of this condition is that the costs of capital replacements and major overhauls *may* be considered variable maintenance costs and thus recoverable in the ISO spot electricity market. This could be the case if the costs are incurred within the Lifespan of the unit (as clarified in Appendix A), if the replacement equipment is identical to the equipment being replaced, and the costs vary with respect to incremental energy production. The ISO intends for this to be consistent with the treatment of Material Modifications per the Large Generator Interconnection Agreement[6]. The ISO is highlighting this point as questions about the difference between major overhauls and capital replacements have arisen during MMA negotiations.

Moving forward, a Maintenance Adder (MA) will represent variable maintenance costs, which can be expressed as $/start, $/run-hour, or $/MWh. For clarity, these activities encompass both variable 'minor' and 'major' maintenance activities. While these costs are typically expressed as $/start or $/run hour for thermal units, the ISO will also accept $/MWh costs if justified by the market participant.

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[6] See Section 5 of ISO Tariff Appendix EE: http://www.caiso.com/Documents/AppendixEE-LargeGeneratorInterconnectionAgreementForGIDAP-asof-Apr30-2019.pdf

Fixed Maintenance Costs: Fixed Maintenance costs are maintenance costs that do not vary with the run-hours, electricity output, or the starting of the Generating Facility. Fixed Maintenance costs are typically routine, predictive, or preventative in nature. Examples include labor costs associated with tools, baseline staff, and shop supplies. Appendix A further expands the ISO definition of predictive and preventative maintenance.

Currently, Fixed Maintenance Costs are not considered in the ISO's spot market. The rationale for excluding Fixed Maintenance costs is consistent with marginal pricing principles by which generators may recover incremental, not fixed, costs of producing electricity for the ISO markets.

General & Administrative Costs: General & Administrative (G&A) costs are non-maintenance costs incurred at a Generating Facility that do not vary with or relate to production of the unit. Examples include, but are not limited to, leasing or rental costs, property taxes, insurance, and fixed industry-related fees.

These costs are considered fixed, therefore not correlated with an adder recoverable in the ISO markets, because they cannot be directly correlated to the starts, run-hours, or MWh production of a Generating Facility. Like Fixed Maintenance costs, this definition of G&A costs is consistent with a marginal pricing methodology.

Table 1 below outlines some of what the ISO considered fixed and variable costs in context of the definitions proposed above; the examples are not intended to be comprehensive, but attempt to provide a clearer picture to stakeholders of what constitutes fixed versus variable costs. Fixed costs are broadly defined as costs incurred at the generator regardless of electrical production. These costs encompass both Fixed Maintenance costs and G&A costs, as defined above. Variable costs are defined as costs that vary directly with the electrical production of a Generating Facility.

Table 1 – Examples of Fixed vs. Variable Costs

Fixed Costs	**Variable Costs**
Maintenance, consumables, or costs associated with the following equipment: safety equipment, shop supplies/parts, tools, buildings, structures, HVAC systems, distributed systems including control, electrical, or communications systems, unless such costs can be clearly tied to electrical production	Consumables required for incremental production of electricity (e.g. raw water, lubricants, chemicals, cooling fluids)
Preventative or predictive maintenance activities	Corrective maintenance activities
Costs of labor and expenses incurred for general plant supervision and administration. This includes annual salaries, benefits, etc.	Labor costs that are supplemental to regular full time staff and that are associated with variable maintenance activities (e.g. contract work).

Maintenance inspections that are scheduled and performed strictly on a calendar basis (e.g. annually, seasonally, monthly) and whose schedules would not change if the production or operating profile of the unit changed	Maintenance inspections that are performed based on maintenance schedules that are defined in terms of hours, starts, and/or MWh production
Leasing or rental costs for any component, facility, or land	Production-based fees related to the operation & maintenance of the unit
Testing costs (e.g. emissions testing, vibration testing, hydrogen embrittlement testing, non-destructive testing, performance testing, relay & interlock testing)	Waste and wastewater disposal expenses, if the waste is a byproduct of electrical generation Hot gas path inspections
Balance-of-Plant, i.e. all supporting and auxiliary components and systems needed to keep a plant running, excluding the actual Generating Unit, unless these costs can be clearly tied to electrical production	Auxiliary electricity costs (e.g. energy needed to cool critical components, energy needed to operate auxiliary equipment directly related to MWh production)

4.2 Component B: Refine Variable Operations Adders

As described above, the ISO proposed updates to the VOM adders in December 2018. In response to the stakeholder feedback on these values, the ISO proposes to update the technology groups and values in a future iteration of this straw proposal.

An important distinction to keep in mind when considering the values to be proposed in the future is that the VOM adder currently used in the markets is intended to estimate VO and variable minor maintenance costs, while the currently proposed VO adder values estimate only VO costs. Variable minor maintenance costs will be captured in the default Maintenance Adder discussed in Section 4.3.

Table 2 below shows the VOM adders which were previously proposed for context. This table also shows the updated technology groups that is further discussed below.

Table 2 –Variable Operations Adder Values

Technology Type	**VOM Adder (Currently Used in Markets)**	**VO Adder (Proposed January 2019)**
	$/MWh	*$/MWh*
Coal	2.00	2.69
Integrated Coal Gasification Combined-Cycle (IGCC)	2.00	1.57
Steam Turbines	2.80	0.32
Combined Cycle Gas Turbines (CCGTs)	2.80	0.26
Advanced CCGTs	2.80	0.38
Combustion Turbines (CTs)	4.80	0.82

Advanced CTs	4.80	0.82
Reciprocating Internal Combustion Engines (RICEs)	4.80	1.10
Hydro	2.50	0.00
Pumped Storage	2.50	0.00
Biomass Power Plant	5.00	1.65
Geothermal Power Plant	3.00	1.16
Land Fill Gas	4.00	1.21
Nuclear	1.00	1.87
Wind Turbines	2.00	0.00
Solar Thermal Power Plant	0.00	0.24
Solar Photovoltaic	0.00	0.00

Technology groups

The ISO proposes to use 17 technology groups going forward which is an increase from the 12 technology types currently listed in the ISO Tariff, but a significant decrease from the 30 groups outlined in the December 2018 report. The new groups will incorporate a broader variety of technology types not currently reflected in the Tariff, which are expected to have changes to costs in the future. Paring down the proposed groups to 17 addresses stakeholders' concerns that some categories proposed in the December 2018 report were too specific.

While some technology groups remain consistent with the current Tariff groups used for VOM adders, some groupings are new to this initiative: Advanced Combustion Turbines (CTs) and Advanced Combined Cycle Gas Turbines (CCGTs). The ISO proposes to utilize industry-accepted definitions to delineate the categories. The ISO considers standard CTs as D/E/F-class or similar CTs, and Advanced CTs as G/H/J-class as well as aeroderivative CTs (e.g. the General Electric LM-series turbines). The distinction between standard and Advanced CCGTs will be made by the type of combustion turbine they use as part of their combined cycle operation. The ISO is also considering whether storage resources such as batteries should receive a VO adder or whether their O&M costs are better represented through a different type of default energy bid (see the ESDER 4 stakeholder initiative for further information on the latter issue).

4.3 Component C: Calculate Default Maintenance Adders

The ISO proposes to calculate default Maintenance Adders (MAs) for variable maintenance costs in the ISO markets. This section discusses the general methodology for the proposed MA calculation and provide examples of default MA values resulting from the calculation methodology.

There are some points to highlight about the estimated default MAs. The estimate for the maintenance costs faced by various generating resources is meant to be an approximation. No calculation could adequately capture every nuance of the maintenance activities performed at different plants. Resource owners have diverse strategies for maintaining their generation equipment that may include factors like equipment age, unit dispatch profiles, or previously negotiated service contracts. The default MAs estimated by the ISO aim to account for these idiosyncrasies within a reasonable range. Further, the ISO will continue to allow market participants to negotiate resource-specific MAs. The default MA values are intended to provide a baseline MA value that can be used by market participants who may not want to face the administrative burden of negotiating resource-specific values with the ISO. Further, as described below, the ISO proposes to apply a scaling factor to decrease the default MA values prior to calculating the resource-specific MA. This will mitigate the impact of individual assumptions on the final resource-specific MA.

Methodology:

The proposed methodology for calculating the default MAs is summarized in the following steps:

1) Estimate annual variable maintenance costs for a representative unit
2) Estimate run-hours, start-ups, and MWh per year
3) Determine whether the technology-type's maintenance costs is represented with a $/run-hour, $/start, or $/MWh adder (or a blend of these)
4) Calculate a default MA on a $/run-hour, $/start, or $/MWh adder basis
5) Calculate a unit-specific adder

Step 1: Estimate annual variable maintenance costs for a representative unit

The ISO utilized estimates prepared by Nexant to establish the starting point of the default MA calculation. The sources used to estimate annual variable maintenance costs are cited in the Appendix. The representative unit estimates for annual variable maintenance costs will be compared to a variety of other sources including other ISOs/RTOs, Integrated Resource Plans, consultant reports, and governmental/non-governmental organizations. The ISO's initial comparison of estimates to external sources is described in Appendix C.

The ISO estimates use a representative unit for each technology type whose baseline Pmax will serve as an input into the later calculations. The ISO assessed the Pmax of each representative unit by technology type against the operating characteristics of the resources in the ISO's balancing area, as well as the broader EIM footprint, and found the estimates to be reasonable. The magnitude of the Pmax assumption is mitigated further in the calculation when the estimated default MA is scaled on a resource-specific basis. Appendix B outlines each representative unit's Pmax.

Step 2: Estimate run-hours, starts and MWh per year

The ISO proposes to express the default Maintenance Adder in terms of $/run-hour, $/start, $/MWh, or a blend of these. After estimating annual variable maintenance costs, run-hours per year, start-ups per year, and MWh per year for each technology type are estimated.

> *Run-hours per year and starts per year:* Estimated on a technology-specific level using two years of actual ISO and EIM meter data.

MWh per year: Estimated using two years of actual ISO and EIM meter data. The ISO also compared the capacity factors (a function of MWh per year) used to other sources and determined our estimates to be reasonable. See Appendix B for more details.

Step 3 - Determine whether the technology-type's maintenance costs is represented with a $/run-hour, $/start, or $/MWh adder (or a blend of these)

This next proposed step involves important assumptions about whether maintenance costs are incurred in relation to run-hours, start-ups, electrical production (i.e. MWh), or a blend of these. The ISO will use the term "increment" to refer collectively to run-hours, start-ups, and MWh. Once those assumptions have been made and justified, the ISO will calculate a default MA on a technology-specific level.

Table 3 below shows the results of the ISO assumptions and justifications.

The ISO understands that most maintenance activities are performed in response to wear-and-tear due to mechanical and thermal factors like creep and fatigue. This implies that most costs are incurred based on run-hours and start-ups, respectively. The ISO assumed that most technology types that fit a baseload operational profile (e.g. Coal, Geothermal, and Biomass) primarily incur their costs in relation to run-hours.

However, wear-and-tear due to creep and fatigue occur simultaneously and depend on the frequency of dispatch in the ISO markets. Accordingly, spreading the annual variable maintenance costs across both a MA for run-hours and a MA for start-ups may be more appropriate. The ISO proposes that units that would incur maintenance costs on a blended basis (*i.e.*, run-hours and start-ups) are units that start frequently, including gas-fired Combined Cycle and Combustion Turbine units and Hydro units. The ISO also proposes that, for technology types that incur costs in this blended manner, costs are incurred evenly (50-50 split) between run-hours and start-ups.

Some technology types may incur maintenance costs in relation to MWh production. An example of this may be wind turbines that turn more quickly during period of high wind, generating more power but also incurring more wear-and-tear on the unit. A similar example would be hydro units: as more water flows through the plant, more power is generated but the unit experiences more wear-and-tear. Therefore, the ISO proposes that a blended rate is also appropriate for certain technology types (e.g. wind and hydro). However, based on our understanding, any such MWh-incurred costs are relatively immaterial compared to costs related to starting and running the unit and thus the ISO proposes that no technology types will have a default $/MWh Maintenance Adder. Units may negotiate this portion of the adder with the ISO consistent with the current negotiation process.

Table 3 – Proposed Start-up/Run-Hour/Output Maintenance Allocations per Increment

Technology Type	**Start-up Allocation**	**Run-Hour Allocation**	**Output Allocation**	**Justification (see references below)**
	%	%	%	
Coal	0	100	0	**1**
IGCC	0	100	0	**1**

Steam Turbines	0	100	0	**1**
CCGTs	50	50	0	**2**
Advanced CCGTs	50	50	0	**2**
CTs	50	50	0	**2**
Advanced CTs	50	50	0	**2**
RICEs	0	100	0	**1**
Hydro	50	50	0	**2**
Pumped Storage	50	50	0	**2**
Biomass Power Plant	0	100	0	**1**
Geothermal Power Plant	0	100	0	**1**
Land Fill Gas	0	100	0	**1**

1 – The ISO proposes to assign these units only to run-hours based on their typical operating profile as baseload-type units

2 – The ISO proposes to have these units to incur costs evenly between start-ups and run-hours as they typically operate as peakers. Such units suffer from fatigue as well as creep and thus should recover costs through a $/start and $/run-hour adder.

Step 4 - Calculate a default MA on a $/run-hour, $/start, or $/MWh adder basis

After estimating the annual variable maintenance costs, annual run-hours, startups and MWh production, and allocation of maintenance costs, the default MA for each increment is calculated by dividing the annual variable maintenance costs by the assigned increment:

Default MA [$/run-hour] = Annual variable maintenance costs/(run-hours per year)

Default MA [$/start] = Annual variable maintenance costs/(start-ups per year)

Default MA [$/MWh] = Annual variable maintenance costs/(MWh per year)

The breakdown of costs in this matter mirrors the three-part bid format used in the ISO energy markets. In other words, this format provides stakeholders with an estimate of the increase to a unit's default commitment cost bids (assuming the unit was the same size as the representative unit). Note that these values do not include the 125% scalar applied to default startup bids and/or default minimum load bids.

For illustration purposes, the ISO performed this calculation using the inputs described above. The results of this calculation are shown below in Table 4. For blended technology types such as CCGTs, the calculations above are modified by multiplying the default MA value by the proposed allocations proposed in Table 3. In this way, adder values are cleanly distributed to avoid double-counting costs across each relevant increment type.

Table 4 –Default Maintenance Adders per increment resulting from proposed methodology

Technology Type	**Default MA Start Adder**	**Default MA Run-Hour Adder**	**Default MA MWh Adder**
	$/start	*$/run-hour*	*$/MWh*
Coal		1,174	
IGCC		2,642	

Steam Turbines		877	
CCGTs	3,405	319	
Advanced CCGTs	5,068	474	
CTs	442	59	
Advanced CTs	497	67	
RICEs		70	
Hydro	3,261	69	
Pumped Storage	9,511	480	
Biomass Power Plant		368	
Geothermal Power Plant		815	
Land Fill Gas		44	

Step 5 – Calculate a unit-specific adder

This step creates a unit-specific adder for each resource that incurs variable maintenance costs by scaling the unit's default MA by the size of the unit and applying a scalar.

The default MAs arrived at in the previous step assume that each resource has the same Pmax as the representative unit size (representative sizes and associated assumptions are detailed in Appendix B). To scale the default MA to a unit's actual capacity, the ISO proposes to divide the default MA value by the Pmax of the representative unit and multiply it by the Pmax of the actual generating resource as registered in Master File. This proposed calculation assumes that variable maintenance is linearly correlated with unit capacity.

The ISO also proposes to apply a scalar, originally set at 60%, to the default MA. Ultimately, the unit-specific default MA is intended to be a conservative baseline value that will allow units to recover their variable maintenance costs to some extent without having to go through a full negotiation with the ISO. The default MA is intended to decrease this negotiation burden. The proposed application of this scalar attempts to strike a balance between providing a conservative reference for market participants that do not wish to negotiate an MA, and the goal to accurately estimate resource's costs in default commitment costs.

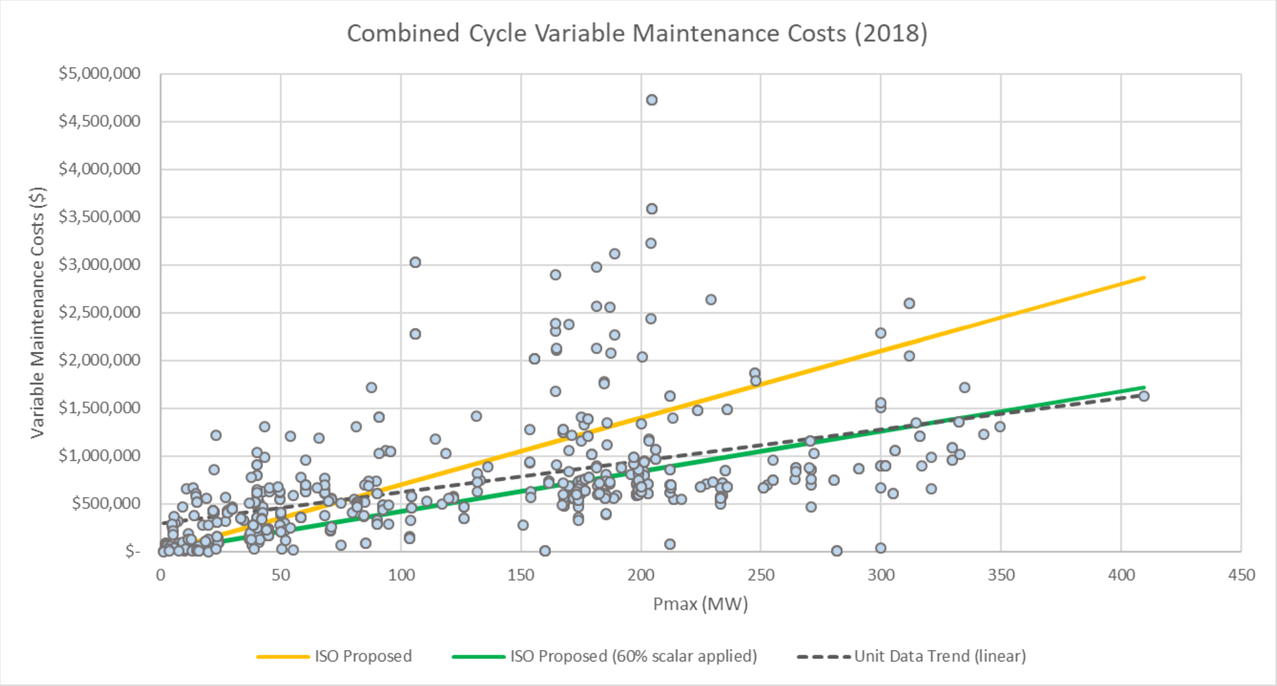
The resource-specific MA calculation proposed for each increment type will be as follows:

Resource-specific MA = Default MA * (Resource's actual Pmax / Representative unit's Pmax) * 60%

The ISO performed an analysis on the relationship between Pmax and variable maintenance costs using unit-specific data from S&P Market Intelligence for thousands of resources across technology types. The results of linear regressions of this data reveal a statistically significant linear relationship between Pmax and variable maintenance costs. This analysis also indicates that scalars can range between 35% and 90% depending on the technology type. As such, the ISO feels that the 60% scalar is reasonable to maintain the default MAs within an adequate range while also serving as a reasonably low hurdle for market participants wishing to avoid MA negotiations. It is also important to note that market participants can continue to include the existing 25% headroom scalar in their default startup and minimum load bids and receive a 10% headroom scalar applied to their DEBs.

The chart below provides a representative example of this scaling methodology for units with CCGT technology. The ISO aggregated operational characteristics and variable maintenance costs for hundreds of CCGT units from S&P Market Intelligence data and plotted to study the correlation between Pmax (MW) and annual variable maintenance costs. The dashed grey line represents a linear approximation of the data set. The yellow line represents the proposed methodology *without* any scalar applied, *i.e.* the result of multiplying the default MA value by the ratio of a resource's actual Pmax to the representative unit's Pmax. The green line represents the proposed equation above, accounting for a 60% scalar. The graphical results from this approach align closely with the linear approximation of the data set. By applying a 60% scalar, the resource-specific MA values will be more closely aligned with the linear approximation from a robust dataset of CCGT units. Similar trends were observed when the methodology was applied to the other technology types. The ISO understands that there will be outliers from these approximations; for example, these deviations could be driven by the fact that 2018 costs for some units included large maintenance items that may occur infrequently, and which happened to occur in 2018. Market participants that feel as if their costs are not adequately represented through this methodology will have the ability to negotiate adders with the ISO directly.

Figure 3 – Annual variable maintenance costs compared to MW capacity (CCGT units)



4.4 Discussion

Comparison to Other Sources

The ISO compared the inputs into the proposed calculation (*i.e.* the annual variable maintenance costs from Step 1) to a variety of sources in order to determine that the estimates are reasonable. Our estimates will seek to be both representative of the industry as a whole while also being specific to the ISO resource base. The comparison of the ISO inputs to other sources is found in Appendix C. Note that the amounts presented in that appendix are the annual variable maintenance costs of the representative unit and have not yet had the 60% scalar applied.

The ISO inputs are typically close to, but lower than, the average of the other sources. This is consistent with our efforts to establish the default Maintenance Adder as a conservative reference.

Technology Groups

The technology groups for the default Maintenance Adder are consistent with those used for the VO adder as described above. However, the ISO has excluded four technologies from receiving default MAs: nuclear, wind turbines, solar thermal, and solar photovoltaic. The following factors assisted the ISO in making this determination: the small representation of these types of resources in the ISO balancing area and EIM footprint; a lack of reliable, consistent third-party sources to use in the estimation of a default MA; and the relative immateriality of the variable maintenance costs incurred by these technology types. The exclusion of these four technologies from receiving default MAs by no means precludes these resources from negotiating a Maintenance Adder with the ISO. Similar to the VO adder, the ISO is also considering whether storage resources such as a batteries should receive a maintenance adder.

5 Implementation of Proposal

The ISO proposes to update the definitions outlined in Section 4.1 and implement the VO adder and MA values proposed simultaneously because the components of this proposal are interdependent. To update the VO adder and MA values, the ISO expects to engage in some stakeholder outreach to assign resources to the proposed technology groups. Some of the proposed technology groups, such as Advanced Combustion Turbines versus standard Combustion Turbines, are not currently tracked in the Master File and will need to be determined prior to the assignment of the resources to a technology group. The ISO expects to reach out to scheduling coordinators to confirm certain information regarding unit characteristics prior to the implementation of the proposal.

As a result of this proposal, the ISO expects that a number of market participants may want to negotiate VO adders or MAs. The ISO proposes to address this increase volume of negotiations by allowing market participants to negotiate their values in multiple ways. Market participants can negotiate the components of the default Maintenance Adder calculation (*e.g.* if annual variable maintenance costs are significantly different from the representative unit's estimated costs), the methodology of the calculation (*e.g.* if unit-specific maintenance costs are better reflected as a \$/start adder than a \$/run-hour adder), or a blend of these reasons. Similarly, the ISO propose to allow market participants the ability to negotiate the VO adder value if they can show that their costs differ from the default values proposed.

Related to the expected increase in negotiations as this proposal is implemented, the ISO also proposes to modify the portion of the Tariff that subjects the ISO to a 15-day calendar day period in which the ISO must review and respond to MA applications and questions. This 15-day period is intended to provide market participants with a timely response to their MMA application. Under a proposed modification, the ISO would still intend to provide timely responses, however the responses would be subject to less time-related pressure. Examples of modifications to this time period are changing the 15-day *calendar* day period to a 15-day *business* day period or increasing the 15-day period to a higher number of days. Removing this requirement is further supported by the proposed creation of default MAs. Resources currently have an effective $0 MMA but, with the adoption of this proposal, these resources will have a nonzero MA to include in their default commitment costs as negotiations are ongoing.

This proposal will affect the negotiated MMAs and VOM adders that are currently in place in the ISO markets. Currently, there is a fair number of resources with negotiated MMAs and VOM adders. The ISO proposes to allow the scheduling coordinators who have completed their MMA and VOM negotiations by 1/1/2020, under the current framework, to use their negotiated values subject to the conditions discussed in the Business Process Manual (BPM) for Market Instruments[7]. Further, negotiations that take place during the interim period between 1/1/2020 and the implementation date of this proposal would take place using the existing definitions and cost framework (i.e. no changes to the negotiating process). The ISO proposes to allow values which are successfully negotiated during this interim period to remain in place for one year after the implementation date unless the scheduling coordinator: 1) decides to renegotiate the values using the updated definitions/cost framework, or 2) decides to use the default MA for the relevant technology group proposed in this paper.

The ISO does not intend this initiative to supersede any agreements made with reliability-must-run (RMR) resources. However, it is anticipated that, if the proposal is implemented, treatment of RMR units will be slightly different from non-RMR units. Currently, the ISO claws back MMA costs prior to the financial settlement of the RMR unit. In doing so, the ISO ensures that capacity payments made to RMR owners and the revenues earned by RMR owners from the ISO's markets are not double-counted. With this proposal, the ISO expects to disallow RMR units from including their Major Maintenance costs in their $/MWh MA. Additionally, the ISO proposes to disallow RMR units from including any Variable Minor Maintenance costs in their $/start MA or $/run-hour MA. In other words, for RMR units, Major Maintenance costs can only be recovered on a $/start or $/run-hour basis and Variable Minor Maintenance costs can only be recovered on a $/MWh basis. This would help the ISO ensure that only Major Maintenance costs are clawed back during the Settlements process and avoid any conflicts with existing or future RMR contracts.

6 Workshop Feedback and ISO Responses

The ISO received helpful feedback and comments from market participants after conducting the July 2019 workshops. A common concern between participants was the fact that costs in California and the broader

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[7] The ISO outlines circumstances under which adders will be reviewed and potentially renegotiated or terminated. See Exhibit 4-2 in Section 4 (VOM adders) and Section L.6 of Attachment L of the BPM for Market Instruments for these circumstances.

EIM areas are typically much higher than in the regions off which the initial report values were based. In addition, participants requested that the ISO clarify definitions of each cost component and further outline methodology and assumptions used to arrive at the proposed values. Table 5 defines some broad concerns held by market participants after the December 2018 report and July 2019 workshops and details how this proposal attempts to address each concern.

Table 5 – Addressing Stakeholder Concerns

Stakeholder Concern	How Concern is Addressed
Unclear definitions	This proposal clarifies definitions of each cost component by grouping both major maintenance and variable minor maintenance costs into "Maintenance Costs", and further defines "Variable Operations Costs", "Fixed Maintenance Costs", "General & Administrative Costs", and the nuances between corrective, preventative, and predictive maintenance. Assumptions and definitions are further detailed in the Appendix.
Proposed definitions and/or technology groups are insufficient	This proposal provides clarity on definitions used to determine adder values. The ISO intends that, upon implementation, the proposed definitions and technology groups will be integrated into BPMs and the Tariff. Stakeholders will have the opportunity to comment on these definitions and groups through this stakeholder process.
Methodology is unclear and/or insufficient	This proposal clarifies the sources used to determine the technology-specific VO adders that were initially proposed in the December 2018 report and refined in this straw proposal. The ISO has attempted to provide a robust methodology for the determination of default MAs as well. Stakeholders will have the opportunity to comment on the proposed methodology and assumptions through this stakeholder process.
Geographical cost concerns	The ISO will integrate geographical and temporal considerations for costs of operation and consumables in California and the broader EIM footprint by applying geographical scaling factors to the calculation of the VO adders in a further iteration of this straw proposal.
Proposed values are insufficient	The December 2018 report clarifies how the VO adder values were determined and this is further clarified by this proposal. The proposal also outlines the process for negotiating VO and MA adders if the market participant believes that the default values are insufficient to adequately reflect costs. The ISO intends for the VO and MA adder values to serve as a baseline for costs to reduce the administrative burden of negotiation.

Technology categories are too broad or too narrow	The proposed technology categories attempt to represent the generation fleet within the ISO BA and EIM footprint but cannot capture every technology type or nuance. Scheduling coordinators may negotiate VOM adder values with the ISO if they believe the proposed technology categories are too broad or too narrow, and fail to capture any nuances of the technology in question.
New technologies are not adequately represented	Cost recovery mechanisms and default energy bids for new technologies not currently defined in the ISO Tariff (e.g. battery storage, fuel cell resources) are being considered through the ESDER 4 initiative. Under the current ISO market framework, scheduling coordinators are unable to bid in VOM costs for non-generator resources. The ISO understands that these new technology types are important to the future of the energy system in the West and is planning to consider the O&M costs in the future.

7 Stakeholder Engagement

The schedule for stakeholder engagement is detailed below in Table 6. The ISO will discuss this Straw Proposal paper with stakeholders during a call on January 6, 2020 at 02:00PM PT. Stakeholders can submit written comments regarding this Straw Proposal paper by January 20, 2020 to initiativecomments@caiso.com.

Table 6 – Stakeholder Engagement and Implementation Timeline

Date	Milestones
December 19, 2019	Post Straw Proposal
January 6, 2019	Hold stakeholder call on Straw Proposal
January 20, 2019	Stakeholder written comments due on Straw Proposal
February 7, 2020	Post Revised Straw Proposal
February 14, 2020	Hold stakeholder call on Revised Straw Proposal
February 28, 2020	Stakeholder written comments due on Revised Straw Proposal
March 13, 2020	Post Draft Final Proposal
March 20, 2020	Hold stakeholder call on Draft Final Proposal
April 3, 2020	Stakeholder comments due on Draft Final Proposal
April 15, 2020	Post Draft Tariff Language
April 15, 2020	Post BRS
April 30, 2020	Stakeholder written comments due on Draft Tariff Language
May 6, 2020	Hold stakeholder meeting on Draft Tariff Language

May 27, 2020	Post Final Tariff Language
June 2020	EIM Governing Body
July 2020	Board of Governors
Fall 2020	Go-Live

8 Appendices

8.1 Appendix A: Clarifying Definitions

This section is intended to augment the terms and definitions discussed in the proposals above.

Capital Costs: These costs are fixed (i.e. do not vary with Generating Facility output) and generally represent the cost of bringing a Generating Facility and its associated components to commercial operation. Capital costs may also represent the cost of significant upgrades to a Generating Facility or the cost of significantly extending a Generating Facility’s operational life; an example may include the upgrade from a simple-cycle plant to a combined cycle plant.

Corrective Maintenance: Corrective maintenance, or maintenance performed after-the-fact when a part fails or equipment malfunctions, is typically variable and performed on a reactive, as-needed basis, thus may be considered as a variable maintenance cost.

Generating Facility: The ISO Tariff, Appendix A, defines a Generating Facility as: “[a]n Interconnection Customer's Generating Unit(s) used for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.”

Generating Unit: The ISO Tariff, Appendix A, defines a Generating Unit as “[a]n individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is: (a) located within the ISO Balancing Authority Area (which includes a Pseudo-Tie of a generating unit to the ISO Balancing Authority Area) or, for purposes of scheduling and operating the Real-Time Market only, an EIM Entity Balancing Authority Area; (b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities or via a Pseudo-Tie; and (c) capable of producing and delivering net Energy (Energy in excess of a generating station’s internal power requirements).”

Predictive Maintenance: Predictive maintenance is routine maintenance performed to determine the actual condition of equipment, automatically (e.g. via sensors) or by physical inspection of specific parts, to give an estimated window for when maintenance needs to be performed before malfunction or failure.

Preventative Maintenance: Preventative maintenance encompasses the maintenance activities that attempt to identify a malfunction or failure before it occurs via regular maintenance and inspection. This type of maintenance will typically occur on a regular schedule, regardless of the activity of the Generating Facility.

Lifespan: The entire useful life of a Generating Unit in which the Unit is capable of producing incremental energy for the ISO markets, considering prudent operational and maintenance practices. Pursuant to Section 25.1.2 of the ISO Tariff and further explained in the Generator Management Business Practice Manual, the following scenarios will be considered to be the end of a Generating Unit's lifespan:

Scenario 1: Repowering / Entered Queue
Scenario 2: Undecided and decommissioning Generating Unit
Scenario 3: Permanent Retirement / Release of Deliverability

8.2 Appendix B: Assumptions used in Default Maintenance Adders

Several key assumptions were made during the ISO's development of inputs and calculations of the annual maintenance costs, shown for comparison purposes in Appendix C. Below, the ISO describes how values used in various calculations were determined, and how reasonableness was assessed.

Representative Unit Pmax

The representative unit Pmax's used as the basis of annual variable maintenance costs were found in the relevant source materials used in estimates of annual variable maintenance costs. The ISO compared these values to the average size of the units operating in ISO markets and found them to be reasonable. As mentioned above, the ISO also accounts for the size of the specific resource in Step 5 of our calculation of the Maintenance Adders.

Table 7 – Representative Unit Pmax Assumptions

Technology Type	**Representative Unit Pmax (Capacity, MW)**
Coal	600
Integrated Coal Gasification Combined-Cycle (IGCC)	600
Steam Turbines	300
Combined Cycle Gas Turbines	359
Advanced Combined Cycle Gas Turbines	440
Combustion Turbines	50
Advanced Combustion Turbines	50
Reciprocating Internal Combustion Engines	20
Hydro	50
Pumped Storage	250
Biomass Power Plant	50
Geothermal Power Plant	50
Land Fill Gas	5

Capacity Factor

The capacity factor (CF) for each technology type was estimated using two years of actual ISO and EIM meter data and resource information. The calculation is as follows for each generating resource and averaged across technology type:

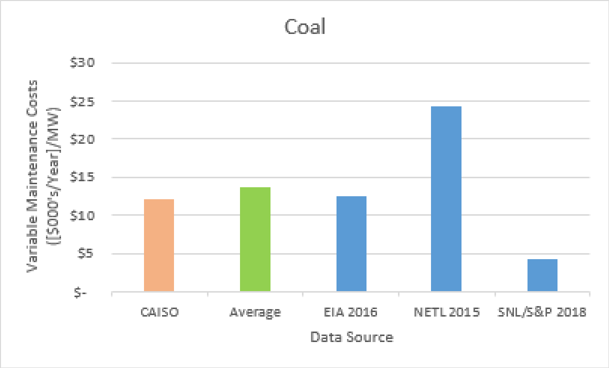
CF = MWh per year / (Pmax * 24 hours * 365 days)

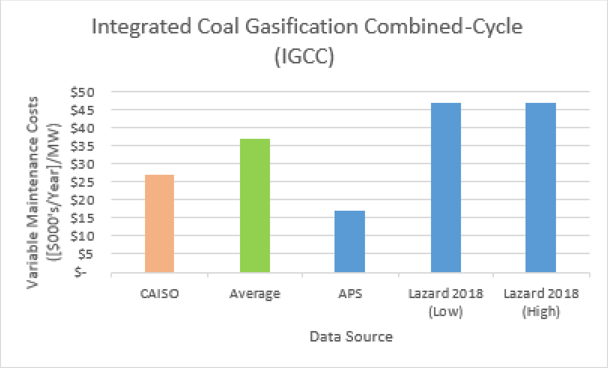
The CFs were assessed by on the ISO understanding of the typical operating profiles of the technologies in question. For example, Combustion Turbines were considered to be peaking units and thus have a much lower CF than Geothermal units, which provide baseload generation.

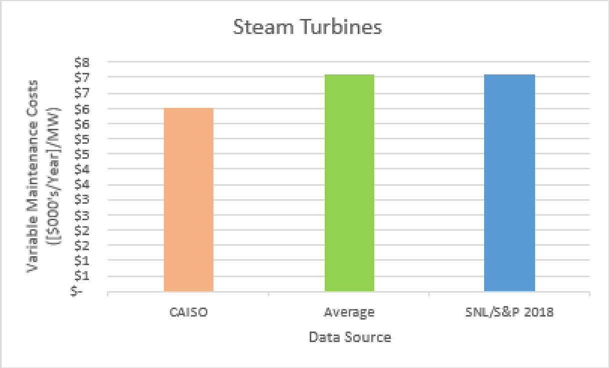
Table 8 – Assumed Capacity Factors by Technology Type

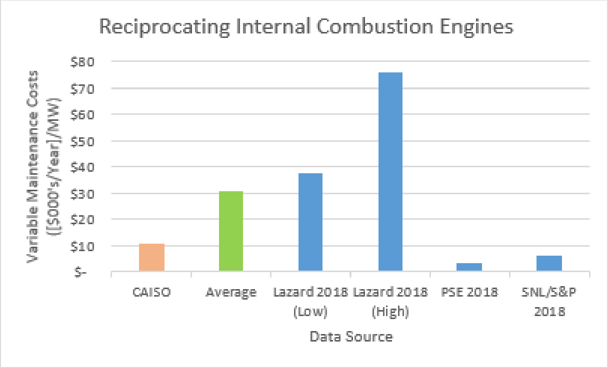
Technology Type	**Capacity Factor**
Coal	60%
Integrated Coal Gasification Combined-Cycle (IGCC)	60%
Steam Turbines	10%
Combined Cycle Gas Turbines	40%
Advanced Combined Cycle Gas Turbines	40%
Combustion Turbines	10%
Advanced Combustion Turbines	10%
Reciprocating Internal Combustion Engines	15%
Hydro	20%
Pumped Storage	20%
Biomass Power Plant	60%
Geothermal Power Plant	60%
Land Fill Gas	60%

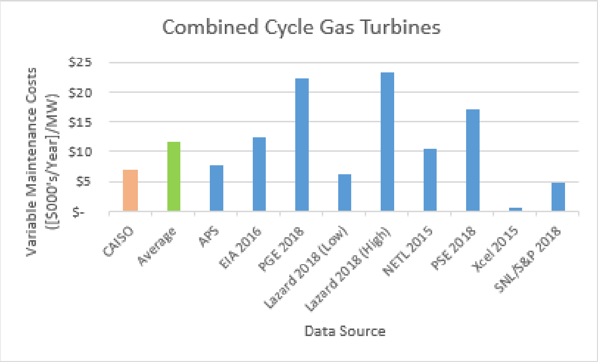
8.3 Appendix C: Comparison of Variable Maintenance Cost Inputs to External Sources

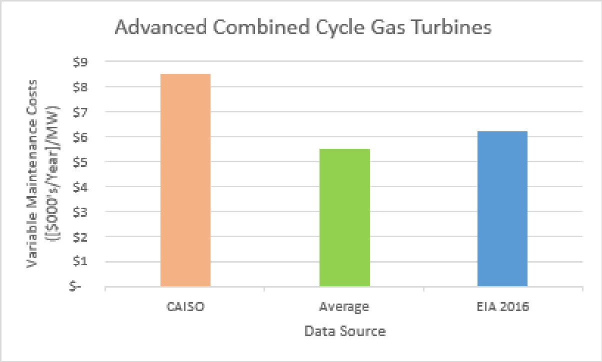


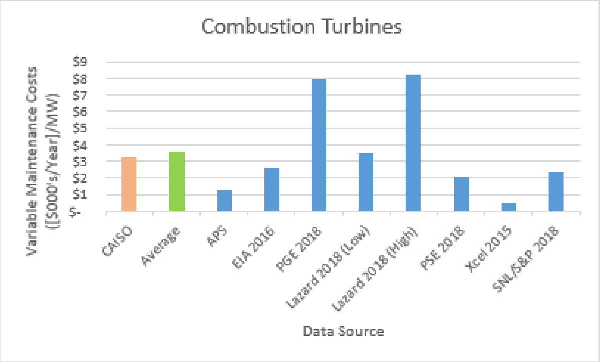


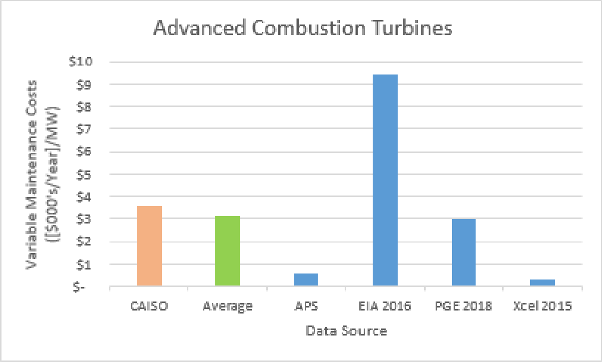


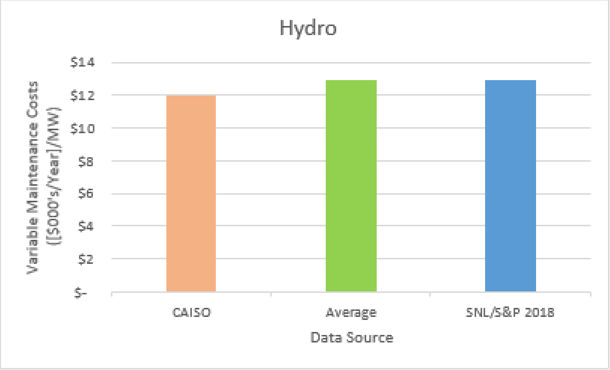


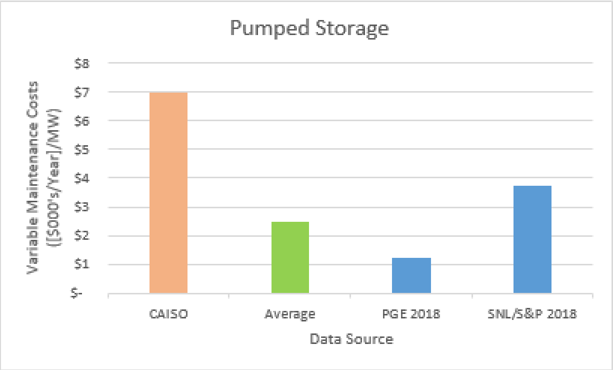


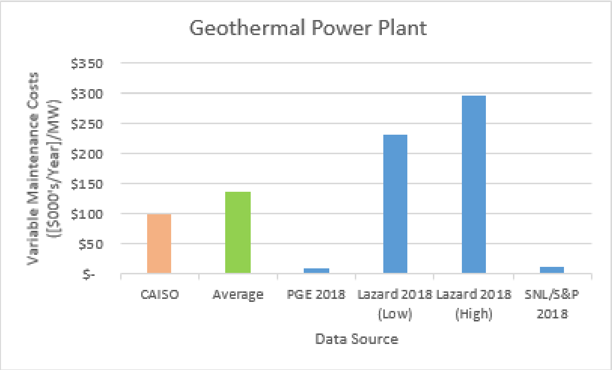


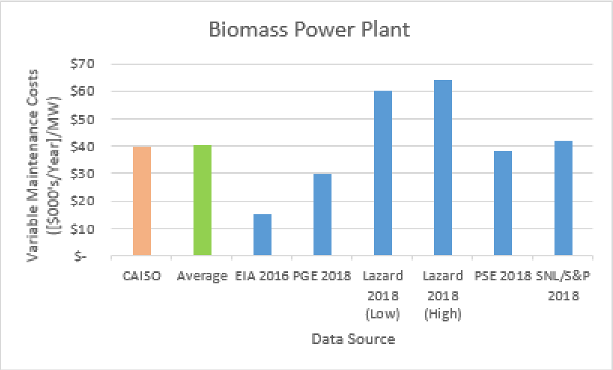


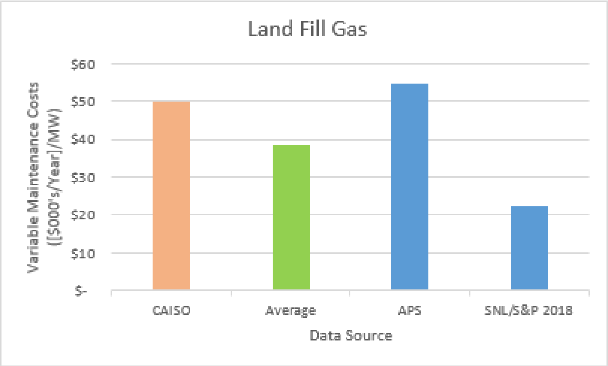



Hydro
Variable Maintenance Costs ([$000's/Year]/MW)
$14
$12
$10
$8
$6
$4
$2
$-
CAISO
Average
SNL/S&P 2018
Data Source


Pumped Storage
Variable Maintenance Costs ([$000's/Year]/MW)
$8
$7
$6
$5
$4
$3
$2
$1
$-
CAISO
Average
PGE 2018
SNL/S&P 2018
Data Source


Geothermal Power Plant
Variable Maintenance Costs ([$000's/Year]/MW)
$350
$300
$250
$200
$150
$100
$50
$-
CAISO
Average
PGE 2018
Lazard 2018 (Low)
Lazard 2018 (High)
SNL/S&P 2018
Data Source


Biomass Power Plant
Variable Maintenance Costs ([$000's/Year]/MW)
$70
$60
$50
$40
$30
$20
$10
$-
CAISO
Average
EIA 2016
PGE 2018
Lazard 2018 (Low)
Lazard 2018 (High)
PSE 2018
SNL/S&P 2018
Data Source


Land Fill Gas
Variable Maintenance Costs ([$000's/Year]/MW)
$60
$50
$40
$30
$20
$10
$-
CAISO
Average
APS
SNL/S&P 2018
Data Source

8.4 Appendix D: Examples of Maintenance Adder calculations

Example 1: Standard resource MA calculation

The following example outlines the methodology for calculating a standard Maintenance Adder in a $/Run-Hour format for a unit whose primary technology type is a steam turbine and whose Pmax is 200 MW.

Table 9. Representative Unit Characteristics

Parameter	***Value***
Technology Type	Steam Turbine
Estimated annual variable maintenance cost ($/year)	$1,800,000
Run-hours (hours/year)	2,052
Pmax (MW)	300

Calculation Steps:

1) *Estimate annual variable maintenance costs for a representative unit:* These annual variable maintenance costs were estimated based on external sources and determined to be $1,800,000 per year.
2) *Estimate run-hours and start-ups per year:* The average run-hours per year, 2,052 hours, was estimated based on all ISO/EIM steam turbine resources.
3) *Determine whether the technology-type's maintenance costs is represented with a $/run-hour, $/start, or $/MWh adder (or a blend of these):* Steam turbines are typically run as baseload-type units due to their relatively long start times. Accordingly, the ISO determined that their maintenance costs would likely be best represented by $/Run-Hour adder.
4) *Calculate a default MA on a $/run-hour, $/start, or $/MWh adder basis:* The ISO then calculated a default MA which would apply to all steam turbine resources on a $/Run-Hour basis:

   Default Maintenance Adder ($/Run-Hour) = Annual variable maintenance costs/Run-hours per year

   = $1,800,000/2,052

   = $877 per run-hour

5) *Calculate a unit-specific adder:* The default Maintenance Adder then needs to be tailored to the size of the specific resource in question. The 60% scalar is also applied at this point.

   Resource specific Maintenance Adder ($/run-hour) = Default MA * (Resource's actual Pmax / Representative unit's Pmax) * 60%

   = $877 * (200/300) * 60%

   = $351 per run-hour

Example 2: Blended resource MA calculation

The following example outlines the methodology for calculating a Maintenance Adder in a blended $/Run-Hour and $/Start format for a unit whose primary technology type is a Combined Cycle Gas Turbine format and whose Pmax is 250 MW.

Table 10. Representative Unit Characteristics

Parameter	***Value***
Technology Type	CCGT
Estimated annual variable maintenance cost ($/year)	$2,513,000
Run-hours (hours/year)	3,942
Start-Ups (starts/year)	369
Pmax (MW)	359

Calculation Steps:

1) *Estimate annual variable maintenance costs for a representative unit:* These annual variable maintenance costs were estimated based on external sources and determined to be $2,513,000 per year.
2) *Estimate run-hours and start-ups per year:* The average run-hours per year, 3,942 hours, was estimated based on all ISO/EIM combined cycle resources.
3) *Determine whether the technology-type's maintenance costs is represented with a $/run-hour, $/start, or $/MWh adder (or a blend of these):* CCGTs are typically dispatched as peaking units so the ISO assumes that the costs are best represented by both a $/start and a $/run-hour adder.
4) *Calculate a default MA on a $/run-hour, $/start, or $/MWh adder basis:* The ISO then calculated a default MA which would apply to all CCGTs resources. Note that the annual variable maintenance costs are multiplied by 50% for each adder calculation to allocate the costs evenly between the $/run-hour and $/start adders:

   Default Maintenance Adder ($/run-hour) = Annual variable maintenance costs/run-hours per year
   = ($2,513,000 * 0.5)/3,942
   = $319 per run-hour

   Default Maintenance Adder ($/start) = Annual variable maintenance costs/start-ups per year
   = ($2,513,000 * 0.5)/369
   = $3,405 per start-up
5) *Calculate a unit-specific adder:* The default Maintenance Adders then needs to be tailored to the size of the specific resource in question. The 60% scalar is also applied at this point. The $/run-hour adder could be included in the resource's minimum load bid cap and the $/start could be included in the resource's start-up bid cap.

Resource specific Maintenance Adder ($/run-hour) = Default MA * (Resource's actual Pmax / Representative unit's Pmax) * 60%
= $319 * (250/359) * 0.6
= $133 per run-hour

Resource specific Maintenance Adder ($/start) = Default MA * (Resource's actual Pmax / Representative unit's Pmax) * 60%
= $3,405 * (250/359) * 0.6
= $2,371 per start-up

8.5 Appendix E: Sources

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